MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("**MD&A**") is a review of the operations and current financial position for the three and nine months ended September 30, 2018 for Petrocapita Income Trust ("**Petrocapita**" or the "**Trust**") and should be read in conjunction with the audited consolidated financial statements as at and for the years ended December 31, 2017 and 2016, together with the notes related thereto (the "**financial statements**"). All amounts are in Canadian dollars, unless otherwise stated and all tabular amounts are in thousands of Canadian dollars, except for percentages and amounts or as otherwise noted. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("**IFRS**") as issued by the International Accounting Standards Board ("**IASB**"). Additional information relating to the Trust can be found on www.sedar.com.

Forward Looking Statements

Certain statements and information contained in these statements constitute forward-looking statements and forward-looking information as defined under applicable securities legislation (collectively, "**forward-looking statements**"). These forward-looking statements relate to future events or Petrocapita's future performance. All statements other than statements of historical fact are forward-looking statements. The use of any of the words "anticipate", "plan", "contemplate", "continue", "estimate", "expect", "intend", "propose", "might", "may", "will", "shall", "project", "should", "could", "would", "believe", "predict", "forecast", "pursue", "potential" and "capable" and similar expressions are intended to identify forward-looking statements. These 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 statements. No assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this MD&A should not be unduly relied upon. These statements speak only as of the date of the statements. In addition, these statements may contain forward-looking statements attributed to third party industry sources.

In particular, and without limitation, these statements contain forward-looking statements pertaining to the following:

- the reserve potential of Petrocapita's assets;
- the estimated production from Petrocapita's assets;
- the estimated quantity and value of Petrocapita's proved and probable reserves;
- Petrocapita's plans to continue with its heavy oil and water disposal based focus;
- Petrocapita's growth strategy of growing organically and through accretive acquisitions;
- expectations with respect to future growth, opportunities and stability;
- expectations regarding commodity prices and costs;
- Petrocapita's capital expenditure program and future capital requirements;
- Petrocapita's estimates of future interest and foreign exchange rates;
- expectations regarding taxability of the Trust;
- the potential for production disruption and constraints;
- supply and demand fundamentals for crude oil and natural gas;
- Petrocapita's access to adequate pipeline capacity;
- Petrocapita's access to third-party infrastructure;
- industry conditions pertaining to the oil and gas industry;
- Petrocapita's plans for exploration and development activities;
- Petrocapita's abandonment and reclamation cost expectations;
- Petrocapita's treatment under governmental regulatory regimes and tax laws;
- Petrocapita's access to capital and overall strategy, development and drilling plans for all of Petrocapita's assets; and
- expectations on how Petrocapita will manage exploration, production and marketing risks.

With respect to forward-looking statements contained in these statements, assumptions have been made regarding, among other things, the following:

- future crude oil, natural gas liquids and natural gas prices;
- Petrocapita's ability to obtain qualified staff and equipment in a timely and cost-efficient manner;
- the regulatory framework governing royalties, taxes and environmental matters in the jurisdictions in which Petrocapita conducts its business and any other jurisdictions in which Petrocapita may conduct its business in the future;
- Petrocapita's ability to market production of oil and gas successfully to customers;
- Petrocapita's future production levels;
- the applicability of technologies for recovery and production of Petrocapita's reserves;
- the recoverability of Petrocapita's reserves;
- future cash flows from production meeting expectations stated;
- geological and engineering estimates in respect of Petrocapita's reserves;
- the geography of the areas in which Petrocapita is conducting exploration and development activities;
- the impact of competition on Petrocapita; and
- Petrocapita's ability to obtain future financing on acceptable terms.

Actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and included elsewhere in these statements, including:

- business operations and capital costs;
- Petrocapita's status and stage of development and the management of growth;
- general economic, market and business conditions;
- volatility in market prices and demand for crude oil and natural gas and hedging activities related thereto;
- seasonality of the Canadian oil and gas industry;
- risks related to the exploration, development and production of oil and natural gas reserves;
- current global financial conditions, including fluctuations in interest rates, foreign exchange rates and stock market volatility;
- competition for, among other things, capital, the acquisition of reserves and skilled personnel;
- operational hazards;
- actions by governmental authorities, including changes in government regulation and taxation;
- environmental risks and hazards;
- risks inherent in the exploration, development and production of oil and natural gas which may create liability to Petrocapita in excess of its insurance coverage;
- cost of new technologies;
- failure to accurately estimate abandonment and reclamation costs;
- failure of third parties' reviews, reports and projections to be accurate;
- the availability of capital on acceptable terms;
- political risks;
- climate change;
- changes to royalty or tax regimes;
- the failure of the General Partner or the holders of certain licenses or leases to meet specific requirements of such licenses or leases;
- claims made in respect of Petrocapita's properties or assets;
- aboriginal claims;
- unforeseen title defects;
- risks arising from future acquisition activities;
- risks associated with the realization of anticipated benefits of acquisitions and dispositions;
- risks associated with the Trust's structure;
- hedging strategies;
- potential conflicts of interest;
- the potential for management estimates and assumptions to be inaccurate;

- risks associated with establishing and maintaining systems of internal controls;
- risks related to the reliance on historical financial information, including that historical financial information does not reflect the added costs that Petrocapita expects to incur as a public entity;
- liquidity and additional funding requirements;
- additional indebtedness;
- failure to engage or retain key personnel;
- potential losses which would stem from any disruptions in production, including work stoppages or other labour difficulties, or disruptions in the transportation network on which Petrocapita is reliant;
- uncertainties inherent in estimating quantities of oil and natural gas reserves;
- failure to acquire or develop replacement reserves;
- geological, technical, drilling and processing problems, including the availability of equipment and access to properties;
- disclosure of confidential information of Petrocapita; and
- other factors discussed under "*Risk Factors*".

