2021 ANNUAL RESULTS

PERPETUAL
ENERGY

TO SHAREHOLDERS

2021 proved to be a transformative year for Perpetual Energy Inc. ("Perpetual" or the Company"). On July 16, 2021, Perpetual announced the creation of Rubellite Energy Inc. ("Rubellite"), a new high growth, pure play Clearwater oil company. Rubellite was incorporated on July 12, 2021 and acquired all of Perpetual's Clearwater lands, wells, roads and related facilities in northeast Alberta (the "Clearwater Assets") on July 15, 2021 for aggregate consideration of $65.5 million. The consideration consisted of:

- i) promissory notes totaling $59.4 million, which were paid in cash on October 5, 2021;
- ii) the issuance of 680,485 Rubellite common shares valued at $1.3 million;
- iii) the return of 8.2 million Perpetual common shares exchanged in the plan of arrangement and valued at $2.8 million; and
- iv) the issuance to Perpetual of warrants to purchase 4.0 million Rubellite common shares at a price of $3.00 per share for a period of five years and valued at $2.0 million.

Following overwhelming support by the shareholders of Perpetual at a special shareholder meeting held on August 31, 2021, and the receipt of the final order of the Court of Queen's Bench of Alberta, on September 3, 2021, a plan of arrangement under the *Business Corporations Act (Alberta)* involving Perpetual, the shareholders of Perpetual, and Rubellite was completed. In conjunction with the plan of arrangement, Rubellite raised an aggregate $83.5 million through: a brokered $30.0 million subscription receipt financing; a $33.5 million backstopped arrangement warrant financing; and a non-brokered $20.0 million private placement financing, all priced at $2.00 per Rubellite common share.

At the same time, Perpetual entered into a debt settlement arrangement with its second lien lender to settle all outstanding obligations under its maturing term loan, which eliminated all but $2.7 million of the Company's second lien secured debt and extend the remaining second lien secured debt's maturity to December 31, 2024. Subsequently, Perpetual's credit facility was also renewed and the term was extended to May 31, 2023.

The Rubellite transactions are a win-win-win for all of Perpetual's stakeholders. They successfully positioned Perpetual shareholders to benefit through Rubellite to unlock the value of the high quality Clearwater Assets, while at the same time providing Perpetual and all of its stakeholders with a full capital solution, reducing Perpetual's leverage and improving its liquidity to surface value from Perpetual's remaining attractive asset base. Perpetual received cash proceeds that were used to repay maturing debt and provided the liquidity to invest capital to capture the intrinsic value of its core assets, boosting the Company's credit worthiness and thereby improving the position of Perpetual's creditors and other stakeholders. Perpetual remains exposed to value appreciation of the Clearwater Assets through its five-year option to purchase four million Rubellite shares.

At the close of the Rubellite transactions, Perpetual's liquidity was sufficient to keep pace with its joint venture partner and fund its share of drilling programs at Edson, continue to optimize its Mannville heavy oil assets, pursue other diversifying new ventures and settle its debt and other obligations as they come due. Simultaneously, Rubellite was well positioned to fund the exploration and development capital required to ramp up its heavy oil production and realize the full potential of the Clearwater Assets and to further expand its position in the emerging Clearwater heavy oil play.

With the sale of the Clearwater Assets and the completion of the plan of arrangement, Perpetual divested approximately 6% of its production, effective September 3, 2021. Despite the disposition, Perpetual's average production grew 30% quarter over quarter to average 6,359 boe/d during the fourth quarter of 2021. Participation in the East Edson drilling program drove the production growth and was enabled by the restored liquidity from the Rubellite transactions. During 2022, production is forecast to grow 20% to 25% from 2021 levels to average between 6,500 to 6,750 boe/d. At current forward market commodity prices, we expect to generate significant free funds flow for further debt repayment.

As global economies have emerged from the COVID-19 pandemic, natural gas, oil and NGL benchmark prices have improved dramatically to levels that support attractive investment returns. As a result of the Rubellite transactions, coupled with strengthening commodity prices, Perpetual is well positioned to capture the inherent value of its assets by investing in the continued development of the Wilrich formation and secondary zones at Edson, optimizing its Mannville heavy oil assets and advancing other diversifying new ventures. With a healthy balance sheet and materially improved commodity prices, Perpetual's business plan is again focused on growing production, reserves, funds flow and value. The Company's strategic priorities for 2022 are to:

1. Maximize Funds Flow and Value of Edson;
2. Maximize Funds Flow and Value of Mannville;
3. Re-ignite Active Exploration for Tight Oil and Gas;
4. Advance Technology-Driven Diversifying New Ventures; and
5. Further Strengthen the Balance Sheet and Manage Risk.

The Board of Directors and Management truly appreciate the commitment of our talented team and the support of our shareholders, service providers and many stakeholders. In May, Ryan Shay was appointed Vice President Finance and Chief Financial Officer ("CFO"), succeeding Mark Schweitzer. We thank Mark for his exceptional leadership and strategic insights that positioned Perpetual for future success. Perpetual is also pleased to welcome Linda Dietsche to the Board of Directors. We look forward to the added depth and expertise that Linda will bring to the Company's financial stewardship and strategic initiatives. The Perpetual team is excited to unlock the many opportunities that lie ahead.

Susan Riddell Rose

SUE RIDDELL ROSE
President and Chief Executive Officer

March 25, 2022

FINANCIAL AND OPERATING HIGHLIGHTS

	Three months ended December 31		Year ended December 31	
($Cdn thousands, except volume and per share amounts)	**2021**	2020	**2021**	2020
Financial				
Oil and natural gas revenue	**21,449**	8,178	**60,814**	29,486
Net income (loss)	**5,669**	14,443	**81,121**	(61,597)
Per share –basic(2)	**0.09**	0.24	**1.29**	(1.01)
Per share – diluted(3)	**0.08**	0.24	**1.16**	(1.01)
Cash flow from (used in) operating activities	**1,624**	(1,104)	**12,815**	(9,533)
Adjusted funds flow(1)	**8,585**	1,240	**16,746**	(7,787)
Per share(2)	**0.13**	0.02	**0.27**	(0.13)
Revolving bank debt	**2,487**	17,495	**2,487**	17,495
Senior notes, principal amount	**36,582**	33,580	**36,582**	33,580
Term loan, principal amount	**2,671**	46,823	**2,671**	46,823
Other liability	**1,387**	–	**1,387**	–
Net working capital deficiency(1)	**16,143**	7,099	**16,143**	7,099
Total net debt(1)	**59,270**	104,997	**59,270**	104,997
Capital expenditures				
Exploration and development(1)	**7,558**	466	**19,062**	5,939
Net proceeds on dispositions, net of cash disposed	**53,407**	–	**49,549**	27,754
Common shares outstanding *(thousands)*				
Weighted average – basic	**63,853**	61,266	**62,969**	61,013
Weighted average – diluted	**70,873**	61,266	**69,989**	61,013
Operating				
Daily average production				
Conventional natural gas *(MMcf/d)*	**31.5**	19.5	**24.6**	21.5
Heavy crude oil *(bbl/d)*	**714**	1,241	**963**	1,082
NGL *(bbl/d)*	**395**	237	**331**	346
Total *(boe/d)*(6)	**6,359**	4,730	**5,389**	5,012
Average prices				
Realized natural gas price *($/Mcf)*(5)	**4.80**	1.46	**3.15**	0.85
Realized oil price *($/bbl)*(5)	**73.96**	52.60	**57.36**	49.37
Realized NGL price *($/bbl)*(5)	**73.44**	38.03	**63.24**	31.40
Wells drilled				
Conventional natural gas – gross (net)	**4 (2.0)**	3 (1.5)	**9 (4.5)**	5 (2.5)
Heavy crude oil – gross (net)	**– (–)**	– (–)	**5 (4.0)**	4 (4.0)
Total – gross (net)	**4 (2.0)**	– (–)	**14 (8.5)**	9 (6.5)

(1) Non-GAAP measure, Non-GAAP ratio or supplementary financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained on pages 28 to 31 within this this Annual Results report.
(2) Based on weighted average basic common shares outstanding for the period.
(3) Based on weighted average diluted common shares outstanding for the period.
(4) Realized natural gas, oil, and NGL prices included physical forward sales contracts for which delivery was made during the reporting period, along with realized gains and losses on financial derivatives and foreign exchange contracts.
(5) Please refer to "Volume conversions" on page 31 of this Annual Results report.

ADVISORIES

This letter to shareholders, 2021 annual highlights and Annual Results report 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 this Annual Results report in "Management's Discussion and Analysis – NON-GAAP MEASURES" on pages 28 to 31, "Management's Discussion and Analysis – FORWARD-LOOKING INFORMATION AND STATEMENTS" on pages 31 and 32, and "Management's Discussion and Analysis – OIL AND GAS ADVISORIES" on page 32.

In addition to the disclosure set out in the Company's Management's Discussion and Analysis for the period ended December 31, 2021, we provide certain supplementary disclosure throughout this Annual Results report in respect of certain specified financial measures (as such term is defined in National Instrument 51-112 – *Non-GAAP and Other Financial Measures*) and in respect of certain oil and gas metrics.

2021 ANNUAL HIGHLIGHTS

2021 FINANCIAL AND OPERATING HIGHLIGHTS

- On July 16, 2021, Perpetual announced the creation of a new wholly owned subsidiary, Rubellite Energy Inc. ("Rubellite") and the sale to Rubellite of all of Perpetual's Clearwater lands, wells, roads and related facilities in northeast Alberta (the "Clearwater Assets"). Rubellite acquired the Clearwater Assets for aggregate consideration of $65.5 million (the "Rubellite Transactions"). The consideration consisted of promissory notes totaling $59.4 million, which were paid in cash on October 5, 2021 upon closing of Rubellite's private placement and arrangement warrant financings (the "Rubellite Financings"). Additional consideration included the issuance of 680,485 Rubellite common shares valued at $1.4 million to Perpetual's second lien term loan lender, the return of 8.2 million Perpetual common shares exchanged in a plan of arrangement with Perpetual, shareholders of Perpetual and Rubellite (the "Arrangement") valued at $2.8 million and issuance of warrants to purchase 4.0 million Rubellite common shares at a price of $3.00 per share for a period of five years, valued at $2.0 million.
- On October 5, 2021, $53.6 million in promissory notes owing to Perpetual from the Rubellite Transactions were repaid in cash by Rubellite. Perpetual paid approximately $38.5 million in cash and delivered 680,485 Rubellite common shares to extinguish all but $2.7 million of its second lien term loan and the remainder of the cash proceeds were used to repay the majority of the Company's outstanding bank debt.
- Results include the Clearwater Assets, which formed part of the Rubellite Transactions, through to September 3, 2021, being the effective date of the completion of the Arrangement.
- Exploration and development capital expenditures(1) totaled $7.6 million in the fourth quarter of 2021, bringing full year 2021 capital spending to $19.1 million.
    - At Perpetual's 50% working interest East Edson property, the Company participated with its joint venture partner in a six (3.0 net) extended reach horizontal well drilling program targeting the Wilrich formation in the second half of the year. Two (1.0 net) wells were drilled, completed and placed on production at the end of September while an additional four (2.0 net) wells were drilled, completed, frac'd and commenced production in November, bringing throughput at the West Wolf gas plant to full capacity to maximize natural gas and NGL sales through the winter months.
    - Three (1.5 net) carried interest wells were previously drilled at East Edson during the year to complete the eight-well carried capital commitment of the purchaser in the East Edson transaction in which Perpetual sold a 50% working interest on April 1, 2020.
- Driven by positive results from the East Edson drilling program, the Company sequentially grew production to 6,359 boe/d in the fourth quarter of 2021 (17% oil and NGL), up 30% from 4,876 boe/d in the third quarter (26% oil and NGL) and 34% higher than the 4,730 boe/d recorded in the fourth quarter of 2020 (31% oil and NGL). Production in 2021 averaged 5,389 boe/d (24% heavy crude oil and NGL), an increase of 8% from 5,012 boe/d (29% heavy crude oil and NGL) in 2020. Production levels steadily increased as 9 (4.5 net) East Edson Wilrich liquids-rich gas wells were progressively brought on production during 2021, partially offset by the disposition of the Clearwater Assets in the third quarter of 2021.
- In 2021, Perpetual spent $1.8 million on abandonment and reclamation projects (Q4 2021 - $0.6 million; 2020 – $1.0 million; Q4 2020 - $0.9 million) of which $0.7 million was funded by Alberta's Site Rehabilitation Program ("SRP"). Perpetual abandoned 32 wells, 19 pipelines and 15 reclamation certificates were received from the Alberta Energy Regulator ("AER") which will result in the cessation of associated property tax and surface lease expenses. Subsequent to year end, the Company has received 1 additional reclamation certificates related to projects completed in 2021.
- Adjusted funds flow(1) in the fourth quarter of 2021 was $8.6 million ($0.13/share), $7.4 million higher than the prior year period (Q4 2020 – $1.2 million). The increase was due primarily to the 34% increase in production and higher realized prices for conventional natural gas, oil and NGLs, combined with lower cash finance expense resulting from repayment of the second lien term loan, partially offset by transaction costs related to the Rubellite Transactions. For the year ended December 31, 2021, adjusted funds flow was $16.7 million ($0.27/share), up materially from a negative $7.8 million in 2020 as the 8% year-over-year increase in production combined with significantly higher commodity prices.
- Net income for the fourth quarter of 2021 was $5.7 million ($0.09/share), a significant improvement from the prior year period (Q4 2020 – net loss of $14.4 million; $0.24/share). Net income for 2021 was $81.1 million ($1.29/share), recovering from a net loss of $61.6 million in 2020 ($1.01/share). Net income in 2021 was impacted by aggregate non-cash impairment reversal charges of $30.6 million (2020 – $42.5 million impairment) and a $47.5 million gain on disposition of the Clearwater Assets.
- Total net debt(1) outstanding at year-end 2021 dropped 44% to $59.3 million, from $105.0 million at year-end 2020, as a result of the Rubellite Transactions and the extinguishment of the second lien Term Loan.
- In December, the borrowing base on the Company's credit facility was confirmed at $17.0 million and the maturity date has been extended to May 31, 2023. The maturity of the $2.7 million second lien Term Loan, has been extended to December 31, 2024. The $36.6 million 2025 Senior Notes are due January 23, 2025. Perpetual had available liquidity(1) at December 31, 2021 of $14.6 million, comprised of the $17 million Credit Facility Borrowing Limit, adjusted for current cash of $1.1 million less borrowings of $2.5 million and letters of credit of $1.0 million.

(1) Non-GAAP measure, Non-GAAP ratio or supplementary financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this Annual Results report.

- Total proved plus probable reserves were 31.6 MMboe at December 31, 2021, a decrease of 11% year-over-year reflecting the sale of the Clearwater Assets. Total future development costs ("FDC") decreased $37.1 million (33%) to $75.3 million at year-end 2021, 79% ($29.3 million) of which related to the Rubellite Transactions. The net present value ("NPV") of Perpetual's total proved plus probable reserves (discounted at 10%), was $230.5 million (2020 – $187.8 million). Perpetual's reserve-based net asset value(1) ("NAV") (discounted at 10%) at year-end 2021 increased 80% to $177.6 million ($2.79 per share), reflecting the significant debt reduction associated with the sale of the Clearwater Assets combined with the increased reserve value driven primarily by the increase in the independent reserve evaluators' forecast for natural gas, crude oil and NGL prices at year-end 2021 as compared to the prior year, commensurate with forward market prices. See *"Year-End 2021 Reserves"* and *"Net Asset Value[1]"*.

YEAR-END 2021 RESERVES

Reserve Highlights

Production of 2.0 MMboe and dispositions of 3.4 MMboe were offset by reserve additions of 1.5 MMboe, resulting in an 11% reduction in total Company proved plus probable reserves year-over-year. Perpetual's proved plus probable reserves at year-end 2021 are 31.6 MMboe, comprised of 19% crude oil and NGL (2020 – 35.4 MMboe; 28% crude oil and NGL).

The quality of Perpetual's assets and positive momentum to drive operational and execution excellence in its core operating areas are demonstrated by the highlights below:

- Total proved reserves were 22.3 MMboe at year-end 2021, representing 71% of the Company's proved plus probable reserves (2020 – 71%).
- Proved plus probable producing reserves were 15.2 MMboe at December 31, 2021, representing 48% of total proved plus probable reserves (2020 – 12.4 MMboe; 35%).
- Total proved plus probable reserves in the Mannville district have increased by 12% excluding production despite no capital spending in 2021. Increases in reserves are largely due to extension of the economic limit due to higher prices combined with lower operating costs as higher cost wells have been permanently shut-in.
- Future development costs ("FDC") dropped to $75.3 million (2020 - $112.5 million) in the proved plus probable category, a reduction of $37.2 million. The disposition of the Clearwater Assets was the primary driver, contributing to a reduction of $29.3 million of FDC in the proved plus probable category. FDC for East Edson was reduced by $7.3 million to $54.1 million in the proved plus probable category with the drilling of 9 (4.5 net) carried and working interest wells in 2021, offset by the addition of 4 (1.5 net) new proved plus probable undeveloped drilling locations targeting the Wilrich formation. At year-end 2021, McDaniel recognized proved plus probable undeveloped reserves for 27 (12.7 net) Wilrich horizontal drilling locations. In the Mannville area, $19.7 million of FDC to drill, complete and tie-in 16 (16.0 net) heavy crude oil drilling locations was recorded.
- Based on the three consultant average price (McDaniel, GLJ, Sproule) forecasts (the "Consultant Average Price Forecast") used by McDaniel, the net present value ("NPV") of Perpetual's total proved plus probable reserves (discounted at 10%) before income tax, was $230.5 million (2020 – $187.8 million). The increase related primarily to the material increase in the independent reserve evaluators' forecast for natural gas, crude oil and NGL prices at year-end 2021 as compared to the prior year.
- All abandonment, decommissioning and reclamation obligations are included in the reserve report, consistent with year-end 2020. All reserve well decommissioning obligations as well as the additional costs expected to be incurred to abandon and reclaim non-reserve wells, facilities and pipelines are included.
- Based on the Consultant Average Price Forecast, Perpetual's reserve-based NAV[1] (discounted at 10%) at year-end 2021 is estimated at $177.6 million ($2.79 per share) as compared to $98.8 million ($1.61 per share) at year-end 2020.

(1) Non-GAAP measure, Non-GAAP ratio or supplementary financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this Annual Results report.

Reserves Disclosure

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 & Associates Consultants Ltd. ("McDaniel") with an effective date of December 31, 2021 (the "McDaniel Report"), and has been prepared in accordance with National Instrument 51-101 ("NI 51-101") using the Consultant Average Price Forecast. Complete NI 51-101 reserves disclosure including after-tax reserve values, reserves by major property and abandonment costs are included in Perpetual's Annual Information Form ("AIF"), which is available on the Company's website at www.perpetualenergyinc.com and SEDAR at www.sedar.com. Perpetual's reserves at December 31, 2021 are summarized below:

Working Interest Reserves at December 31, 2021[1]

	Light and Medium Crude Oil (*Mbbl*)	Heavy Oil (*Mbbl*)	Conventional Natural Gas (*MMcf*)	Natural Gas Liquids (*Mbbl*)	Oil Equivalent (*Mboe*)
Proved Producing	12	1,629	61,676	872	12,793
Proved Non-Producing	–	177	2,621	4	618
Proved Undeveloped	–	865	44,022	689	8,891
Total Proved	**12**	**2,671**	**108,319**	**1,565**	**22,301**
Probable Producing	3	331	11,490	170	2,420
Probable Non-Producing	–	44	4,910	39	901
Probable Undeveloped	–	791	28,318	441	5,952
Total Probable	**3**	**1,167**	**44,719**	**650**	**9,273**
Total Proved plus Probable	**15**	**3,838**	**153,038**	**2,215**	**31,574**

(1) May not add due to rounding.

Total proved reserves at December 31, 2021 account for 71% (2020 – 71%) of total proved plus probable reserves. Proved producing reserves of 12.8 MMboe comprise 57% (2020 – 40%) of total proved reserves. Proved plus probable producing reserves of 15.2 MMboe represent 48% (2020 – 35%) of total proved plus probable reserves.

Reserves Reconciliation

Working Interest Reserves[1]

Barrels of Oil Equivalent (*Mboe*)	Proved	Probable	Proved and Probable
Opening Balance, December 31, 2020	**25,050**	**10,386**	**35,436**
Extensions and Improved Recovery	605	(605)	–
Discoveries	–	–	–
Technical Revisions	(763)	(987)	(1,749)
Acquisitions	740	1,733	2,474
Dispositions	(2,020)	(1,396)	(3,415)
Production	(1,958)	–	(1,958)
Economic Factors	646	141	787
Closing Balance, December 31, 2021	**22,301**	**9,273**	**31,574**

(1) May not add due to rounding.

Dispositions included the Clearwater Asset disposition to Rubellite that was completed in 2021 and a small disposition in the Mannville Area.

Lands acquired in East Edson area added four additional locations and provided revisions to three previously recognized locations to extend their length thereby increasing their booked reserves. As well, reserve recoveries per well assigned to 8 (3.6 net) undeveloped locations were reduced slightly in the proved and probable undeveloped categories following updated type curve analysis, resulting in the negative technical revision in the conventional natural gas and natural gas liquids categories.

An in depth review of well performance and operating costs in the Mannville heavy oil property identified wells with high water cuts and high individual well operating costs. The decision to leave these wells shut-in resulted in a heavy crude oil negative technical revision but has had a positive impact in improved per barrel operating costs for the property.

The table below summarizes the FDC estimated by McDaniel by play type to bring proved plus probable non-producing and undeveloped reserves to production.

Future Development Capital[1]

(*$ millions*)	2022	2023	2024	2025	2026	Remainder	Total
Eastern Alberta Shallow Gas	–	0.3	0.3	0.3	0.6	–	1.6
Mannville Heavy Oil	6.7	3.8	4.4	4.8	–	–	19.7
Clearwater	–	–	–	–	–	–	–
East Edson Wilrich	15.5	12.3	7.5	12.8	5.6	0.4	54.1
Total	**22.2**	**16.4**	**12.2**	**17.9**	**6.2**	**0.4**	**75.3**

(1) May not add due to rounding.

The McDaniel Report estimates that FDC of $75.3 million will be required over the life of the Company's proved plus probable reserves. Proved plus probable reserve forecast FDC have decreased by $37.1 million (33%) from $112.5 million at December 31, 2020.

The most significant reduction in FDC was a result of the disposition of the Clearwater Assets with a reduction of $29.3 million in the proved plus probable undeveloped reserve category.

FDC for East Edson was reduced by $7.3 million to $54.1 million in the proved plus probable category with the drilling of nine (4.5 net) carried and working interest wells in 2021, offset by the addition of four (1.5 net) new proved plus probable undeveloped drilling locations targeting the Wilrich formation. At year-end 2021, McDaniel recognized proved plus probable undeveloped reserves for 27 (12.7 net) Wilrich horizontal drilling locations.

In the Mannville area, $19.7 million of FDC to drill, complete and tie-in 16 (16.0 net) heavy crude oil drilling locations was recorded. This is down from 17 (17.0 net) at year end 2020. Future capital costs also include recompletion of 14 conventional natural gas wells included in Perpetual's proved plus probable reserves.

RESERVE LIFE INDEX

Perpetual's proved plus probable reserves to production ratio, also referred to as reserve life index ("RLI"), was 12.2 years at year-end 2021, while the proved RLI was 9.1 years, based upon the 2022 production estimates in the McDaniel Report. The following table summarizes Perpetual's historical calculated RLI.

Reserve Life Index(1)

Year-end	2021	2020	2019	2018	2017
Total Proved	9.1	10.9	13.4	13.1	9.1
Total Proved plus Probable	12.2	14.5	21.5	19.9	13.2

(1) Calculated as year-end reserves divided by year one production estimate from the McDaniel Report.

NET PRESENT VALUE OF RESERVES SUMMARY

Perpetual's heavy crude oil, conventional natural gas, and NGL reserves were evaluated by McDaniel using the Consultant Average Price Forecast effective January 1, 2022 and include the forecasted impact of the Company's market diversification contract, but prior to provision for financial oil and natural gas price hedges, foreign exchange contracts, income taxes, interest, debt service charges and general and administrative expenses. The following table summarizes the NPV of future revenue from reserves at December 31, 2021, assuming various discount rates:

NPV of Reserves, before income tax(1)(2)(3)

(*$ millions except as noted*)	Undiscounted	5%	10%	15%	Discounted at 20%	Unit Value Discounted at 10%/Year (*$/boe*)(4)
Proved Producing	112	101	88	77	69	8.67
Proved Non-Producing	4	4	3	3	2	5.89
Proved Undeveloped	134	90	66	50	39	8.03
Total Proved	**251**	**195**	**157**	**130**	**111**	**8.31**
Probable Producing	52	31	22	17	13	10.01
Probable Non-Producing	10	6	4	3	2	5.45
Probable Undeveloped	113	71	48	34	26	8.94
Total Probable	**176**	**108**	**74**	**54**	**42**	**8.89**
Total Proved plus Probable	**426**	**304**	**230**	**184**	**153**	**8.49**

(1) January 1, 2022 Consultant Average price forecast
(2) Inclusive of the East Edson royalty and a further reduction for the retained East Edson royalty obligation by Perpetual through December 31, 2022 as part of the East Edson Transaction, asset retirement obligations for sites not assigned reserves, and natural gas market diversification contracts.
(3) May not add due to rounding.
(4) The unit values are based on net reserve volumes.

McDaniel's NPV10 estimate of Perpetual's total proved plus probable reserves at year-end 2021 was $230.5 million, up 23% from $187.8 million at year-end 2020. The increase related primarily to the material increase in the independent reserve evaluators' forecast for crude oil prices at year-end 2021 as compared to the prior year. At a 10% discount factor, total proved reserves account for 68% (2020 – 63%) of the proved plus probable value. Proved plus probable producing reserves represent 47% (2020 – 24%) of the total proved plus probable value (discounted at 10%) as obligations for non-producing wells, facilities and pipelines and forecast corporate marketing adjustments reduce the value of the developed producing reserves.

FAIR MARKET VALUE OF UNDEVELOPED LAND

Perpetual held 163,953 net undeveloped acres of land as at December 31, 2021, including 84,002 net undeveloped acres of oil sands leases. Undeveloped acres refers to land where there are not any existing wells within the rights associated with those lands and includes 56,198 net acres of undeveloped land assigned value by an independent third party at year end 2021. The estimate of the fair market value of the Company's undeveloped acreage was prepared by Seaton-Jordan & Associates Ltd. ("Seaton-Jordan") and is based on past Crown land sale activity, adjusted for tenure and other considerations. No undeveloped land value was assigned where proved and probable undeveloped reserves have been booked. The fair market value of Perpetual's undeveloped land at year-end 2021 is estimated by Seaton Jordan at $6.4 million.

