



Financial Statements

For the years ended December 31, 2017 and 2016



March 20, 2018

Independent Auditor's Report

To the Shareholders of InPlay Oil Corp.

We have audited the accompanying financial statements of InPlay Oil Corp., which comprise the statements of financial position as at December 31, 2017 and December 31, 2016 and the statements of profit (loss) and comprehensive income (loss), statements of change in equity, and the statements of cash flows for the year then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, 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.

Auditor's responsibility

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

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

Opinion

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

PricewaterhouseCoopers LLP

Chartered Professional Accountants

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"PwC" refers to PricewaterhouseCoopers LLP, an Ontario limited liability partnership.

Statements of Financial Position

AS AT DECEMBER 31,

(Thousands of Canadian dollars)	Note	2017	2016
ASSETS			
Current assets			
Cash and cash equivalents		\$ -	\$ 100
Accounts receivable and accrued receivables	21	9,205	8,456
Prepaid expenses and deposits		2,181	2,119
Total current assets		11,386	10,675
Assets held for sale	24	4,489	-
Property, plant and equipment	5, 6, 7	224,420	225,067
Exploration and evaluation	8	25,987	11,599
Deferred tax asset	12	57,511	56,149
Total assets		\$ 323,793	\$ 303,490
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Deferred lease credits	9	\$ 11	\$ 129
Accounts payable and accrued liabilities	21	17,764	15,476
Flow-through share premium		1,161	244
Derivative contracts	21	1,578	1,549
Decommissioning obligation	11	492	-
Total current liabilities		21,006	17,398
Decommissioning obligation associated with assets held for sale	24	1,052	-
Deferred lease credits	9	-	11
Bank debt	10	44,888	29,755
Decommissioning obligation	11	66,666	68,948
Total long term liabilities		111,554	98,714
Total liabilities		133,612	116,112
Shareholders' equity			
Share capital	13	233,957	226,541
Contributed surplus	14	12,966	9,878
Deficit		(56,742)	(49,041)
Total shareholders' equity		190,181	187,378
Total liabilities and shareholders' equity		\$ 323,793	\$ 303,490

Commitments 23

The above Statements of Financial Position should be read in conjunction with the accompanying notes.

On behalf of the Board of Directors:

(signed) "Steve Nikiforuk"
 Steve Nikiforuk
 Director

(signed) "Doug Bartole"
 Doug Bartole
 Director

Statements of Profit (Loss) and Comprehensive Income (Loss)

FOR THE YEARS ENDED DECEMBER 31,

(Thousands of Canadian dollars, except per share amounts)

	Note	2017	2016
Oil and natural gas sales	16	\$ 62,239	\$ 27,850
Royalties		(6,267)	(2,468)
Revenue		55,972	25,382
Gain (loss) on derivative contracts	16	1,084	(2,096)
		57,056	23,286
Operating expenses		23,346	12,322
Transportation expenses		894	587
Exploration and evaluation expenses	8	2,636	1,398
General and administrative expenses	18	5,929	4,475
Share-based compensation	14	1,611	1,856
Transaction & integration costs	17	341	2,412
Depletion and depreciation	6	22,551	13,725
Impairment	7	6,052	12,162
Gain on acquisition	5	-	(41,376)
Finance expenses	19	3,082	2,283
		66,442	9,844
Profit (loss) before tax		(9,386)	13,442
Deferred income tax (recovery)	12	(1,685)	(6,577)
Profit (loss) and comprehensive income (loss)		\$ (7,701)	\$ 20,019
PROFIT (LOSS) PER COMMON SHARE			
Basic and diluted	15	\$ (0.12)	\$ 1.02

The above Statements of Profit (Loss) and Comprehensive Income (Loss) should be read in conjunction with the accompanying notes.

Statements of Changes in Equity

(Thousands of Canadian dollars)	Note	Share capital	Contributed surplus	Deficit	Total shareholders' equity
Balance at December 31, 2015		\$ 118,262	\$ 7,480	\$ (69,060)	\$ 56,682
Issuance of shares on acquisition	13	109,859	-	-	109,859
Share-issue costs, net of deferred tax	13	(1,580)	-	-	(1,580)
Share-based compensation	14	-	2,398	-	2,398
Profit (loss) for the year		-		20,019	20,019
Balance at December 31, 2016		\$ 226,541	\$ 9,878	\$ (49,041)	\$ 187,378
Issuance of share capital	13	8,811	-	-	8,811
Share-issue costs, net of deferred tax	13	(146)	-	-	(146)
Repurchase of shares	13	(1,249)	726	-	(523)
Share-based compensation	14	-	2,362	-	2,362
(Loss) for the year		-	-	(7,701)	(7,701)
Balance at December 31, 2017		\$ 233,957	\$ 12,966	\$ (56,742)	\$ 190,181

The above Statements of Changes in Equity should be read in conjunction with the accompanying notes.

Statements of Cash Flows

FOR THE YEARS ENDED DECEMBER 31,

(Thousands of dollars)	Note	2017	2016
Cash flows provided by (used in):			
OPERATING ACTIVITIES			
Profit (loss) for the year		\$ (7,701)	\$ 20,019
Non-cash items:			
Depletion and depreciation	6	22,551	13,725
Unrealized loss on derivative contract	16	30	4,753
Accretion on decommissioning obligation	11	1,480	566
Share-based compensation expense	14	1,611	1,856
Exploration expense	8	2,636	1,398
Gain on acquisition	5	-	(41,376)
Impairment loss	7	6,052	12,162
Deferred income tax expense (recovery)	12	(1,685)	(6,577)
Decommissioning expenditures	11	(644)	(119)
Net change in non-cash working capital	20	(1,778)	(1,107)
Net cash flow provided by operating activities		22,552	5,300
FINANCING ACTIVITIES			
Issuance of share capital, net of issue costs	13	\$ 9,904	\$ 68,183
Repurchase of common shares, net of issue costs	13	(523)	-
Increase in bank debt	10	15,133	30,870
Repayment of bank debt	10	-	(59,016)
Net cash flow provided by financing activities		24,514	40,037
INVESTING ACTIVITIES			
Capital expenditures – Property, plant and equipment	6	\$ (32,142)	\$ (10,611)
Capital expenditures – Exploration and evaluation	8	(17,082)	(471)
Property acquisitions	5	(1,067)	(41,104)
Cash from corporate acquisition	5	-	2,459
Net change in non-cash working capital	20	3,125	4,490
Net cash flow (used in) investing activities		(47,166)	(45,237)
Increase (decrease) in cash and cash equivalents		(100)	100
Cash and cash equivalents, beginning of the year		100	-
Cash and cash equivalents, end of the year		\$ -	\$ 100
Interest paid in cash		\$ 1,602	\$ 1,517

The above Statements of Cash Flows should be read in conjunction with the accompanying notes.

Notes to the Financial Statements

DECEMBER 31, 2017 AND DECEMBER 31, 2016

(Tabular amounts in thousands of Canadian dollars, unless otherwise stated)

1. CORPORATE INFORMATION

InPlay Oil Corp. (“**InPlay**” or the “**Company**”) is actively engaged in the acquisition, exploration and development of petroleum and natural gas properties, and the production and sale of crude oil, natural gas and natural gas liquids. InPlay is a publicly traded company incorporated and domiciled in Alberta, Canada. InPlay’s common shares are listed on the Toronto Stock Exchange (the “**TSX**”) and trade under the symbol IPO. InPlay’s corporate office is located at 920, 640 - 5th Avenue SW, Calgary, Alberta, its registered office is located at 2400, 525 - 8th Avenue SW Calgary Alberta, and its petroleum and natural gas operations are located in the Province of Alberta.