In addition, information and statements in these statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and that the reserves described can be profitably produced in the future.

There are numerous uncertainties inherent in estimating quantities of oil and natural gas and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in these statements are estimates only. In general, estimates of economically recoverable oil and natural gas and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially. For these reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. Petrocapita's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. Readers are cautioned that the foregoing list of risk factors should not be construed as exhaustive.

The forward-looking statements included in this MD&A are expressly qualified by this cautionary statement and are made as of the date of this MD&A. Petrocapita does not undertake any obligation to publicly update or revise any forward-looking statements except as required by applicable securities laws.

General Business Description

Petrocapita Income Trust (the "Trust") was formed pursuant to a Declaration of Trust dated January 22, 2010. The Declaration of Trust was amended and restated on October 1, 2010, October 26, 2015 and October 18, 2016. The beneficiaries of the unincorporated Trust are the unitholders.

Following the internal reorganization, the Trust has the objective of investing directly in Petrocapita Energy Corp., who, through its ownership in Petrocapita Processing L.P. and Petrocapita Oil & Gas L.P. (the "Partnerships"), has the following business objectives:

- The primary business carried on by Petrocapita Oil & Gas L.P. will consist of drilling and development of its heavy oil assets and production thereof in the Lloydminster area of Alberta and Saskatchewan.

- The primary business carried on by the Petrocapita Processing L.P. will consist of oil and gas transport, disposal and processing activities and the conduct of well servicing and waste disposal activities.

The Trust is a public entity and accordingly, the Trust is a "specified investment flow-through" (SIFT) trust for purposes of the *Income Tax Act (Canada)*. As a result, under the SIFT rules, certain distributions from a SIFT are not deductible in computing taxable income and the Trust is subject to tax on such distributions at a rate that is substantially equivalent to the general income tax rate applicable to a Canadian corporation. Distributions paid by a SIFT as returns of capital are not subject to the SIFT tax. Based on the current organization of the Trust and its subsidiaries, the Trust expects that its income distributed to unitholders will not be subject to SIFT tax.

Effective August 31, 2017, a 100 for 1 common unit consolidation was approved by the unitholders of the Trust. This MD&A is presented on the basis of the post-consolidated common units outstanding. All common units, warrant and per unit comparative numbers have been retroactively restated to reflect the common unit consolidation.

The address and principal place of business of the Trust is Suite 1400, 717 – 7th Avenue SW, Calgary, Alberta, T2P 0Z3. The Trust's units are listed on the Canadian Securities Exchange ("CSE") and trade under the symbol "CSE.PCE.UN".

Non-GAAP Measures

In addition to using financial measures prescribed by IFRS, references are made in this MD&A to "operating netback", "funds flow from operations" and "funds flow netback", which are measures that do not have any standardized meaning as prescribed by IFRS and are not presented in the consolidated financial statements of Petrocapita. Accordingly, the Trust's use of such terms may not be comparable to similarly defined measures presented by other entities. Management uses such terms in the evaluation of Petrocapita's operating and financial performance and to provide Unitholders with a measurement of Petrocapita's efficiency and its ability to generate the cash necessary to fund its capital expenditures, repay debt or pay distributions.

"***Operating netback***" is calculated as operating income divided by barrels of oil production volume for the period. Management uses operating netback as an indicator of operating performance and profitability relative to current commodity prices, calculated on a per barrel basis. There are no IFRS measures that are reasonably comparable to operating netback. "*Operating income (loss)*" is calculated as total revenues less royalties and expenses for the period.

"***Funds flow netback***" is calculated as operating netback less general and administrative expenses (on a per barrel basis). By starting with operating netback and further deducting general and administrative (but not financing) costs, management uses funds flow netback as a supplemental indicator of operational profitability. There are no IFRS measures that are reasonably comparable to funds flow netback.

"***Funds flow from operations***" is calculated as cash flow from operating activities, as determined in accordance with IFRS, adjusted for changes in non-cash working capital and decommissioning obligations expenditures. Management considers funds flow from operations a key measure as it demonstrates Petrocapita's ability to generate cash flow necessary to fund future growth through capital investment and to repay debt. Funds flow from operations does not have any standardized meaning prescribed by IFRS and management's calculation of funds flow from operations may not be comparable to that reported by other entities. Funds flow from operations should not be considered an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with IFRS. Funds flow from operations per bbl is calculated using boe production volume for the period. Funds flow from operations per unit is calculated using the weighted average units (basic and diluted) used in calculating net income (loss) per unit on a basic and diluted basis.