NET ASSET VALUE[7]

The following NAV[7] table shows what is normally referred to as a "produce-out" NAV calculation under which the Company's proved plus probable 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 Company'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[7] at December 31, 2021[1]

		Discounted at		
(*$ millions, except as noted*)	**Undiscounted**	**5%**	**10%**	**15%**
Total Proved plus Probable Reserves[2]	426.4	303.6	230.5	184.3
Fair market value of undeveloped lands[3]	6.4	6.4	6.4	6.4
Bank debt, net of working capital[1]	(18.6)	(18.6)	(18.6)	(18.6)
Term loan[4]	(2.7)	(2.7)	(2.7)	(2.7)
AIMCo contingent payments[5]	(1.4)	(1.4)	(1.4)	(1.4)
Senior notes[4]	(36.6)	(36.6)	(36.6)	(36.6)
NAV	**378.7**	**255.6**	**177.6**	**136.6**
Common shares outstanding (*million*)[6]	63.6	63.6	63.6	63.6
NAV per share (*$/share*)[6][7]	**5.88**	**3.94**	**2.79**	**2.07**

(1) Financial information is per Perpetual's 2021 audited consolidated financial statements.
(2) Reserve values per McDaniel Report as at December 31, 2021, including adjustments for natural gas market diversification contracts. All abandonment and reclamation obligations, including future abandonment and reclamation costs for pipelines and facilities and non-reserve wells, are included in the McDaniel Report.
(3) Independent third-party estimate; excludes undeveloped land in West Central Alberta with reserves assigned.
(4) Measured at principal amount.
(5) Estimated fair value of contingent liability based on forward market commodity prices.
(6) NAV per share is calculated by dividing NAV by the number of issued and outstanding shares for the specified period. Shares outstanding are net of shares held in trust.
(7) The terms "net asset value" or "NAV" and "net asset value per share" or "NAV per share" are non-GAAP financial measures which do not have a standardized meaning under IFRS and might not be comparable to similar measures presented by other companies where similar terminology is used. Management believes that NAV and NAV per share are key industry performance measures of value creation and are measures that provide investors with information that is commonly presented by other crude oil and natural gas producers.

The above evaluation includes FDC expectations required to bring undeveloped reserves on production, as recognized by McDaniel, that meet the criteria for booking under NI 51-101. 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.

2022 OUTLOOK

The Rubellite transactions provided a "full capital solution" for Perpetual by reducing Perpetual's net debt[4] to $59.3 million, normalizing the balance sheet leverage ratios and surfacing incremental value. The Rubellite transactions have materially improved Perpetual's liquidity and enhanced the Company's ability to capture the inherent value in its asset base by funding investment opportunities to grow and sustain production and adjusted funds flow. Interest cost savings are forecast to improve Perpetual's adjusted funds flow by approximately $4 million annually. General and administrative cost recoveries under the management services agreement with Rubellite will further enhance Perpetual's funds flow by approximately $2 to $3 million annually. Additionally, 4.0 million Rubellite Share Purchase Warrants owned by Perpetual provide an opportunity for Perpetual to participate in value creation from the Clearwater Assets over the next five years.

Perpetual's Board of Directors has approved exploration and development capital spending[4] of up to $28 million for 2022 to be fully funded from adjusted funds flow.

The winter drilling program is currently underway at Mannville in Eastern Alberta where two (2.0 net) horizontal, multi-lateral wells targeting heavy oil in the Sparky formation will be drilled and brought on stream prior to the end of the first quarter. Sales production is expected to commence in late April, several weeks after full recovery the oil-based drilling mud ("OBM") used during the drilling process, which are not recorded as sales production as the OBM is reused in future drilling operations to the extent possible or sold and credited back to drilling capital. Perpetual plans to monitor performance of the new Sparky multi-laterals for several months prior to executing a follow-up drilling program of up to four (4.0 net) additional horizontal multi-lateral wells in the second half of 2022. Perpetual will also continue to be focused on waterflood optimization and battery consolidation projects as well as shallow gas recompletions and abandonment and reclamation activities in the Mannville property.

During the second half of 2022, Perpetual is planning to participate at its 50% working interest in an East Edson drilling program to drill, complete, equip and tie-in six (3.0 net) extended reach horizontal wells in the Wilrich formation, targeting to fill the West Wolf gas plant to maximize natural gas and NGL sales through next winter. Depending on processing capability, one (0.5 net) additional horizontal well is planned to begin evaluating the potential of secondary zones at East Edson.

Exploration and development capital spending[4] for Perpetual for full year 2022 is expected to be $20 to $28 million, with $5 to $7 million to be spent in the first quarter. The table below summarizes anticipated capital spending and drilling activities for Perpetual for the first quarter and full year of 2022.

2022 Exploration and Development Forecast Capital Expenditures[4]

	Q1 2022 (*$ millions*)	**# of wells (*gross/net*)**	**2022 (*$ millions*)**	**# of wells (*gross/net*)**
West Central[1]	$0 - $1	-	$14 - $15	6 – 7 / 3.0 - 3.5
Eastern Alberta[2]	$5 - $6	2 / 2.0	$6 - $13	2 – 6 / 2.0 - 6.0
Total[3]	**$5 - $7**	**2 / 2.0**	**$20 - $28**	**8 - 13 / 5.0 - 9.5**

(1) Include six (3.0 net) Wilrich development wells and one (0.5 net) secondary zone evaluation well.
(2) Two (2.0 net) multi-lateral wells to be drilled in the first quarter of 2022 will be monitored for performance prior to drilling up to four 4.0 net) follow-up wells in the second half of 2022.
(3) Excludes abandonment and reclamation spending.
(4) Non-GAAP measure, Non-GAAP ratio or supplementary financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this this Annual Results report.

Total Company average production is expected to exceed 6,500 boe/d (18% oil and NGL) for the first quarter of 2022. Average production is forecast to grow 20% to 25% from 2021 levels to 6,500 to 6,750 boe/d in 2022, with oil and NGL representing approximately 20% of the production mix.

Perpetual continues its environmental, social, and corporate governance (“ESG”) focus, with total abandonment and reclamation expenditures of up to $2.0 million planned in 2022, with an estimated $0.6 million to be funded through Alberta’s Site Rehabilitation Program (“SRP”). The remaining $1.4 million will more than satisfy the Company’s annual area-based closure spending requirements of $0.9 million.

2022 Guidance assumptions are as follows:

	2022 Guidance
Exploration and development expenditures[2](*$ millions*)	$20 - $28
Cash costs[1][2] (*$/boe*)	$17.00 - $20.00
Average daily production (*boe/d*)	6,500 - 6,750
Production mix (*%*)	20% oil and NGL

(1) Cash costs represents operating, transportation, interest, G&A and royalties.
(2) Non-GAAP measure, Non-GAAP ratio or supplementary financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this this Annual Results report.

SEQUOIA LITIGATION UPDATE

On March 25, 2022, the Company received the Alberta Court of Appeal (the "Court of Appeal") judgment with respect to the appeal heard on February 10, 2022 relating to the sale by Perpetual of legacy shallow gas properties in October 2016 to an arm's length third party purchaser after an extensive and lengthy marketing, due diligence and negotiation process (the "Sequoia Disposition"). As previously disclosed, on February 25, 2020, Perpetual filed a second application to strike and summarily dismiss the claim brought under Section 96 of the Bankruptcy and Insolvency Act (the "BIA Claim") by PricewaterhouseCoopers Inc. ("PwC"), in its capacity as trustee in bankruptcy of Sequoia Resources Corp. ("Sequoia"). On January 14, 2021, the Court of Queen’s Bench released its decision with respect to this summary dismissal application, finding that PwC could not establish a necessary element of the BIA Claim as Sequoia was not insolvent at the time of, nor rendered insolvent by, the Sequoia Disposition. The Court of Queen’s Bench therefore concluded there is "no merit" to the BIA Claim and it was summarily dismissed. On January 21, 2021, PwC filed a notice of appeal of this judgment to the Court of Appeal and the appeal was heard on February 10, 2022.

The Court of Appeal allowed the appeal of PricewaterhouseCoopers Inc. ("PwC"), in its capacity as trustee in bankruptcy of Sequoia Resources Corp. ("Sequoia") on the basis that the Court of Queen’s Bench erred in law in its handling of the end-of-life obligations and that based on the record, it could not be concluded the error was without consequence, and that the Court of Queen’s Bench also erred in agreeing to hear the second summary dismissal application. On this basis, the matter has been directed to trial.

Perpetual received the Statement of Claim in August 2018. As opposed to proceeding to a full trial at that time, Perpetual filed a Statement of Defence and Application for Summary Dismissal later in August 2018. All allegations made by PwC were denied and the summary dismissal application was made on the basis that there was no merit to any of the claims and that the claims constituted an abuse of process. Through various Court of Queen’s Bench proceedings, including the second summary dismissal application, as at January 14, 2021, all claims against the Company had been struck or summarily dismissed. Subsequently, through numerous Court of Appeal proceedings, certain aspects of the appeals filed by PwC have been granted by the Court of Appeal, with certain aspects of outstanding claims being directed to trial, putting Perpetual into a similar situation as in August 2018.

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, 2021 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, 2021 and 2020. 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 March 14, 2022.

This MD&A contains certain specified financial measures that are not recognized by GAAP and used by management to evaluate the performance of the Corporation and its business. Since certain specified financial measures may not have a standardized meaning, securities regulations require that specified financial measures are clearly defined, qualified and, where required, reconciled with their nearest GAAP measure. See "Non-GAAP and Other Financial Measures" for further information on the definition, calculation and reconciliation of these measures. This MD&A also contains forward-looking information. See "Forward-Looking Information". Readers are also referred to the other advisory sections at the end of this MD&A for additional information.

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

2021 MATERIAL TRANSACTIONS

On July 16, 2021, Perpetual announced the creation of a new wholly owned subsidiary, Rubellite Energy Inc. ("Rubellite") and the sale of all of Perpetual's Clearwater lands, wells, roads and related facilities in northeast Alberta (the "Clearwater Assets") to Rubellite. On September 3, 2021, the Plan of Arrangement involving Perpetual, the shareholders of Perpetual, and Rubellite was completed following approval of the plan by the shareholders of Perpetual at its special shareholder meeting held on August 31, 2021 and the receipt of the final order of the Court of Queen's Bench of Alberta approving the Plan of Arrangement. At this time, Rubellite exchanged 1.4 million Rubellite common shares valued at $2.8 million and 16.7 million arrangement warrants with Perpetual shareholders for 8.2 million Perpetual common shares valued at $2.8 million. This MD&A includes operating results for Rubellite's Clearwater Assets up to the effective date of the Plan of Arrangement of September 3, 2021.

Rubellite acquired the Clearwater Assets from Perpetual for aggregate consideration of $65.5 million. The consideration consisted of promissory notes totaling $59.4 million, which were paid in cash on October 5, 2021, the issuance of 680,485 Rubellite common shares valued at $1.4 million, the return of the 8.2 million Perpetual common shares valued at $2.8 million and issuance of warrants to purchase 4.0 million Rubellite common shares at a price of $3.00 per share for a period of five years, valued at $2.0 million.

The Rubellite Financings were all completed on October 5, 2021 at $2.00 per Rubellite common share equivalent and included:

(i) a backstopped arrangement warrant financing, which resulted in the issuance of 16.7 million Rubellite common shares for total proceeds of $33.5 million;

(ii) a non-brokered $20.0 million private placement financing (10.0 million Rubellite common shares); and

(iii) a brokered $30.0 million subscription receipt financing (15.0 million subscription receipts) that closed on July 13, 2021 with cash held in escrow by a third-party trustee that was released on October 5, 2021. When each subscription receipt issued was exchanged on a one-to-one basis for 15.0 million common shares of Rubellite.

On July 15, 2021, Perpetual reached an agreement with its Term Loan lender for the settlement of principal and all interest owing on the Term Loan upon closing of the Rubellite Financings, for the payment of approximately $38.5 million in cash, delivery by Perpetual of 0.7 million Rubellite common shares (the "AIMCo Bonus Shares"), the issuance of a new $2.7 million second lien term loan bearing interest at 8.1% annually and maturing December 31, 2024, and up to a total of $4.5 million in contingent payments over the three year period ended June 30, 2024 in the event that Perpetual's annual average realized oil and natural gas prices exceed certain thresholds (the "Second Lien Loan Settlement"). As part of the Second Lien Loan Settlement, the Term Loan lender committed to fully exercise the arrangement warrants it received under the Plan of Arrangement associated with its approximately 4.0% equity ownership of Perpetual. In addition, the Term Loan lender agreed to subscribe for $4.5 million of the Non-Brokered Private Placement and upon completion of the transaction owned approximately 8.3% of the Rubellite common shares.

Upon closing of the Rubellite Financings on October 5, 2021, Perpetual received cash proceeds of approximately $53.6 million, and used the cash proceeds to satisfy the $38.5 million cash component of the Second Lien Loan Settlement with the remaining cash applied to repay a significant portion of the Credit Facility. Upon closing of the Rubellite Financings and concurrent completion of the Second Lien Loan Settlement, the Credit Facility has a Borrowing Limit of $17.0 million, reduced from $20.0 million, with a maturity of May 31, 2023.

FOURTH QUARTER 2021 HIGHLIGHTS

Fourth quarter production averaged 6,359 boe/d, up 34% from the comparative period of 2020 (Q4 2020 – 4,730 boe/d). The increase was due to production from nine (4.5 net) East Edson wells drilled in 2021 and the reactivation of heavy crude oil production which was shut-in during the second quarter of 2020 as oil prices recovered and stabilized, partially offset by the sale of the Clearwater oil assets. As of December 31, 2021, Perpetual had restarted substantially all heavy crude oil production that was initially suspended in late March 2020 in response to extremely low oil prices.

Realized revenue(1) was $36.56/boe in the fourth quarter of 2021, 68% higher than the comparative period of 2020 (Q4 2020 – $21.73/boe). The increase was due primarily to higher realized natural gas prices of $4.80/Mcf, which were significantly higher than the prior year period (Q4 2020 – $1.46/Mcf). Perpetual's realized oil price was $73.96/bbl and realized NGL price was $73.44/bbl in the fourth quarter of 2021, higher than 2020 due to an increase in West Texas Intermediate ("WTI") benchmark prices and all natural gas liquid ("NGL") component prices which tracked the rise in WTI prices.

Cash costs(1) were $12.2 million or $20.88/boe (Q4 2020 – $7.8 million and $17.92/boe). Compared to Q4 2020, total cash costs increased, reflecting higher royalties on improved commodity prices, higher production and operating expenses with increased production volumes and increased general and administrative costs as a result of restoring employee salaries and wages which were reduced in response to low commodity prices in 2020 and transaction costs related to the Rubellite transaction.

Adjusted funds flow(1) in the fourth quarter of 2021 was $8.6 million ($0.13/share), $7.4 million higher than the prior year period (Q4 2020 – $1.2 million). The increase was due primarily to significantly higher realized prices for conventional natural gas, oil and NGLs, combined with the 34% increase in production and lower cash finance expense resulting from repayment of the second lien term loan, partially offset by higher cash costs. Cash flow from operating activities was $1.6 million (Q4 2020 – cash flow used in operating activities of $1.1 million) was higher for the same reasons impacting adjusted funds flow(1).

Net income for the fourth quarter of 2021 was $5.7 million ($0.09/share), an improvement from the prior year period (Q4 2020 – net loss of $14.4 million; $0.24/share) due to the same reasons that impacted adjusted funds flow as well as the impairment reversal of $0.5 million in the Company's Eastern CGU.

(1) Non-GAAP measure, Non-GAAP ratio or supplementary financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this release.

2021 ANNUAL HIGHLIGHTS

On September 3, 2021, Perpetual and Rubellite completed the previously announced Plan of Arrangement involving Perpetual, the shareholders of Perpetual and Rubellite. The Rubellite Financings closed subsequent to the third quarter on October 5, 2021 and $53.6 million in promissory notes were repaid. The Rubellite Transactions provided a "full capital solution" for Perpetual by reducing Perpetual's net debt(1) to $56.4 million at September 30, normalizing the balance sheet leverage ratios and surfacing incremental value from enhanced ability to fund the future development of its assets. The Rubellite Transactions have materially improved Perpetual's liquidity and will enhance Perpetual's ability to capture the inherent value in its asset base by funding investment opportunities to grow and sustain production and adjusted funds flow. Interest cost savings alone is expected to improve Perpetual's adjusted funds flow(1) by approximately $4 million annually. The general and administrative cost recoveries under the Management and Operating Services Agreement ("MSA") with Rubellite will further enhance Perpetual's liquidity by approximately $2 to $3 million annually. Additionally, the 4.0 million, five-year Rubellite Share Purchase Warrants owned by Perpetual provide an opportunity for Perpetual to participate in value creation from Rubellite's Clearwater Assets.

Exploration and development capital expenditures(1) in 2021 was $19.1 million, more than triple the prior year (2020 – $6.0 million). Capital investment was focused at Perpetual's 50% working interest East Edson property, where the last of the 8-well carried interest commitment was drilled, completed and tied in during the third quarter of 2021 and the joint venture partner drilled an additional six (3.0 net) wells targeting the Wilrich formation in the second half of 2021. All of these wells have been completed and were on production by the end of 2021. Capital activity in Eastern Alberta during 2021 focused on waterflood optimization and battery consolidation projects as well as several shallow gas recompletions. Additionally, the Company has identified a number of horizontal, multi-lateral drilling opportunities targeting heavy oil at Mannville and modest capital spending was directed for preparatory work for first quarter 2022 activities. Six (5.0 net) wells were drilled in the Clearwater area and formed part of the assets in the Rubellite Transactions.

Production in 2021 averaged 5,389 boe/d (24% heavy crude oil and NGL), an increase of 8% from 5,012 boe/d (29% heavy crude oil and NGL) in 2020. Production levels steadily increased following the 50% working interest disposition of the East Edson properties in the second quarter of 2020, as three (1.5 net) remaining wells of the eight (4.0 net) carried interest wells were drilled at east Edson and brought on production along with six (3.0 net) wells drilled and completed in the second half of 2021 and brought on production in November in advance of the winter heating season. Production additions from East Edson drilling were partially offset by the disposition of the Clearwater oil assets in the third quarter of 2021.

Realized revenue(1) was $56.0 million in 2021, more than 1.7 times higher than $30.2 million of revenue in 2020 due to the combined effect of the 8% increase in average daily production and significantly higher commodity prices. Realized revenue(1) was $28.47/boe, 73% higher than the prior year period (2020 – $16.46/boe). Compared to the AECO Daily Index price of $3.44/Mcf, realized natural gas prices of $3.15/Mcf were impacted by modifications made to the natural gas market diversification contract for future periods. The market diversification contract reduced the realized natural gas price by $4.8 million or $0.60/Mcf in 2021. For the year ended December 31, 2021, Perpetual's realized oil price was $57.36/bbl, up 16% from $49.37/bbl in 2020. Realized oil prices were reduced modestly relative to benchmark prices by physical forward sales arrangements during 2021 while in 2020 Perpetual realized hedging gains of $19.05/bbl.

Cash costs[1] were $37.8 million in 2021, up $1.6 million (4%) from 2020. The increase was due primarily to higher royalties and production and operating expenses associated with the 8% increase in production, partially offset by increased general and administrative costs as result of restoring employee salaries and wages and increased professional fees on the Rubellite transaction. The deferral of Term Loan interest and payment in kind of Senior Notes interest also reduced cash finance expense by $5.3 million during 2021.

Net income for 2021 was $81.1 million ($1.29/share), up from a net loss of $61.6 million in 2020 ($1.01/share). Net income in 2021 was impacted by aggregate non-cash impairment reversal charges of $30.6 million (2020 – $42.5 million impairment) and a $47.5 million gain on disposition of the Clearwater Assets.

For the year ended December 31, 2021 , adjusted funds flow[1] was $16.7 million ($0.27/share), up from a negative $7.8 million ($0.13/share) in 2020 as the impact of the 8% year-over-year increase in production combined with significantly higher commodity prices outweighed the 3% increase in cash costs.

Perpetual's reserve-based first lien credit facility (the "Credit Facility") borrowing limit (the "Borrowing Limit"), was confirmed at $17.0 million in December 2021. The Credit Facility has a maturity date that has been extended to May 31, 2023. As part of the Second Lien Loan Settlement, the maturity of the $2.7 million New Second Lien Term Loan has been extended to December 31, 2024.

(1) Non-GAAP measure, Non-GAAP ratio or supplementary financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this release.

2022 OUTLOOK

The Rubellite Transactions provided a "full capital solution" for Perpetual by reducing Perpetual's net debt[1] to $59.3 million, normalizing the balance sheet leverage ratios and surfacing incremental value. The Rubellite Transactions have materially improved Perpetual's liquidity and enhanced the Company's ability to capture the inherent value in its asset base by funding investment opportunities to grow and sustain production and adjusted funds flow[1]. Interest cost savings are forecast to improve Perpetual's adjusted funds flow[1] by approximately $4 million annually. General and administrative cost recoveries under the MSA with Rubellite will further enhance Perpetual's funds flow by approximately $2 to $3 million annually. Additionally, 4.0 million Rubellite Share Purchase Warrants owned by Perpetual provide an opportunity for Perpetual to participate in value creation from the Clearwater Assets over the next five years.

Perpetual's Board of Directors has approved exploration and development capital spending of up to $28 million for 2022 to be fully funded from adjusted funds flow[1].

A two-well drilling program is currently underway at Mannville in Eastern Alberta where two (2.0 net) horizontal, multi-lateral wells targeting heavy oil in the Sparky formation will be drilled and brought on stream prior to the end of the first quarter. Sales production is expected to commence in late April, several weeks after full recovery the oil-based drilling mud ("OBM") used during the drilling process. Recovered OBM is not recorded as sales production as it is reused in future drilling operations to the extent possible or sold and credited back to drilling capital. Perpetual plans to monitor performance of the new Sparky multi-laterals for several months prior to executing a follow-up drilling program of up to four (4.0 net) additional horizontal multi-lateral wells in the second half of 2022. Perpetual will also continue to be focused on waterflood optimization and battery consolidation projects as well as shallow gas recompletions and abandonment and reclamation activities in the Mannville property.

During the second half of 2022, Perpetual is planning to participate at its 50% working interest in an East Edson drilling program to drill, complete, equip and tie-in six (3.0 net) extended reach horizontal wells in the Wilrich formation, targeting to fill the West Wolf gas plant to maximize natural gas and NGL sales through next winter. Depending on processing capability, one (0.5 net) additional horizontal well is planned to begin evaluating the potential of secondary zones at East Edson.

Exploration and development capital spending for Perpetual for full year 2022 is expected to be $20 to $28 million, with $5 to $7 million to be spent in the first quarter. The table below summarizes anticipated capital spending and drilling activities for Perpetual for the first quarter and full year of 2022.

(1) Non-GAAP measure, Non-GAAP ratio or supplementary financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this release.

2022 Exploration and Development Forecast Capital Expenditures[4]

	Q1 2022 (*$ millions*)	# of wells (*gross/net*)	2022 (*$ millions*)	# of wells (*gross/net*)
West Central[1]	$0 - $1	–	$14 - $15	6 – 7 / 3.0 - 3.5
Eastern Alberta[2]	$5 - $6	2 / 2.0	$6 - $13	2 – 6 / 2.0 - 6.0
Total[3]	**$5 - $7**	**2 / 2.0**	**$20 - $28**	**8 - 13 / 5.0 - 9.5**

(1) Includes six (3.0 net) Wilrich development wells and one (0.5 net) secondary zone evaluation well.
(2) Two (2.0 net) multi-lateral wells to be drilled in the first quarter of 2022 will be monitored for performance prior to drilling up to four (4.0 net) follow-up wells in the second half of 2022.
(3) Excludes abandonment and reclamation spending.

(1) Non-GAAP measure, Non-GAAP ratio or supplementary financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this release.

Total Company average production is expected to exceed 6,500 boe/d (18% oil and NGL) for the first quarter of 2022. Average production is forecast to grow 20% to 25% from 2021 levels to 6,500 to 6,750 boe/d in 2022 with oil and NGL representing approximately 20% of the production mix.

Perpetual continues its environmental, social, and corporate governance ("ESG") focus, with total abandonment and reclamation expenditures of up to $2.0 million planned in 2022, with an estimated $0.6 million to be funded through Alberta's Site Rehabilitation Program ("SRP"). The remaining $1.4 million will more than satisfy the Company's annual area-based closure spending requirements of $0.9 million.

2022 Guidance assumptions are as follows:

	2022 Guidance
Exploration and development expenditures(2)(*$ millions*)	$20 - $28
Cash costs(1)(2) (*$/boe*)	$17.00 - $20.00
Average daily production (*boe/d*)	6,500 - 6,750
Production mix (*%*)	20% oil and NGL

(1) Cash costs represents operating, transportation, interest, G&A and royalties.
(2) Non-GAAP measure, Non-GAAP ratio or supplementary financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this release.

2021 FOURTH QUARTER AND ANNUAL CAPITAL EXPENDITURES(1)

	Three months ended December 31,		Years ended December 31,	
(*$ thousands*)	**2021**	2020	**2021**	2020
Exploration and development	**7,558**	464	**19,060**	5,975
Corporate assets	–	2	**2**	(36)
Capital expenditures(1)	**7,558**	466	**19,062**	5,939
Proceeds from dispositions, net of cash disposed(1)(2)	**53,407**	-	**49,549**	-

(1) Non-GAAP measure, Non-GAAP ratio or supplementary financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this release.
(2) As at December 31, 2021 includes $53.6 million in promissory notes payable to Perpetual which were repaid in cash October 5, 2021, net of cash disposed of 4.1 million.

Acquisitions and Dispositions

In 2021, Perpetual participated for its 50% working interest in the acquisition of certain undeveloped lands, wells, pipelines and gross overriding royalties from third parties in the East Edson core area, for net consideration of $1.3 million.

In addition, Perpetual exercised an option to acquire certain assets in the Figure Lake area for $5.8 million. Consideration was in the form of a demand promissory note secured by the Figure Lake lands in the amount of $5.8 million. The acquired Figure Lake lands comprised part of the Clearwater Assets sold to Rubellite. The secured promissory note obligation owing to 197Co was assigned by Perpetual to Rubellite as part of the total consideration.