A plan of arrangement (the “**Arrangement**”) involving the predecessor to InPlay (“**Prior InPlay**”) and Anderson Energy Inc. (“**Anderson**”), a publicly traded company listed on the TSX, was completed on November 7, 2016. The Arrangement constituted a reverse acquisition that involved a change of control of Anderson and a business combination of Anderson and Prior InPlay to form a new corporation that now carries on Prior InPlay’s and Anderson’s business and operations under the name InPlay Oil Corp. InPlay has the same directors and management as Prior InPlay. Effective November 10, 2016, InPlay common shares commenced trading on the TSX in substitution of Anderson common shares. All regulatory filings of InPlay and Anderson can be accessed electronically under InPlay’s profile on the SEDAR website at www.sedar.com.

2. BASIS OF PRESENTATION

2(a) Compliance with IFRS

These financial statements comply with International Financial Reporting Standards (“**IFRS**”) and International Accounting Standards (“**IAS**”) as issued by the International Accounting Standards Board (“**IASB**”).

The financial statements were approved and authorized for issuance by the Board of Directors on March 20, 2018.

2(b) Historical cost convention

These financial statements have been prepared on the historical cost basis, except for derivative financial instruments, which are measured at fair value. The methods used to measure fair values are discussed in note 21.

2(c) Functional and presentation currency

The financial statements are presented in Canadian dollars, which is the Company’s functional currency.

2(d) Function and nature of expenses

Expenses in the statements of profit (loss) and comprehensive income (loss) are presented as a combination of function and nature in conformity with industry practice. Transportation expenses, share-based compensation, depletion and depreciation, and impairment of property, plant and equipment are presented in separate lines by their nature, while operating expenses, general and administrative expenses and transaction costs are presented on a functional basis. Significant general and administrative and transaction expenses are presented by their nature in note 17 & 18.

3. SUMMARY OF ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently to all periods presented in these financial statements.

3(a) Jointly-controlled assets

Many of the Company's petroleum and natural gas operations are conducted under joint operating agreements whereby two or more parties jointly control the assets. These joint arrangements are classified as joint operations, and the financial statements include the Company's ownership-interest share of the assets, liabilities, revenue and expenses of these joint operations.

3(b) Business combinations

Business combinations are accounted for using the acquisition method. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured at their fair values at the acquisition date. 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 acquisition date. The excess of the cost of the acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of the acquisition is less than the fair value of the net assets acquired, the difference is recognized immediately in profit (loss). Transaction costs associated with a business combination are expensed as incurred.

3(c) Cash and cash equivalents

Cash and cash equivalents include short-term investments with original maturities of less than 90 days.

3(d) Financial instruments

InPlay recognizes a financial asset or liability when it becomes a party to the contractual provisions of a financial instrument. Financial assets and liabilities within the scope of IAS 39 "Financial Instruments: Recognition and Measurement" are classified as either financial assets or liabilities at fair value through profit and loss, loans and receivables, held to maturity investments, available for sale financial assets, or financial liabilities at amortized cost as appropriate. InPlay does not designate derivative instruments as hedges and does not have available-for-sale financial assets or held-to-maturity investments. Transaction costs are included in the initial carrying amount of financial instruments except for fair value through profit and loss items, in which case they are expensed as incurred.

(i) Financial assets and liabilities at fair value through profit or loss

Financial assets and liabilities at fair value through profit or loss include financial assets and liabilities held-for-trading and financial assets and liabilities designated upon initial recognition at fair value through profit or loss. Financial assets and liabilities are classified as held-for-trading if they are acquired for the purpose of selling in the near term. Derivatives are also classified as financial assets and liabilities at fair value through profit of loss. Gains or losses on financial assets and liabilities are recognized at fair value in the statement of profit (loss) and comprehensive income (loss).

(ii) Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. After initial measurement, loans and receivables are subsequently carried at amortized cost less any allowance for impairment. Amortized cost is calculated taking into account any discount or premium on acquisition and includes fees that are an integral part of the effective interest rate and transaction costs. Gains and losses are recognized in the statement of profit (loss) and comprehensive income (loss) when the loans and receivables are derecognized or impaired, as well as through the amortization process.

(iii) Financial liabilities at amortized cost

All loans and borrowings are initially recognized at the fair value of the consideration received less directly attributable transaction costs. After initial recognition, interest bearing loans and borrowings are subsequently measured at amortized cost using the effective interest method.

Gains and losses are recognized in the statement of profit (loss) and comprehensive income (loss) when the liabilities are derecognized, as well as through the amortization process.

(iv) Fair value

The fair value of financial instruments that are actively traded in organized financial markets is determined by reference to quoted market bid prices at the valuation date. For financial instruments that have no active market, fair value is determined using valuation techniques including the use of recent arm's length market transactions, reference to the current market value of equivalent financial instruments and discounted cash flow analysis.

(v) Derivative financial instruments

The Company has entered into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices. These instruments are not used for trading or speculative purposes. The Company has not designated its financial derivative contracts as effective accounting hedges and, therefore, has not applied hedge accounting, even though the Company considers all commodity contracts to be economic hedges. As a result, all financial derivative contracts are classified as fair value through profit or loss and are recorded on the statement of financial position at fair value. Transaction costs are recognized in profit (loss) and comprehensive income (loss) when incurred.

3(e) Exploration and evaluation ("E&E") expenditures

Expenditures incurred to explore for and evaluate oil and natural gas reserves may include costs to acquire unproven oil and natural gas properties or licenses to explore, drill exploratory wells, geological and geophysical costs to evaluate the underlying resource, and directly-attributable general and administrative costs. E&E expenditures are recognized and measured as follows:

(i) Prior to obtaining the right to explore

Expenditures are recognized as an expense in profit or loss when incurred.

(ii) Subsequent to acquiring the right to explore, and before technical feasibility and commercial viability have been established

Expenditures incurred are accumulated on an area-by-area basis and are measured at cost as E&E assets. E&E assets are not subject to depletion and depreciation; however, E&E assets are assessed for impairment when facts and circumstances suggest that the carrying amount of an E&E asset may exceed its recoverable amount. Any impairment loss is recognized as an expense in profit or loss.

(iii) Upon demonstration of technical feasibility and commercial viability

An E&E asset is assessed for impairment, and any impairment loss is recognized immediately in profit or loss. The carrying amount of the E&E assets, net of any impairment loss, is reclassified to property, plant and equipment.

3(f) Property, plant and equipment

Property, plant and equipment carrying amounts are measured at cost less accumulated depreciation and depletion, and accumulated impairment losses.

(i) Development and production expenditures

All costs directly associated with the development of oil and natural gas reserves are recognized as property, plant and equipment assets if the expenditures extend or enhance the recoverable reserves of the underlying assets. Such costs include property acquisitions, carrying amounts reclassified from E&E assets to property, plant and equipment, drilling and completion costs, gathering and processing infrastructure, capitalized decommissioning obligations, and directly attributable general and administration costs.

Repairs and maintenance and operational expenditures that do not extend or enhance recoverable reserves are charged to profit or loss when incurred.

(ii) Impairment and reversals of impairment

Oil and natural gas assets are grouped into cash generating units (“CGUs”) for impairment testing. The Company has the following CGUs: Pembina, Rocky Mountain House, Pigeon Lake and Red Deer/Minors.

At the end of each reporting date, the Company considers various external and internal sources of information when assessing whether any indication exists that a CGU may be impaired or that an impairment loss recognized in prior periods may no longer exist or may have decreased. If any such indication exists, the Company estimates the CGU’s recoverable amount. A CGU’s recoverable amount is the higher of its value in use and its fair value less costs of disposal.

When the carrying amount of a CGU exceeds its recoverable amount, the carrying value is reduced to its recoverable amount. That reduction is an impairment loss, which is recognized immediately in profit or loss.