A reconciliation of the cash flow from operating activities and funds flow from operations is as follows:

	Three months ended September 30		**Nine months ended September 30**	
($000s)	**2018**	**2017**	**2018**	**2017**
Cash flow from operating activities – IFRS	577	(1,227)	483	(3,791)
Changes in non-cash operating working capital	1,295	(227)	3,759	966
Decommissioning obligation expenditures	**-**	**-**	55	-
Funds flow from operations	(718)	(1,000)	(3,221)	(4,757)

Overview

During the three months ended September 30, 2018, Petrocapita's production increased 2% over the same quarter in the prior year as it produced an average of 561 (2017 – 550) net equivalent boe/d of heavy oil, natural gas and natural gas liquids including royalty income volumes. In addition, Petrocapita's salt water disposal program processed approximately 27,877 bbls (2017 – 70,159 bbls) of fluid (4,430 and 11,149 m3 respectively) from third parties and produced approximately 256 barrels of skim oil (included in total oil production) for the three months ended September 30, 2018 (2017 – 1,234 bbls).

Earlier in the year, the Trust closed two additional tranches of secured convertible debentures for total aggregate principal amounts of approximately $191,000 and two additional tranches of preferred units for aggregate principal amounts of approximately $193,000. Prior to the start of the second quarter, the Trust discontinued its preferred unit offering.

Management has found it increasingly challenging to raise additional funds to supplement continued cash flow deficiencies which have been experienced over the past three years. The recent pricing of Western Canadian Select (WCS) resulting from an over-supply situation has made it virtually impossible to generate sufficient cash flows to fund operations.

As at the date of this report, a total of 11.1 million common units, 3.1 million preferred units and 4.8 million warrants are outstanding.

Heavy Oil Revenue and Production Volumes

	Three months ended September 30			Nine months ended September 30		
	2018	2017	%	2018	2017	%
Oil						
Heavy oil revenue ($000s)	2,348	1,976	19	6,540	6,870	-5
Total oil production (bbls/day)	561	550	2	550	640	-14
Total oil production	51,647	50,554	2	150,123	174,773	-14
Average realized price ($ per bbl)	45.74	40.15	14	43.90	39.92	10
Benchmark Prices						
WTI Oil (US$ per bbl) (1)	69.76	48.21	45	66.89	49.47	35
WCS Oil (US$ per bbl)) (2)	47.25	42.16	12	44.82	37.59	19
Heavy oil differential (3)	32%	13%	157	33%	24%	38
CAD/USD average exchange rate	1.31	1.25	5	1.29	1.31	-2

Note:

(1) Western Texas Intermediate ("WTI") refers to the arithmetic average based on NYMEX prompt month WTI.
(2) Western Canada Select blend ("WCS") refers to the average posting price for the benchmark WCS.
(3) Heavy oil differential refers to the WCS discount to WTI

During the third quarter of 2018, Petrocapita's production increased slightly to 561 bbls per day from 550 bbls per day in the third quarter of 2017 representing a 2% increase in production. For the nine months ended September 30, 2018 production dropped to 550 bbls per day from 640 bbls per day for the same period in the prior year. The decrease in production experienced for the year to date compared to the prior year period was due to the natural decline from producing assets and the inability to repair and maintain wells due to limited cash.

Oil revenue for the third quarter increased by 19% over the prior year quarter due to an increase in the average realized price during the quarter. For the nine months ended, despite a 14% drop in production, oil revenue decreased by only 5% over the same period in the prior year as a result of the increase in the average realized price over that period.

Other revenues

	Three months ended September 30			Nine months ended September 30		
	2018	2017	%	2018	2017	%
Transport and disposal						
Skim oil revenue ($000s)	15	53	-72	51	106	-52
Water disposal revenue ($000)	24	28	-14	55	100	-45
Water disposal volumes (m3)	4,430	8,707	-49	13,783	30,730	-55
Oilfield service						
Oilfield service revenue ($000)	-	15	-100	45	132	-66

Water disposal revenue decreased from $28 thousand to $24 thousand for the three months ended September 30, 2018 compared to the same period in the prior year, and from $100 to $55 thousand for the nine months ended September 30, 2018 compared to the same period in the prior year. These decreases are consistent with the lower production volumes during the respective periods.

Oilfield service revenue decreased for the nine months ended September 30, 2018 compared to the same period ended September 30, 2017 due to seasonal road bans and lower third-party demand.

Royalties

	Three months ended September 30			Nine months ended September 30		
	2018	2017	%	2018	2017	%
Oil revenue ($000s)	2,363	2,029	16	6,591	6,976	-6
Total royalties ($000s)	329	232	42	846	815	4
Total royalties ($ per bbl)	6.37	4.59	39	3.74	4.66	-20
Percent of oil revenue	13.9%	11.4%	22	12.8%	11.7%	10

Royalties incurred as a percent of oil revenue in the three and nine months ended September 30, 2018 over the prior year periods were slightly higher than the respective prior periods. A greater percentage of the wells currently producing have additional royalties payable based on a financing agreement made at the time of their original acquisition.

Heavy Oil operating expense

	Three months ended September 30			Nine months ended September 30		
	2018	2017	%	2018	2017	%
Total ($000s)	1,453	1,242	17	4,900	5,730	-14
Total ($ per bbl)	28.13	24.57	15	32.64	32.79	-

Heavy oil operating expenses for the three months ending September 30, 2018 were higher on per bbl basis over the same period in the prior year as a result of higher than expected property taxes recorded in the current quarter. For the nine months ended September 30, 2018 these costs were consistent on a per bbl basis.