During the year ended December 31, 2021, dispositions included the sale of the Clearwater Assets to Rubellite for total consideration of $65.5 million, including $53.6 million in promissory notes, the assumption by Rubellite of $5.8 million in promissory notes due to 197Co, the return to Perpetual of 8.2 million Perpetual common shares valued at $2.8 million, 0.7 million Rubellite common shares ("AIMCo bonus shares") valued at $1.4 million and the issuance of Rubellite Share Purchase Warrants to purchase 4.0 million Rubellite common shares valued at $2.0 million.

Exploration and development spending by area

	Three months ended December 31,		Years ended December 31,	
(*$ thousands*)	**2021**	2020	**2021**	2020
West Central	**7,382**	441	**15,522**	476
Eastern Alberta(1)	**176**	23	**3,538**	5,499
Total	**7,558**	464	**19,060**	5,975

(1) Net of $4.1 million of payments received from the Figure Lake GORR financing for three (3.0 net) Figure Lake wells rig released prior to the effective date of the Plan of Arrangement.

Wells drilled by area

	Three months ended December 31,		Years ended December 31,	
(*gross/net*)	**2021**	2020	**2021**	2020
West Central - Edson(1)	**4.0/2.0**	3/1.5	**9.0/4.5**	5/2.5
Eastern Alberta – Clearwater Assets	**-/-**	–/–	**5.0/4.0**	–/–
Eastern Alberta – Mannville	**-/-**	–/–	**-/-**	4/4.0
Total	**4.0/2.0**	3/1.5	**14.0/8.5**	9/6.5

(1) Includes carried interest wells funded by the Edson joint venture partner.

Perpetual's exploration and development spending in the fourth quarter of 2021 was $7.6 million and for the year ended December 31, 2021 was $19.1 million. At the 50% owned East Edson Property, spending of $0.7 million included costs to upgrade roads and to maintain and optimize production through well workovers, including the installation of plunger lifts on 25 wells. The eighth and final carried interest well at East Edson was spud July 26, 2021, pursuant to Perpetual's joint venture partner's carried interest drilling commitment following which Perpetual is responsible for funding its 50% working interest share of future drilling costs. Six (3.0 net) additional extended reach horizontal wells targeting the Wilrich formation were drilled in 2021. All East Edson wells drilled and completed during 2021 were on production by December 2021.

For the year ended December 31, 2021, spending in Eastern Alberta included costs to drill five (4.0 net) Clearwater heavy crude oil wells and formed part of the Rubellite Transactions which were accounted for effective September 3, 2021.

Expenditures on decommissioning obligations

For the year ended December 31, 2021, Perpetual executed $1.7 million (2020 – $1.0 million) of which $0.7 million was funded by Alberta's Site Rehabilitation Program ("SRP"). SRP funding is presented on the consolidated statements of loss and comprehensive loss as "other income". During 2021 Perpetual received 15 reclamation certificates which will result in the cessation of associated property tax and surface lease expenses. Subsequent to year end, the Company has received 1 additional reclamation certificates related to projects completed in 2021.

Perpetual has been awarded an additional $0.6 million in SRP funding that is expects to utilize for abandonment and reclamation activities in 2022.

Operating netbacks(3)

The following table highlights Perpetual's operating netbacks for the three and twelve months ended December 31, 2021 and 2020:

	Three months ended December 31,				Twelve months ended December 31,			
($/boe) ($ thousands)		**2021**		2020		**2021**		2020
Production (*boe/d*)		**6,359**		4,730		**5,389**		5,012
Petroleum and natural gas revenue(1)	**36.66**	**21,449**	18.79	8,178	**30.92**	**60,814**	16.07	29,486
Realized gains (losses) on derivatives(2)	**(0.10)**	**(61)**	2.94	1,278	**(2.45)**	**(4,810)**	0.39	708
Royalties	**(6.47)**	**(3,786)**	(4.21)	(1,831)	**(5.04)**	**(9,920)**	(3.58)	(6,571)
Production and operating expenses	**(4.89)**	**(2,862)**	(6.93)	(3,014)	**(6.54)**	**(12,859)**	(6.34)	(11,634)
Transportation costs	**(1.49)**	**(871)**	(1.85)	(804)	**(1.52)**	**(2,993)**	(1.97)	(3,617)
Total operating netback(3)	**23.71**	**13,868**	8.74	3,807	**15.37**	**30,232**	4.57	8,372

(1) Includes revenues and payments related to the natural gas market diversification contract and physical forward sales contracts which settled during the period.
(2) Includes realized gains and losses on financial derivatives and financial prompt month price optimization contracts.
(3) Non-GAAP measure, Non-GAAP ratio or supplementary financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this release.

Perpetual's operating netback(3) of $13.9 million ($23.71/boe) in the fourth quarter of 2021 increased from $3.8 million ($8.74/boe) in the comparative period of 2020. The increase was due to higher realized revenue on increased prices combined with average production that was 34% higher than the prior year period. The increase in production was the result of the reactivation of heavy crude oil production as oil prices recovered and stabilized, combined with increased conventional natural gas production from nine (4.5 net) East Edson wells during 2021. Higher realized revenue per boe was due to increased AECO Index prices, and Western Canadian Select ("WCS") benchmark oil prices and higher realized NGL prices.

For the fourth quarter of 2021, royalties increased significantly due to the increase in production volumes, combined with higher reference prices for all products. Production and operating costs in the fourth quarter of 2021 were slightly lower than the comparable period in 2020, but lower on a unit of production basis due to the effect of largely fixed costs at East Edson being applied to higher sales volumes. Transportation costs of $0.9 million were comparable to the fourth quarter of 2020 despite higher production due to transportation optimization activities to manage costs.

Perpetual's operating netback(3) of $30.2 million ($15.37/boe) for the year ended December 31, 2021, increased from $8.4 million ($4.57/boe) in the comparative year. The increase was due to higher revenue driven by increased pricing for all commodities, which more than offset higher royalties and production and operating expenses.

Production

	Three months ended December 31,		Years ended December 31,	
	2021	2020	**2021**	2020
Production				
Conventional natural gas (Mcf/d) [1]	**31,500**	19,512	**24,568**	21,504
Heavy crude oil (bbl/d) [2]	**714**	1,241	**963**	1,082
NGL (bbl/d) [3]	**395**	237	**331**	346
Total production (*boe/d*)	**6,359**	4,730	**5,389**	5,012

(1) Conventional natural gas production yielded a heat content of 1.17 GJ/Mcf for the fourth quarter of 2021 and year ended December 31, 2021, resulting in higher realized natural gas prices on a $/Mcf basis. See "Commodity Prices".
(2) Primarily heavy crude oil.
(3) Primarily related to West Central liquids-rich conventional natural gas.

Fourth quarter production averaged 6,359 boe/d, up 1,629 boe/d or 34% from 4,730 boe/d in the prior year period. In the fourth quarter of 2021, the production mix was comprised of 83% conventional natural gas and 17% heavy crude oil and NGL, an increase from 69% of conventional natural gas and 31% heavy crude oil and NGL in the fourth quarter of 2020.

Fourth quarter conventional natural gas production averaged 31.5 MMcf/d, an increase of 61% from 19.5 MMcf/d in the comparative period of 2020 with production additions from 9.0 (4.5 net) East Edson wells, partially offset by natural declines. During 2020, conventional natural gas production was impacted by the sale of a 50% working interest in the East Edson property in the second quarter of 2020, combined with the deferral of capital investment for drilling and completions in response to low AECO natural gas prices.

Fourth quarter NGL production was 395 bbl/d, 67% higher than the comparative period of 2020. The increase in NGL production is closely tied to higher conventional natural gas production at East Edson, where NGL yields were 12.5 bbls per MMcf in the fourth quarter of 2021 (Q4 2020 – 12.1 bbls per MMcf). Perpetual's average NGL sales composition for the fourth quarter of 2021 consisted of 65% condensate, higher than the prior year period when condensate represented 61% of total NGL production.

Heavy crude oil production in Eastern Alberta was 42% lower than the fourth quarter of 2020 due primarily to natural declines and the sale of the Clearwater Assets. For much of 2020, Perpetual had temporarily shut-in heavy crude oil production in response to the significant decline in global oil prices which began in late March 2020. The Company began reactivating certain low-cost heavy production in mid-May 2020 and continued to add production as oil prices strengthened.

For the year ended December 31, 2021, production increased 8% to 5,389 boe/d compared to 5,012 boe/d in the prior year. Production levels steadily increased following the 50% working interest disposition of the East Edson properties in the second quarter of 2020, as the nine (4.5 net) wells were progressively drilled and brought on production, partially offset by the disposition of the Clearwater oil assets in the third quarter of 2021.

Revenue

	Three months ended December 31,		Years ended December 31,	
(*$ thousands, except as noted*)	**2021**	2020	**2021**	2020
Petroleum and natural gas revenue				
Natural gas[1]	**13,914**	3,502	**33,012**	13,329
Oil	**4,863**	3,846	**20,172**	12,015
NGL	**2,672**	830	**7,630**	4,142
Petroleum and natural gas revenue	**21,449**	8,178	**60,814**	29,486
Realized gains (losses) on derivatives[2]	**(61)**	1,278	**(4,810)**	708
Realized revenue[3]	**21,388**	9,456	**56,004**	30,194
Unrealized gains (losses) on derivatives	**1,302**	(825)	**3,733**	9,901
Total revenue[3]	**22,690**	8,631	**59,737**	40,095
Realized revenue *($/boe)*	**36.56**	21.73	**28.47**	16.46
Total revenue *($/boe)*	**38.79**	19.83	**30.37**	21.86

(1) Includes revenues related to the market diversification contract and physical forward sales contracts which settled during the period.
(2) Includes realized gains and losses on financial derivatives and certain financial prompt month price optimization contracts.
(3) Non-GAAP measure, Non-GAAP ratio or supplementary financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this release.

	Three months ended December 31,		Years ended December 31,	
	2021	2020	**2021**	2020
Reference prices				
NYMEX Daily Index (*US$/MMBtu*)	**5.83**	2.66	**3.84**	2.08
AECO 5A Daily Index (*$/GJ*)	**4.18**	2.50	**3.26**	2.11
AECO 5A Daily Index (*$/Mcf*)(1)	**4.41**	2.64	**3.44**	2.23
West Texas Intermediate ("WTI") light oil (*US$/bbl*)	**77.13**	42.66	**67.90**	39.40
Western Canadian Select ("WCS") differential (*US$/bbl*)	**(14.63)**	(9.30)	**(13.04)**	(12.60)
WCS average (*Cdn$/bbl*)(2)	**78.65**	43.37	**68.76**	35.91
Average Perpetual realized prices(5)				
Natural gas (*$/Mcf*)(1) (5) (6)				
AECO Daily Index	**4.41**	2.64	**3.44**	2.23
Heat content premium(3)	**0.48**	0.27	**0.37**	0.24
Market diversification contract(4) (5)	**-**	(0.37)	**(0.60)**	(0.09)
Realized gains (losses) on financial and physical gas derivatives(5)	**(0.22)**	(1.18)	**(0.35)**	(1.53)
Realized gains (losses) on prompt month price optimization(5)	**0.13**	0.10	**0.29**	–
Realized natural gas price (*$/Mcf*) (5)	**4.80**	1.46	**3.15**	0.85
Percent of AECO Daily Index	**109%**	55%	**107%**	38%
Realized oil price (*$/bbl*)(5) (6)	**73.96**	52.60	**57.36**	49.37
Realized NGL price (*$/bbl*) (5) (6)	**73.44**	38.03	**63.24**	31.40

(1) Converted from $/GJ using a standard energy conversion rate of 1.055 GJ:1 Mcf.
(2) Derived using the Bank of Canada average foreign exchange rate of US$1.00 = Cdn$1.26 for the three months ended December 31, 2021 (Q4 2020 – $1.30) and $1.25 for the year ended December 31, 2021 (2020 – $1.34).
(3) Realized natural gas prices are at a premium to the AECO Daily Index due to higher average heat content of 1.17 GJ/Mcf for the fourth quarter of 2021 and year ended December 31. Perpetual received an 11% premium to the AECO Daily Index for the three and twelve months ended December 31, 2021 (Q4 2020 – 10%; 2020 – 11%) related to its higher average heat content.
(4) For the year ended December 31, 2021, realized losses on derivatives include $4.8 million ($0.60/Mcf) of losses from the elimination of the Company's market diversification contract obligations for the period April 1, 2021 through October 31, 2022 (Q4 2021 – nil).
(5) Non-GAAP measure, Non-GAAP ratio or supplementary financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this release.
(6) Realized natural gas, oil and NGL prices include physical forward sales contracts for which delivery was made during the reporting period, along with realized gains and losses on financial derivatives and foreign exchange contracts.

Perpetual's petroleum and natural gas ("P&NG") revenue, before financial derivatives, for the three months ended December 31, 2021 of $21.4 million increased significantly from $8.2 million the fourth quarter of 2020, due to the 34% increase in average daily production combined with the impact of significantly higher reference prices for all products. For the year ended December 31, 2021, P&NG revenue was more than 2.0 times higher (2020 – $29.5 million), due to the 8% increase in average daily production and significantly higher commodity prices.

Natural gas revenue, before derivatives, of $13.9 million in the fourth quarter of 2021 comprised 65% (Q4 2020 – 43%) of total P&NG revenue while conventional natural gas production was 83% (Q4 2020 – 69%) of total production. Natural gas revenue increased significantly to $13.9 million (2020 - $3.5 million), reflecting a 61% increase in average daily production through the East Edson drilling, combined with significantly higher AECO Daily Index prices of $4.18 /GJ (Q4 2020 – $2.50/GJ). Higher AECO prices were partially offset by realized market diversification contract and hedging losses on financial and physical gas derivatives. The Company continued to realize physical hedging losses on AECO-NYMEX basis hedge positions that were locked-in during the second quarter of 2020. For the year ended December 31, 2021, natural gas revenue increased 1.5 times compared to the prior year, as a result of increased average daily production and higher reference prices.

Oil revenue of $4.9 million represented 23% (Q4 2020 – 47%) of total P&NG revenue while heavy crude oil production was 11% (Q4 2020 – 26%) of total production. Oil revenue was higher than the same period in 2020, due to the 81% increase in WCS average prices, partially offset by a 42% decrease in heavy crude oil production from the sale of the Clearwater oil assets. The increase in the WCS average price was mainly due to the increase in WTI light oil prices to US$77.13/bbl (Q4 2020 - $42.66) and increase in WCS differentials to US$14.63/bbl (Q4 2020 - US$9.30/bbl). For the year ended December 31, 2021, oil revenue increased 68% compared to the prior year, due primarily to the increase in the WCS average price to $68.76/bbl (2020 – $35.91/bbl).

NGL revenue for the fourth quarter of 2021 of $2.7 million comprised 12% (Q4 2020 – 10%) of total P&NG revenue while NGL production represented only 6% (Q4 2020 – 5%) of total Company production. Perpetual's realized NGL price for the fourth quarter of 2021 was $73.44/bbl, 93% higher than the fourth quarter of 2020 due to an increase in all NGL component prices which tracked the rise in WTI light oil prices.

Realized losses on derivatives totaled $4.8 million for 2021 which related to the elimination of the Company's remaining natural gas market diversification contract obligations for the April 1, 2021 to October 31, 2022 period (Q4 2020 – $2.4 million realized loss from natural gas derivatives) and $0.1 million of realized financial hedging losses from oil.

Unrealized gains on derivatives of $1.3 million were recorded in the fourth quarter of 2021 (Q4 2020 – unrealized gains of $0.8 million) and $3.7 million for the year ended December 31, 2021 (2020 – unrealized gains of $9.9 million). Unrealized gains and losses represent the change in mark-to-market value of derivative contracts as forward commodity prices and foreign exchange rates change. Unrealized gains and losses on derivatives are excluded from the Corporation's calculation of cash flow from (used in) operating activities as non-cash items. Derivative gains and losses vary depending on the nature and extent of derivative contracts in place, which in turn, vary with the Corporation's assessment of commodity price risk, committed capital spending and other factors.

Royalties

($ thousands, except as noted)	Three months ended December 31, **2021**	2020	Years ended December 31, **2021**	2020
Natural gas royalties – crown	**460**	190	**126**	313
Oil royalties – crown	**595**	209	**1,116**	264
NGL royalties – crown	**203**	52	**860**	537
Total crown(1)	**1,258**	451	**2,102**	1,114
Natural gas royalties – freehold and overriding	**1,753**	839	**4,849**	3,349
Oil royalties – freehold and overriding	**378**	373	**1,607**	1,279
NGL royalties – freehold and overriding	**397**	168	**1,364**	829
Total freehold and overriding(1)	**2,528**	1,380	**7,820**	5,457
Total royalties	**3,786**	1,831	**9,920**	6,571
$/boe	**6.47**	4.21	**5.04**	3.58
Crown *(% of P&NG revenue)*(1)	**5.9**	5.5	**3.5**	3.8
Freehold and overriding *(% of P&NG revenue)*(1)	**11.8**	16.9	**12.9**	18.5
Total *(% of P&NG revenue)*	**17.7**	22.4	**16.4**	22.3
Natural gas royalties *(% of natural gas revenue)*(1)	**15.9**	29.4	**15.1**	27.5
Oil royalties *(% of oil revenue)*(1)	**20.0**	15.1	**13.5**	12.8
NGL royalties *(% of NGL revenue)*(1)	**22.4**	26.5	**29.1**	33.0

(1) Non-GAAP measure, Non-GAAP ratio or supplementary financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this release.

For the fourth quarter of 2021, royalties were $3.8 million, more than 2.0 times higher from the comparative period of 2020 as a result of increased production and higher reference prices. For the year ended December 31, 2021, royalties were $9.9 million (2020 – $6.6 million), 51% higher than the prior year period. The combined average royalty rate on P&NG revenue decreased from 2020, due primarily to the impact of higher reference prices and the fixed volume East Edson gross overriding royalty as a percentage of higher production. Specifically, the Alberta Gas Reference price and AECO Daily Index prices which are used to calculate crown and freehold natural gas royalties, respectively, increased significantly during the year.

For the three months and year ended December 31, 2021, freehold and overriding royalties of $2.5 million and $7.8 million increased from the comparative period (2022 - $1.8 million and $6.6 million), due primarily to the impact of higher AECO Daily Index, WCS and Alberta reference prices which are used to calculate freehold royalties and increased production. As part of the East Edson Transaction, Perpetual agreed to retain its joint venture partner's 50% working interest in the existing gross overriding royalty obligation on the property, equivalent to 2.8 MMcf/d of natural gas and associated NGL production for the period April 1, 2020 to December 31, 2022. This obligation has been recorded in the condensed interim consolidated statement of financial position under the heading "Royalty obligations". Prior to November 1, 2021, the retained East Edson royalty obligation was paid in-kind, and settled through non-cash delivery of contractual natural gas and NGL volumes to the royalty holder (note 20). As of November 1, 2021, the royalty obligation is settled through payment in cash.

Production and operating expenses

($ thousands, except as noted)	Three months ended December 31, **2021**	2020	Years ended December 31, **2021**	2020
Production and operating expenses	**2,862**	3,014	**12,859**	11,634
$/boe	**4.89**	6.93	**6.54**	6.34

Total production and operating expenses decreased 29% on a unit-of-production basis to $4.89/boe for the fourth quarter of 2021, compared to $6.93/boe for the comparable period of 2020. On an absolute dollar basis, production and operating costs decreased by 5% due to increased conventional natural gas production at East Edson which has a high percentage of fixed operating costs and much lower operating costs as compared to heavy crude oil production. The decrease was also related to the decrease in oil production as a result of natural declines and the sale of the Clearwater oil Assets.

For the year ended December 31, 2021, production and operating expenses increased by 3% on a unit-of-production basis to $6.54/boe, compared to $6.34/boe for the comparable period of 2020. The increase was due to the reactivation of heavy crude oil production in Eastern Alberta which is higher cost as compared to the Company's other operating areas, partially offset by higher natural gas production and the sale of the Clearwater assets in the third quarter of 2021.

Transportation costs

($ thousands, except as noted)	Three months ended December 31, **2021**	2020	Years ended December 31, **2021**	2020
Transportation costs	**871**	804	**2,993**	3,617
$/boe	**1.49**	1.85	**1.52**	1.97

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 2021, transportation costs were $0.9 million, an 8% increase from the prior year period of $0.8 million as a result of increased natural gas production and an increase in transportation rates charged on the NGTL system. On a unit-of-production basis, transportation costs decreased by 19% to $1.49/boe in the fourth quarter of 2021 (Q4 2020 – $1.85/boe), due to increased natural gas production and increased transportation optimization activities.

For the year ended December 31, 2021, transportation costs were $3.0 million, a decrease of 17% over the prior year period. The decrease was due to the reduction in Perpetual's natural gas firm transportation capacity, eliminating unutilized demand charges at East Edson, which took effect in the third quarter of 2020 and was offset by an increase in transportation rates on the NGTL system.

Exploration and evaluation ("E&E") expenses

	Three months ended December 31,		Years ended December 31,	
($ thousands)	**2021**	2020	**2021**	2020
Total E&E expense	**27**	483	**120**	712

Exploration and evaluation expenses include lease rentals on undeveloped acreage, geological and geophysical costs, and the write-down of carrying costs related to lease expiries. During the year ended December 31, 2021, the Company did not record any non-cash write-downs (2020 – $0.5 million) associated with expiring P&NG leases.

General and administrative ("G&A") expenses

	Three months ended December 31,		Years ended December 31,	
($ thousands, except as noted)	**2021**	2020	**2021**	2020
G&A expense before recoveries	**3,847**	2,011	**11,451**	8,300
Overhead recoveries	**(190)**	(17)	**(694)**	(430)
Total G&A expense	**3,657**	1,994	**10,757**	7,870
$/boe	**6.25**	4.58	**5.47**	4.29

During the fourth quarter of 2021, G&A expense was $3.7 million, an 82% increase from the prior year period of $2.0 million. For the year ended December 31, 2021, G&A expense was $10.8 million, up 36% from the prior year (2020 – $7.9 million). The increase in G&A was related to the restoration to first quarter 2020 levels of employee salaries and benefits which had been reduced by over 20% in response to the collapse in commodity prices in March 2020 and increased professional fees related to the Rubellite Transaction.

Perpetual entered into the MSA with Rubellite whereby Perpetual receives payment for certain technical and administrative services provided to Rubellite on a cost recovery basis. For the year ended December 31, 2021, the amount of general and administrative costs billed to Rubellite was $0.4 million.

For the three and twelve months ended December 31, 2021, Perpetual received payments from the Canada Emergency Wage Subsidy ("CEWS") and Canada Emergency Rent Subsidy ("CERS") programs which reduced general and administrative expenses by $0.8 million and $0.1 million, respectively (2020 – $1.0 million and $0.3 million).

Overhead recoveries of $0.7 million increased over the prior year period (Q3 2020 – $0.4 million) due to increased capital spending and higher G&A costs.

Share-based payments

	Three months ended December 31,		Years ended December 31,	
($ thousands, except as noted)	**2021**	2020	**2021**	2020
Share-based payments (non-cash)	**149**	104	**360**	517
Share-based payments (cash)	**319**	413	**1,684**	1,500
Total share-based payments	**468**	517	**2,044**	2,017

For the three and twelve months ended December 31, 2021 share-based payments expense was $0.5 million and $2.0 million, unchanged from the comparative period of 2020. During the year ended December 31, 2021, the Company granted 6.8 million share-based payment awards, comprised of deferred options, deferred shares, share options, and performance share rights (2020 – 6.4 million).

Depletion and depreciation

	Three months ended December 31,		Years ended December 31,	
($ thousands, except as noted)	**2021**	2020	**2021**	2020
Depletion and depreciation	**4,182**	2,906	**14,020**	15,533
$/boe	**7.15**	6.68	**7.13**	8.47

The Company calculates depletion using the net book value of the asset, future development costs associated with proved and probable reserves, salvage values on associated production equipment, as well as proved and probable reserves. As at December 31, 2020, depletion was calculated on a $154.3 million depletable balance and $75.3 million in future development costs (2020 – $108.1 million depletable balance and $112.5 million in future development costs). The depletable base excluded an estimated $3.7 million (2020 – $3.5 million) of salvage value.

Depletion and depreciation expense for the fourth quarter of 2021 was $4.2 million or $7.15/boe (2020 – $2.9 million or $6.68/boe). The increase reflects the 34% increase in production volumes compared to the prior year period as well as an increased depletable base, related to the impairment reversals recorded during 2021. On a unit-of-production basis, depletion and depreciation expense increased by 10% compared to the fourth quarter of 2020.

For the year ended December 31, 2021, Perpetual recorded $14.0 million or $7.13/boe (2020 – $15.5 million or $8.47/boe) of depletion and depreciation expense. The decrease is due primarily to the disposition of the Clearwater Assets, slightly offset by the 8% increase in production. On a unit-of-production basis, depletion and depreciation expense decreased by 15% to $7.13/boe (2020 – $8.47/boe), due primarily to the disposition of the Clearwater Assets and increased production.

Depreciation expense for the year ended December 31, 2021 was attributable to office furniture, office and computer equipment, leasehold improvements and right of use assets.

Impairment and impairment reversals

In accordance with IFRS, the Company is required to assess when internal or external indicators of impairment or reversal exist, and impairment testing is required. During the fourth quarter of 2021, the Company determined that indictors of impairment reversal existed and that the estimated recoverable amounts of the Eastern Alberta CGU exceeded the carrying amounts of $42.2 million. Accordingly, a non-cash impairment reversal of $0.5 million was included in net income.

During the second quarter of 2021, the Company determined that indictors of impairment reversal existed and that the estimated recoverable amounts of the West Central CGU and Eastern Alberta CGU exceeded the carrying amounts of $89.6 million and $28.6 million, respectively. Accordingly, a non-cash impairment reversal of $30.1 million was included in net income.

E&E assets are tested for impairment when internal or external indicators of impairment or impairment reversal exist as well as upon their reclassification to oil and natural gas properties in PP&E. At December 31, 2021, the Company conducted an assessment of indicators of impairment and impairment reversal for the Company's E&E assets. There were no triggers identified and therefore, no impairments or impairment reversals recognized during 2021.