When the recoverable amount exceeds the carrying amount of a CGU, and the carrying value had been reduced in a prior period due to an impairment loss, the carrying amount of the CGU is increased to the revised estimate of its recoverable amount not exceeding the carrying amount that would have been determined had no impairment loss been recognized for the asset or CGU in prior periods. That increase in carrying value is a reversal of an impairment loss, which is recognized immediately in profit or loss.

3(g) Depletion and depreciation

The net carrying amount of oil and natural gas producing properties, including tangible equipment associated with these oil and natural gas properties, is depleted using the unit-of-production method based on estimated proven and probable reserves taking into account the estimated future development and decommissioning costs required to produce these reserves. For other assets, depreciation is recognized in profit or loss on a straight-line or declining basis over the assets’ estimated useful lives.

3(h) Assets held for sale

Non-current assets are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This condition is met when the sale is highly probable and the asset is available for immediate sale in its present condition. For the sale to be highly probable, management must be committed to a plan to sell the asset and an active program to locate a buyer has been initiated. The asset must be actively marketed for sale at a price that is reasonable in relation to its current fair value and the sale should be expected to be completed within one year from the date of classification.

Non-current assets classified as held for sale are measured at the lower of the carrying amount and fair value less costs of disposal, with impairments recognized in the statement of comprehensive income in the period measured. Non-current assets held for sale are presented as a separate asset category on the balance sheet. Assets held for sale are not depleted, depreciated or amortized. Decommissioning obligations associated with assets held for sale are presented as a separate liability category on the balance sheet.

3(i) Decommissioning obligations

The Company has regulatory obligations for the future decommissioning of the Company's oil and gas locations following the end of the assets' useful lives. Decommissioning activities include abandonment of wellbores, dismantling and decommissioning surface equipment and remediating site disturbance. Provision is made for the estimated costs of decommissioning and site restoration and capitalized in the relevant E&E asset or property, plant and equipment category.

Decommissioning obligations are measured at the present value of management's estimation of the amount and timing of expenditures. Changes in the estimated timing of decommissioning and restoration or related cost estimates are dealt with prospectively by recording an adjustment to the provision, and a corresponding adjustment to property, plant and equipment. The accretion on the decommissioning and restoration provision is classified as a finance cost.

3(j) Income taxes

The income tax expense or credit for the period is the tax payable on the current period's taxable income based on the applicable income tax rate for each jurisdiction adjusted by changes in deferred tax assets and liabilities attributable to temporary differences and to unused tax losses. The current income tax charge is calculated on the basis of the tax laws enacted or substantively enacted at the balance sheet date.

Deferred income tax is provided, using the liability method, on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the financial statements. However, deferred tax liabilities are not recognized if they arise from the initial recognition of goodwill, or the initial recognition of an asset or liability in a transaction other than a business combination that at the time of the acquisition affects neither accounting, nor taxable, profit or loss. Deferred income tax is determined using tax rates (and laws) that have been enacted or substantively enacted at the end of the reporting period and are expected to apply when the deferred tax asset is realized or the deferred tax liability is settled.

Deferred tax assets are recognized only if it is probable that future taxable amounts will be available to utilize those temporary differences and losses.

Deferred income tax relating to items recognized directly in equity is recognized in equity and not in the statement of profit (loss) and comprehensive income (loss). Deferred income tax assets and liabilities are offset, if legally enforceable rights exist to set off current income tax assets against current income tax liabilities and the deferred income taxes relate to the same taxable entity and the same taxation authority.

3(k) Share capital

Shares, consisting of common shares are classified as equity.

3(l) Profit (loss) per share

Basic profit (loss) per share is calculated by dividing the profit (loss) for the period by the weighted average number of common shares outstanding during the period.

Diluted profit (loss) per share is calculated using the treasury stock method by adjusting the weighted average number of common shares outstanding for dilutive instruments.

3(m) Revenue Recognition

Revenue from the sale of oil and natural gas is recognized when the significant risks and rewards of ownership are transferred, which is, generally, when title passes to the customer in accordance with the terms of the sales contract.

Revenue from the production of oil and natural gas from properties in which InPlay has an ownership interest with other producers is recognized on a net working interest basis.

3(n) Future accounting pronouncements not yet adopted

The Company has reviewed the following reporting and accounting standards that have been issued, but are not yet effective:

(i) IFRS 9 “Financial Instruments”

This new standard replaces IAS 39 “Financial Instruments: Recognition and Measurement” and provides a logical model for classification and measurement, a single, forward looking ‘expected loss’ impairment model and a substantially-reformed approach to hedge accounting. The Company intends to adopt IFRS 9 in its financial statements for the annual period beginning on January 1, 2018. The impact of the standard has been evaluated and is expected to have no material impact on the Company’s financial statements.

(ii) IFRS 15 “Revenue from Contracts with Customers”

The new standard replaces IAS 18 “Revenue” and established principles for reporting useful information to users of financial statements about the nature, amount, timing and uncertainty of revenue and cash flows arising from an entity’s contracts with customers. The Company intends to adopt IFRS 15 in its financial statements for the annual period beginning on January 1, 2018. The Company is still in the process of evaluating the impact of adopting this standard.

(iii) IFRS 16 “Leases”

The new standard replaces IAS 17 “Leases” and addresses recognition and measurement of assets and liabilities for most leases. The Company intends to adopt IFRS 16 in its financial statements for the annual periods beginning on January 1, 2019. The extent of the impact of the adoption of this new standard has not yet been determined.

3(o) Changes in accounting policies

There were no new or amended accounting policies adopted during the year ended December 31, 2017 that had a material impact on the determination of financial position or profit or loss.

4. SIGNIFICANT ACCOUNTING JUDGEMENTS, ESTIMATES AND ASSUMPTIONS

The preparation of financial statements requires management to use judgment in applying its accounting policies and estimates and assumptions about the future that affect the reported amounts of assets, liabilities, revenues and expenses. Actual results may differ from these estimates.

4(a) Significant judgements in applying accounting policies

The judgements made in applying accounting policies that have the most significant effect on the amounts recognized in these financial statements are as follows:

(i) Exploration and evaluation expenditures

The application of the Company’s policy for exploration and evaluation expenditures requires management to make certain judgements as to the nature of the expenditures and the technical and commercial feasibility of the underlying resource property.

E&E assets remain capitalized as long as sufficient progress is being made in assessing whether the recovery of the petroleum products is technically feasible and commercially viable. The concept of “sufficient progress” is a judgmental area, and it is possible to have E&E assets remain classified as such for several years while additional E&E activities are carried out or the Company seeks government, regulatory or internal approval for development plans. E&E assets are subject to ongoing technical, commercial and Management review to confirm the continued intent to establish the technical feasibility and commercial viability of the discovery. When Management is making this assessment, changes to project economics, expected capital expenditures and

production costs, results of other operators in the region and access to infrastructure and potential infrastructure expansions are important factors.

(ii) Identification of CGUs

A CGU is defined as the smallest identifiable group of assets that generate cash inflows that are largely independent of the cash inflows from other assets or groups of assets. The classification of assets into CGUs requires judgement with respect to similarity of sales points, shared infrastructure, geographical proximity, commodity type and similarity of exposures to market risks.

(iii) Impairment / reversal of impairment of non-financial assets

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

4(b) Major sources of estimation uncertainty

Information about assumptions and estimation uncertainties that have a significant risk of resulting in a material adjustment within the next financial year are as follows:

(i) Estimation of oil and natural gas reserves

Depletion and depreciation of property, plant and equipment costs, and amounts used in impairment calculations are based on estimates of oil and natural gas reserves. At least once per year, independent qualified reserves engineers prepare a reserves assessment and evaluation of the Company's oil and natural gas properties. Reserves estimates are based on engineering data, estimated future commodity prices and costs, expected future rates of production, and the timing of future capital expenditures, all of which are subject to many uncertainties and interpretations.