Transport and disposal and Oilfield service operating costs

	Three months ended September 30			Nine months ended September 30		
	2018	2017	%	2018	2017	%
Transport and disposal operating costs ($000s)	262	303	-14	660	591	12
Oilfield service operating costs ($000s)	-	2	100	-	101	100

Transport and disposal costs were lower for the three months ended September 30, 2018 due to lower volumes and related activity. Costs for the nine months ended September 30, 2018 were higher than the same period in the prior year as the Trust identified and reclassified additional costs related to the transport and disposal facilities earlier in the year.

Oilfield operating costs were nil for the three and nine months ended September 30, 2018 compared to the comparative period as the Trust essentially wound down its third-party service operations.

Heavy Oil Operating Netback

	Three months ended September 30			Nine months ended September 30		
	2018	2017	%	2018	2017	%
Production volumes (bbl/day)	561	550	2	550	640	-14
Heavy oil revenue ($ per bbl)	45.74	40.15	14	43.90	39.92	10
Less: Royalties ($ per bbl)	(6.37)	(4.59)	39	(3.74)	(4.66)	-20
Operating expense ($ per bbl)	(28.13)	(24.57)	15	(32.64)	(32.79)	0
Operating netback ($ per bbl)	11.23	10.99	2	7.52	2.47	204
General & administrative expense ($ per bbl)	(11.25)	(14.12)	-20	(14.04)	(16.83)	-17
Total funds flow netback ($ per bbl)	(0.02)	(3.13)	100	(6.51)	(14.35)	55

Despite the 14% increase in revenue per bbl, the heavy oil funds flow netback increased only 2% for the three months ended September 30, 2018 primarily as a result of higher than expected operating expenses (property taxes and regulatory fees) recorded in the current quarter. For the nine months ended September 30, 2018, the heavy oil funds flow netback increased over the comparative period largely due to the increase in revenue per bbl as operating costs on a per bbl basis remained consistent. G&A expenses were allocated to heavy oil operations for purposes of the netback calculation as heavy oil represents 98% of revenues.

Transport and Disposal Operating Netback

	Three months ended September 30			Nine months ended September 30		
	2018	2017	%	2018	2017	%
Skim oil revenue ($000s)	15	53	-72	51	106	-52
Water disposal revenues	24	28	-14	55	100	-45
Less: Operating expense	262	302	-13	660	590	12
Operating netback	(223)	(221)	1	(554)	(384)	44

The transport and disposal operating netback for the nine months ended September 30, 2018 was impacted as the Trust identified and reclassified additional costs related to the transport and disposal facilities earlier in the year.

General and Administrative Expenses

	Three months ended September 30			Nine months ended September 30		
	2018	2017	%	2018	2017	%
General & administrative expense ($000s)	591	718		2,124	2,954	
General & administrative recoveries ($000s)	(10)	(4)		(17)	(13)	
Total G & A expense ($000s)	581	714		2,107	2,941	
Total G & A expense ($ per bbl)	11.25	14.12	-20	14.04	16.83	-17

Decreases in G&A costs on a per bbl basis experienced in the three and nine months ended September 30, 2018 over the prior year period was largely the result of concerted measures taken by management to continue to reduce overhead over the past year.

Depletion and Depreciation

	Three months ended September 30			Nine months ended September 30		
	2018	2017	%	2018	2017	%
Depletion and depreciation ($000s)	617	658	-6	1,891	2,128	-11
Depletion and depreciation ($ per bbl)	11.95	13.02	-8	12.60	12.18	3

Depletion and depreciation costs were lower for the three months ended September 30, 2018 compared to the prior year period due to a lower depletion base resulting from dispositions made during the current quarter. The slight increase in depletion and depreciation costs on a per bbl basis experienced in the nine months ended September 30, 2018 over the prior year period is the result of depreciation recorded on transport and disposal assets and oilfield service assets which were acquired in the prior year.

Finance Expense

	Three months ended September 30			Nine months ended September 30		
($000s)	2018	2017	%	2018	2017	%
Total finance expense	889	1,903	-53	2,696	3,361	-20

The decrease in finance expense in the three and nine months ended September 30, 2018, is a result of the one-time adjustment of $1,124,000 recorded in the prior year third quarter related to the re-pricing of the Trust's warrants.

Taxes

Current taxes relate solely to the Saskatchewan Resource surcharge.

Loss and Comprehensive Loss

	Three months ended September 30			Nine months ended September 30		
	2018	2017	%	2018	2017	%
Loss ($000s)	(1,956)	(3,158)	-38	(6,620)	(9,449)	-30
Loss per common unit, basic and diluted	(0.18)	(0.28)	-38	(0.60)	(0.85)	-30

The reduction in loss and comprehensive loss for the three and nine months ended September 30, 2018 compared to the prior year periods primarily reflects a combination lower operating and administrative expenses associated with lower production levels and concerted measures taken by management to reduce costs.