Finance expenses

	Three months ended December 31,		Years ended December 31,	
(*$ thousands*)	**2021**	2020	**2021**	2020
Cash finance expense				
Interest on revolving bank debt	**150**	293	**953**	1,662
Interest on term loan	**53**	(912)	**53**	1,812
Interest on 2022 Senior Notes(1)	**(608)**	733	**(1,253)**	2,938
Interest on 2025 Senior Notes(2)	**1,408**	–	**1,408**	–
Interest on lease liabilities	**36**	41	**148**	175
Total cash finance expense	**1,039**	155	**1,309**	6,587
Non-cash finance expense				
Interest accrued on Term Loan	**–**	–	**2,743**	–
Interest paid in-kind on 2022 Senior Notes(1)	**–**	1,823	**1,469**	1,823
Interest paid in-kind on 2025 Senior Notes(2)	**–**	–	**1,533**	–
Gain on senior note maturity extension(1)	**–**	–	**(1,591)**	–
Gain on Second Lien Loan Settlement(3)	**–**	–	**(6,820)**	–
Amortization of debt issue costs	**235**	502	**962**	1,673
Accretion on decommissioning obligations	**165**	96	**531**	443
Change in fair value of other liability(4)	**131**	–	**1,159**	–
Change in fair value of royalty obligations	**(663)**	(914)	**4,101**	1,305
Total non-cash finance expense (income)	**(151)**	1,507	**4,087**	5,244
Finance expenses recognized in net income (loss)	**888**	1,662	**5,396**	11,831

(1) On January 22, 2021, Perpetual's 2022 Senior Notes were exchanged for 2025 Senior Notes, providing Perpetual the option to pay interest in-kind. Perpetual elected to pay the January 23, 2021 semi-annual interest of $1.5 million by a PIK Interest Payment. As a result, the previously accrued 2022 Senior Note cash interest of $1.3 million was reversed and replaced by $1.3 million of 2025 Senior Note non-cash interest expense.

(2) The Company satisfied the semi-annual interest payment due July 23, 2021 by making a PIK Interest Payment. Subsequent to year end, the company satisfied the semi-annual interest payment due January 22, 2022 by making a cash interest payment.

(3) On September 3, 2021, upon completion of the Plan of Arrangement, Perpetual's Term Loan was substantively modified pursuant to the Second Lien Loan Settlement which included payment of $38.5 million, delivery of 0.7 million Rubellite shares valued at $1.4 million, the entry into a new second lien term loan of $2.7 million, and a contingent payment obligation valued at $0.2 million resulting in a gain of $6.8 million.

(4) Pursuant to the terms of the Second Lien Loan Settlement, $0.2 million has been earned related to the 2021 payment cap, and Perpetual is committed to pay up to an additional $3.2 million in potential contingent payments in the event that Perpetual's annual average realized crude oil and natural gas prices exceed certain thresholds. The change in fair value of this liability was recorded in the statement of comprehensive income (loss) as a non-cash finance expense.

Total cash finance expense was $1.0 million in the fourth quarter of 2021, higher than the prior year period (Q4 2020 – $0.2 million) due primarily to payment of interest on the Senior Notes and Term Loan in cash rather than in-kind.

Total non-cash finance income for the fourth quarter of 2021 was $0.1 million, $1.6 million lower than the prior year period (Q4 2020 – $1.5 million), due the extinguishment of the Term Loan, partially offset by a change in the fair value of the royalty obligations due to changing AECO natural gas and NGL prices and the recognition of fair value of "other liability" related to contingent payments related to the Second Lien Loan Settlement.

On January 22, 2021, the Company exchanged its unsecured 2022 Senior Notes for new $33.6 million secured 8.75% third lien senior notes due January 23, 2025. Interest on the 2025 Senior Notes may be paid in-kind at the option of the Company by adding the interest payment to the principal amount owing (a "PIK Interest Payment"). The Company elected to pay the January 23, 2021 and July 23, 2021 semi-annual interest payments by a PIK Interest Payment, which increased the principal amount of the 2025 Senior Notes outstanding to $36.6 million on July 23, 2021. Perpetual intends to pay the January 23, 2022 semi-annual interest payment in cash.

The Company recorded a net gain on the senior note maturity extension of $1.6 million, representing the difference between the carrying amount of 2022 Senior Notes of $34.5 million and the present value of the modified cash flows for the 2025 Senior Notes of $32.9 million, discounted at an effective interest rate of 12.4%. The gain has been recorded as a reduction of non-cash finance expense.

On September 3, 2021, upon completion of the Plan of Arrangement, Perpetual's agreement with its Term Loan lender for the settlement of principal and all interest owing on the Term Loan was accounted for as being effective. Perpetual extinguished the previous Term Loan in exchange for the payment of approximately $38.5 million in cash (reflected as current Term Loan payable on the statement of financial position), the delivery by Perpetual of the AIMCo Bonus Shares at a value of $1.4 million, the issuance of a new $2.7 million second lien Term Loan bearing interest at 8.1% annually and maturing December 31, 2024 (the "New Term Loan") and up to an aggregate $4.5 million in contingent payments over the three year period ended June 30, 2024 in the event that Perpetual's annual average realized oil and natural gas prices exceed certain thresholds (the "Second Lien Loan Settlement").

LIQUIDITY, CAPITALIZATION AND FINANCIAL RESOURCES

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

Capital management and net debt(1)

(*$ thousands, except as noted*)	**December 31, 2021**	December 31, 2020
Revolving bank debt	**2,487**	17,495
Term loan, principal amount	**2,671**	46,823
Senior notes, principal amount	**36,582**	33,580
Other liability	**1,387**	
Net working capital deficiency (surplus)(1)	**16,143**	7,099
Net debt(1)	**59,270**	104,997
Shares outstanding at end of period (*thousands*)(2)	**63,567**	61,305
Market price at end of period (*$/share*)	**0.70**	0.08
Market value of shares(1)	**44,496**	4,904
Enterprise value(1)	**103,767**	109,901
Net debt as a percentage of enterprise value(1)	**57**	96
Trailing twelve-months adjusted funds flow(1)	**16,746**	(7,787)

(1) Non-GAAP measure, Non-GAAP ratio or supplementary financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this release.

(2) Shares outstanding are presented net of shares held in trust.

At December 31, 2021, Perpetual had total net debt of $59.3 million, down $45.7 million (44%) from December 31, 2020 as a result of the Rubellite Transactions and the extinguishment of the Term Loan.

Perpetual had available liquidity at December 31, 2021 of $14.6 million, comprised of the $17.0 million Credit Facility Borrowing Limit, adjusted for current cash of $1.1 million less borrowings of $2.5 million and letters of credit of $1.0 million.

Revolving bank debt

As at December 31, 2021, the Company's Credit Facility had a Borrowing Limit of $17.0 million (December 31, 2020 – $20.0 million) under which $2.5 million was drawn (December 31, 2020 – $17.5 million) and $1.0 million of letters of credit had been issued (December 31, 2020 – $0.9 million). Borrowings under the Credit Facility bear interest at its lenders' prime rate or Banker's Acceptance rates, plus applicable margins and standby fees. The applicable Banker's Acceptance margins range between 3.0% and 5.5%. The effective interest rate on the Credit Facility at December 31, 2021 was 5.9%. For the year ended December 31, 2021, if interest rates changed by 1% with all other variables held constant, the impact on annual cash finance expense and net income would be $nil.

During the third quarter of 2021, Perpetual entered into an agreement with its syndicate of lenders to extend its Credit Facility maturity to November 30, 2022 with the opportunity to extend the revolving period for a further six months subject to approval by the syndicate. If not extended on or before November 30, 2022 all outstanding advances will be repayable on May 31, 2023.

During the fourth quarter of 2021, the Credit Facility borrowing limit was reduced from $20.0 million to $17.0 million and on December 17, 2021 the semi-annual borrowing base redetermination of the Company's first lien credit facility was completed and the existing $17.0 million borrowing limit and term of the credit facility was maintained. The next borrowing limit redetermination is scheduled to occur on or before May 31, 2022.

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

At December 31, 2021, the Credit Facility was not subject to any additional financial covenants and the Company was in compliance with all customary non-financial covenants.

Term loan

			December 31, 2021		December 31, 2020	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
Term loan	November 30, 2021	8.1%	**$ 2,671**	**$ 2,469**	$ 46,823	$ 46,691

During the third quarter, Perpetual and its Term Loan lender entered into an agreement establishing the terms and conditions of the Second Lien Loan Settlement. On September 3, 2021, upon completion of the Plan of Arrangement, Perpetual's agreement with its Term Loan lender for the settlement of principal and accrued interest owing on the Term Loan was accounted for as being effective. Perpetual substantively modified the previous Term Loan for the payment of approximately $38.5 million in cash, the delivery by Perpetual of 0.7 million Rubellite common shares (AIMCo Bonus Shares) at a value of $1.4 million, the issuance of a new $2.7 million second lien Term Loan, and up to an aggregate of $4.5 million in potential contingent payments in the event that Perpetual's annual average realized oil and natural gas prices exceed certain thresholds initially valued at $0.2 million (note 11). The New Second Lien Term Loan bears interest at 8.1% annually, which Perpetual may elect to pay-in-kind, and will mature on December 31, 2024. All amounts related to the Second Lien Loan Settlement were paid.

The Company and the Term Loan lender agreed to allow $1.8 million of interest due on the December 31, 2020 to be paid-in-kind and added to the outstanding principal amount of the loan and all other interest owing on the Term Loan to be settled as part of the Second Lien Loan Settlement. Non-cash paid in-kind interest of $0.8 million was recorded in the third quarter of 2021, which increased the principal amount of the Term Loan owing upon settlement to $49.6 million. As a result of the Second Lien Loan Settlement , the carrying amount of $49.6 million was in excess of the consideration received of $42.8 million, resulting in a gain of $6.8 million being recognized (note 20).

The New 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.

At December 31, 2021 the Term Loan is presented net of $0.2 million in issue costs which are amortized over the remaining term of the loan using a weighted average effective interest rate of 11.1%.

At December 31, 2021, the Term Loan was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Senior notes

			December 31, 2021		December 31, 2020	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
Senior notes	January 23, 2025	8.75%	**$ 36,583**	**$ 34,189**	$ 33,580	$ 32,359

On January 22, 2021, Perpetual announced the completion of a Court-approved plan of arrangement whereby the unsecured 2022 Senior Notes were exchanged for new 8.75% secured third lien notes due January 23, 2025. The 2025 Senior Notes have been issued under a trust indenture that contains substantially the same terms as the 2022 Senior Notes, other than the 2025 Senior Notes are secured on a third lien basis and allow for the semi-annual interest payments to be paid at Perpetual's option, in cash, or in additional 2025 Senior Notes (a "PIK Interest Payment"). The Company elected to pay the January 23, 2021 semi-annual interest of $1.5 million by a PIK Interest Payment, and satisfied the semi-annual interest payment due July 23, 2021 by making a PIK Interest Payment of $1.6 million, increasing the principal amount owing at December 31, 2021 to $36.6 million. Subsequent to year end, the Company satisfied the January 23, 2022 semi-annual interest payment of $1.6 million by making a cash payment.

At December 31, 2021, the senior notes are recorded at the present value of future cash flows, net of $2.4 million in issue and principal discount costs which are amortized over the remaining term using a weighted average effective interest rate of 11.3%.

The senior notes are direct senior secured, third lien obligations of the Company. The Company may redeem the senior notes without any repayment penalty. The senior notes have a cross-default provision with the Company's Credit Facility. In addition, the senior notes indenture contains restrictions on certain payments including dividends, retirement of subordinated debt, and stock repurchases. At December 31, 2021, the senior notes were not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Entities controlled by the Company's CEO hold $15.9 million of the 2025 Senior Notes outstanding. An entity that is associated with the Company's CEO, and entities associated with Directors of the Company hold an additional $10.3 million and $0.8 million of the 2025 Senior Notes outstanding, respectively.

Equity

At December 31, 2021 there were 63.6 million common shares outstanding, net of 0.5 million shares held in trust to resource employee compensation programs. Basic and diluted weighted average shares outstanding for the three months ended December 31, 2021 were 63.6 million (Q4 2020 – 61.3 million) and 70.0 million for the year ended December 31, 2021 (2020 – 61.0 million).

At March 14, 2022, there were 63.1 million common shares outstanding which is net of 1.0 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)	**March 14, 2022**
Share options	**4,077**
Performance share rights	**3,065**
Compensation awards	**8,634**
Total[1]	**15,776**

(1) 4.6 million compensation awards, 0.7 million share options, and 1.7 million performance share rights have an exercise price below the December 31, 2021 closing price of the Company's common shares of $0.70 per share.

SEQUOIA LITIGATION UPDATE

On August 3, 2018, the Company received a Statement of Claim that was filed by PricewaterhouseCoopers Inc. LIT ("PwC"), in its capacity as trustee in bankruptcy (the "Trustee") of Sequoia Resources Corp. ("Sequoia"), with the Alberta Court of Queen's Bench (the "Court"), against Perpetual (the "Sequoia Litigation"). The claim relates to a six-year-old transaction when, on October 1, 2016, Perpetual closed the disposition of shallow conventional natural gas assets in Eastern Alberta to an arm's length third party at fair market value at the time after an extensive and lengthy marketing, due diligence, and negotiation process (the "Sequoia Disposition"). This transaction was one of several completed by Sequoia. Sequoia assigned itself into bankruptcy on March 23, 2018. PwC is seeking an order from the Court to either set this transaction aside or declare it void, or damages of approximately $217 million. On August 27, 2018, Perpetual filed a Statement of Defence and Application for Summary Dismissal with the Court in response to the Statement of Claim. All allegations made by PwC have been denied and applications to the Court to dismiss all claims has been made on the basis that there is no merit to any of them.

On January 13, 2020, the Court issued its written decision related to the Sequoia Disposition. The decision dismissed and struck all claims against the Company's CEO and all but one of the claims filed against Perpetual. The Court did not find that the test for summary dismissal relating to whether the asset transaction was an arm's length transfer for purposes of section 96(1) of the Bankruptcy and Insolvency Act (the "BIA") was met, on the balance of probabilities. Accordingly, the BIA claim was not dismissed or struck and only that part of the claim could continue against Perpetual. The Trustee filed a notice of appeal with the Court of Appeal of Alberta, challenging the entire decision, and Perpetual filed a similar notice of appeal contesting the BIA claim portion of the decision (the "First Appeal").

On February 25, 2020, Perpetual filed a second application to strike and summarily dismiss the BIA claim on the basis that there was no transfer at undervalue, and Sequoia was not insolvent at the time of the asset transaction nor caused to be insolvent by the asset transaction. In July 2020, the Orphan Well Association ("OWA"), certain oil and gas companies, and six municipalities applied to intervene in the second BIA dismissal application proceedings. The OWA and certain oil and gas companies were permitted to intervene (the "Intervenors") in the proceedings which took place on October 1 and 2, 2020. The Intervenors were also permitted to intervene in the First Appeal proceedings. On January 14, 2021 the Court issued its decision, finding that the Trustee could not establish a necessary element of the BIA Claim as Sequoia was not insolvent at the time of, nor rendered insolvent by, the Sequoia Disposition. The Court therefore concluded there is "no merit" to the BIA Claim and it summarily dismissed the balance of the Statement of Claim. The Trustee appealed this decision, and the Court of Appeal hearing took place on February 10, 2022, with the panel reserving judgement.

The First Appeal proceedings were heard on December 10, 2020. On January 25, 2021, the Court of Appeal of Alberta issued their judgement with respect to the First Appeal proceedings, dismissing the appeal filed by Perpetual and granting certain aspects of the appeals filed by the Trustee, thereby reinstating certain elements of the Sequoia Litigation for trial. On March 24, 2021, Perpetual applied for leave to appeal the First Appeal decision to the Supreme Court of Canada (the "SCC"). On July 8, 2021, the SCC dismissed Perpetual's application.

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

SUMMARY OF QUARTERLY RESULTS

($ thousands, except as noted)	**Q4 2021**	Q3 2021	Q2 2021	Q1 2021
Financial				
Oil and natural gas revenue	**21,449**	14,603	13,226	11,536
Net income (loss)	**5,669**	51,141	27,017	(2,706)
Per share – basic	**0.09**	0.80	0.43	(0.04)
Per share – diluted	**0.08**	0.72	0.38	(0.04)
Cash flow from (used in) operating activities	**1,624**	6,655	2,854	1,682
Adjusted funds flow[(1)]	**8,585**	3,315	2,302	2,544
Per share[(3)]	**0.13**	0.05	0.04	0.04
Capital expenditures[(1)]	**7,558**	9,947	1,554	3
Net proceeds on dispositions, net of cash disposed	**53,407**	(4,060)	46	156
Common shares *(thousands)*				
Weighted average – basic	**63,853**	63,801	62,574	61,603
Weighted average – diluted	**70,873**	71,266	70,460	61,603
Operating				
Daily average production				
Natural gas *(MMcf/d)*	**31.5**	21.6	22.2	22.9
Oil *(bbl/d)*	**714**	972	1,074	1,097
NGL *(bbl/d)*	**395**	300	331	294
Total *(boe/d)*	**6,359**	4,876	5,099	5,211
Average prices				
Realized natural gas price *($/Mcf)* [(1) (2)]	**4.80**	2.59	2.25	2.25
Realized oil price *($/bbl)* [(1) (2)]	**73.96**	65.19	55.75	40.85
Realized NGL price *($/bbl)* [(1) (2)]	**73.44**	65.37	55.48	56.03

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

(1) Non-GAAP measure, Non-GAAP ratio or supplementary financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this release.

(2) Realized natural gas, oil and NGL prices include physical forward sales contracts for which delivery was made during the reporting period, along with realized gains and losses on financial derivatives and foreign exchange contracts.

(3) Based on weighted average common shares outstanding for the period.

(4) During the fourth quarter of 2021 includes $53.6 million in promissory notes payable to Perpetual which were repaid in cash October 5, 2021. Cash disposed was recognized during the third quarter of 2021.

The Company's oil and natural gas revenue, net income (loss), cash flow from (used in) operating activities and adjusted funds flow are influenced by commodity prices and production levels. Conventional natural gas production levels decreased during 2020 due to natural declines and reduced capital expenditures in response to depressed and volatile AECO natural gas prices. The disposition of a 50% working interest in the East Edson property which closed on April 1, 2020 for net cash consideration of $34.8 million and an eight well carried capital commitment, further reduced conventional natural gas production in the second and third quarters of 2020, before being restored in the fourth quarter of 2020 and all of 2021 as nine (4.0 net) wells have been tied-in to production. In response to the significant decline in global oil prices which began in March 2020, oil-focused capital expenditures and high-cost production was temporarily suspended, pending a recovery of oil prices, and oil focused hedging gains were locked-in. Heavy crude oil production was restarted progressively in step with the recovery of oil prices.

For the year ended December 31, 2021, the Company's net income was driven by a gain on disposition of the Clearwater Assets of $47.5 million and impairment reversals of $30.6 million, compared to total net impairments of $42.5 million in the prior year (Q4 2020 – $18.0 million impairment reversal; Q1 2020 – $60.5 million impairment charge).

Commodity price risk management and sales obligations

Perpetual's commodity price risk management strategy is focused on managing downside risk and increasing certainty in adjusted funds flow[(1)] by mitigating the effect of commodity price volatility. Physical forward sales contracts and financial derivatives are used to increase certainty in adjusted funds flow[(1)], manage the balance sheet, lock in economics on capital programs, and to take advantage of perceived anomalies in commodity markets. Perpetual also utilizes foreign exchange derivatives and physical or financial derivatives related to the differential between natural gas prices at the AECO and NYMEX trading hubs and oil basis differentials between WTI and WCS in order to mitigate the effects of fluctuations in foreign exchange rates and basis differentials on the Corporation's realized revenue. Diversification of markets is a further risk management strategy employed by the Company.

As at March 14, 2022, the Company entered into the following swap commodity contracts:

Commodity	Volumes sold	Term	Reference/ Index	Contract Traded Bought/sold	Market Price *(CAD$/bbl)*
Crude Oil	100 bbls/d	Apr 1 – Jun 30, 2022	WTI (CAD$/bbl)	Swap – sold	$104.50
Crude Oil	100 bbls/d	Jul 1 – Dec 31, 2022	WTI (CAD$/bbl)	Swap – sold	$103.30
Crude Oil	200 bbls/d	Jan 1 – Jun 30, 2022	WCS FP (CAD$/bbl)	Swap – sold	$76.70
Crude Oil	200 bbls/d	Jan 1 – Dec 31, 2022	WCS FP (CAD$/bbl)	Swap – sold	$70.65
Crude Oil	200 bbls/d	Jul 1 – Dec 31, 2022	WCS FP (CAD$/bbl)	Swap – sold	$70.80

As at March 14, 2022, the Company entered into the following swap WTI-WCS basis differential which settle in US$:

Commodity	Volumes sold	Term	Reference/ Index	Market Price *(US$/bbl)*
Crude oil	100 bbls/d	Mar 1 – Dec 31, 2022	WCS Differential	(17.25)
Crude oil	100 bbls/d	Jan 1, 2023 – Dec 31, 2023	WCS Differential	(17.30)

As a March 14, 2022, the Company entered into the following physical fixed price natural gas sales arrangements at AECO:

Commodity	Volumes sold	Term	Reference/ Index	Contract Traded Bought/sold	Average Price *(CAD$/bbl)*
Natural gas	30,000 GJ/d	Mar 2022	AECO	Sold	$4.44
Natural gas	22,500 GJ/d	Mar 2022	AECO	Bought	$4.01
Natural gas	5,000 GJ/d	Apr 2022	AECO	Bought	$4.22

In the third quarter of 2021, the Company eliminated its fixed volume obligations of 25,400 MMBtu/d for the period commencing April 1, 2022 and ending on October 31, 2022 in consideration for the payment of $1.8 million over the term of the associated contract volumes. In the second quarter of 2021, the Company eliminated its 25,400 MMBtu/d market diversification contract obligations for the period commencing November 1, 2021 and ending on March 31, 2022 in consideration for the payment of $1.6 million over the term of the associated contract volumes. In the first quarter of 2021, the Company eliminated its remaining 10,000 MMBtu/d market diversification contract obligations for the period of April 1, 2021 to October 31, 2021, in consideration for the payment of $1.4 million over the term of the associated contract volumes. These modifications have been recognized as realized losses on derivatives in the condensed interim consolidated statements of loss and comprehensive loss.

(1) Non-GAAP measure, Non-GAAP ratio or supplementary financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this release.

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

Market/Pricing Point	**November 1, 2022 to October 31, 2024 Daily sales volume *(MMBtu/d)***
Chicago	–
Malin	15,000
Dawn	15,000
Michcon	–
Emerson	10,000
Total sales volume obligation	**40,000**

Subsequent to December 31, 2021, the company eliminated 10,000 MMBtu/d of fixed volume obligations for the period commencing November 1, 2022 and ending on March 31, 2023 and will receive payment of $1.2 million over the term of the associated contract volumes.

SELECTED ANNUAL INFORMATION

($ thousands, except where noted)	**2021**	2020	2019
Financial			
Oil and natural gas revenue	**60,814**	29,486	74,361
Net income (loss)	**81,121**	(61,597)	(94,015)
Per share – basic and diluted[1]	**1.29 / 1.16**	(1.01)	(1.56)
Cash flow from (used in) operating activities	**12,815**	(9,533)	17,806
Adjusted funds flow[2]	**16,746**	(7,787)	14,534
Per share[1]	**0.27**	(0.13)	0.24
Total assets	**178,851**	140,454	241,148
Total long-term liabilities	**73,393**	68,722	118,061
Revolving bank debt	**2,487**	17,495	47,552
Senior notes, principal amount	**36,582**	33,580	33,580
Term loan, principal amount	**2,671**	46,823	45,000
AIMCO Contingent payments	**1,387**		
TOU share margin demand loan, principal amount	**-**	–	100
TOU share investment	**-**	–	(15,220)
Net working capital deficiency[2]	**16,143**	7,099	7,068
Total net debt[2]	**59,270**	104,997	118,080
Capital expenditures			
Capital expenditures[2]	**19,062**	5,939	12,939
Net proceeds on dispositions, net of cash disposed[1][4]	**49,549**	27,754	–
Common shares (*thousands*)			
End of period[3]	**63,567**	61,305	60,513
Weighted average – basic and diluted	**62,969 / 69,989**	61,013	60,258
Operating			
Daily average production			
Conventional natural gas (*MMcf/d*)	**24.6**	21.5	42.3
Heavy crude oil (*bbl/d*)	**963**	1,082	1,224
NGL (*bbl/d*)	**331**	346	719
Total average production (*boe/d*)	**5,389**	5,012	8,988
Average prices			
Realized natural gas price *($/Mcf)* [1] [2]	**3.15**	0.85	2.77
Realized oil price *($/bbl)* [1] [2]	**57.36**	49.37	44.87
NGL price (*$/bbl*) [1] [2]	**63.24**	31.40	41.01
Wells drilled			
Conventional natural gas – gross (net)	**9 (4.5)**	5 (2.5)	– (–)
Heavy crude oil – gross (net)	**5 (4.0)**	4 (4.0)	5 (5.0)
Total – gross (net)	**14 (8.5)**	9 (6.5)	5 (5.0)

(1) Based on weighted average common shares outstanding for the year.
(2) Non-GAAP measure, Non-GAAP ratio or supplementary financial measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this release.
(3) Reduced by shares held in trust (2021 – 532; 2020 – 556; 2019 – 801). See "Note 16 to the Consolidated Financial Statements".
(4) As at December 31, 2021 includes $53.6 million in promissory notes payable to Perpetual which were repaid in cash October 5, 2021, net of cash disposed of 4.1 million.

OFF BALANCE SHEET ARRANGEMENTS

Perpetual has no off balance sheet arrangements.

CHANGES IN ACCOUNTING POLICIES

Government grants

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

During the year ended December 31, 2021, the Company received government grants through the Canada Emergency Wage Subsidy ("CEWS") and Canada Emergency Rent Subsidy ("CERS") of $0.9 million (2020 – $1.3 million). For the year ended December 31, 2021, the grants were recognized as a reduction to general and administrative and production and operating expenses of $0.8 million and $0.1 million, respectively (2020 – $1.0 million and $0.3 million). For the year ended December 31, 2021, the Company also received government grants through the Alberta Site Rehabilitation program of $0.7 million (2020 - $0.8 million) to fund approved abandonment and remediation projects. These grants were recognized as "Other income" in the consolidated statements of loss and comprehensive loss. Associated expenditures were recorded as a reduction to decommissioning obligations on the consolidated statements of financial position.