(ii) Impairment of non-financial assets

Value in use is determined by estimating the present value of the future net cash flows from the continued use of the CGU, and is subject to the risks associated with estimating the value of reserves.

Fair value less costs of disposal refers to the amount obtainable from the sale of a CGU in an arm's length transaction between knowledgeable, willing parties, less costs of disposal.

The key assumptions and estimates of the value of oil and gas reserves and the existing and potential markets for the Company's oil and natural gas assets are made at the time of reserves estimation and market assessment and are subject to change as new information becomes available. Changes in international and regional factors including supply and demand of commodities, inventory levels, drilling activity, currency exchange rates, weather, geopolitical and general economic environment factors may result in significant changes to the estimated recoverable amounts of CGUs.

(iii) Business combinations

The amounts recorded for identifiable assets acquired, liabilities assumed, goodwill or a gain from a bargain purchase will depend on management's assumptions and estimates of future events, in particular, those assumptions and estimates used in the estimation of the fair value of oil and natural gas reserves.

(iv) Decommissioning obligation

The decommissioning obligation is 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 years, based on current legal and constructive requirements and technology. The estimated obligations and actual costs may change significantly

due to changes in regulations, technology, timing of the expenditure and the discount rates used to determine the net present value of the obligations.

(v) Deferred tax

Deferred tax assets and liabilities are measured using enacted or substantively enacted tax rates at the reporting date in effect for the period in which the temporary differences are expected to be recovered or settled. The recognition of deferred tax assets is based on the significant assumptions and estimations regarding future revenues and expenses and the probability that the deductible temporary differences will reverse in the foreseeable future. Changes in the tax rates or assumptions and estimates used in the recognition of deferred taxes may result in material adjustment to the amount recognized.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

5. BUSINESS COMBINATIONS

On November 7, 2016, InPlay completed the Arrangement that included a reverse acquisition of Anderson, a publicly-traded company with an oil and gas production business in Alberta, Canada. See notes 1, 6 and 13. In connection with the Arrangement, InPlay also completed an issue of common shares for proceeds of \$70.3 million and an asset acquisition of oil and natural gas properties for a purchase price of \$47 million prior to purchase price adjustments (the “**Asset Acquisition**”). See notes 6 and 13.

5(a) 2016 Arrangement

As part of the Arrangement, Anderson’s 17,771,472 outstanding common shares were effectively converted into InPlay common shares at an exchange ratio of one for one. As a part of the Arrangement, Anderson was amalgamated with prior InPlay to form InPlay. The former shareholders of Prior InPlay owned 72% of the outstanding common shares of InPlay, and the management and board of directors of Prior InPlay became the management and board of directors of InPlay, thereby obtaining control of Anderson. The reverse acquisition of Anderson by InPlay has been accounted for as a business combination under IFRS 3.

InPlay completed the Arrangement with Anderson to expand InPlay’s asset base with producing assets and interests in facilities in the Cardium area as well as undeveloped lands in Pembina and other areas in Alberta that were complementary to those of InPlay. The transaction also enabled InPlay to become a publicly traded entity on the Toronto Stock Exchange.

The fair value at November 7, 2016 of the total consideration transferred and the amounts recognized attributed to the assets and liabilities acquired was as follows:

Consideration:		(\$’000s)
Share consideration	\$	35,543
Total Consideration		35,543
Recognized amounts of assets acquired and liabilities assumed		
Cash		2,459
Accounts receivable and accrued receivables		3,268
Prepaid expenses		1,076
Exploration and evaluation		5,410
Property, plant and equipment		45,332
Deferred tax asset		37,589

Accounts payable and accrued liabilities	(4,472)
Decommissioning obligation	(13,743)
Total identifiable net assets	76,919
Gain on acquisition	(41,376)
	\$ 35,543

The fair value of the 17,771,472 common shares of InPlay effectively issued to the former shareholders of Anderson in exchange for the Anderson common shares outstanding immediately prior to the completion of the Arrangement on a one-for-one basis was \$2.00 per common share, or \$35.5 million, based on Anderson's closing price quoted on the TSX on November 7, 2016, the date of closing of the Arrangement. See note 13.

A gain on acquisition was recorded with this business combination as a result of the deferred tax asset on acquisition being recorded at book value rather than fair value in addition to the fact that final consideration is based upon a lower share price at closing compared to the price contemplated at the time the deal was negotiated.

The fair value of accounts receivable was \$3.3 million, which consisted of trade receivables arising from the sale of oil and natural gas production and billings related to joint operations activities. The gross contractual amount for trade receivables was \$3.7 million, of which \$0.4 million was expected to be uncollectible.

The fair value of the decommissioning obligation at November 7, 2016 was based on the estimated future cash flows to decommission the acquired property, plant and equipment at the end of its useful life. The discount rates used to determine the net present value of the decommissioning obligation were credit adjusted risk-free rates that ranged from 7.5% to 8.4%. At December 31, 2016 the decommissioning liability was revalued at risk-free rates ranging from 1.4% to 2.3%, resulting in incremental additions of \$17.4 million of decommissioning obligation and corresponding additions to property, plant and equipment.

The acquired business contributed revenues consisting of oil and natural gas sales net of royalties of approximately \$2.3 million and operating income which is defined as oil and natural gas sales net of royalties less operating and transportation costs of \$1.6 million to InPlay for the period from November 7, 2016 to December 31, 2016. Had the Arrangement occurred on January 1, 2016, additional pro-forma oil and natural gas sales net of royalties of \$11.2 million and operating income of \$5.4 million would have been recognized over the year ended December 31, 2016.

5(b) 2016 Asset Acquisition

The Asset Acquisition involved the purchase of producing assets, undeveloped lands and interests in various facilities in the Pembina area of Alberta, Canada. The Asset Acquisition has been accounted for as a business combination under IFRS 3.

The fair value at November 7, 2016 of the total consideration transferred and the amounts recognized attributed to the assets acquired was as follows:

Consideration:		(\$'000s)
Cash consideration	\$	41,422
Share consideration		4,347
Total Consideration		45,769

Recognized amounts of assets acquired and liabilities assumed

Accounts receivable and accrued receivables	470
Prepaid expenses	191
Exploration and evaluation	1,457
Property, plant and equipment	47,489
Decommissioning obligation	(3,838)
Total identifiable net assets	\$ 45,769

During the year ended December 31, 2017, the cash consideration was reduced by \$0.3 million as a result of receipt of the final statement of adjustments relating to the acquisition, with a corresponding reduction in the recognized amounts of Property, plant and equipment.

The fair value of the 2,171,667 common shares of InPlay, which were the 16,666,666 Prior InPlay common shares converted at the 0.1303 exchange ratio under the Arrangement, issued as partial consideration for the purchase of assets was \$2.00 per common share, or \$4.3 million. This price was based on Anderson's closing price quoted on the TSX on November 7, 2016, the date of closing of the Arrangement. See note 13.

The fair value of the decommissioning obligation at November 7, 2016 was based on the estimated future cash flows to decommission the acquired property, plant and equipment at the end of its useful life. The discount rates used to determine the net present value of the decommissioning obligation were credit adjusted risk-free rates that ranged from 8.0% to 8.3%. At December 31, 2016 the decommissioning liability was revalued at risk-free rates ranging from 2.0% to 2.3%, resulting in incremental additions of \$12.6 million of decommissioning obligation and corresponding additions to property, plant and equipment.