Capital Expenditures

Capital expenditures (including exploration and evaluation assets) are summarized as follows:

	Three months ended September 30			Nine months ended September 30		
($000s)	**2018**	**2017**	**%**	**2018**	**2017**	**%**
Additions:						
Land	160	19		350	74	
Drilling and completion	627	14		903	504	
Equipping	193	(32)		218	434	
Disposal assets	5			19	-	
Acquisitions	-	-		-	22	
Other	(2)	(4)		130	3	
Total capital expenditures – cash	983	(3)	N/A	1,620	1,037	56

During the first nine months of the year, the Trust incurred capital expenditures primarily related to reactivations, workovers and well re-completions In addition, during the second and third quarters, the Trust spent a total of $597,000 on the drilling of a 5-Leg horizontal well with partners in anticipation of future economic production. Total expenditures year to date were up 56% primarily as a result of the costs incurred related to this well.

Selected Financial Information – Quarterly Results

	Quarter Ended							
Financial ($000s)	**Q3 2018**	**Q2 2018**	**Q1 2018**	**Q4 2017**	**Q3 2017**	**Q2 2017**	**Q1 2017**	**Q4 2016**
Total revenue (1)	2,387	2,358	1,948	2,310	2,073	2,054	3,081	3,139
Funds flow from operations (2)	(718)	(991)	(1,512)	(961)	(4,757)	(1,268)	(2,156)	(2,958)
Net income (loss)	(1,956)	(1,974)	(2,690)	(3,687)	(3,158)	(2,481)	(3,809)	(4,772)
Cash capital expenditures (3)	983	331	306	79	(3)	218	822	1,025
Total Assets	52,120	51,660	53,040	53,857	60,540	60,593	61,753	54,676
Operating								
Total oil production (bbls)	51,647	46,387	52,089	49,963	50,554	50,015	74,204	63,060
Total oil production (bbls/day)	561	510	579	544	550	550	824	685
Average realized oil price ($ per bbl)	45.74	49.94	36.70	45.53	40.15	39.93	39.74	38.23
Operating netback ($ per bbl)(2)	11.23	6.33	(0.56)	(6.58)	10.99	5.12	(8.71)	(22.98)

Note:
(1) Includes heavy oil revenue, royalty income and transport and disposal revenues
(2) See "Non-GAAP Measures"
(3) Cash only capital expenditures including assets swaps, business combinations and asset acquisitions

With the closing of the acquisition of the Palliser assets in the third quarter of 2016, production increased significantly in the following two quarters as the Palliser wells contributed to overall production starting in the third quarter of 2016. Over the following quarters, the decrease in production was mainly attributed to the natural decline of the oil and gas properties, the focus on producing only from the Trust's economic wells, and limited cash flow to repair and maintain existing wells.

Water Disposal activities (included in above totals)

	Quarter Ended							
Financial ($000s)	**Q3 2018**	**Q2 2018**	**Q1 2018**	**Q4 2017**	**Q3 2017**	**Q2 2017**	**Q1 2017**	**Q4 2016**
Skim oil sold (bbls)	256	517	205	1,199	1,234	693	625	657
Skim oil revenue (4)	15	28	8	51	53	27	26	24
Water disposed (m3)	4,430	4,801	4,552	13,234	8,707	11,149	10,874	15,342
Water disposed (bbls)	27,877	30,212	28,645	83,241	54,792	70,159	68,429	96,545
Water disposal revenue (5)	24	18	13	46	28	38	34	53
Operating								
Total revenue ($ per bbl)	58.46	54.63	37.22	44.86	43.02	38.75	41.30	38.05
Royalties ($ per bbl)	(0.60)	(0.34)	(0.19)	(0.16)	(0.04)	(0.03)	(0.05)	(0.16)
Production expense ($ per bbl)	(9.10)	(4.64)	(8.52)	(5.10)	(5.29)	(1.60)	(2.28)	(3.87)
Transportation expense ($ per bbl)	(0.20)	(0.11)	(0.22)	(0.16)	(0.04)	(0.03)	(0.05)	(0.01)
Operating netback ($ per bbl)(2)	48.56	49.54	28.29	39.44	37.65	37.09	38.92	34.01

Note:
(2) See "Non-GAAP Measures"
(4) Income received from selling the oil that is recovered from the water to be disposed
(5) Income received from charging third parties for the disposal of water

Water disposal wells receive outside third party water deliveries and associated skim oil. During the first nine months of the year, deliveries to disposal wells have decreased over the same period in the prior year due to lower production volumes and third-party demand.

Liquidity and Capital Resources

The Trust's ongoing liquidity is impacted by various external events and conditions, including commodity price fluctuations. The Trust will require additional funding to reduce its exposure to liquidity risk. The Trust continually monitors its actual and forecast cash flows to review whether there are adequate reserves available to meets its obligations. Management continues to seek additional means to maintain the Trust's working capital, including but not limited to, reviewing potential mergers, acquisitions, arranging additional debt or equity financing or seeking to convert existing debt to equity. In addition, the Trust continues to minimize capital expenditures, reduce operating and general and administrative costs and enhance operational efficiencies.

The condensed interim consolidated financial statements at September 30, 2018 have been prepared on a going concern basis, which contemplates the realization of assets and the settlement of obligations in the normal course of business. Continuing weak commodity prices experienced over the past three years, the high cost of rural municipal taxes and surface lease rentals associated with suspended wells acquired, and reactivation costs of suspended wells acquired in the prior year have negatively impacted operating income and cash flow during the current period and prior years.