RISK FACTORS

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

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

Perpetual manages these risks by:

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

A complete discussion of risk factors is included in the Corporation's 2021 Annual Information Form ("AIF") available on the Corporation's website at www.perpetualenergyinc.com or on SEDAR at www.sedar.com.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

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

Disclosure controls and procedures

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

Perpetual's CEO and CFO have concluded, based on their evaluation at December 31, 2021, the DC&P are designed and operating effectively to provide reasonable assurance that information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the issuer's management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure.

Management's annual report on internal controls over financial reporting

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

Under the supervision and with the participation of management, including the CEO and CFO, an evaluation of the effectiveness of the internal controls over financial reporting was conducted as of December 31, 2021 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, 2021, the internal controls over financial reporting were designed and operating effectively.

INTERNAL CONTROLS AND PROCEDURES

Evaluation of disclosure controls and procedures

There were no changes in the Corporation's internal control over financial reporting during the period beginning on October 1, 2021 and ended December 31, 2021 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 2021 report filed with the Canadian securities regulators.

CRITICAL ACCOUNTING JUDGMENTS AND ESTIMATES

Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Management reviews its estimates on a regular basis. The emergence of new information and changed circumstances may result in actual results or changes to estimates that differ materially from current estimates.

Perpetual's financial and operational results incorporate certain estimates including:

- estimated commodity sales from production at a specific reporting date for which actual revenues have not yet been received, including associated estimated credit losses;
- estimated royalty obligations, transportation, and operating expenses at a specific reporting date for which costs have been incurred but have not yet been settled;
- estimated capital expenditures on projects that are in progress;
- estimated depletion charges that are based on estimates of reserves that Perpetual expects to recover in the future;
- estimated future recoverable value of PP&E and E&E and any associated impairment charges or reversals;
- estimated fair values of financial instruments that are subject to fluctuation depending upon the underlying forward curves for commodity prices, foreign exchange rates and interest rates, as well as volatility curves, and the risk of non-performance;
- estimated value of ARO that is dependent upon estimates of future costs and timing of expenditures;
- estimated compensation expense under Perpetual's share-based compensation plans including the PSUs awarded under the PSU Plans that are dependent on the final number of PSU awards that eventually vest based on a performance multiplier; and
- estimated fair values of assets acquired and liabilities assumed in a business combination.

A change in a critical accounting estimate can have a significant effect on net loss, including their impact on the depletion rate, provisions, impairments, and income taxes. A change in a critical accounting estimate can have a significant effect on the value of property, plant, and equipment, provisions, derivative financial instruments and accounts payable. A complete discussion of critical accounting estimates is included in the notes to the consolidated financial statements at December 31, 2021.

NON-GAAP MEASURES

Throughout this MD&A and in other materials disclosed by the Company, Perpetual employs certain measures to analyze financial performance, financial position, and cash flow. These non-GAAP measures, non-GAAP ratios and other supplemental financial measures do not have any standardized meaning prescribed under IFRS and therefore may not be comparable to similar measures presented by other entities. The non-GAAP measures, non-GAAP ratios and other supplemental financial measures should not be considered to be more meaningful than GAAP measures which are determined in accordance with IFRS, such as net income (loss), cash flow from operating activities, and cash flow used in investing activities, as indicators of Perpetual's performance.

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

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

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

The following table reconciles net cash flows from (used in) operating activities as reported in the Company's condensed interim consolidated statements of cash flows, to adjusted funds flow:

	Three months ended December 31,		Years ended December 31,	
($ thousands, except per share and per boe amounts)	**2021**	2020	**2021**	2020
Net cash flows from (used in) operating activities	**1,624**	(1,104)	**12,815**	(9,533)
Change in non-cash working capital	**4,197**	1,479	**(3,406)**	(1,015)
Decommissioning obligations settled	**1,382**	95	**1,759**	210
Oil and natural gas revenue in-kind	**1,382**	917	**4,995**	2,319
Payments of gas over bitumen royalty financing	**-**	(197)	**-**	(704)
Payments of restructuring costs	**-**	50	**583**	936
Adjusted funds flow	**8,585**	1,240	**16,746**	(7,787)
Adjusted funds flow per share	**0.13**	0.02	**0.27**	(0.13)
Adjusted funds flow per boe	**14.67**	2.85	**8.51**	(4.25)

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

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

	Three months ended December 31,		Years ended December 31,	
($ thousands, except per boe amounts)	**2021**	2020	**2021**	2020
Royalties	**3,786**	1,831	**9,920**	6,571
Production and operating	**2,863**	3,014	**12,859**	11,634
Transportation	**871**	804	**2,993**	3,617
General and administrative	**3,657**	1,994	**10,757**	7,870
Cash finance expense	**1,039**	155	**1,309**	6,587
Cash costs	**12,215**	7,798	**37,839**	36,279
Cash costs per boe	**20.88**	17.92	**19.24**	19.78

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

Operating netback: Operating netback is calculated by deducting royalties, production and operating expenses, and transportation costs from realized revenue. Operating netback is also calculated on a per boe basis using total production sold in the period. Perpetual considers operating netback to be an important performance measure to evaluate its operational performance as it demonstrates its profitability relative to current commodity prices. Realized revenue is realized oil revenue which includes realized gains (losses) on financial crude oil and foreign exchange contracts. Realized revenue is used by management to calculate the Company's net realized commodity prices, taking into account the monthly settlements of financial crude oil and natural gas forward sales, collars, basis differentials, and forward foreign exchange sales. These contracts are put in place to protect Perpetual's adjusted funds flow from potential volatility. Refer to reconciliations earlier in the MD&A.

Net Debt and Working Capital: Net debt is calculated by deducting any borrowing under the Credit Facility from working capital. Working capital is calculated by adding cash, accounts receivable and prepaids less accounts payables and accrued liabilities. Perpetual uses net debt as an alternative measure of outstanding debt. Management considers net debt and working capital as important measures in assessing the liquidity of the Company.

Net debt includes the carrying value of net bank debt, other liability, the principal amount of the Term Loan, and the principal amount of senior notes. Net debt, net bank debt, and net debt to adjusted funds flow ratios are used by management to assess the Corporation's overall debt position and borrowing capacity. Net debt to adjusted funds flow ratios are calculated on a trailing twelve-month basis.

The following table reconciles working capital and net debt as reported in the Company's statements of financial position:

	As at December 31, 2021
Cash and cash equivalents	**1,090**
Accounts and accrued receivable	**11,671**
Prepaid expenses and deposits	**910**
Marketable securities	**2,409**
Accounts payable and accrued liabilities	**(32,223)**
Working capital deficiency	**(16,143)**
Bank indebtedness	**(2,487)**
Term loan (principal)	**(2,671)**
AIMCO contingent payments	**(1,387)**
Senior notes (principal)	**(36,582)**
Net debt	**(59,270)**

Realized Revenue and Total Revenue: Realized revenue is calculated as oil revenue less realized gains on derivatives. Total revenue is calculated as realized revenue less unrealized gain on derivates. The Company considers realized revenue and total revenue as important measures in assessing the operating performance of the Company after taking into consideration risk management activities. Refer to reconciliations earlier in the MD&A.

Capital Expenditures: Perpetual uses capital expenditures related to exploration and development to measure its capital investments compared to the Company's annual capital budgeted expenditures. Perpetual's capital budget excludes acquisition and disposition activities as well as the accounting impact of any accrual changes.

The most directly comparable GAAP measure for capital expenditures is cash flow used in investing activities. A summary of the reconciliation of cash flow used in investing activities to capital expenditures, is set forth below:

	Three months ended December 31,		Years ended December 31,	
	2021	2020	**2021**	2020
Net cash flows used in (from) investing activities	**(49,217)**	266	**(43,725)**	(34,925)
Acquisitions	**(700)**	-	**(1,325)**	(222)
Net proceeds on dispositions, net of cash disposed	**53,407**	-	**49,549**	27,754
Proceeds of sale of marketable securities	**-**	-	**-**	14,316
Change in non-cash working capital	**4,068**	200	**14,563**	(984)
Capital expenditures	**7,558**	466	**19,062**	5,939

Enterprise value: Enterprise value is calculated by multiplying the current shares outstanding by the market price at the end of the period and then adjusting it by the net debt. The Company considers enterprise value as an important measure as it normalizes the market value of the Company's shares for its capital structure. Refer to reconciliations earlier in the MD&A.

Non-GAAP Financial Ratios: Perpetual calculates certain non-GAAP measures per boe as the measure divided by weighted average daily production. Management believes that per boe ratios are a key industry performance measure of operational efficiency and one that provides investors with information that is also commonly presented by other crude oil and natural gas producers. Perpetual also calculates certain non-GAAP measures per share as the measure divided by outstanding common shares.

Supplementary financial measures

"Average realized price" is comprised of total commodity sales from production, as determined in accordance with IFRS, divided by the Company's total production.

"Realized NGL price" is comprised of NGL commodity sales from production and include physical forward sales contracts for which delivery was made during the reporting period, along with realized gains and losses on financial derivatives and foreign exchange contracts, as determined in accordance with IFRS, divided by the Company's NGL production.

"Realized oil price" is comprised of oil commodity sales from production and include physical forward sales contracts for which delivery was made during the reporting period, along with realized gains and losses on financial derivatives and foreign exchange contracts, as determined in accordance with IFRS, divided by the Company's oil production.

"Realized natural gas price" is comprised of natural gas commodity sales from production and include physical forward sales contracts for which delivery was made during the reporting period, along with realized gains and losses on financial derivatives and foreign exchange contracts, as determined in accordance with IFRS, divided by the Company's natural gas production.

"Depletion and depreciation expense per boe" is comprised of DD&A expense, as determined in accordance with IFRS, divided by the Company's total production.

"G&A expense per boe" is comprised of G&A expense, as determined in accordance with IFRS, divided by the Company's total production.

"Operating expense per boe" is comprised of operating expense, as determined in accordance with IFRS, divided by the Company's total production.

"Realized gain on derivative per boe" is comprised of realized gain on derivative, as determined in accordance with IFRS, divided by the Company's total production.

"Transportation expense per boe" is comprised of operating expense, as determined in accordance with IFRS, divided by the Company's total production.

"Royalties as a percentage of oil revenue" is comprised of royalties, as determined in accordance with IFRS, divided by oil revenue from production as determined in accordance with IFRS.

"Royalties per boe" is comprised of royalties, as determined in accordance with IFRS, divided by the Company's total production.

“Market value of shares” is comprised of common shares outstanding multiplied by the market price of shares.

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

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

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

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

December 31, 2021 and in other reports on file with Canadian securities regulatory authorities which may be accessed through the SEDAR website (www.sedar.com) and at Perpetual's website (www.perpetualenergyinc.com).

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

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

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

OIL AND GAS ADVISORIES

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

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

CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT

The consolidated financial statements of Perpetual Energy Inc. ("Perpetual" or 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 2021 to 2020 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 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 Riddell Rose

Susan L. Riddell Rose
President &
Chief Executive Officer

Ryan Shay

Ryan A. Shay
Vice President, Finance &
Chief Financial Officer

March 14, 2022

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Perpetual Energy Inc.

Opinion

We have audited the consolidated financial statements of Perpetual Energy Inc. (the "Company"), which comprise:

- the consolidated statements of financial position as at December 31, 2021 and December 31, 2020
- the consolidated statements of income (loss) and comprehensive income (loss) for the years then ended
- the consolidated statements of changes in equity for the years then ended
- the consolidated statements of cash flows for the years then ended
- and notes to the consolidated financial statements, including a summary of significant accounting policies

Hereinafter referred to as the "financial statements".

In our opinion, the accompanying financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2021 and December 31, 2020, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the **"*Auditors' Responsibilities for the Audit of the Financial Statements*"** section of our auditors' report.

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

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

Key Audit Matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the financial statements for the year ended December 31, 2021. These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

We have determined the matters described below to be the key audit matters to be communicated in our auditors' report.

Assessment of the recoverable amount of the West Central and Eastern Alberta cash generating units

Description of the matter

We draw attention to note 2, note 3, and note 5 to the financial statements. 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 are any internal or external indicators of impairment or impairment reversal. Significant judgement is required to assess when internal or external indicators of impairment or impairment reversal exist, and impairment testing is required. If any such indicator exists, then the recoverable amount is estimated. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. The Company identified an indicator of impairment reversal at June 30, 2021 for the West Central and Eastern Alberta cash generating units ("CGU") and additionally at December 31, 2021 for the Eastern Alberta CGU and performed impairment reversal tests to estimate the recoverable amount of each CGU. It was determined the recoverable amount of the West Central and Eastern Alberta CGUs exceeded each CGUs carrying value, resulting in all previous West Central impairment, net of depletion, of $22.6 million and Eastern Alberta impairment of $7.5 million, respectively being reversed.

The estimated recoverable amount of each CGU involves significant estimates including:

- The estimate of proved and probable oil and gas reserves and the related cash flows
- The discount rates.

The estimate of proved and probable oil and gas reserves and the related cash flows includes significant assumptions related to:

- Forecasted oil and gas commodity prices
- Forecasted production
- Forecasted operating costs
- Forecasted royalty costs
- Forecasted future development costs.

The estimated proved and probable oil and gas reserves and the related cash flows are evaluated by independent third party reserve evaluators at least annually.

Why the matter is a key audit matter

We identified the assessment of the recoverable amount of the West Central and Eastern Alberta cash generating units as a key audit matter. Significant auditor judgment was required in evaluating the results of our audit procedures regarding the estimate of proved and probable oil and gas reserves and the related cash flows and the discount rates.

How the matter was addressed in the audit

The following are the primary procedures we performed to address this key audit matter:

We independently developed the estimated recoverable amount of the West Central CGU as at December 31, 2021 and compared it to the carrying value to assess that the reversal of all previous impairment, net of depletion, recognized for the year ended December 31, 2021 was appropriate.

We examined management's impairment reversal test for the Eastern Alberta CGU as at December 31, 2021 by agreeing amounts to the underlying source documents and performing recalculations.

With respect to the estimate of proved and probable oil and gas reserves and the related cash flows for the West Central and Eastern Alberta CGUs as at December 31, 2021:

• We evaluated the competence, capabilities and objectivity of the independent third party reserve evaluators engaged by the Company

• We compared forecasted oil and gas commodity prices to those published by other independent third party reserve evaluators

• We compared the 2021 actual production, operating costs, royalty costs and development costs of the Company to those estimates used in the prior year's estimate of proved oil and gas reserves and the related cash flows to assess the Company's ability to accurately forecast

• We evaluated the appropriateness of forecasted production and forecasted operating costs, royalty costs and future development costs assumptions by comparing to 2021 historical results. We took into account changes in conditions and events affecting the Company to assess the adjustments or lack of adjustments made by the Company in arriving at the assumptions.

We involved valuation professionals with specialized skills and knowledge, who assisted in:

• Developing an independent estimate of the West Central CGU recoverable amount as at December 31, 2021 using proved and probable oil and gas reserves and related cash flows evaluated by independent third party reserve evaluators as at December 31, 2021 with an independently developed discount rate

• Evaluating the appropriateness of the Eastern Alberta CGU discount rate by comparing the discount rate to market and other external data

• Assessing the reasonableness of the Company's estimate of the recoverable amount of the Eastern Alberta CGU by comparing the Company's estimate to market metrics and other external data.

Other Information

Management is responsible for the other information. Other information comprises:

• the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions.

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

We obtained the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions as at the date of this auditors' report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditors' report.

We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS as issued by the IASB, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

• Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

• Obtain an understanding of internal control relevant to the audit 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 Company's internal control.

• Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

• Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Company to cease to continue as a going concern.

• Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

• Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

• Provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

• Determine, from the matters communicated with those charged with governance, those matters that were of most significance in the audit of the financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditors' report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our auditors' report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

The engagement partner on the audit resulting in this auditors' report is Gregory Ronald Caldwell.

KPMG LLP

Chartered Professional Accountants
Calgary, Canada
March 14, 2022

PERPETUAL ENERGY INC.
Consolidated Statements of Financial Position

As at	**December 31, 2021**	December 31, 2020
(*Cdn$ thousands*)		
Assets		
Current assets		
Cash	**$ 1,090**	$ –
Accounts receivable (note 21)	**11,671**	3,953
Marketable securities (note 4)	**2,409**	–
Prepaid expenses and deposits	**910**	872
Fair value of derivatives (note 22)	**682**	–
	16,762	4,825
Property, plant and equipment (note 5)	**153,620**	123,985
Exploration and evaluation (note 6)	**7,329**	10,272
Right-of-use assets (note 7)	**1,140**	1,372
Total assets	**$ 178,851**	$ 140,454
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 32,223**	$ 11,924
Revolving bank debt (note 9)	**–**	17,495
Term loan (note 10)	**–**	46,691
Other liability (note 11)	**63**	–
Fair value of derivatives (note 22)	**321**	3,373
Royalty obligations (note 13)	**4,697**	3,553
Lease liabilities (note 14)	**778**	710
Decommissioning obligations (note 15)	**1,327**	1,048
	39,409	84,794
Term loan (note 10)	**2,469**	–
Revolving bank debt (note 9)	**2,487**	–
Other liability (note 11)	**1,324**	–
Senior notes (note 12)	**34,189**	32,359
Royalty obligations (note 13)	–	2,596
Lease liabilities (note 14)	**1,324**	1,791
Decommissioning obligations (note 15)	**31,600**	31,976
Total liabilities	**112,802**	153,516
Equity		
Share capital (note 17)	**94,809**	97,333
Contributed surplus	**45,731**	45,217
Deficit	**(74,491)**	(155,612)
Total equity	**66,049**	(13,062)
Total liabilities and equity	**$ 178,851**	$ 140,454

Contingencies (note 8)
Contractual obligations (note 16)

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, 2021	December 31, 2020
(Cdn$ thousands, except per share amounts)		
Revenue		
Oil and natural gas (note 19)	**$ 60,814**	$ 29,486
Royalties	**(9,920)**	(6,571)
	50,894	22,915
Change in fair value of derivatives (note 22)	**(1,077)**	10,609
Gas over bitumen royalty credit	**385**	685
Other income (note 15)	**704**	812
	50,906	35,021
Expenses		
Production and operating	**12,859**	11,634
Transportation	**2,993**	3,617
Exploration and evaluation (note 6)	**120**	712
General and administrative (note 1)	**10,757**	7,870
Share-based payments (note 18)	**2,044**	2,017
Depletion and depreciation (note 5 and 7)	**14,020**	15,533
Gain on dispositions (note 5)	**(47,522)**	–
Impairment (reversal) (note 5(c) and 6)	**(30,600)**	42,500
Net income (loss) from operating activities	**86,235**	(48,862)
Finance expense (note 20)	**(5,396)**	(11,831)
Change in fair value of marketable securities (note 4)	**282**	(904)
Net income (loss) and comprehensive income (loss)	**81,121**	(61,597)
Income (loss) per share (note 17f)		
Basic	**$ 1.29**	$ (1.01)
Diluted	**$ 1.16**	$ (1.01)

See accompanying notes to the consolidated financial statements.

PERPETUAL ENERGY INC.
Consolidated Statements of Changes in Equity

	Share capital (thousands)	Share capital ($thousands)	Contributed surplus	Deficit	Total equity
(Cdn$ thousands, except share amounts)					
Balance at December 31, 2020	61,305	$ 97,333	$ 45,217	$ (155,612)	$ (13,062)
Net income	–	–	–	81,121	81,121
Common shares issued (note 17 and 18)	2,828	473	(284)	–	189
Change in shares held in trust (note 17 and 18)	24	(14)	(49)	–	(63)
Common share split (note 17)	8,158	–	–	–	-
Common share cancellation (note 17)	(8,158)	(2,779)	–	–	(2,779)
Common share odd-lot consolidation (note 17)	(590)	(204)	–	–	(204)
Share-based payments (note 18)	-	-	847	–	847
Balance at December 31, 2021	**63,567**	**$ 94,809**	**$45,731**	**$ (74,491)**	**$ 66,049**

	Share capital (thousands)	Share capital ($thousands)	Warrants	Contributed surplus	Deficit	Total equity
(Cdn$ thousands, except share amounts)						
Balance at December 31, 2019	60,513	$ 96,876	$ 923	$ 44,234	$ (94,015)	$ 48,018
Net loss	–	–	–	–	(61,597)	(61,597)
Common shares issued (note 17 and 18)	548	340	(923)	583	–	–
Change in shares held in trust (note 17 and 18)	244	117	–	(117)	–	–
Share-based payments (note 18)	–	–	–	517	–	517
Balance at December 31, 2020	**61,305**	**$ 97,333**	**$ –**	**$ 45,217**	**$ (155,612)**	**$ (13,062)**

See accompanying notes to the consolidated financial statements.

PERPETUAL ENERGY INC.
Consolidated Statements of Cash Flows

For the year ended	**December 31, 2021**	December 31, 2020
(*Cdn$ thousands*)		
Cash flows from (used in) operating activities		
Net income (loss)	**$ 81,121**	$ (61,597)
Adjustments to add (deduct) non-cash items:		
Other income (note 15)	**(704)**	(812)
Depletion and depreciation (note 5 and 7)	**14,020**	15,533
Exploration and evaluation (note 6)	**–**	529
Share-based payments (note 18)	**360**	517
Unrealized change in fair value of derivatives (note 22)	**(3,734)**	(9,901)
Change in fair value of marketable securities (note 4)	**(282)**	904
Finance expense (note 20)	**4,087**	5,244
Loss (gain) on dispositions (note 5)	**(47,522)**	–
Impairment (reversal) (note 5(c) and note 6)	**(30,600)**	42,500
Oil and natural gas revenue in-kind (note 13)	**(4,995)**	(2,319)
Decommissioning obligations settled (note 15)	**(1,759)**	(210)
Transaction costs (note 5)	**(583)**	–
Payments of restructuring costs	**–**	(936)
Change in non-cash working capital (note 21)	**3,406**	1,015
Net cash flows from operating activities	**12,815**	(9,533)
Cash flows used in financing activities		
Change in revolving bank debt, net of issue costs	**(15,174)**	(30,483)
Change in term loan, net of issue costs	**(38,700)**	–
Change in share margin demand loan, net of issue costs	**–**	(100)
Change in senior notes, net of issue costs	**(233)**	(549)
Net proceeds on dispositions (note 5)	**–**	6,996
Payments of lease liabilities (note 14)	**(620)**	(552)
Payments of gas over bitumen royalty financing (note 13)	**(558)**	(704)
Shares purchased and held in trust	**(395)**	–
Common shares issued, net of issue costs	**230**	–
Net cash flows used in financing activities	**(55,450)**	(25,392)
Cash flows from investing activities		
Capital expenditures	**(19,062)**	(5,939)
Acquisitions	**(1,325)**	(222)
Net proceeds on dispositions, net of cash disposed (note 5)	**49,549**	27,754
Proceeds on sale of marketable securities (note 4)	**–**	14,316
Change in non-cash working capital (note 21)	**14,563**	(984)
Net cash flows from investing activities	**43,725**	34,925
Change in cash and cash equivalents	**1,090**	–
Cash and cash equivalents, beginning of year	**-**	–
Cash and cash equivalents, end of year	**$ 1,090**	$ –

See accompanying notes to the consolidated financial statements.

1. REPORTING ENTITY

Perpetual Energy Inc. ("Perpetual" or the "Company") is an oil and natural gas exploration, production and marketing company headquartered in Calgary, Alberta. Perpetual owns a diversified asset portfolio, including liquids-rich conventional natural gas assets in the deep basin of West Central Alberta, heavy crude oil and shallow conventional natural gas in Eastern Alberta, and undeveloped bitumen leases in Northern Alberta.

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., Perpetual Energy Partnership, and Perpetual Operating Trust, which are incorporated in Alberta.

Material transactions

On September 3, 2021, the Plan of Arrangement involving Perpetual Energy Inc, the shareholders of Perpetual, and Rubellite Energy Inc ("Rubellite") (the "Arrangement") was completed following approval of the plan by the shareholders of Perpetual at its special shareholder meeting held on August 31, 2021 and the receipt of the final order of the Court of Queen's Bench of Alberta approving the Plan of Arrangement on September 3, 2021. At this time, Rubellite exchanged 1.4 million Rubellite common shares and 16.7 million arrangement warrants with Perpetual shareholders for 8.2 million Perpetual common shares valued at $2.8 million. These 8.2 million Perpetual common shares held by Rubellite were delivered to Perpetual as part of the purchase consideration.

All of Perpetual's Clearwater lands, wells, roads and facilities in northeast Alberta (the "Clearwater Assets") were acquired by Rubellite. The Clearwater assets were acquired for aggregate consideration of $65.5 million. The consideration consisted of promissory notes totaling $59.4 million, which were paid in cash on October 5, 2021, the issuance of 680,485 Rubellite common shares valued at $1.3 million, the return of 8.2 million Perpetual common shares exchanged in the Arrangement valued at $2.8 million and issuance of warrants to purchase 4.0 million Rubellite common shares at a price of $3.00 per share for a period of five years, valued at $2.0 million.

Perpetual also entered into a Management and Operating Services Agreement ("MSA") with Rubellite whereby Perpetual receives payment for certain technical and administrative services provided to Rubellite on a cost recovery basis. For the year ended December 31, 2021, the amount of general and administrative costs billed to Rubellite was $0.4 million. As a result of various other transactions between the parties, the Company recorded an accounts receivable of $3.8 million owing from Rubellite and an accounts payable of $3.9 million owing to Rubellite.

Upon completion of the Plan of Arrangement, Perpetual executed its agreement with its Term Loan lender for the settlement of principal and all interest owing on the Term Loan. Perpetual substantively modified the previous Term Loan with Alberta Investment Management Corporation ("AIMCo") in exchange for the payment of approximately $38.5 million in cash, the delivery by Perpetual of the AIMCo Bonus Shares at a value of $1.4 million, the issuance of a new $2.7 million second lien Term Loan bearing interest at 8.1% annually and maturing December 31, 2024 (the "New Term Loan") (note 10), and up to an aggregate $4.5 million in contingent payments over the three year period ended June 30, 2024 in the event that Perpetual's annual average realized oil and natural gas prices exceed certain thresholds (the "Second Lien Loan Settlement") (note 11).

On October 5, 2021, Perpetual received cash proceeds of approximately $53.6 million. The cash proceeds were used to satisfy the $38.5 million cash component of the Second Lien Loan Settlement with the remaining cash applied to repay a significant portion of the Credit Facility. In addition, the borrowing limit on the Credit Facility was reduced from $20.0 million to $17.0 million, and the maturity was extended from November 15, 2021 to May 31, 2023.

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 March 14, 2022.