The acquired business contributed revenues consisting of oil and natural gas sales net of royalties of approximately \$1.8 million and operating income which is defined as oil and natural gas sales net of royalties less operating and transportation costs of \$0.6 million to InPlay for the from period November 7, 2016 to December 31, 2016. Had the Corporate Acquisition occurred on January 1, 2016, an additional pro-forma oil and natural gas sales net of royalties of \$9.0 million and operating income of \$3.9 million would have been recognized over the year ended December 31, 2016.

5(c) Other

Effective June 6, 2017, the Company purchased producing assets, undeveloped lands and interests in various facilities in the Cardium area of Alberta, Canada. The transaction has been accounted for as a business combination under IFRS 3.

The fair value at June 6, 2017 of the total consideration transferred and the amounts recognized attributed to the assets acquired was as follows:

Consideration:	(\$'000s)
Cash consideration	\$ 1,410
Total Consideration	1,410

Recognized amounts of assets acquired and liabilities assumed

Prepaid expenses	11
Exploration and evaluation	358
Property, plant and equipment	1,248
Decommissioning obligation	(207)
Total identifiable net assets	\$ 1,410

Subsequent to the acquisition, the cash consideration was reduced by \$0.2 million as a result of receipt of the final statement of adjustments relating to the acquisition, with a reduction in the recognized amounts of Prepaid expenses and Property, plant and equipment.

The fair value of the decommissioning obligation at June 6, 2017 was based on the estimated future cash flows to decommission the acquired property, plant and equipment at the end of its useful life. The discount rates used to determine the net present value of the decommissioning obligation were credit adjusted risk-free rates that ranged from 8.0% to 8.1%. At June 30, 2017 the decommissioning liability was revalued at risk-free rates ranging from 2.0% to 2.1%, resulting in incremental additions of \$0.7 million of decommissioning obligation and corresponding additions to property, plant and equipment.

The acquired business contributed revenues consisting of oil and natural gas sales net of royalties of approximately \$0.4 million and operating income, which is defined as oil and natural gas sales net of royalties less operating and transportation costs of \$0.3 million to InPlay for the period from June 6, 2017 to December 31, 2017. Had the asset acquisition occurred on January 1, 2017, an additional pro-forma oil and natural gas sales net of royalties of approximately \$0.7 million and operating income of \$0.5 million would have been recognized over the year ended December 31, 2017.

The fair values of the identifiable assets and liabilities acquired as reported in the table in note 5 were estimated based on information available at the time of preparation of the financial statements and could be subject to change.

6. PROPERTY, PLANT AND EQUIPMENT

Cost (\$'000s)	Oil & Natural Gas Assets	Other Equipment	Total
Balance at December 31, 2015	226,127	338	226,464
Additions	11,102	51	11,154
Additions/revisions to decommissioning obligation	28,156	-	28,156
Acquisitions	93,165	-	93,165
Transfer from exploration and evaluation assets	57	-	57
Balance at December 31, 2016	358,607	389	358,996
Additions	33,136	129	33,265
Additions/revisions to decommissioning obligation	(1,781)	-	(1,781)
Acquisitions	904	-	904
Transfer from exploration and evaluation assets	57	-	57
Transfer to assets held for sale	(4,489)	-	(4,489)
Balance at December 31, 2017	386,434	518	386,952

Accumulated Depletion & Impairment (\$'000s)	Oil & Natural Gas Assets	Other Equipment	Total
Balance at December 31, 2015	107,956	86	108,042
Impairment loss	12,162	-	12,162
Depletion and depreciation	13,669	56	13,725
Balance at December 31, 2016	133,787	142	133,929
Impairment loss	6,052	-	6,052
Depletion and depreciation	22,479	72	22,551
Balance at December 31, 2017	162,318	214	162,532

Net book value (\$'000s)	Oil & Natural Gas Assets	Other Equipment	Total
At December 31, 2016	224,820	247	225,067
At December 31, 2017	224,116	304	224,420

For the year ended December 31, 2017, additions to property, plant and equipment included capitalized general and administrative expenses of \$1.3 million (December 31, 2016: \$0.8 million) and costs related to share-based compensation of \$0.8 million (December 31, 2016: \$0.5 million). Future development costs in the amount of \$191 million (2016 - \$178 million) were included in the depletion calculation for the three months ended December 31, 2017.

At December 31, 2017, the Company classified certain processing facility and associated gather equipment and infrastructure assets as held for sale. Immediately prior to classifying the assets as held for sale, the Company conducted a review of the assets' recoverable amounts based on expected consideration to be received and transferred these assets at their carrying amount, with no impairment or recovery recognized. The decommissioning obligation associated with these assets has also been classified as a liability relating to assets held for sale.

7. IMPAIRMENT LOSS

2017 Impairment Considerations

Indicators of impairment relating to Property, plant and equipment were considered to exist as at December 31, 2017 as sustained long-term commodity price forecast decreases were present. Impairment tests were performed for each the Company's CGUs which resulted in impairment losses recorded in the Company's statement of profit (loss) and comprehensive income (loss) on the Pigeon Lake CGU in the amount of \$6.1 million. The Company used the income approach technique to measure fair value of the CGUs whereby the net present value of the future cash flows were calculated using a discount rate of 12%. The future cash flows were based on level 3 fair value hierarchy inputs: the Company's reserves prepared by its independent reserves evaluator, including key assumptions regarding the discount rate, quantities of reserves and production volumes, future commodity prices as prepared by its independent reserves evaluator, royalty obligations, operating expenses, development costs, and decommissioning costs.

If the discount rate used was one percent higher, impairment of approximately \$3.0 million would have been recorded, all relating to the Pigeon Lake CGU. If the commodity prices used in the impairment tests were five percent lower, approximately \$7.3 million of impairment would have been recorded, all relating to the Pigeon Lake CGU.

2016 Impairment Considerations

Indicators of impairment relating to Property, plant and equipment were considered to exist as at December 31, 2016 as long-term commodity price forecasts continued to weaken in the fourth quarter. Impairment tests were performed for each the Company's CGUs which resulted in no impairment charges as of December 31, 2016. The Company used the income approach technique to measure fair value of the CGUs whereby the net present value of the future cash flows were calculated using a discount rate of 12%. The future cash flows were based on level 3 fair value hierarchy inputs: the Company's reserves prepared by its independent reserves evaluator, including key assumptions regarding the discount rate, quantities of reserves and production volumes, future commodity prices as prepared by its independent reserves evaluator, royalty obligations, operating expenses, development costs, and decommissioning costs.

If the discount rate used was one percent higher, impairment of approximately \$1.4 million would have been recorded. If the commodity prices used in the impairment tests were five percent lower, approximately \$4.5 million of impairments would have been recorded.

During the quarter ended June 30, 2016, the Company actively reviewed potential acquisitions and completed three transactions, during which the Company considered reasonably comparable market transactions for assets similar to those owned by InPlay. The review of market prices of assets provided the Company with an indication of potential impairment of its assets, and impairment tests were performed on all of its CGUs as at June 30, 2016, and impairment losses were recorded in the Company's statement of profit (loss) and comprehensive income (loss) on the historical Pembina CGU (\$11.3 million) and the historical Minors CGU (\$0.8 million) for a total impairment loss for the year ended December 31, 2016 of \$12.2 million.

If the discount rate used in determining the above recoverable amounts were one percent higher, impairment recognized would have been approximately \$6.6 million higher. If the commodity prices used were five percent lower the impairment recognized would have been approximately \$18.5 million higher.

The following table shows the benchmark commodity prices used in the impairment calculation of Property, plant and equipment at December 31, 2017 and December 31, 2016.