The Trust experienced a net loss for the nine months ended of $6,620,095 (year ended December 31, 2017 - $13,135,382). Cash flows used in operating activities prior to changes in non-cash working capital for the nine months ended was $3,276,231 (year ended December 31, 2017 - $4,753,428). As at September 30, 2018, the Trust had a working capital deficiency excluding derivative liabilities of $8,340,343 (December 31, 2017 - $4,519,960). Additionally, during the first quarter of this year, the Trust was assessed to pay $912,494 in abandonment and reclamation deposits. The Trust is currently in active discussions with the Alberta and Saskatchewan regulatory bodies regarding settlement of these deposits.

The Trust's financial liabilities under obligations that have contractual maturities are summarized below:

	Less than year	2-5 years	After 5 years	Total
Accounts payable and accrued liabilities	$ 11,007,039	$ -	$ -	$ 11,007,039
Bank debt	175,000	-	-	175,000
Loans payable	211,442	-	-	211,442
Obligations under finance leases	86,629	-	-	86,629
Debentures	-	7,000,000	-	7,000,000
Convertible debentures [1]	663,494	10,288,794	81,041	11,033,329
Preferred units [1]	-	-	3,122,053	3,122,053
	$ 12,143,604	$17,288,794	$3,203,094	$ 32,635,492

[1] presented at face value on maturity date

At September 30, 2018, $313,109 (December 31, 2017 - $80,162) of convertible debenture interest payments, $654,452 of debenture interest payments (December 31, 2017-nil), $124,243 (December 31, 2017 - $39,985) of preferred unit interest payments and $110,118 (December 31, 2017 - $nil) in principal repayments are past due and are included in accounts payable and accrued liabilities. During the third quarter, the Trust announced that it will be suspending future interest payments on all of its convertible debentures and preferred units until further notice. During the first quarter, the Trust was assessed to pay $648,080 in abandonment and reclamation deposits to the Saskatchewan Ministry of Energy and Resources and $264,414 to the Alberta Energy Regulator. The Trust is currently in active discussions with the Alberta and Saskatchewan regulatory bodies regarding settlement of these deposits.

The Trust will require additional funding to reduce its exposure to liquidity risk. Management has found it increasingly challenging to raise additional funds to supplement continued cash flow deficiencies which have been experienced over the past three years. Management continues to actively investigate all avenues of financing to meet existing debt obligations and to ultimately achieve profitability. Management continues to focus its efforts to capitalize on and realize value for it midstream assets and continues to actively diversify risk by seeking additional joint venture partners and projects. Management remains optimistic that that it will be able to raise additional necessary funds in the future but there is no certainty that this will occur.
The Trust continually monitors its actual and forecast cash flows to review whether there are adequate reserves available to meets its obligations as well as continues to focus on operating and general and administrative cost structures and enhancing operational efficiencies to preserve the Trust's financial health and sustainability in the current commodity price environment. The Trust cannot provide any assurance that sufficient cash flows will be generated from operating activities or proceeds from other activities noted above will improve its working capital.

Capital Funding

During the first nine months, the Trust completed two separate tranches of the issuance of convertible secured subordinated debentures for gross proceeds of $191,000. The convertible debentures bear interest at 8% per annum, payable quarterly. Both tranches were closed in the first quarter.

The Trust offered up to $20,000,000 series 1 preferred trust units of the Trust by way of an exempt market offering. The offering consisted of a tied offering of preferred units of the Trust and Class A Shares of Petrocapita Energy. A tied unit means a combination of 0.23 Class A shares of Petrocapita Energy and one series 1 preferred unit of the Trust. The Trust has closed two tranches of Preferred Units for aggregate principal amounts of approximately $193,000. This offering was discontinued by the Trust prior to the start of the second quarter of the year.

Capital Management

The Trust's capital includes unitholders' equity and other debt. The Trust's objective in managing capital is to ensure that it has sufficient working capital and access to sources of capital to finance its operations and to make planned capital expenditures or capital acquisitions as opportunities present themselves. The Trust monitors the level of risk associated for each capital project to balance the proportion of debt and equity in its capital structure. The Trust monitors capital based on its current working capital, projected cash flow from operating activities and anticipated capital expenditures. The Trust's officers are responsible for managing the Trust's capital and do so through weekly meetings and regular reviews of financial information, including budgets and forecasts. The Trust's directors are responsible for overseeing this process. The Trust manages its capital structure and makes changes to it in light of changes in economic conditions, anticipated or planned capital expenditures, opportunities for acquisitions and the risk characteristics of the underlying investments. The Trust's capital management objectives have not changed during the three and nine months ended September 30, 2018 and 2017.

Total capital managed is determined as follows:

	September 30 2018	December 31 2017
Bank debt	**$ 175,000**	$ 175,000
Loans payable	**211,442**	211,442
Obligations under finance leases	**86,629**	158,296
Debenture	**6,679,892**	6,502,138
Convertible debentures	**9,571,179**	9,328,238
Equity (deficit)	**(4,911,436)**	1,680,756
	$ 11,812,706	$ 18,055,870

Total capital has decreased from the prior year end due the net loss during the period offset in part by the debentures and convertible debentures issued during the nine months ended September 30, 2018.