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 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

Significant judgment is required to assess when internal or external indicators of impairment or impairment reversal exist, and impairment testing is required. Management considers internal and external sources of information including oil and gas commodity prices, expected production volumes, estimated proved and probable oil and gas reserves and the related cash flows and rates used to discount the related future cash flow estimates. Judgement is required to assess these factors when determining if the carrying amount of an asset or CGU is impaired, or in the case of a previously impaired asset or CGU, whether the carrying amount of the asset or CGU has been restored.

iii) Componentization

For the purposes of depletion, the Company allocates its oil and gas 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 ("E&E") expenditures

Costs associated with acquiring oil and gas licenses and exploratory drilling are accumulated as exploration and evaluation 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 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 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.

vii) Revenue – principal versus agent

When determining if the Company acted as a principal or as an agent in transactions, management determines if the Company obtains control of the product. As part of this assessment, management considers if the Company obtained control of the goods or services more than momentarily, in advance of transferring those goods or services to the customer. In this assessment, the Company considers indicators that it controlled the goods or services, including whether the Company was primarily responsible for the goods and services, whether the Company had inventory risk and whether the Company had discretion in establishing prices for the goods or services. Where control was indicated, the Company has been determined to be the principal and has recorded revenue and the associated expenses on a gross basis. In other cases, the Company has been determined to be the agent and has recorded revenue net of associated expenses.

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 proved and probable oil and gas 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 proved and probable oil and gas reserves and their related cash flows are based upon a number of significant assumptions, such as forecasted production volumes, oil and gas commodity prices, operating costs, royalty costs, and future development costs. Additional estimates are made in relation to the marketability of oil and gas, and the assumed effects of regulation by government agencies. 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 gas properties, the calculation of depletion and depreciation, and the timing of decommissioning expenditures.

The estimate of proved and probable oil and gas reserves and the related cash flows are evaluated by independent third party reserve evaluators at least annually. This evaluation of proved and proved plus probable oil and gas reserves is prepared in accordance with the reserve definitions contained in National Instrument 51-101 and the COGE Handbook.

The Company is also required to estimate the recoverable amount of exploration and evaluation assets, which consists of undeveloped lands, exploratory drilling assets and bitumen evaluation assets, for impairment testing. The recoverable amount is based on relevant industry sales value data.

ii) Marketable securities

Rubellite Share Purchase Warrants are recorded at fair value using the Black Scholes option pricing model. In assessing the fair value of the warrants, estimates have to be made regarding the expected volatility in share price, option life, dividend yield, and risk-free rate.

iii) 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.

iv) 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 forecasted 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.

v) Other liability

The other liability is measured at fair value on each reporting date. The fair value of the other liability is estimated by discounting future cash payments based on Perpetual's annual average realized oil and natural gas prices exceeding certain thresholds. Changes in market pricing between period end and settlement could have a material impact on financial results related to the other liability.

vi) Royalty obligations

The retained East Edson royalty obligation and the gas over bitumen royalty financing are measured at fair value on each reporting date. The fair value is estimated by discounting future cash payments based on the forecasted natural gas and NGL commodity prices multiplied by the remaining royalty obligation volumes. Changes in market pricing between period end and settlement could have a material impact on financial results related to the royalty obligations.

vii) Share-based payments

Share options, deferred share options, and long-term incentive awards issued by the Company are recorded at fair value using the Black Scholes option pricing model. In assessing the fair value of share options and deferred 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 (loss).

iii) Jointly owned assets

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

iv) 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 comprise accounts receivable, marketable securities, deposits, fair value of derivative assets and liabilities, accounts payable and accrued liabilities, revolving bank debt, Term Loan, other liability, royalty obligations, and senior notes. These financial instruments are recognized initially at fair value, net of any directly attributable transaction costs.

i) Classification and measurement of financial assets

A financial asset is measured at amortized cost if it meets both of the following conditions and is not designated at fair value through profit or loss ("FVTPL"):

- it is held within a business model whose objective is to hold assets to collect contractual cash flows; and
- its contractual terms give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

A debt investment is measured at fair value through other comprehensive income ("FVOCI") if it meets both of the following conditions and is not designated at FVTPL:

- it is held within a business model whose objective is achieved by both collecting contractual cash flows and selling financial assets; and
- its contractual terms give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

On initial recognition of an equity investment that is not held for trading, the Company may irrevocably elect to present subsequent changes in the investment's fair value in other comprehensive income ("OCI"). This election is made on an investment-by-investment basis.

All financial assets not classified as measured at amortized cost or FVOCI as described above are measured at FVTPL. On initial recognition, the Company may irrevocably designate a financial asset that otherwise meets the requirements to be measured at amortized cost or at FVOCI at FVTPL if doing so eliminates or significantly reduces an accounting mismatch that would otherwise arise.

A financial asset (unless it is a trade receivable without a significant financing component that is initially measured at the transaction price) is initially measured at fair value plus, for an item not at FVTPL, transaction costs that are directly attributable to its acquisition.

The following accounting policies apply to the subsequent measurement of financial assets:

a) Financial assets at FVTPL

These assets are subsequently measured at fair value. Net gains and losses, including any interest or dividend income, are recognized in profit or loss.

b) Financial assets at amortized cost

These assets are subsequently measured at amortized cost using the effective interest method. The amortized cost is reduced by impairment losses. Interest income, foreign exchange gains and losses and impairment are recognized in profit or loss. Any gain or loss on derecognition is recognized in profit or loss.

ii) Classification and measurement of financial liabilities

Financial liabilities are classified and measured at amortized cost or FVTPL. A financial liability is classified at FVTPL if it is a derivative or it is designated as such on initial recognition. Financial liabilities at FVTPL are measured at fair value and net gains and losses, including any interest expense, are recognized in profit or loss. Other financial liabilities are subsequently measured at amortized cost using the effective interest method. Interest expense and foreign exchange gains and losses are recognized in profit or loss. Any gain or loss on derecognition is also recognized in profit or loss.

The Company has classified accounts receivable, deposits, accounts payable and accrued liabilities, revolving bank debt, Term Loan and senior notes as amortized cost. The marketable securities, other liability, and royalty obligations have been classified as FVTPL.

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 FVTPL 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 (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 FVTPL and recorded as derivatives on the statement of financial position at fair value.

Transaction costs on derivatives are recognized in net income (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 FVTPL. Changes in the fair value of separable embedded derivatives are recognized immediately in net income (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 ("PP&E")

i) Production and development costs

Items of property, plant and equipment, which include oil and 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 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 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 (loss). Proceeds may include cash, or other non-cash consideration such as retained drilling rights which are fair valued at the time of disposition. 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. Such capitalized property, plant and equipment generally represent costs incurred in developing proved and/or probable oil and gas reserves and bringing on or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. All other expenditures including the costs of the day-to-day servicing of property, plant and equipment are recognized as production and operating expense in net income (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 oil and gas reserves, considering estimated future development costs necessary to bring those reserves into production and future decommissioning costs. The future development cost estimates are reviewed by independent third-party reserve evaluators 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 (loss) as incurred.

E&E costs, consisting of the costs of acquiring oil and 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 gas properties, after impairment is assessed and any applicable impairment loss is recognized in net income (loss).

The Company's E&E assets consist of undeveloped lands, 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 (loss).

e) Right-of-use assets

The Company recognizes right-of-use assets and lease liabilities at the lease commencement date. The assets are measured at the lease liability initially recognized, which comprise the present value of the future lease payments adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received.

The right-of-use assets are depreciated to the earlier of the end of the useful life of the asset or the lease term using the straight-line method as this most closely reflects the expected pattern of consumption of the future economic benefits. The Company presents right-of-use assets as its own line item on the consolidated statements of financial position. In determining the lease term, management considers the non-cancellable period along with all facts and circumstances that create an economic incentive to exercise an extension option, or not to exercise a termination option. In addition, the right-of-use assets are periodically reduced by impairment losses, if any, and adjusted for certain remeasurements of the lease liabilities. The depreciation term of the right-of-use assets is between two and five years.

f) Lease liabilities

The lease liabilities are initially measured at the present value of the future lease payments, discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the Company's incremental borrowing rate. Generally, the Company uses its incremental borrowing rate as the discount rate, which is determined based on judgments about the economic environment in which the Company operates and theoretical analyses about the security provided by the underlying leased asset, the amount of funds required to be borrowed in order to meet the future lease payments associated with the leased asset, and the term for which these funds would be borrowed.

The lease liabilities are measured at amortised cost using the effective interest rate method. They are remeasured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Company's estimate of the amount expected to be payable under a residual value guarantee, or if the Company changes its assessment of whether it will exercise a purchase, extension or termination option. When the lease liabilities are remeasured in this way, a corresponding adjustment is made to the carrying amount of the right-of-use assets, or is recorded in profit or loss if the carrying amount of the right-of-use assets has been reduced to zero. Lease payments are applied against the lease liabilities, with a portion allocated as cash finance expense using the effective interest rate method. The Company presents lease liabilities as their own line item on the consolidated statements of financial position.

g) 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 FVLCD, with impairments recognized in net income (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.

h) Impairment

i) Financial assets

The Company has elected to measure loss allowances for trade receivables and contract assets at an amount equal to lifetime expected credit losses ("ECLs"). The maximum period considered when estimating ECLs is the maximum contractual period over which the Company is exposed to credit risk.

ECLs are a probability-weighted estimate of credit losses. Credit losses are measured as the present value of all cash shortfalls (i.e. the difference between the cash flows due to the entity in accordance with the contract and the cash flows that the Company expects to receive). ECLs are discounted at the effective interest rate of the financial asset.

Loss allowances for financial assets are deducted from the gross carrying amount of the assets. Impairment losses on financial assets are presented under "other expenses" in the consolidated statements of income (loss) and comprehensive income (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 are any internal or external indicators of impairment or impairment reversal. If any such indicator exists, then the recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped together at a CGU level. The estimated 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 the future cash flows expected to be derived from production of proved and probable oil and gas reserves estimated by the Company's independent third-party reserve evaluators.

An impairment is recognized if the carrying amount of a CGU exceeds the estimated recoverable amount for that CGU. The Company determines the estimated recoverable amount by using the greater of FVLCD and the VIU. 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.

E&E assets are assessed for impairment at the time that any triggering facts and circumstances suggest that the carrying amount exceeds the estimated recoverable amount as well as upon their eventual reclassification to oil and 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 estimated recoverable amount of the CGUs and E&E assets at the total company level is sufficient to cover the combined carrying value of the CGUs and E&E assets.

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.

i) Share-based payments

Fixed equity awards granted under the equity-settled share-based payment plans and agreements 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 share price volatility, and interest rates over the expected contractual life of the equity award. 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 general and administrative expense, production and operating expense, or 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.

Certain awards granted under the performance share rights plan may be settled in cash, in common shares of the Company, or a combination thereof at the discretion of the Company's Board of Directors. Fixed value, equity-settled awards are accounted for as cash-settled share-based payment transactions and are expensed into profit and loss over the unit vesting period with an associated accumulation in accounts payable and accrued liabilities, as a variable number of equity units will be required to settle the liability.

j) Shares held in trust

The Company has 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 consolidated statements of financial position (note 17(b)). 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.

k) 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 obligation 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 the extent and timing of expenditures required to settle the obligation at the statement of financial position date, 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 reporting period to reflect the passage of time, changes in the timing and estimate of 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 (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 and can no longer withdraw the offer of those benefits. 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. The provision is measured on initial recognition at the Company's best estimate of the expenditure required to settle the obligation.

l) Revenue

Revenue from the sale of heavy crude oil, conventional natural gas and NGL is recognized based on the consideration specified in contracts with customers. The Company recognizes revenue when control of the product transfers to the buyer and collection is reasonably assured. This is generally at the point in time when the customer obtains legal title to the product which is when it is physically transferred to the pipelines or other transportation method agreed upon.

Revenues from processing activities are recognized over time as processing occurs and are generally billed monthly.

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

When allocating the transaction price realized in contracts with multiple performance obligations, management is required to make estimates of the prices at which the Company would sell the product separately to customers. The Company does not currently have any contracts with multiple performance obligations.

If the consideration promised in a contract includes a variable amount, the Company estimates the amount of consideration to which it will be entitled in exchange for transferring the promised goods or services to a customer. Royalty obligations (note 13) are considered to be variable consideration that will be remeasured at fair value at each reporting date.

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 natural gas wells shut-in for the benefit of bitumen producers in the Athabasca oil sands area, is recognized as gas over bitumen royalty credit revenue in the period that deemed production occurs, to the extent that the revenue is expected to be recovered through gas Crown royalties otherwise payable. The final payment related to the gas over bitumen royalty financing was made on July 25, 2021.

m) Income tax

Income tax expense comprises current and deferred components. Income tax expense is recognized in net income (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.

n) Income (loss) per share amounts

Basic income or loss per share is calculated by dividing the net income (loss) by the weighted average number of common shares outstanding during the period. For the dilutive net income 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.

Diluted income per share is calculated giving effect to the potential dilution that would occur if outstanding warrants, share options, restricted rights, performance share rights, 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, performance share rights and deferred compensation awards. 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.

o) Government grants

Government grants are recognized when there is reasonable assurance that the grant will be received, and all attached conditions will be complied with. When the grant relates to an expense item, it is recognized as an expense reduction in the period in which the costs are incurred. Government grants related to income are recorded as other income in the period in which eligible expenses were incurred or when the services have been performed. During the year ended December 31, 2021, the Company received government grants through the Canada Emergency Wage Subsidy ("CEWS") and Canada Emergency Rent Subsidy ("CERS") of $0.9 million (2020 – $1.3 million). For the year ended December 31, 2021, the grants were recognized as a reduction to general and administrative and production and operating expenses of $0.8 million and $0.1 million, respectively (2020 – $1.0 million and $0.3 million).

The Company also received government grant funding pursuant to Alberta's Site Rehabilitation Program ("SRP") with respect to approved abandonment and reclamation expenditures incurred by the Company. SRP funding of $0.7 million was received in 2021 (2020 - $0.8 million) and has been reported as other income (note 15).

p) Changing regulation

Regulations and government programs regarding emissions and climate-related matters are constantly evolving. With respect to environmental, social and governance ("ESG") and climate reporting, the IASB has issued an IFRS Disclosure Standard with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. In addition, the Canadian Securities Administrators have issued a proposed National Instrument 51-107 Disclosure of Climate-related Matters. The cost to comply with these standards and others that may be developed over time has not yet been quantified.

4. MARKETABLE SECURITIES

	Amount *($thousands)*
December 31, 2019	$ 15,220
Tourmaline Oil Corp ("TOU") shares sold	(14,316)
Change in fair value of marketable securities	(904)
December 31, 2020	$ –
Plan of Arrangement Rubellite shares and warrants received	9
Plan of Arrangement warrants exercised	118
AIMCo Bonus Shares received (note 10)	1,361
AIMCo Bonus Shares delivered (note 10)	(1,361)
Rubellite Share Purchase Warrants received (1)	2,000
Change in fair value of marketable securities	282
December 31, 2021	**$ 2,409**

(1) The Company used the Black Scholes option pricing model to calculate the estimated fair value of the Rubellite Share Purchase Warrants at the date of grant using an expected volatility of 40%, risk-free interest rate of 1.2%, dividend yield of nil, contractual life of 5-years, share price at grant date of $2.00 and exercise price of $3.00. The fair value was $0.50 per Rubellite Share Purchase Warrant.

Under the terms of the Plan of Arrangement, for every 46 common shares of Perpetual held, shareholders received 1 common share of Rubellite and 12 warrants to purchase Rubellite common shares ("Rubellite Warrants"). Each Rubellite Warrant entitled the holder to subscribe for one Rubellite common share at a price of $2.00 per share until October 4, 2021. Through it's employee trust, Perpetual received 4,500 Rubellite common shares and 54,000 Rubellite Warrants as part of the Plan of Arrangement. In the fourth quarter of 2021, Perpetual exercised its 54,000 Rubellite Warrants for $0.1 million in exchange for 54,000 Rubellite shares. As at December 31, 2021 the Company holds 58,500 Rubellite shares valued at $0.1 million using the Rubellite common share price of $2.20 per share.

In the fourth quarter of 2021, as part of the Second Lien Loan Settlement Perpetual delivered the AIMCo Bonus Shares at a value of $1.4 million.

Under the terms of the Plan of Arrangement, Perpetual also received 4.0 million Rubellite Share Purchase Warrants that were initially valued at $2.0 million when received and revalued to $2.3 million as at December 31, 2021. The Company used the Black Scholes pricing model to calculate the estimated fair value of the Rubellite Share Purchase Warrants. The following assumptions were used to arrive at the estimate of fair value at period end:

	December 31, 2021
Dividend yield (%)	–
Expected volatility (%)	40%
Risk-free interest rate (%)	1.68%
Contractual life (years)	4.7
Share price	$2.20
Exercise price	$3.00
Fair value	$0.57

During the year ended December 31, 2020, the Company sold its remaining 1,000,000 TOU shares at a weighted average price of $14.32 per share for net cash proceeds of $14.3 million. Proceeds were used to repay the $0.1 million TOU share margin demand loan in full and to pay down a portion of the Credit Facility.

5. PROPERTY, PLANT AND EQUIPMENT

	Oil and Gas Properties	Corporate Assets	Total
Cost			
December 31, 2019	$ 731,526	$ 7,688	$ 739,214
Additions	5,884	(36)	5,848
Drilling program rights (b)	18,000	–	18,000
Acquisitions	222	–	222
Change in decommissioning obligations related to PP&E (note 15)	2,747	–	2,747
Transfers from exploration and evaluation (note 6)	252	–	252
Dispositions (b)	(193,672)	–	(193,672)
December 31, 2020	$ 564,959	$ 7,652	$ 572,611
Additions	19,060	2	19,062
Acquisitions	1,325	–	1,325
Change in decommissioning obligations related to PP&E (note 15)	2,689	–	2,689
Transfers from exploration and evaluation (note 6)	2,943	–	2,943
Dispositions (a)	(16,442)	–	(16,442)
December 31, 2021	**$ 574,534**	**$ 7,654**	**$ 582,188**
Accumulated depletion and depreciation			
December 31, 2019	$ (537,149)	$ (7,431)	$ (544,580)
Depletion and depreciation	(14,926)	(136)	(15,062)
Impairment (c)	(32,300)	–	(32,300)
Dispositions (b)	143,316	–	143,316
December 31, 2020	$ (441,059)	$ (7,567)	$ (448,626)
Depletion and depreciation	(13,500)	(67)	(13,567)
Dispositions (a)	3,025	–	3,025
Impairment reversal (c)	30,600	–	30,600
December 31, 2021	**$ (420,934)**	**$ (7,634)**	**$ (428,568)**
Carrying amount			
December 31, 2020	$ 123,900	$ 85	$ 123,985
December 31, 2021	**$ 153,600**	**$ 20**	**$ 153,620**

At December 31, 2021, property, plant and equipment included $1.0 million (December 31, 2020 – $1.0 million) of costs currently not subject to depletion.

For the year ended December 31, 2021, $0.4 million (December 31, 2020 – $0.2 million) of direct general and administrative expenses were capitalized. Future development costs for the year ended December 31, 2021 of $75.3 million (December 31, 2020 – $112.5 million) were included in the depletion calculation.

a) Clearwater Assets Disposition

On September 3, 2021, the disposition of the Clearwater Assets, working capital and associated cash, and decommissioning obligations to Rubellite was accounted for as being effective for consideration of $65.5 million, including $53.6 million in promissory notes, the assumption of $5.8 million of promissory notes due to 197Co, 8.2 million Perpetual common shares valued at $2.8 million, AIMCo Bonus Shares valued at $1.4 million, and the issuance of Rubellite Share Purchase Warrants valued at of $2.0 million. The consideration received, and calculation of the gain recorded on disposition is summarized below:

($ thousands)	
Proceeds from disposition (i)	**65,514**
Transaction costs and closing adjustments (ii)	**(583)**
Carrying amount of assets disposed (iii)	**(19,085)**
Carrying amount of net working capital disposed, including cash (iv)	**823**
Carrying amount of decommissioning obligations disposed (v)	**853**
Gain on disposition	**47,522**

i) Total consideration — $65.5 million of consideration as outlined below:

($ thousands)	
Promissory note issued by Rubellite to Perpetual[(1)]	**53,600**
PEI-197Co note assumed by Rubellite[(2)]	**5,773**
AIMCo Bonus Shares[(3)]	**1,361**
8.2 million Perpetual common shares[(4)]	**2,780**
Rubellite Share Purchase Warrants[(5)]	**2,000**
Total consideration received	**$ 65,514**

(1) Demand promissory note, secured by the Clearwater Assets, and settled on October 5, 2021.

(2) On July 15, 2021, Perpetual exercised an option to acquire certain E&E lands located at Figure Lake in exchange for a demand promissory note secured by the Figure Lake lands in the amount of $5.8 million owing to 197Co (note 6). The acquired Figure Lake lands comprised part of the Clearwater Assets sold to Rubellite. The secured promissory note obligation owing to 197Co was assigned by Perpetual to Rubellite as part of the total consideration.

(3) Rubellite shares issued to Perpetual on September 3, 2021 valued at $1.4 million.

(4) Rubellite returned to Perpetual 8.2 million Perpetual common shares valued at $2.8 million. Pursuant to the Plan of Arrangement, Perpetual shareholders exchanged 8.2 million Perpetual common shares with Rubellite for Rubellite common shares and warrants. The Perpetual shares received were subsequently cancelled.

(5) Represents the estimated value of 4.0 million Rubellite Share Purchase Warrants at $3.00 per share exercise price (note 4) valued at $2.0 million.

ii) Transaction costs and closing adjustments — $0.6 million of transaction costs and closing adjustments.

iii) Carrying amount of assets disposed — $19.1 million of assets including oil and gas properties ($16.1 million of costs less $2.8 million of accumulated depletion) and exploration and evaluation assets ($5.8 million).

iv) Carrying amount of net working capital disposed — $0.8 million of net working capital including cash ($4.1 million), accounts receivable ($0.7 million), and accounts payable ($5.6 million).

v) Carrying amount of decommissioning obligations disposed — $0.9 million of decommissioning obligations associated with oil and gas properties disposed.

b) East Edson Disposition

On April 1, 2020, the Company sold a 50% working interest in its East Edson property in West Central Alberta to a third party (the "Purchaser") for consideration including a cash payment of $35 million and the carried interest funding of the drill, complete and tie-in costs for an eight well drilling program (the "East Edson Transaction"). The consideration received, and calculation of the gain (loss) recorded on disposition is summarized below:

($ thousands)	
Cash proceeds from disposition (i)	**34,750**
Drilling program rights received (ii)	**18,000**
Retained East Edson royalty obligation (iii)	**(6,996)**
Carrying amount of PP&E and E&E disposed (iv)	**(52,803)**
Carrying amount of decommissioning obligations disposed (v)	**7,049**
Gain (loss) on disposition	**–**

i)	Cash proceeds from disposition	$35.0 million of cash received on closing, net of $0.2 million of transaction costs and closing adjustments. In order to reflect the nature of the proceeds received, cash proceeds from disposition have been allocated on the consolidated statements of cash flows to financing and investing activities in the amount of $7.0 million and $27.8 million, respectively.
ii)	Drilling program rights received	$18.0 million of drilling program rights, comprised of the carried interest funding of the drill, complete, and tie-in costs for an eight-well drilling program. All eight horizontal wells targeting development of the Wilrich formation have been drilled, completed, and commenced production. Drilling program rights have been subject to depletion.
iii)	Retained East Edson royalty obligation	$7.0 million that Perpetual will retain until December 31, 2022 on behalf of the Purchaser, comprising the fair value of the Purchaser's 50% working interest in the existing gross overriding royalty on the East Edson property equivalent to 2.8 MMcf/d of conventional natural gas and associated NGL production (note 13).
iv)	Carrying amount of PP&E and E&E disposed	$52.8 million of oil and gas properties ($50.4 million) and exploration and evaluation assets ($2.4 million).
v)	Carrying amount of decommissioning obligations disposed	$7.0 million of decommissioning obligations associated with oil and gas properties disposed.

c) Cash-generating units and impairment and impairment reversals

During the year ended December 31, 2021, the Company reversed $30.6 million of historical impairments, net of depletion.

The Company identified an indicator of impairment reversal at June 30, 2021 for the West Central and Eastern Alberta cash generating units and additionally at December 31, 2021 for the Eastern Alberta CGU and performed impairment reversal tests to estimate the recoverable amount of each CGU. It was determined the recoverable amount of the West Central and Eastern Alberta CGUs exceeded each CGU's carrying value, resulting in all previous West Central impairment, net of depletion, of $22.6 million and Eastern Alberta impairment of $7.5 million, respectively, being reversed. No historical impairments remain for the West Central CGU.

At December 31, 2021, indicators of impairment reversal for the Eastern Alberta CGU included the recovery in global oil and gas commodity prices, changing development plans, positive proved and probable oil and gas reserve revisions, and increasing economic stability and certainty in the oil and gas industry, all of which positively impact operating cash flows. There were no internal or external indicators of impairment for the West Central CGU as at December 31, 2021. The estimated recoverable amount of the Eastern Alberta CGU was determined using the value-in-use methodology, based on the estimates of proved and probable oil and gas reserves and the related cash flows as evaluated by the Company's independent third party reserve evaluators at December 31, 2021, along with forecasted oil and gas commodity prices based on an average of three independent third party reserve evaluators, and an estimate of market discount rates between 10% and 20% to consider risks specific to the Eastern Alberta CGU.

At December 31, 2021, the Company determined that the estimated recoverable amount of the Eastern Alberta CGU exceeded the carrying amount of $42.2 million. Accordingly, an impairment reversal of $0.5 million was included in net income.

Forecasted oil and gas commodity prices based on an average of three independent third party reserve evaluators were used in the VIU calculation as at December 31, 2021:

Year	West Texas Intermediate ("WTI") Crude Oil *(US$/bbl)*	USD/CDN exchange rate *(US$/Cdn$)*	Alberta Heavy Crude Oil *(Cdn$/bbl)*	AECO Gas *(Cdn$/MMBtu)*	NYMEX Gas *(Cdn$/MMBtu)*
2022	72.83	0.797	66.45	3.56	4.83
2023	68.78	0.797	61.90	3.21	4.32
2024	66.76	0.797	59.45	3.05	3.98
2025	68.09	0.797	60.64	3.11	4.06
2026	69.45	0.797	61.87	3.17	4.15
2027	70.84	0.797	63.11	3.23	4.23
2028	72.26	0.797	64.37	3.30	4.31
2029	73.70	0.797	65.67	3.36	4.40
2030	75.18	0.797	66.68	3.43	4.49
2031	76.68	0.797	68.02	3.50	4.58
2032	78.21	0.797	69.38	3.57	4.67
2033	79.78	0.797	70.77	3.64	4.76
2034	81.37	0.797	72.18	3.71	4.86
2035	83.00	0.797	73.63	3.79	4.95
2036(1)	84.66	0.797	75.10	3.86	5.05

(1) Forecasted oil and gas commodity prices escalate 2.0% per year thereafter.