Year	Light, Sweet Crude Edmonton (\$Cdn/bbl)			AECO Gas Price (\$Cdn/MMBtu)		
	December 31, 2017	December 31, 2016	Change	December 31, 2017	December 31, 2016	Change
2018	68.60	74.51	(5.91)	2.43	3.27	(0.84)
2019	72.02	78.24	(6.22)	2.77	3.22	(0.45)
2020	74.48	80.64	(6.16)	3.19	3.91	(0.72)
2021	78.60	82.25	(3.65)	3.48	4.00	(0.52)
2022	80.84	83.90	(3.06)	3.67	4.10	(0.43)
2023	82.83	85.58	(2.75)	3.76	4.19	(0.43)
2024	85.17	87.29	(2.12)	3.85	4.29	(0.44)
2025	87.53	89.03	(1.50)	3.93	4.40	(0.47)
2026	89.66	90.81	(1.15)	4.02	4.50	(0.48)
2027	91.49	92.63	(1.14)	4.10	4.61	(0.51)
2028	93.31	94.48	(1.17)	4.19	4.70	(0.51)

8. EXPLORATION AND EVALUATION

(\$'000s)	December 31, 2017	December 31, 2016
Balance at January 1	\$ 11,599	\$ 5,716
Additions	2,408	471
Acquisitions related to Business Combinations	358	6,867
Acquisitions	14,315	-
Transfers to property, plant and equipment	(57)	(57)
Transfers to exploration and evaluation expense	(2,636)	(1,398)
Ending balance	\$ 25,987	\$ 11,599

At December 31, 2017, the Company evaluated its remaining Exploration and evaluation assets for indicators of any potential impairment. As a result of this assessment, no indicators were identified and no additional impairment was recorded relating to the Company's Exploration and evaluation assets.

9. DEFERRED LEASE CREDITS

The Company entered into a lease for its current head office location during 2014, at which time the Company received incentives to enter into the lease in the amount of \$0.4 million. The Company has deferred recognition of the incentives and has amortized the credit as a reduction of lease expense over the initial term of the lease.

10. BANK DEBT

At December 31, 2017, the Company has a syndicated \$60.0 million senior secured revolving credit facility (the "**Credit Facility**"). The Credit Facility consists of a \$50 million revolving line of credit and a \$10 million operating line of credit. The Credit Facility has a term date of May 31, 2018, and if not extended, additional advances would not be permitted and any outstanding advances would become repayable one year later on May 31, 2019. The Credit Facility is secured by a floating charge debenture and a general security agreement on the assets of the Company. At December 31, 2017 the Company had drawn \$44.9 million on the credit facility.

Under the credit agreement, advances can be drawn as prime rate loans and bear interest at the bank's prime lending rate plus interest rates between 1.00% and 3.25%. Advances may also be drawn as banker's acceptances, Libor loans, and letters of credit, subject to stamping fees and margins ranging from 2.00% to 4.25%. Standby fees are charged on the undrawn portion of the Credit Facility at rates ranging from 0.50% to 1.0625%. These interest rates, fees and margins vary based on adjusted debt to earnings metrics determined at each quarter end for the preceding 12 months. There are standard reporting covenants under the Credit Facility, however there are no financial covenants. The Company was in compliance with these standard reporting covenants as at December 31, 2017. Prior to this Credit Facility, up to Nov. 7, 2016 Prior InPlay had in place a \$60 million senior secured demand credit facility which was paid out in full at closing in conjunction with the closing of the Nov 7, 2016 financing, Asset Acquisition and Arrangement.

Subsequent to December 31, 2017, an assignment agreement to the credit agreement was entered into (the "**Assignment Agreement**"), changing the Agent under the Credit Facility. No other changes were made to the Credit Facility as result of the Assignment Agreement.

The available lending limit of the Credit Facility is scheduled for annual review on or before May 31, 2018 and is based on the Lenders' interpretation of the Company's reserves and future commodity prices. There can be no assurance that the amount or terms of the available Credit Facility will not be adjusted at the next review. In the event that the lenders reduced the borrowing base below the amount drawn at the time

of the redetermination, the Company would have 60 days to eliminate any borrowing base shortfall by repaying the amount drawn in excess of the re-determined borrowing base or by providing additional security or other consideration satisfactory to the lenders. Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties.

11. DECOMMISSIONING OBLIGATION

(\$'000s)	December 31, 2017	December 31, 2016
Balance at January 1	\$ 68,948	\$ 22,763
Provisions incurred	663	457
Acquired through Business Combinations	207	17,581
Provisions settled	(644)	(119)
Revaluation of liabilities acquired based on discount rate	718	30,061
Change in estimates	(3,162)	(2,361)
Accretion expense	1,480	566
Transfer to liabilities associated with assets held for sale	(1,052)	-
Ending balance	\$ 67,158	\$ 68,948
Expected to be incurred within one year	492	-
Expected to be incurred beyond one year	66,666	68,948

The estimated future cash out flows as at December 31, 2017 are based on the current estimated costs, government regulations and industry practices to decommission the Company's exploration and production assets. The Company used an inflation rate of 2.0% per annum (Dec 31, 2016 – 2.0%) until settlement of the obligations, which is assumed to occur over the next 7 to 52 years, to determine the future estimated cash flows. The net present value of the future estimated cash flows have been determined using risk-free discount rates of 1.9% to 2.3% depending on the estimated timing of the future settlement of the obligations (Dec 31, 2016 – 1.4% to 2.3%). The total inflation adjusted undiscounted amount of estimated future cash flows required to settle the decommissioning obligation at December 31, 2017 was approximately \$109.6 million (Dec 31, 2016 - \$112.6 million).

At the date of business combinations, the acquired decommissioning obligations were recognized at fair value which was estimated using credit adjusted discount rates of 7.5% to 8.4%. The impact of the change in the estimated present value using risk-free discount rates is recorded as 'Revaluation of liabilities acquired based on discount rate'.

There are material uncertainties about the amount and timing of the decommissioning obligation, which include the future market prices for services and equipment required to undertake decommissioning activities, the government regulations and industry practices that set out the relevant standards, and the life-span of the Company's portfolio of exploration and production assets.

12. INCOME TAX

The following table reconciles the income tax (recovery) calculated using the statutory tax rates to the income tax (recovery) per the statement of profit (loss) and comprehensive income (loss):

(\$'000s)	December 31, 2017	December 31, 2016
Profit (loss) before tax	\$ (9,386)	\$ 13,442
Expected income tax rate	27%	27%
Expected income tax expense (recovery)	(2,534)	3,629
Increase in income taxes resulting from:		
Non-taxable permanent differences – stock based comp.	435	501
Flow through share expenditure effect	380	442
Non-taxable permanent differences – (gain) on purchase	-	(11,171)
Other	34	22
Income tax (recovery)	\$ (1,685)	\$ (6,577)

Deferred tax asset and (liability) components and continuity:

(\$'000s)	December 31, 2015	Charged (credited) Profit or loss	Directly to balance sheet	Acquisitions	December 31, 2016
Property, plant and equipment, and E&E	\$ (813)	\$ (7,936)	\$ (133)	\$ 29,051	\$ 20,169
Decommissioning obligation	6,146	8,759	-	3,710	18,615
Non-capital losses	6,680	4,730	-	4,563	15,973
Derivative contract	(865)	1,283	-	-	418
Share issue costs	384	(259)	584	265	974
Total	\$ 11,532	\$ 6,577	\$ 451	\$ 37,589	\$ 56,149

(\$'000s)	December 31, 2016	Charged (credited) Profit or loss	Directly to balance sheet	Acquisitions	December 31, 2017
Property, plant and equipment, and E&E	\$ 20,169	\$ 2,854	\$ (377)	\$ -	\$ 22,646
Decommissioning obligation	18,615	(199)	-	-	18,416
Non-capital losses	15,973	(848)	-	-	15,125
Derivative contract	418	8	-	-	426
Share issue costs	974	(130)	54	-	898
Total	\$ 56,149	\$ 1,685	\$ (323)	\$ -	\$ 57,511

The Company's non-capital losses will begin to expire between 2029 and 2033. The amount and timing of reversals of temporary differences will be dependent upon a number of factors, including the Company's future operating results. With the exception of the temporary differences related to the derivative contract gain, the Company does not expect any deferred income tax assets or liabilities to reverse within the next twelve months. The deferred tax asset is supported by the expected future

utilization of tax attributes based upon future cashflows derived from the Company's independent year end reserve report using the total proven and probable cashflows and expenditures and factoring in expected corporate general and administrative and interest expenses.