The Trust monitors its working capital closely, which is determined on the following basis:

	September 30 2018	December 31 2017
Total current assets	**$ 3,803,261**	$ 4,129,542
Total current liabilities (excluding derivative liabilities)	**(12,143,604)**	(8,649,502)
Working capital deficiency	**$ (8,340,343)**	$ (4,519,960)

Working capital deficiency has increased from the prior year end mainly due to the commencement of principal repayments on certain convertible debentures and negative cash flows generated from operations.

The Trust is not subject to any externally imposed capital requirements other than certain financial and reporting covenants as a result of bank facility and the conversion features of the debentures and preferred units.

Contractual Obligations and Contingencies

(a) The Trust has entered into lease agreements for office space and equipment which expire in May 2019 and March 2022. The required lease payments, exclusive of operating costs, over the remaining term of the leases are as follows:

2018	69,000
2019	190,000
2020	179,000
2021	182,000
Thereafter	45,000
	$ 665,000

(b) The Trust has a majority interest in certain oil and gas wells for which the well and facility licenses are held by a third party. The Trust has signed an agreement with the license holder, company that is owned by the debenture holder, to transfer the licenses to the Trust by March 1, 2019 for a buy-back option price of $330,000 or the Trust will be subject to a fee of $25,000 per month for the company to remain as the license holder.

(c) The Trust is a party to a contingent GORR agreement whereby, for the period to July 11, 2021 and in respect of any calendar month when the average daily selling price for the near month light, sweet crude oil future contracts as reported by the New York Mercantile Exchange in US dollars for West Texas Intermediate Oil exceeds $80.00 USD per barrel, the Trust is subject to an additional 1.5% GORR payable on certain oil and natural gas properties.

At September 30, 2018 and December 31, 2017, the Trust determined the contingent payable related to the GORR has no value and therefore no amounts have been recorded. This determination was made with reference to forecast prices of West Texas Intermediate Oil published by external reserve engineers over a period of five years.

Related Party Transactions

Transactions

During the nine months ended September 30, 2018, the Trust issued convertible secured subordinated debentures as described in note 11(a) to certain officers and directors for aggregate principal amounts of $nil (2017 - $130,000). Total convertible secured subordinated debentures outstanding to certain officers and directors at September 30, 2018 is $493,000 (December 31, 2017 - $493,000).

Compensation of Executives

Executives include the Trust's directors and executive officers. Total remuneration executives included in general and administrative expenses during the nine months ended September 30, 2018 was approximately $304,950 (2017 - $529,000).

As at September 30, 2018, $279,582 (December 31, 2017 - $130,000) remains outstanding to executives and is included in accounts payable and accrued liabilities.

Off-Balance Sheet Transactions

The Trust was not involved in any off-balance sheet transactions during the nine months ended September 30, 2018 and 2017.

Critical Accounting Estimates

The preparation of financial statements requires management to make estimates and assumptions and use judgment based on currently available information that may affect the application of accounting policies and the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities as at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the year. By their nature, estimates are subject to estimation uncertainty.

Estimates and judgments are continually evaluated and are based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Accounting estimates will, by definition, seldom equal the actual results. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future years affected.

Significant estimates made by management in the preparation of these consolidated financial statements are as follows:

Reserve and cash flow estimates

Amounts recorded for depletion and depreciation and amounts used for impairment calculations relating to property and equipment are based on estimates of reserves, including the estimates of future prices, costs, discount rates and the related future cash flows as well as cash flows related to transport and disposal assets.

The assessment of reported recoverable quantities of proved and probable reserves include estimates regarding production volumes, commodity prices, exchange rates, remediation costs, timing and amount of future development costs, and production, transportation and marketing costs for future cash flows. It also requires interpretation of geological and geophysical models in anticipated recoveries. The economical, geological and technical factors used to estimate reserves may change from period to period. Changes in reported reserves can impact the carrying values of the Trust's heavy oil properties and transport and disposal assets, the calculation of depletion and depreciation and the provision for decommissioning provisions due to changes in expected future cash flows.

The Trust's oil reserves and cash flows related to its transport and disposal business activities and infrastructure are assessed at least annually by independent reserve engineers and are determined pursuant to *Alberta Securities Commission National Instrument 51-101, Standard of Disclosures for Oil and Gas Activities*.

Valuation of property and equipment and exploration and evaluation assets

In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of oil reserves, production rates, future oil prices, estimate of fixed fees earned on water disposal volumes and associated costs, recent land sales, management's future intentions, future development costs, estimates of rates for oilfield services and associated costs, discount rates and other relevant assumptions.

Decommissioning provisions

The calculation of decommissioning provisions and related accretion expense requires estimates of future remediation costs of production facilities, wells and pipelines at different stages of development and construction of assets or facilities. In most instances, removal of assets occurs many years into the future. In addition, the calculation requires assumptions regarding abandonment date, future environmental and regulatory legislation, the extent of reclamation activities, the engineering methodology for estimating cost, future removal technologies in determining the removal cost and liability-specific discount rates to determine the present value of these cash flows.