As at December 31, 2021, if discount rates used in the calculation of impairment reversal changed by 1% with all other variables held constant, the impairment reversal would change by approximately $1.5 million. As at December 31, 2021, if commodity price estimates changed by 5% with all other variables held constant, the impairment reversal would change by approximately $5.8 million.

At June 30, 2021, indicators of impairment reversal for the West Central and Eastern Alberta CGUs related to the significant recovery in global oil and natural gas prices, coupled with the increasing economic stability and certainty in the oil and natural gas industry which positively impacts operating cash flows. The estimated recoverable amounts of the CGUs were determined using VIU based on the estimates of proved and probable oil and gas reserves and the related cash flows as evaluated or reviewed by the Company's independent third party reserves evaluators and updated by internal reserve evaluators, along with forecasted oil and gas commodity prices based on an average of three independent third party reserve evaluators as at July 1, 2021, and an estimate of market discount rates between 12% and 22% to consider risks specific to the CGUs.

The Company determined that the estimated recoverable amounts of the West Central CGU and Eastern Alberta CGU exceeded their carrying amounts of $89.6 million and $28.6 million, respectively. Accordingly, an impairment reversal of $30.1 million was included in net income in the second quarter of 2021.

Forecasted oil and gas commodity prices based on an average of three independent third party reserve evaluators were used in the VIU calculations as at June 30, 2021:

Year	WTI Crude Oil *(US$/bbl)*	USD/CDN exchange rate *(US$/Cdn$)*	Alberta Heavy Crude Oil *(Cdn$/bbl)*	AECO Gas *(Cdn$/MMBtu)*	NYMEX Gas *(Cdn$/MMBtu)*
2021	66.59	0.80	61.66	3.18	4.16
2022	67.20	0.80	61.13	3.13	3.98
2023	63.95	0.80	55.88	2.72	3.65
2024	63.23	0.80	54.95	2.71	3.70
2025	64.50	0.80	56.06	2.76	3.78
2026	65.79	0.80	57.19	2.82	3.85
2027	67.10	0.80	58.34	2.88	3.93
2028	68.44	0.80	59.51	2.94	4.01
2029	69.81	0.80	60.71	2.99	4.09
2030	71.21	0.80	61.92	3.05	4.17
2031	72.63	0.80	63.16	3.12	4.26
2032	74.09	0.80	64.43	3.18	4.34
2033	75.57	0.80	65.71	3.24	4.43
2034	77.08	0.80	67.03	3.31	4.52
2035(1)	78.62	0.80	68.37	3.37	4.61

(1) Commodity price estimates escalate 2.0% per year thereafter.

For the year ended December 31, 2020, the Company recorded an aggregate non-cash impairment charge of $32.3 million related to its CGUs, comprised of a $50.3 million impairment at March 31, 2020 and a $18.0 million impairment reversal at December 31, 2020.

At March 31, 2020, the Company conducted an assessment of internal and external indicators of impairment for all the Company's CGUs. In performing the assessment, management determined that the significant decline in global oil and gas commodity prices that was experienced following the onset of the COVID-19 pandemic, coupled with the considerable economic instability and uncertainty in the oil and gas industry which negatively impacts operating cash flows, justified calculation of the estimated recoverable amount of the liquids-rich conventional natural gas assets and heavy crude oil assets which comprise the West Central CGU and Eastern Alberta CGU, respectively. The estimated recoverable amounts of the CGUs were determined using VIU based on the estimates of proved and probable oil and gas reserves and the related cash flows as evaluated by the Company's independent third party reserves evaluators at December 31, 2019 and updated by internal reserve evaluators to March 31, 2020, along with forecasted oil and gas commodity prices based on an average of three independent third party reserve evaluators, and an estimate of market discount rates between 12% and 25% to consider risks specific to the CGUs. At March 31, 2020, the Company determined that the carrying amounts of the West Central CGU and Eastern Alberta CGU exceeded the estimated recoverable amounts of $66.3 million and $26.4 million, respectively. Accordingly, an aggregate non-cash impairment charge of $50.3 million was included in net loss.

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

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

Forecasted oil and gas commodity prices based on an average of three independent third party reserve evaluators were used in the VIU calculations as at December 31, 2020:

Year	West Texas Intermediate Crude Oil *(US$/bbl)*	USD/CDN exchange rate *(US$/Cdn$)*	Alberta Heavy Crude Oil *(Cdn$/bbl)*	AECO Gas *(Cdn$/MMBtu)*	NYMEX Gas *(Cdn$/MMBtu)*
2021	47.17	0.768	39.87	2.78	3.69
2022	50.17	0.765	43.20	2.70	3.75
2023	53.17	0.763	46.86	2.61	3.80
2024	54.97	0.763	48.67	2.65	3.88
2025	56.07	0.763	49.65	2.70	3.95
2026	57.19	0.763	50.65	2.76	4.03
2027	58.34	0.763	51.67	2.81	4.11
2028	59.50	0.763	52.71	2.87	4.19
2029	60.69	0.763	53.76	2.92	4.28
2030	61.91	0.763	54.84	2.98	4.36
2031	63.15	0.763	55.94	3.04	4.45
2032	64.41	0.763	57.05	3.10	4.54
2033	65.70	0.763	58.20	3.16	4.63
2034	67.01	0.763	59.36	3.23	4.72
2035(1)	68.35	0.763	60.55	3.29	4.81

(1) Forecasted oil and gas commodity prices escalate 2.0% per year thereafter.

6. EXPLORATION AND EVALUATION

	December 31, 2021	December 31, 2020
Balance, beginning of year	**$ 10,272**	$ 23,609
Additions	**–**	91
Acquisitions	**5,773**	–
Dispositions	**(5,773)**	(2,447)
Impairments	**–**	(10,200)
Non-cash exploration and evaluation expense	**–**	(529)
Transfers to property, plant and equipment	**(2,943)**	(252)
Balance, end of year	**$ 7,329**	$ 10,272

On July 15, 2021, Perpetual exercised an option to acquire lands located at Figure Lake in exchange for a demand promissory note secured by the Figure Lake lands in the amount of $5.8 million owing to 197Co. The acquired Figure Lake lands comprised part of the Clearwater Assets sold to Rubellite. The secured promissory note obligation owing to 197Co was assigned by Perpetual to Rubellite as part of the disposition of the Clearwater Assets.

During the year ended December 31, 2021, $0.1 million (2020 – $0.2 million) in costs were charged directly to E&E expense in net income (loss).

Impairment of E&E assets

E&E assets are tested for impairment when internal or external indicators of impairment or impairment reversal exist as well as upon their eventual reclassification to oil and natural gas properties in PP&E.

At December 31, 2021, the Company conducted an assessment of indicators of impairment and impairment reversal for the Company's E&E assets. There were no triggers identified and therefore, no impairments or impairment reversals recognized during the year ended 2021.

As at December 31, 2020, the Company conducted an assessment of internal and external indicators of impairment and impairment reversal for the Company's E&E assets. In performing the assessment, management determined that the recovery in global oil and gas commodity prices, changing development plans, positive revisions to reserves, and increasing economic stability and certainty in the oil and gas industry, all of which positively impacts operating cash flows, justified calculation of the estimated recoverable amount of E&E assets. As a result of this calculation, the Company determined that there was no non-cash impairment charge or impairment reversal to record.

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

7. RIGHT-OF-USE ASSETS

The Company leases several assets including office space, vehicles, and miscellaneous other assets. Information about leases for which the Company is a lessee is presented below:

	Head office	Vehicles	Other leases	Total
Cost				
January 1, 2020	$ 1,498	$ 200	$ 161	$ 1,859
Additions	93	189	86	368
December 31, 2020	$ 1,591	$ 389	$ 247	$ 2,227
Additions	–	221	–	221
December 31, 2021	**$ 1,591**	**$ 610**	**$ 247**	**$ 2,448**
Accumulated depreciation				
January 1, 2020	$ (240)	$ (80)	$ (64)	$ (384)
Depreciation	(257)	(135)	(79)	(471)
December 31, 2020	$ (497)	$ (215)	$ (143)	$ (855)
Depreciation	(258)	(134)	(61)	(453)
December 31, 2021	**$ (755)**	**$ (349)**	**$ (204)**	**$ (1,308)**
Carrying amount				
December 31, 2020	$ 1,094	$ 174	$ 104	$ 1,372
December 31, 2021	**$ 836**	**$ 261**	**$ 43**	**$ 1,140**

8. CONTINGENCIES

On August 3, 2018, the Company received a Statement of Claim that was filed by PricewaterhouseCoopers Inc. LIT ("PwC"), in its capacity as trustee in bankruptcy (the "Trustee") of Sequoia Resources Corp. ("Sequoia"), with the Alberta Court of Queen's Bench (the "Court"), against Perpetual (the "Sequoia Litigation"). The claim relates to a six-year-old transaction when, on October 1, 2016, Perpetual closed the disposition of shallow conventional natural gas assets in Eastern Alberta to an arm's length third party at fair market value at the time after an extensive and lengthy marketing, due diligence, and negotiation process (the "Sequoia Disposition"). This transaction was one of several completed by Sequoia. Sequoia assigned itself into bankruptcy on March 23, 2018. PwC is seeking an order from the Court to either set this transaction aside or declare it void, or damages of approximately $217 million. On August 27, 2018, Perpetual filed a Statement of Defence and Application for Summary Dismissal with the Court in response to the Statement of Claim. All allegations made by PwC have been denied and applications to the Court to dismiss all claims has been made on the basis that there is no merit to any of them.

On January 13, 2020, the Court issued its written decision related to the Sequoia Disposition. The decision dismissed and struck all claims against the Company's CEO and all but one of the claims filed against Perpetual. The Court did not find that the test for summary dismissal relating to whether the asset transaction was an arm's length transfer for purposes of section 96(1) of the Bankruptcy and Insolvency Act (the "BIA") was met, on the balance of probabilities. Accordingly, the BIA claim was not dismissed or struck and only that part of the claim could continue against Perpetual. The Trustee filed a notice of appeal with the Court of Appeal of Alberta, challenging the entire decision, and Perpetual filed a similar notice of appeal contesting the BIA claim portion of the decision (the "First Appeal").

On February 25, 2020, Perpetual filed a second application to strike and summarily dismiss the BIA claim on the basis that there was no transfer at undervalue, and Sequoia was not insolvent at the time of the asset transaction nor caused to be insolvent by the asset transaction. In July 2020, the Orphan Well Association ("OWA"), certain oil and gas companies, and six municipalities applied to intervene in the second BIA dismissal application proceedings. The OWA and certain oil and gas companies were permitted to intervene (the "Intervenors") in the proceedings which took place on October 1 and 2, 2020. The Intervenors were also permitted to intervene in the First Appeal proceedings. On January 14, 2021 the Court issued its decision, finding that the Trustee could not establish a necessary element of the BIA Claim as Sequoia was not insolvent at the time of, nor rendered insolvent by, the Sequoia Disposition. The Court therefore concluded there is "no merit" to the BIA Claim and it summarily dismissed the balance of the Statement of Claim. The Trustee appealed this decision, and the Court of Appeal hearing took place on February 10, 2022, with the panel reserving judgement.

The First Appeal proceedings were heard on December 10, 2020. On January 25, 2021, the Court of Appeal of Alberta issued their judgement with respect to the First Appeal proceedings, dismissing the appeal filed by Perpetual and granting certain aspects of the appeals filed by the Trustee, thereby reinstating certain elements of the Sequoia Litigation for trial. On March 24, 2021, Perpetual applied for leave to appeal the First Appeal decision to the Supreme Court of Canada (the "SCC"). On July 8, 2021, the SCC dismissed Perpetual's application.

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

9. REVOLVING BANK DEBT

As at December 31, 2021, the Company's Credit Facility had a Borrowing Limit of $17.0 million (December 31, 2020 – $20.0 million) under which $2.5 million was drawn (December 31, 2020 – $17.5 million) and $1.0 million of letters of credit had been issued (December 31, 2020 – $0.9 million). Borrowings under the Credit Facility bear interest at its lenders' prime rate or Banker's Acceptance rates, plus applicable margins and standby fees. The applicable Banker's Acceptance margins range between 3.0% and 5.5%. The effective interest rate on the Credit Facility at December 31, 2021 was 5.9%. For the year ended December 31, 2021, if interest rates changed by 1% with all other variables held constant, the impact on annual cash finance expense and net income would be nil.

During the third quarter of 2021, Perpetual entered into an agreement with its syndicate of lenders to extend its Credit Facility maturity to November 30, 2022 with the opportunity to extend the revolving period for a further six months subject to approval by the syndicate. If not extended on or before November 30, 2022 all outstanding advances will be repayable on May 31, 2023.

During the fourth quarter of 2021, the Credit Facility borrowing limit was reduced from $20.0 million to $17.0 million and on December 17, 2021 the semi-annual borrowing base redetermination of the Company's first lien credit facility was completed and the existing $17.0 million borrowing limit and term of the credit facility was maintained. The next borrowing limit redetermination is scheduled to occur on or before May 31, 2022.

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

At December 31, 2021, the Credit Facility was not subject to any additional financial covenants and the Company was in compliance with all customary non-financial covenants.

10. TERM LOAN

			December 31, 2021		December 31, 2020	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
Term loan	December 31, 2024	8.1%	**$ 2,671**	**$ 2,469**	$ 46,823	$ 46,691

During the third quarter, Perpetual and its Term Loan lender entered into an agreement establishing the terms and conditions of the Second Lien Loan Settlement. On September 3, 2021, upon completion of the Plan of Arrangement, Perpetual's executed its agreement with its Term Loan lender for the settlement of principal and all interest owing on the Term Loan. Perpetual substantively modified the previous Term Loan for the payment of approximately $38.5 million in cash, the delivery by Perpetual of 0.7 million Rubellite common shares (AIMCo Bonus Shares) at a value of $1.4 million, the issuance of a new $2.7 million second lien Term Loan, and up to an aggregate of $4.5 million in potential contingent payments in the event that Perpetual's annual average realized oil and natural gas prices exceed certain thresholds initially valued at $0.2 million (note 11). The New Second Lien Term Loan bears interest at 8.1% annually, which Perpetual may elect to pay-in-kind, and will mature on December 31, 2024. All amounts related to the Second Lien Loan Settlement were paid on October 5, 2021.

The Company and the Term Loan lender agreed to allow $1.8 million of interest due on the December 31, 2020 to be paid-in-kind and added to the outstanding principal amount of the loan and all other interest owing on the Term Loan to be settled as part of the Second Lien Loan Settlement. Non-cash paid in-kind interest of $0.8 million was recorded in the third quarter of 2021, which increased the principal amount of the Term Loan owing upon settlement to $49.6 million. As a result of the Second Lien Loan Settlement, the carrying amount of $49.6 million was in excess of the consideration received of $42.8 million, resulting in a gain of $6.8 million being recognized (note 20).

The New 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.

At December 31, 2021 the Term Loan is presented net of $0.2 million in issue costs which are amortized over the remaining term of the loan using a weighted average effective interest rate of 11.1%.

At December 31, 2021, the Term Loan was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

11. OTHER LIABILITY

Pursuant to the terms of the Second Lien Loan Settlement, Perpetual was committed to pay up to $4.5 million in potential contingent payments in the event that the Company's annual average realized crude oil and natural gas prices exceed certain thresholds in each of the annual periods ended December 31, 2023. The payment for 2021 was capped at $1.3 million; the payment for 2022 is capped at $1.3 million; and the payment for 2023 is capped at $1.9 million. Of the 2021 payment cap, only $0.2 million was earned. This leaves a maximum remaining total obligation to be earned in 2022 and 2023 of $3.2 million. At December 31, 2021 the Company estimated the fair value of the contingent liability to be $1.4 million. The change in fair value of this liability was recorded in the statement of comprehensive income (loss) as a non-cash finance expense. The table below summarizes the change in fair value of the contingent payments:

	December 31, 2021	December 31, 2020
Balance, initial recognition	**$ 228**	$ –
Change in fair value	**1,159**	–
Total other liability	**$ 1,387**	$ –

	December 31, 2021	December 31, 2020
Current	**$ 63**	$ –
Non-current	**1,324**	–
Total other liability	**$ 1,387**	$ –

The Company has designated the other liability as financial liabilities which are measured at fair value through profit and loss, estimated by discounting potential contingent payments. For the year ended December 31, 2021, an unrealized loss of $1.1 million is included in non-cash finance expense related to the change in fair value of other liability (note 20).

At December 31, 2021, if forecasted natural gas commodity prices changed by $0.25 per GJ with all other variables held constant, the fair value of the total other liability and net income for the period would change by nil as the annual average natural gas prices thresholds would still not be met. If forecasted crude oil commodity prices changed by $5.00 per bbl with all other variables held constant, the fair value of the other liability and net income for the period would change by $0.7 million.

12. SENIOR NOTES

			December 31, 2021		December 31, 2020	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
Senior notes	January 23, 2025	8.75%	**$ 36,583**	**$ 34,189**	$ 33,580	$ 32,359

On January 22, 2021, Perpetual announced the completion of a Court-approved plan of arrangement whereby the unsecured 2022 Senior Notes were exchanged for new 8.75% secured third lien notes due January 23, 2025. The 2025 Senior Notes have been issued under a trust indenture that contains substantially the same terms as the 2022 Senior Notes, other than the 2025 Senior Notes are secured on a third lien basis and allow for the semi-annual interest payments to be paid at Perpetual's option, in cash, or in additional 2025 Senior Notes (a "PIK Interest Payment"). The Company elected to pay the January 23, 2021 semi-annual interest of $1.5 million by a PIK Interest Payment, and satisfied the semi-annual interest payment due July 23, 2021 by making a PIK Interest Payment of $1.5 million, increasing the principal amount owing at December 31, 2021 to $36.6 million. Subsequent to year end, the Company satisfied the January 23, 2022 semi-annual interest payment of $1.6 million by making a cash payment.

At December 31, 2021, the senior notes are recorded at the present value of future cash flows, net of $2.4 million in issue and principal discount costs which are amortized over the remaining term using a weighted average effective interest rate of 11.3%

The senior notes are direct senior secured, third lien obligations of the Company. The Company may redeem the senior notes without any repayment penalty. The senior notes have a cross-default provision with the Company's Credit Facility. In addition, the senior notes indenture contains restrictions on certain payments including dividends, retirement of subordinated debt, and stock repurchases. At December 31, 2021, the senior notes were not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Entities controlled by the Company's CEO hold $15.9 million of the 2025 Senior Notes outstanding. An entity that is associated with the Company's CEO, and entities associated with other Directors of the Company hold an additional $10.3 million and $0.8 million of the 2025 Senior Notes outstanding, respectively.

13. ROYALTY OBLIGATIONS

	Retained East Edson royalty obligation	Gas over bitumen royalty financing	Total
December 31, 2019	–	871	871
Initial recognition (note 5)	6,996	–	6,996
Cash payments	–	(704)	(704)
Non-cash payments in-kind	(2,319)	–	(2,319)
Change in fair value (note 20)	1,037	268	1,305
December 31, 2020	5,714	435	6,149
Cash payments[1]	–	(558)	(558)
Non-cash payments in-kind	(4,995)	–	(4,995)
Change in fair value (note 20)	3,978	123	4,101
December 31, 2021	**4,697**	**–**	**4,697**

(1) The final payment related to the gas over bitumen royalty financing was made on July 25, 2021.

	December 31, 2021	December 31, 2020
Current	**$ 4,697**	$ 3,553
Non-current	**–**	2,596
Total royalty obligations	**$ 4,697**	$ 6,149

The retained East Edson royalty obligation formed part of the net consideration received by Perpetual from the East Edson Transaction whereby Perpetual agreed to retain the Purchaser's 50% working interest in the existing gross overriding royalty obligation on the property, equivalent to 2.8 MMcf/d of natural gas and associated NGL production for the period April 1, 2020 to December 31, 2022 (see note 5(b)). Prior to November 1, 2021, the retained East Edson royalty obligation was paid in-kind, and settled through non-cash delivery of contractual natural gas and NGL volumes to the royalty holder. As of November 1, 2021, the royalty obligation is settled through payment in cash.

The Company has designated the retained East Edson royalty obligation and the gas over bitumen royalty financing as financial liabilities which are measured at fair value through profit and loss, estimated by discounting future royalty obligations based on forecasted natural gas and NGL commodity prices multiplied by the royalty obligation volumes. For the year ended December 31, 2021, an unrealized loss of $4.1 million (2020 – unrealized loss of $1.3 million) is included in non-cash finance expense related to the change in fair value of total royalty obligations (note 20).

As at December 31, 2021, if forecasted natural gas commodity prices changed by $0.25 per GJ with all other variables held constant, the fair value of the total royalty obligations and net income (loss) for the period would change by $0.3 million.

14. LEASE LIABILITIES

	December 31, 2021	December 31, 2020
Balance, beginning of year	**$ 2,501**	$ 2,685
Additions	**221**	368
Interest on lease liabilities (note 20)	**148**	175
Payments	**(768)**	(727)
Total lease liabilities	**$ 2,102**	$ 2,501
Current	**$ 778**	$ 710
Non-current	**1,324**	1,791
Total lease liabilities	**$ 2,102**	$ 2,501

Lease terms are negotiated on an individual basis and contain a wide range of terms and conditions. Incremental borrowing rates used to measure the present value of the future lease payments were between 4.3% and 6.6%. During the year ended December 31, 2021, the Company recognized $0.1 million (2020 – $0.1 million) of short-term, low value, and variable lease costs directly in net income (loss)

15. DECOMISSIONING OBLIGATIONS

The following table summarizes changes in decommissioning obligations:

	December 31, 2021	December 31, 2020
Obligations incurred, including acquisitions	**$ 965**	$ 603
Change in risk free interest rate	**(1,309)**	2,344
Change in estimates	**3,033**	(200)
Change in decommissioning obligations related to PP&E (note 5)	**2,689**	2,747
Obligations settled (cash)	**(1,760)**	(210)
Obligations settled[1] (non-cash)	**(704)**	(812)
Obligations disposed (note 5(a), 5(b))	**(853)**	(7,049)
Accretion (note 20)	**531**	443
Change in decommissioning obligations	**(97)**	(4,881)
Balance, beginning of year	**33,024**	37,905
Balance, end of year	**$ 32,927**	$ 33,024
Current	**$ 1,327**	$ 1,048
Non-current	**31,600**	31,976
Total decommissioning obligations	**$ 32,927**	$ 33,024

(1) Obligations settled (non-cash) of $0.7 million (2020 – $0.8 million) were funded by payments made directly to Perpetual's service providers through the Alberta Site Rehabilitation Program. These amounts have been recorded as other income.

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 increase in the provision due to the passage of time, which is referred to as accretion, is recognized as non-cash finance expense in the consolidated statements of loss and comprehensive loss. Decommissioning obligations are further adjusted at each period end date for changes in the risk-free interest rate, after considering additions and dispositions of PP&E. Decommissioning obligations are also adjusted for revisions to future cost estimates and the estimated timing of costs to be incurred in future periods.

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

	December 31, 2021	December 31, 2020
Undiscounted obligations	**$ 32,254**	$ 31,683
Average risk-free rate	**1.7%**	1.2%
Inflation rate	**1.8%**	1.5%
Expected timing of settling obligations	**1 to 25 years**	1 to 25 years

16. CONTRACTUAL OBLIGATIONS

As at December 31, 2021, the Company's minimum contractual obligations and lease commitments over the next five years and thereafter, excluding estimated interest payments, are as follows:

	2022	2023	2024	2025	2026 and thereafter	Total
Contractual obligations						
Accounts payable and accrued liabilities	32,223	–	–	–	–	32,223
Revolving bank debt	–	2,487	–	–	–	2,487
Term loan, principal amount	–	–	2,671	–	–	2,671
Senior notes, principal amount	–	–	–	36,583	–	36,583
Royalty obligations	4,697	–	–	–	–	4,697
Lease liabilities	778	651	550	123	–	2,102
Pipeline transportation commitments	1,688	1,535	1,231	1,231	303	5,988
Total	**39,386**	**4,673**	**4,452**	**37,937**	**303**	**86,751**

17. SHARE CAPITAL

	December 31, 2021		December 31, 2020	
	Shares *(thousands)*	**Amount** *($thousands)*	Shares *(thousands)*	Amount *($thousands)*
Balance, beginning of year	**61,305**	**$ 97,333**	60,513	$ 96,876
Issued pursuant to share-based payment plans	**1,828**	**243**	548	340
Shares held in trust purchased (b)	**(542)**	**(191)**	–	–
Shares held in trust issued (b)	**566**	**168**	244	117
Treasury shares issued (c)	**1,000**	**230**	–	–
Shares held in trust sold pursuant to the Plan of Arrangement (d)	**189**	**9**	–	–
Shares held in trust split pursuant to the Plan of Arrangement (d)	**(189)**	**–**	–	–
Common share split (d)	**8,158**	**–**	–	–
Common share cancellation (d)	**(8,158)**	**(2,779)**	–	–
Common share odd-lot consolidation (e)	**(590)**	**(204)**	–	–
Balance, end of year	**63,567**	**$ 94,809**	61,305	$ 97,333

a) Authorized

Authorized capital consists of an unlimited number of common shares.