13. SHARE CAPITAL

Authorized share capital consists of an unlimited number of voting common shares.

	Number of Common Shares ⁽¹⁾	Amount (\$'000s)
Balance at December 31, 2015	12,063,110	118,262
Issued in exchange for the Asset Acquisition	2,171,667	4,347
Issued for cash	28,887,516	66,510
CEE Flow-through shares issued	635,642	1,708
CDE Flow-through shares issued	866,762	2,128
Flow-through share premium liability	-	(377)
Issued under the Anderson Arrangement	17,771,472	35,543
Share issue costs	-	(1,580)
Balance at December 31, 2016	62,396,169	226,541
Repurchase of shares	(342,600)	(1,249)
CEE Flow-through shares issued	3,173,050	5,711
CDE Flow-through shares issued	2,660,000	4,394
Flow-through share premium liability	-	(1,294)
Share issue costs	-	(146)
Balance at December 31, 2017⁽¹⁾	67,886,619	233,957

⁽¹⁾ The number of common shares have been adjusted retrospectively to reflect the InPlay Exchange Ratio.

In connection with the Arrangement (see notes 1 and 5), Prior InPlay completed a private placement of common shares for proceeds of \$0.4 million (195,015 common shares) and a subscription receipt financing for aggregate gross proceeds of approximately \$69.9 million (the "**InPlay Financing**"). The private placement for \$0.4 million was issued to insiders and management of InPlay in conjunction with the Arrangement. The outstanding common shares of Prior InPlay ("**Prior InPlay Shares**") and subscription receipts ("**Prior InPlay Subscription Receipts**") issued under the InPlay Financing were, through a series of steps under the Arrangement, exchanged for common shares of InPlay ("**InPlay Shares**") on the basis of 0.1303 of an InPlay Share for each one (1) Prior InPlay Share and each one (1) Prior InPlay Subscription Receipt previously held (the "**InPlay Exchange Ratio**"). Holders of Anderson common shares continued to hold one (1) InPlay Share for each one (1) Anderson common share held prior to completion of the Arrangement without any action on their part. The number of commons shares for all periods shown above were adjusted retrospectively to reflect the InPlay Exchange Ratio.

Also connected with the Arrangement, the Company issued 2,171,667 InPlay common shares (reflecting the InPlay Exchange Ratio) having a deemed value of \$4.3 million as partial consideration for the Asset Acquisition. See note 5.

As a part of the above noted financing 1,502,405 Subscription Receipts were also issued to be converted into flow-through common shares upon completion of the Arrangement. Following the conversion of these Subscription Receipts, 635,642 Canadian Exploration Expense ("CEE") flow-through common

shares of InPlay were issued and 866,762 Canadian Development Expense (“CDE”) flow-through common shares of InPlay were issued. Proceeds of \$3.8 million were raised and \$0.4 million of this amount was recorded to Flow-through share premium liability. Following this offering, the Company has spent the required \$2,128,000 million in required CDE expenditures by December 31, 2016 and the \$1,707,000 in CEE expenditures by December 31, 2017.

During the year ended December 31, 2017, 3,173,050 Canadian Exploration Expense (“CEE”) flow-through common shares of InPlay and 2,660,000 Canadian Development Expense (“CDE”) flow-through common shares of InPlay were issued. Proceeds of \$10.1 million were raised and \$1.3 million of this amount was recorded to Flow-through share premium liability. Following this offering, the Company has spent \$0.6 million in required CDE expenditures and \$0.5 million of the required CEE expenditures by December 31, 2017, with the remaining \$3.8 million in CDE expenditures to be spent by March 31, 2018 and remaining \$5.2 million in required CEE expenditures to be spent by December 31, 2018.

During the year ended December 31, 2017, 342,600 common shares (year ended December 31, 2016 – nil) were repurchased under a normal course issuer bid at an average cost of \$1.53 per share for total consideration of \$0.5 million (year ended December 31, 2016 – \$nil). Contributed surplus was increased by \$0.7 million during the year ended December 31, 2017 (year ended December 31, 2016 – \$nil) for the average carrying value of the shares repurchased in excess of their repurchase cost.

14. SHARE-BASED COMPENSATION

14(a) Stock option plan

The Company has an incentive stock option plan pursuant to which options to purchase common shares may be granted to directors, officers, employees and service providers of the Company. The aggregate number of stock options that may be granted at any time under the plan shall not exceed 10% of the aggregate number of issued and outstanding common shares. The exercise price, terms of vesting and expiry date of stock options are fixed by the directors of the Company at the time of grant. All outstanding stock options vest over a three year period, or otherwise in accordance with the stock option plan, and expire five years from the date of grant. The directors of the Company may amend, alter or revise the terms and conditions of the stock option plan or of any outstanding stock options, subject to the terms of the plan. All options of Prior InPlay were surrendered for cancellation in conjunction with the completion of the Arrangement. Following the completion of the Arrangement, new options were issued in the first quarter of 2017.

	Number of options	Weighted average remaining life (years)	Weighted average exercise price
Balance at December 31, 2015 ⁽¹⁾	927,215	4.5	9.59
Cancelled during the year ⁽¹⁾	(927,215)	3.5	9.59
Balance at December 31, 2016	-	-	-
Granted during the period	4,955,400	4.09	1.97
Forfeited during the period	(90,000)	4.00	1.98
Balance at December 31, 2017	4,865,400	4.09	1.97

⁽¹⁾ The number of options and weighted average exercise price for all options issued in Prior InPlay up to December 31, 2016 have been adjusted retrospectively to reflect the InPlay Exchange Ratio. See note 13.

Range of Exercise Prices (\$)	Options Outstanding			Options Exercisable		
	Number of Options Outstanding	Weighted Average Exercise Price (\$)	Weighted Average Remaining Life (Years)	Number of Options Exercisable	Weighted Average Exercise Price (\$)	Weighted Average Remaining Life (Years)
1.48 - 1.75	51,000	1.48	4.53	-	-	-
1.76 - 2.00	4,799,400	1.98	4.08	-	-	-
2.01 - 2.04	15,000	2.04	4.27	-	-	-
	4,865,400	1.97	4.09	-	-	-

14(b) Performance Warrants

Prior InPlay had an incentive plan pursuant to which performance warrants were granted to officers, directors, employees and service providers of the Company. All performance warrants were surrendered for cancellation in conjunction with the completion of the Arrangement.

	Number of warrants	Weighted average exercise price
Balance at December 31, 2015 ⁽²⁾	2,045,059	19.19
Cancelled during the year ⁽²⁾	(2,04,059)	19.19
Balance at December 31, 2016 and 2017	-	-

⁽²⁾ The number of performance warrants and weighted average exercise price for all years have been adjusted retrospectively to reflect the InPlay Exchange Ratio. See note 13.

14(c) Share-based compensation amounts recognized

Share-based compensation in the amount of \$1.6 million was recognized in the year ended December 31, 2017 (December 31, 2016 - \$1.9 million), in addition to \$0.8 million (December 31, 2016 - \$0.5 million) of capitalized stock based compensation recognized for year ended December 31, 2017, all with a corresponding credit to contributed surplus.