Business combinations, asset swaps and asset acquisitions

Management estimates the fair value of the acquired identifiable net assets at the date of acquisition and specifically in identifying and valuing property and equipment, exploration and evaluation assets, oilfield service equipment and transport and disposal equipment and decommissioning provisions acquired in acquisitions. The fair value of these specific net assets is based on numerous estimates including discount rates, estimates of proved and probable reserves, future oil prices, estimates of fair value based on independent appraisals, estimates of abandonment and reclamation costs and other factors.

Management has used estimates to determine the likelihood of factors being met related to the contingent consideration-GORR on the acquisition of assets. These estimates are based on forecast prices of West Texas Intermediate oil published by external reserve engineers over a period of five years.

Fair value of derivative liabilities

The Trust measures the embedded derivatives within the convertible debentures and preferred trust units by reference to the fair value of the financial instrument using a pricing model, taking into consideration management's best estimate of the expected volatility and the market price / fair value of the trust units on the date of issue and at each reporting date.

Warrants

The fair value of warrants is measured at the grant date using a Black-Scholes option pricing model, taking into consideration management's best estimate of the expected volatility and the expected life of the warrants.

Convertible debentures and Preferred units

The allocation of proceeds on the issuance of convertible debentures and preferred units between the debt and equity components is determined by the estimate of the fair value of the debt component based on similar instruments with no conversion/redemption feature.

Estimates of useful lives of transport and disposal assets and oilfield service assets

Management's judgment involves the use of estimates for determining the expected useful lives of depreciable assets, to determine depreciation methods and the asset's residual value.

Taxes

Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in profit or loss both in the period of change, which would include any impact on cumulative provisions, and in future periods.

Accounts receivable

The valuation of accounts receivable is based on management's best estimate of collectability and the provision for doubtful accounts.

Significant judgments made by management in the preparation of these consolidated financial statements are as follows:

Identification of cash-generating units

The Trust's exploration and evaluation assets and property and equipment are aggregated into cash-generating units ("CGUs") based on their ability to generate largely independent cash flows and are used for impairment testing. The classification of assets into CGUs requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, external users, shared infrastructures and the way in which management monitors the Trust's operations. The Trust has identified heavy oil properties, transport and disposal assets and oilfield service assets as its core CGUs.

Valuation of property and equipment and exploration and evaluation assets

Judgments are required to select, consider and interpret various external and internal sources of information to assess when impairment indicators, or reversal indicators, exist and impairment testing is required.

Exploration and evaluation assets

The application of the Trust's accounting policy for exploration and evaluation assets requires management to make certain judgments as to future events and circumstances as to whether economic quantities of proved and/or probable reserves have been found in assessing an area's technical feasibility and commercial viability.

The decision to transfer exploration and evaluation assets to property and equipment is based on management's determination of an area's technical feasibility and commercial viability based on proved and/or probable reserves as well as the related future cash flows.

Componentization

For the purposes of depletion, the Trust allocates its oil and natural gas assets to components with similar lives and depletion methods. The groupings of assets are subject to management's judgment and are performed on the basis of geographical proximity and similar reserve life.

Business combinations

Determining whether an acquisition should be accounted for as a business combination or represents an asset purchase requires judgment on a case by case basis, depending on management's assessment as to whether the acquisition meets the definition of a business.

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.

Judgments are made by management to determine the likelihood of whether deferred tax assets at the end of the reporting period will be realized from future taxable earnings. To the extent that 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.

The determination of the Trust's income and other tax liabilities requires interpretation of complex laws and regulations. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

Gross overriding royalty arrangement

Management has applied judgement in determining the accounting treatment of the gross overriding royalty arrangement. Management has considered the specific terms of the arrangement to determine whether the Trust has disposed of an interest in the related oil and natural gas property.

Contingencies

By their nature, contingencies will only be resolved when one or more future events occur or fail to occur. The assessment of contingencies inherently involves the exercise of significant judgment and estimates of the outcome of future events.

New Accounting Pronouncements

<u>IFRS 16-Leases ("IFRS 16")</u>

IFRS 16 provides for a single recognition and measurement model for leases, with required recognition of assets and liabilities for most leases. The standard will come into effect for annual periods beginning on or after January 1, 2019. The Trust is still finalizing its assessment as to whether or not this standard will have a material impact on the Trust's consolidated financial statements.

Outlook

Management has found it increasingly challenging to raise additional funds to supplement continued cash flow deficiencies which have been experienced over the past three years. The recent pricing of Western Canadian Select (WCS) resulting from an over-supply situation has made it virtually impossible to generate sufficient cash flows to fund operations. Management continues to actively investigate all avenues of financing to meet existing debt obligations and to ultimately achieve profitability. Management continues to focus its efforts to capitalize on and realize value for its midstream and conventional heavy oil assets and continues to actively diversify risk by seeking additional joint venture partners and projects.

Management is working closely with its secured creditors to restructure its debt and address its environmental and regulatory obligations in this challenging environment and remains cautiously optimistic that it will be able to successfully restructure and raise additional necessary funds in the future. However, management cautions readers that there is no certainty that the Trust will be able to meet all of its regulatory and or debt obligations should it be unable to raise additional funds and oil prices continue to fall or remain at current levels.

Calgary, Alberta
November 27, 2018