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 18). 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, 2021, 0.5 million shares were held in trust (December 31, 2020 – 0.6 million).

c) Treasury shares issued

During the first quarter of 2021, 1.0 million common shares were issued to an Officer of the Company in exchange for $0.2 million in cash consideration at a price of $0.23 per share, representing the volume weighted average trading price of the shares for the 5-day period immediately preceding the issuance.

d) Common share split and common share cancellation

As part of the Plan of Arrangement, 8.2 million Perpetual common shares were received by Rubellite from Perpetual shareholders in exchange for Rubellite common shares and warrants, and Perpetual split its shares by a ratio such that the number of Perpetual shares exchanged to Rubellite was equal to the number of shares split. On September 3, 2021, Perpetual received 8.2 million Perpetual common shares held by Rubellite as part of the consideration for the disposition of the Clearwater Assets and these shares were cancelled.

e) Common share odd-lot consolidation

Pursuant to steps in the Plan of Arrangement, Perpetual consolidated its common shares on the basis of 1,000 to 1 (the "Consolidation") and subsequently split the Common Shares on the same ratio. Shareholders who owned a number of common shares less than 1 subsequent to the consolidation and preceding the split (the "Consolidated Shareholders") were paid an amount in cash of $0.3419 per pre consolidated common share, being the volume weighted average trading price of the common shares on the Toronto Stock Exchange for the 20-day period prior to the effective date. Based on the ratio, 590,000 Common Shares were cancelled as a result of the Consolidation and Perpetual paid an aggregate of $0.2 million to the Consolidated Shareholders.

f) Per share information

For the year ended	**December 31, 2021**	December 31, 2020
(*thousands, except per share amounts*)		
Net income (loss) – basic	**$ 81,121**	$ (61,597)
Effect of dilutive securities	**-**	–
Net income (loss) – diluted	**$ 81,121**	$ (61,597)
Weighted average shares		
Issued common shares	**63,377**	61,577
Effect of shares held in trust	**(408)**	(564)
Weighted average common shares outstanding – basic	**62,969**	61,013
Weighted average common shares outstanding – diluted(1)	**69,989**	61,013
Net income (loss) per share – basic	**$ 1.29**	$ (1.01)
Net income (loss) per share – diluted	**$ 1.16**	$ (1.01)

(1) For the year ended December 31, 2021, 8.8 million potentially issuable common shares through the share-based compensation plans were excluded as they were not dilutive. For year ended December 31, 2020, 16.3 million potentially issuable common shares through the share-based compensation plans were excluded as they were not dilutive.

18. SHARE-BASED PAYMENTS

The components of share-based payment expense are as follows:

	December 31, 2021	December 31, 2020
Compensation awards	$ 277	$ 155
Share options	83	216
Performance share rights	1,684	1,646
Share-based payment expense	**$ 2,044**	$ 2,017

The following tables summarize information about options, rights, and awards outstanding:

	Compensation awards					
(thousands)	**Deferred options**	**Deferred shares**	**Share options**	**Performance share rights(1)**	**Restricted rights**	**Total**
December 31, 2019	3,587	1,276	4,604	2,745	–	12,212
Granted	2,250	1,571	873	1,710	557	6,961
Exercised for common shares	–	–	–	–	(548)	(548)
Exercised for shares held in trust	–	(244)	–	–	–	(244)
Exercised for restricted rights	–	(40)	–	(517)	–	(557)
Performance adjustment	–	–	–	(518)	–	(518)
Cancelled/forfeited	(754)	(162)	–	–	(9)	(925)
Expired	(26)	–	(80)	–	–	(106)
December 31, 2020	5,057	2,401	5,397	3,420	–	16,275
Granted(2)	2,448	1,367	1,258	1,715	1,436	8,224
Exercised for common shares	–	–	(398)	N/A	(1,428)	(1,826)
Exercised for shares held in trust	(198)	(161)	–	–	–	(359)
Exercised for restricted rights	(303)	(278)	–	(855)	–	(1,436)
Performance adjustment(3)	–	–	–	(855)	–	(855)
Cancelled/forfeited	(1,090)	(151)	(455)	(360)	(8)	(2,064)
Expired	(438)	(20)	(1,725)	–	–	(2,183)
December 31, 2021	**5,476**	**3,158**	**4,077**	**3,065**	–	**15,776**

(1) Certain performance share rights contain monetary awards that may be settled in cash, in common shares of the Company, or a combination thereof at the discretion of the Board of Directors, equal to the monetary amount at the time of vesting. These awards are accounted for as cash-settled share-based compensation in which the fair value of the amounts payable under the plan are recognized incrementally as an expense over the vesting period, with a corresponding change in liabilities. As at December 31, 2021, $0.3 million had been accrued pursuant to cash-settled share-based compensation awards (December 31, 2020 – $0.4 million).

(2) During the year ended December 31, 2021, 1.3 million share options, 1.7 million performance share rights, and 0.3 million deferred shares were granted to Officers and Directors of the Company.

(3) Performance share rights are subject to a performance multiplier of 0.5 to 2.

During the year ended December 31, 2021, the Company granted 6.8 million share-based payment awards, comprised of deferred options, deferred shares, share options, and performance share rights (2020 – 6.4 million). The Company used the Black Scholes pricing model to calculate the estimated fair value of the outstanding deferred options (note 18(a)) and share options (note 18(b)) at the date of grant. The following assumptions were used to arrive at the estimate of fair value as at the date of grant:

	2021	2020
Dividend yield (%)	0.0	0.0
Forfeiture rate (%)	5.0-10.0	5.0-10.0
Expected volatility (%)	60.0	60.0
Risk-free interest rate (%)	0.6-0.9	0.5
Expected life (years)	3.2-3.4	2.9-3.1
Vesting period (years)	4.0	4.0
Contractual life (years)	5.0	5.0
Weighted average share price at grant date	0.31-0.35	0.07
Weighted average fair value at grant date	0.13-0.14	0.03

During the year ended December 31, 2021, 0.9 million restricted rights were issued in exchange for the exercise of performance share rights (2020 – 0.5 million), 0.3 million in exchange for the exercise of deferred shares (2020 – nominal amount), and 0.3 million in exchange for deferred options (2020 – nil).

a) Compensation awards

Deferred options

The Company has deferred option agreements in place with certain employees whereby 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. Deferred options generally vest one quarter on each year of the term, with expiry occurring five years after issuance. The shares purchased by the independent trustee are reported as shares held in trust (note 18(b)).

The following table summarizes information about the deferred options and performance-based long-term incentive awards outstanding:

	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*)**
$0.01 to $0.29	3,739	2.8	0.21	282	0.21
$0.30 to $0.48	1,005	4.7	–	–	–
$0.85 to $1.72	732	0.8	1.72	672	1.72
Total	5,476	3.0	1.27	954	1.27

There were 2.4 million deferred options granted during 2021 (2020 - 2.3 million).

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 of Directors, cash, a grant of restricted rights (note 18(d)), 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 17(b)).

The fair value of these awards 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% (2020 – 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 share 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 average value of deferred shares at the time of grant during the year ended December 31, 2021 was $0.34 per deferred share (2020 – $0.07).

b) Share options

Perpetual's share option plan provides a long-term incentive to executive officers 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 vest evenly over four years, with expiry occurring five years after issuance.

The following table summarizes information about share options outstanding:

	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*)**
$0.07 to $0.30	1,514	3.0	0.17	433	0.21
$0.31 to $1.44	948	4.5	0.37	40	1.15
$1.45 to $1.72	1,615	0.4	1.72	1,615	1.72
Total	4,077	2.3	0.83	2,088	1.40

There were 1.3 million share options granted during 2021 (2020 – 0.9 million)

c) Performance share rights

The Company has an equity-settled performance share rights plan for the Company's executive officers. 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 18(d)), at the discretion of the Board of Directors. Performance rights are forfeited if participants of the performance share rights plan leave the organization other than through retirement or termination without cause prior to the vesting date.

The fair value of a performance share rights award is determined at the date of grant by using the closing price of common shares and multiplied by the estimated performance multiplier. As at December 31, 2021, performance multipliers of 2.0 have been assumed for those unvested awards granted in 2020 and 2021. 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% (2020 – 5%) for outstanding awards. The estimated value of performance share rights granted during the year ended December 31, 2021 was $0.23 per performance share right (2020 – $0.07).

In 2018, the Company introduced a performance-based long-term incentive awards plan (the "PLTI" plan) for the executive officers. The awards granted pursuant to the plan are tied to specific individual-based performance metrics established by the Board which can be based on "total shareholder return" or other metrics specifically designed to align with value creation for shareholders and to incentivize and retain key executive officers. The awards vest evenly over four years, with expiry occurring five years after issuance. Upon vesting, award holders may be entitled to receive, at the discretion of the Board of Directors, cash, a grant of restricted rights (note 18(d)), or a combination of cash and restricted rights.

Certain awards granted under the PLTI plan contain monetary awards that may be settled in cash, in common shares of the Company, or a combination thereof at the discretion of the Board of Directors, equal to the monetary amount at the time of vesting. These awards are accounted for as cash-settled share-based compensation in which the fair value of the amounts payable under the plan are recognized incrementally as an expense over the vesting period, with a corresponding change in liabilities. Upon exercise of these awards in exchange for cash, the liability is reduced. Upon exercise of these awards in exchange for a variable number of shares, the value in liabilities pertaining to the exercise is recorded as share capital. In 2021, the Company made payments of $1.3 million (2020 – $1.5 million) pursuant to cash-settled share-based payment awards. As at December 31, 2021, $0.3 million had been accrued pursuant to cash-settled share-based compensation awards (December 31, 2020 – $0.4 million).

d) Restricted rights

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. During the year ended December 31, 2021, the Company did not grant any restricted rights to employees, other than to settle performance share rights and deferred shares.

Restricted rights granted upon the exercise of performance share rights (note 18(c)) vest on the grant date and have a 90-day exercise period. Restricted rights granted upon the exercise of deferred compensation awards (note 18(a)) 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 previously recognized over the vesting period of the underlying performance share rights and deferred compensation awards.

19. REVENUE

The Company sells its production pursuant to fixed or variable price contracts. The transaction price for variable priced contracts is based on the commodity price, adjusted for quality, location, or other factors, whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Under the contracts, the Company is required to deliver fixed or variable volumes of conventional natural gas, heavy crude oil or NGL as may be applicable to the contract counterparty. Revenue is recognized when a unit of production is delivered to the contract counterparty. The amount of revenue recognized is based on the agreed transaction price, whereby any variability in revenue relates specifically to the Company's efforts to transfer production, and therefore the resulting revenue is allocated to the production delivered in the period during which the variability occurs. As a result, none of the variable revenue is considered constrained.

Conventional natural gas, heavy crude oil and NGL are mostly sold under contracts of varying price and volume terms of up to one year. Revenues are typically collected on the 25th day of the month following production.

For the year ended December 31, 2021, the Company had sales to two customers (2020 – two customers) which exceeded ten percent of oil and natural gas revenue. The first customer represented 26% and $15.6 million (2020 – 31% and $9.0 million) of oil and natural gas revenue, and included revenues of $2.2 million (2020 – $1.0 million) related to the market diversification contract below. The second customer represented 37% and $22.5 million (2020 – 33% and $9.7 million) of oil and natural gas revenue.

Natural gas volumes sold pursuant to the Company's market diversification contract are sold at fixed volume obligations and priced at daily index prices plus US$0.02/MMBtu until October 31, 2022 and less US$0.08/MMBtu thereafter, less transportation costs from AECO to each market price point as detailed in the table below.

In the first quarter of 2021, the Company eliminated its remaining fixed volume obligations of 10,000 MMBtu/d for the period commencing April 1, 2021 and ending on October 31, 2021 in consideration for the payment of $1.4 million over the term of the associated contract volumes. The amount was recognized as a realized loss on derivatives (note 22).

In the second quarter of 2021, the Company eliminated its remaining fixed volume obligations of 25,400 MMBtu/d for the period commencing November 1, 2021 and ending on March 31, 2022 in consideration for the payment of $1.6 million over the term of the associated contract volumes. The amount was recognized as a realized loss on derivatives (note 22).

In the third quarter of 2021, the Company eliminated its remaining fixed volume obligations of 25,400 MMBtu/d for the period commencing April 1, 2022 and ending on October 31, 2022 in consideration for the payment of $1.8 million over the term of the associated contract volumes. The amount was recognized as a realized loss on derivatives (note 22).

Market/Pricing Point	November 1, 2022 to October 31, 2024 Daily sales volume *(MMBtu/d)*
Chicago	–
Malin	15,000
Dawn	15,000
Michcon	–
Emerson	10,000
Total sales volume obligation	**40,000**

Subsequent to December 31, 2021, the company eliminated 10,000 MMBtu/d of fixed volume obligations for the period commencing November 1, 2022 and ending on March 31, 2023 and will receive payment of $1.2 million over the term of the associated contract volumes.

The following table presents the Company's oil and natural gas sales disaggregated by revenue source:

	December 31, 2021	December 31, 2020
Oil and natural gas revenue		
Natural gas[(1)(2)]	**33,012**	13,329
Oil[(3)]	**20,172**	12,015
NGL	**7,630**	4,142
Total oil and natural gas revenue	**60,814**	29,486

(1) Includes revenue related to the market diversification contract of $2.2 million for the year ended December 31, 2021 (2020 –$1.0 million). Also included are losses related to physical forward sales contracts which settled during of the period of $3.2 million for the year ended December 31, 2021 (2020 – losses of $5.2 million).

(2) For the year ended December 31, 2021, natural gas revenue includes $5.0 million of non-cash revenue taken in-kind of related to production used in the settlement of the retained East Edson royalty obligation (2020 - $2.3 million) (note 13).

(3) Also included are losses related to physical forward sales contracts which settled during of the period of $1.2 million for the year ended December 31, 2021 (2020 – losses of nil).

Included in accounts receivable at December 31, 2021 is $7.0 million of accrued oil and natural gas revenue related to December 2021 production (December 31, 2020 – $2.3 million related to December 2020 production).

20. FINANCE EXPENSE

The components of finance expense are as follows:

	December 31, 2021	December 31, 2020
Cash finance expense		
Interest on revolving bank debt	**$ 953**	$ 1,662
Interest on Term Loan	**53**	1,812
Interest on 2022 Senior Notes[(1)]	**(1,253)**	2,938
Interest on 2025 Senior Notes[(2)]	**1,408**	–
Interest on lease liabilities (note 14)	**148**	175
Total cash finance expense	**$ 1,309**	$ 6,587
Non-cash finance expense		
Interest accrued on Term Loan (note 10)	**2,743**	–
Interest paid in-kind on 2022 Senior Notes[(1)] (note 12)	**1,469**	1,823
Interest paid in-kind on 2025 Senior Notes[(2)] (note 12)	**1,533**	–
Gain on senior note maturity extension (note 12)	**(1,591)**	–
Gain on Second Lien Loan Settlement [(3)] (note 10)	**(6,820)**	–
Amortization of debt issue costs	**962**	1,673
Accretion on decommissioning obligations (note 15)	**531**	443
Change in fair value of other liability[(4)] (note 11)	**1,159**	–
Change in fair value of royalty obligations (note 13)	**4,101**	1,305
Total non-cash finance expense	**$ 4,087**	$ 5,244
Finance expense recognized in net income (loss)	**$ 5,396**	$ 11,831

(1) On January 22, 2021, Perpetual's 2022 Senior Notes were exchanged for 2025 Senior Notes, providing Perpetual the option to pay interest in-kind. Perpetual elected to pay the January 23, 2021 semi-annual interest of $1.5 million by a PIK Interest Payment. As a result, the previously accrued 2022 Senior Note cash interest of $1.3 million was reversed and replaced by $1.3 million of 2025 Senior Note non-cash interest expense.

(2) The Company satisfied the semi-annual interest payment due July 23, 2021 by making a PIK Interest Payment. Subsequent to year end, the company satisfied the semi-annual interest payment due January 22, 2022 by making a cash interest payment.

(3) On September 3, 2021, upon completion of the Plan of Arrangement, Perpetual's Term Loan was substantively modified pursuant to the Second Lien Loan Settlement which included payment of $38.5 million, delivery of 0.7 million Rubellite shares valued at $1.4 million, the entry into a new second lien term loan of $2.7 million, and a contingent payment obligation valued at $0.2 million resulting in a gain of $6.8 million.

(4) Pursuant to the terms of the Second Lien Loan Settlement, $0.2 million has been earned related to the 2021 payment cap, and Perpetual is committed to pay up to an additional $3.2 million in potential contingent payments in the event that Perpetual's annual average realized crude oil and natural gas prices exceed certain thresholds. The change in fair value of this liability was recorded in the statement of comprehensive income (loss) as a non-cash finance expense.

21. CHANGES IN NON-CASH WORKING CAPITAL INFORMATION

For the year ended	**December 31, 2021**	December 31, 2020
Accounts receivable	**$ (7,718)**	$ 1,103
Prepaid expenses and deposits	**(38)**	282
Change in non-cash working capital on disposition and other	**5,426**	–
Accounts payable and accrued liabilities	**20,299**	(1,354)
Change in non-cash working capital	**$ 17,969**	$ 31

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

For the year ended	**December 31, 2021**	December 31, 2020
Operating	**$ 3,406**	$ 1,015
Investing	**14,563**	(984)
Change in non-cash working capital	**$ 17,969**	$ 31

22. 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.

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 natural 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, accounts receivable and fair value of derivative assets at December 31, 2021 was $13.4 million (December 31, 2020 – $4.0 million), representing the Company's maximum credit exposure. The Company's credit provisions are represented by its loss allowance based on lifetime expected credit losses as at December 31, 2021 of $0.4 million (December 31, 2020 – $0.6 million). The amount of the loss allowance was determined based on historical credit loss experience, adjusted for forward-looking factors specific to the debtors and the economic environment. The total amount of accounts receivables 90 days past due is nominal as at December 31, 2021 (December 31, 2020 – $0.6 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.

c) Market risk

Market risk is the risk that changes in market prices such as foreign exchange rates, commodity prices and interest rates will affect the Company's net income (loss) 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 and foreign currency rates. 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.

Natural gas contracts

At December 31, 2021 the Company had entered into the following financial fixed price natural gas sales arrangements at AECO:

Term	**Sold/bought**	**Volumes (*GJ/d*)**	**Average price (*$/GJ*)**	**Fair Value (*$ thousands*)**
January 2022	Sold	(20,000)	4.33	147
January 2022 – March 2022	Sold	(2,500)	4.60	155
April 2022 – December 2022	Sold	(2,500)	3.57	380

Natural gas contracts - sensitivity analysis

As December 31, 2021, if future natural gas prices changed by $0.25 per GJ with all other variables held constant, the fair value of derivatives for the period of the open contracts would change by $0.4 million. Fair value sensitivity was based on published forward AECO prices.

Oil contracts

At December 31, 2021, the Company had entered into the following financial fixed price oil sales arrangements which settle in CAD$:

Term	**Volumes (*bbls/d*)**	**Western Canadian Select ("WCS") (CAD*$/bbl*)**	**Fair Value (*$ thousands*)**
January 2022 – June 2022	200	76.70	19
July 2022 – December 2022	200	70.80	(68)
January 2022 – December 2022	200	70.66	(273)

Oil contracts - sensitivity analysis

As at December 31, 2021, if future WCS oil prices changed by CAD$5.00 per bbl with all other variables held constant, the fair value of derivatives for the period of the open contracts would change by $0.7 million.

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

	December 31, 2021	December 31, 2020
Physical natural gas contracts	**$ –**	$ (3,351)
Financial natural gas contracts	**682**	–
Physical oil contracts	**–**	(22)
Financial oil contracts	**(322)**	–
Fair value of derivatives	**$ 360**	$ (3,373)
Derivative assets – current	**682**	–
Derivative liabilities – current	**(322)**	(3,373)
Fair value of derivatives	**$ 360**	$ (3,373)

The following table details the change in fair value of derivatives:

	December 31, 2021	December 31, 2020
Unrealized gain (loss) on physical natural gas contracts	**3,351**	2,943
Unrealized gain (loss) on financial natural gas contracts	**682**	4,302
Unrealized gain (loss) on physical oil contracts	**22**	(22)
Unrealized gain (loss) on financial oil contracts	**(322)**	2,253
Unrealized gain (loss) on financial NGL contracts	**–**	351
Unrealized gain (loss) on financial foreign exchange contracts	**–**	74
Unrealized change in fair value of derivatives	**3,733**	9,901
Realized gain (loss) on financial natural gas contracts(1)	**(4,748)**	(6,619)
Realized gain (loss) on financial oil contracts	**(62)**	7,967
Realized gain (loss) on financial NGL contracts	**–**	(171)
Realized gain (loss) on financial foreign exchange contracts	**–**	(469)
Change in fair value of derivatives	**(1,077)**	10,609

(1) Includes realized losses of $4.7 million (December 31, 2020 – realized losses of $0.5 million from the elimination of the Company's market diversification contract obligations.

Fair value of financial assets and liabilities

The Company's fair value measurements are classified into 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 forecasted commodity prices.

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, accounts receivable, deposits, and accounts payable and accrued liabilities approximate their carrying amounts due to their short terms to maturity. The Credit Facility bears interest at a floating market rate, and accordingly, the fair market value approximates the carrying amount.

The fair value of the other liability is estimated by discounting future cash payments based on Perpetual's annual average realized oil and natural gas prices exceeding certain thresholds. This fair value measurement is classified as level 3 as significant unobservable inputs, including the discount rate and Perpetual's forecasted annual average realized oil and natural gas prices, are used in determination of the carrying amount. A discount rate of 8.1% was determined on inception of the agreement based on the characteristics of the instrument.

The fair value of the royalty obligations is estimated by discounting future cash payments based on the forecasted natural gas and NGL commodity prices multiplied by the royalty volumes. This fair value measurement is classified as level 3 as significant unobservable inputs, including the discount rate and forecasted natural gas and NGL commodity prices, are used in determination of the carrying amount. Discount rates of 12.0% to 12.2% were determined on inception of the agreements based on the characteristics of the instruments.

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

				Fair value		
As at December 31, 2021	**Gross**	**Netting[(1)]**	**Carrying Amount**	**Level 1**	**Level 2**	**Level 3**
Financial assets						
Fair value through profit and loss						
Marketable securities	2,409	–	2,409	–	2,409	–
Fair value of derivatives	775	(93)	682	–	682	–
Financial liabilities						
Financial liabilities at amortized cost						
Revolving bank debt	(2,487)	–	(2,487)	(2,487)	–	–
Senior notes	(34,189)	–	(34,189)	–	(34,189)	–
Term loan	(2,469)	–	(2,469)	–	–	(2,469)
Fair value through profit and loss						
Other liability	(1,387)	–	(1,387)	–	–	(1,387)
Fair value of derivatives	(414)	93	(321)	–	(321)	–
Royalty obligations	(4,697)	–	(4,697)	–	–	(4,697)

(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.

				Fair value		
As at December 31, 2020	**Gross**	**Netting[(1)]**	**Carrying Amount**	**Level 1**	**Level 2**	**Level 3**
Financial assets						
Fair value through profit and loss						
Fair value of derivatives	10,384	(10,384)	–	–	–	–
Financial liabilities						
Financial liabilities at amortized cost						
Revolving bank debt	(17,495)	–	(17,495)	(17,568)	–	–
Senior notes	(32,359)	–	(32,359)	–	(32,359)	–
Term loan	(46,691)	–	(46,691)	–	–	(46,822)
Fair value through profit and loss						
Fair value of derivatives	(13,757)	10,384	(3,373)	–	(3,373)	–
Royalty obligations	(6,149)	–	(6,149)	–	–	(6,149)

(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.

d) Capital risk

The Company's policy is to maintain a strong but flexible capital structure so as to maintain investor, creditor and market confidence and to sustain its future development. The Company manages its capital structure and adjusts it in light of changes in economic conditions. The Company's capital structure consists of shareholders' equity and working capital. The Company has access to its $17.0 million first lien credit facility with a syndicate of lenders, under which $2.5 million was drawn (December 31, 2020 – $17.5 million) and $1.0 million of letters of credit had been issued (December 31, 2020 – $0.9 million).

23. 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 net income (loss) before income tax. This difference results from the following items:

	December 31, 2021	December 31, 2020
Net income (loss) before income tax	**$ 81,121**	$ (61,597)
Combined federal and provincial tax rate	**23.0%**	24.0%
Computed income tax expense (recovery)	**18,658**	(14,783)
Increase (decrease) in income taxes resulting from:		
Non-deductible expenses	**162**	127
Non-taxable capital (gain) loss	**(952)**	108
Other	**218**	526
Change in tax losses applied	**-**	7,395
Change in tax rates and unrecognized tax assets	**(18,086)**	6,627
Deferred income tax expense	**$ -**	$ –

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, 2021**	December 31, 2020
Liabilities:		
Property, plant and equipment	**$ 28,187**	$ -
Senior notes	**550**	281
Term loan	**46**	30
Revolving bank debt	**118**	-
Share investment	**262**	-
Fair value of derivatives	**157**	-
Right-of-use-assets	**262**	315
Total deferred income tax liabilities	**29,582**	626
Assets:		
Decommissioning obligations	**$ (7,573)**	$ (626)
Lease liabilities	**(484)**	-
Royalty obligations	**(1,080)**	-
Share and debt issue costs	**(548)**	-
Fair value of derivatives	**(74)**	-
Other liabilities	**(319)**	-
Non-capital losses	**(19,504)**	-
Total deferred income tax assets	**(29,582)**	(626)
	$ -	$ -

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, 2021**	December 31, 2020
Non-capital losses	**$ 100,923**	$ 213,221
Capital losses	**219,345**	227,346
Property, plant and equipment	**-**	80,025
Decommissioning obligations	**-**	30,299
Fair value of derivatives	**-**	3,373
Share and debt issue costs	**-**	2,070
Lease liabilities	**-**	2,501
Royalty obligations	**-**	6,149
	$ 320,268	$ 564,984

As at December 31, 2021, the Company had approximately $187 million (December 31, 2020 – $213 million) of non-capital losses available for future use. The unused non-capital losses expire between 2036 and 2041, and unused capital losses have no expiry date. The oil and gas properties and facilities owned by the Company and its subsidiaries have an approximate tax basis of $39 million (December 31, 2020 – $214 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.

24. 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, 2021**	December 31, 2020
Short-term compensation	**$ 2,074**	$ 1,685
Share-based payments	**1,547**	1,906
	$ 3,621	$ 3,591

25. SUPPLEMENTAL DISCLOSURE

The Company's consolidated statements of loss and comprehensive 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 loss and comprehensive loss.

For the years ended	**December 31, 2021**	December 31, 2020
Production and operating	**$ 1,198**	$ 1,259
General and administrative	**5,145**	3,963
Share-based payments	**2,044**	2,017
	$ 8,387	$ 7,239

CORPORATE INFORMATION

DIRECTORS

Susan L. Riddell Rose
President, Chief Executive Officer and Executive Chairman
Linda A. Dietsche
Independent Director[(1)(2)(3)(4)]
Robert A. Maitland
Independent Director[(1)(2)(3)(4)]
Geoffrey C. Merritt
Independent Director[(1)(2)(3)(4)]
Ryan A. Shay
Vice President, Finance and Chief Financial Officer
Howard R. Ward
Independent Director[(1)(2)(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
Ryan A. Shay
Vice President, Finance and Chief Financial Officer
Ryan M. Goosen
Vice President, Business Development and Land
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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Bank of Montreal
Bank of Nova Scotia

RESERVE EVALUATION CONSULTANTS

McDaniel & Associates Consultants Ltd.

REGISTRAR AND TRANSFER AGENT

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