The fair value of each stock option granted in the year ended December 31, 2017 is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions:

	2017	2016
Risk free interest rate	0.91%	-
Expected volatility	58%	-
Expected life	3.5 years	-
Dividend yield	nil	-
Expected forfeiture rate	nil	-
Stock price on grant date	1.98	-
Fair value per option	\$0.83	-

15. PROFIT (LOSS) PER SHARE

(\$'000s except per share amounts)	December 31, 2017	December 31, 2016
Profit (loss) for the year	\$ (7,701)	\$ 20,019
Weighted average number of common shares (basic and diluted) ⁽¹⁾	62,688,280	19,626,821
Basic and diluted profit (loss) per share	\$ (0.12)	\$ 1.02

⁽¹⁾ The weighted average number of common shares and calculation of basic and diluted earnings (loss) per share for all periods presented have been adjusted retrospectively to reflect the InPlay Exchange Ratio. See note 13.

16. REVENUE AND DERIVATIVE CONTRACTS

(\$'000s)	December 31, 2017	December 31, 2016
Oil sales	50,821	23,985
Natural Gas sales	6,823	2,659
NGL sales	4,595	1,206
Total	\$ 62,239	\$ 27,850

Changes in fair value of derivative contracts:

Realized gain on derivative contracts	1,114	2,657
Unrealized (loss) on derivative contracts	(30)	(4,753)
Gain (loss) on derivative contracts	\$ 1,084	\$ (2,096)

17. TRANSACTION COSTS

For the year ended December 31, 2017 \$0.3 million of transaction costs were incurred for costs incurred to realign the Company's workforce subsequent to the Arrangement. For the year ended December 31, 2016 \$2.4 million of transaction costs were incurred for advisory and professional fees associated with the Arrangement, Asset Acquisition and financing and related evaluations.

18. GENERAL AND ADMINISTRATIVE EXPENSES BY NATURE

(\$'000s)	December 31, 2017	December 31, 2016
Salaries, benefits and bonuses	\$ 4,294	\$ 2,916
Office Rent & Parking	475	837
Computer related fees	556	378
Professional Consulting Services	338	415
Legal Expenses	92	60
Other – (Office & Admin)	1,664	843
Capitalized Recoveries	(1,490)	(974)
Total General and Administrative Expense	\$ 5,929	\$ 4,475

19. FINANCE EXPENSE

(\$'000s)	December 31, 2017	December 31, 2016
Interest expense (Credit Facility and other)	\$ 1,602	\$ 1,717
Accretion expense on decommissioning obligation	1,480	566
Finance expense	\$ 3,082	\$ 2,283

20. SUPPLEMENTAL CASH FLOW INFORMATION

Net change in non-cash working capital is comprised of:

(\$'000s)	December 31, 2017	December 31, 2016
Source (use) of cash		
Accounts receivable and accruals	\$ (749)	\$ (1,424)
Prepaid expenses, deposits and deferred lease credits	(192)	(484)
Accounts payable and accruals	2,288	5,291
	\$ 1,347	\$ 3,383
Related to operating activities	\$ (1,778)	\$ (1,107)
Related to financing activities	\$ -	\$ -
Related to investing activities	\$ 3,125	\$ 4,490

21. FINANCIAL INSTRUMENTS AND CAPITAL MANAGEMENT

The Company has exposure to credit, liquidity and market risk from its use of financial instruments. This note presents information about the Company's exposure to these risks, the Company's objectives, policies and processes for measuring and managing risk, and the Company's management of capital. Further quantitative disclosures are included throughout these financial statements.

Management of InPlay has overall responsibility for identifying the principal risks of the Company and ensuring the policies and procedures are in place to appropriately manage these risks. InPlay's management identifies, analyzes and monitors risks and considers the implication of the market condition in relation to the Company's activities.

21(a) Fair value of financial instruments

Financial instruments comprise cash and cash equivalents, accounts receivable and accrued receivables, deposits, derivative contracts, accounts payable and accrued liabilities and bank debt.

The carrying amounts for cash and cash equivalents, accounts receivable and accrued receivables, deposits, and accounts payable and accrued liabilities are reasonable approximations of their respective fair values due to the short-term maturities of those instruments. Bank debt's carrying amount is also a reasonable approximation of its fair value as it is variable rate debt with similar terms to what would be available as of balance sheet date.

The Company classified the fair value of its financial instruments measured at fair value according to the following hierarchy based on the nature of inputs used to value the instrument:

- Level 1 – observable inputs such as quoted prices in active markets;
- Level 2 – inputs, other than the quoted market prices in active markets, which are observable, either directly and/or indirectly; and
- Level 3 – one or more of the significant inputs is not based on observable market data exists.

The fair values of the derivative contracts used for risk management as shown in the statements of financial position as at December 31, 2017 and December 2016 were measured using level 2 observable inputs, including quoted prices received from financial institutions based on published forward price curves as at the measurement date, using the remaining contracted oil and natural gas volumes.

During the years ended December 31, 2017 and December 31, 2016, there were no transfers between level 1, level 2 and level 3 classified assets and liabilities.

21(b) 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 operations partners and petroleum and natural gas customers.

Receivables from petroleum and natural gas marketers are normally collected on the 25th day of the month following production. When production is not taken in kind payment comes from the common stream operator and facility operator in which payment is typically received within one month following the 25th day of the month following production. InPlay's approach to mitigate credit risk associated with these balances is to maintain marketing relationships with large, established and reputable customers, common stream operators and facility operators that are considered to be creditworthy. InPlay has not experienced any collection issues with its current common stream and facility operators. Joint operations receivables are typically collected within two to three months of the joint operations billing being issued to the partner.

InPlay mitigates collection risk from joint operations receivables by obtaining partner approval of significant capital and operating expenditures prior to expenditure and, in certain circumstances, may collect cash deposits in advance of incurring financial obligations on behalf of joint operations partners. Joint operations receivables are from partners in the petroleum and natural gas industry who are subject to the risks and conditions of the industry. Significant changes in industry conditions and risks that negatively impact partners' ability to generate cash flow will increase the risk of not collecting receivables.

The Company does not typically obtain collateral from oil and natural gas customers or joint interest partners; however, the Company does have the ability to withhold production from joint interest partners in the event of non-payment.

Trade and other receivables are non-interest bearing and are generally on 25 to 90 day terms. The Company's allowance for doubtful accounts as at December 31, 2017 was \$0.2 million (December 31, 2016 – \$0.4 million). This allowance was associated with the Corporate Acquisition and relates to either industry counterparties with financial solvency issues or potential joint interest billing disputes. See note 5.

In determining the recoverability of trade and other receivables, InPlay considers the type and age of the outstanding receivables, the credit risk of the counterparties, and the recourse available to InPlay. The maximum exposure to credit risk for accounts receivable and accruals, net of allowance for doubtful accounts at the reporting date by type of customer was:

(\$'000s)	Carrying Amount	
	December 31, 2017	December 31, 2016
Oil and natural gas customers	\$ 7,295	\$ 4,672
Joint operations partners	1,381	1,084
Accruals & Other	529	2,700
Total	\$ 9,205	\$ 8,456

As of December 31, 2017 and December 31, 2016, the Company's accounts receivable and accrued receivables, net of allowance for doubtful accounts was aged as follows:

Aging (\$'000s)	December 31, 2017	December 31, 2016
0 – 30 days	7,869	7,403
30- 90 days	812	437
Greater than 90 days	524	616
Total	\$ 9,205	\$ 8,456

The Company considers amounts greater than 90 days past due. Receivables normally collectible within 30 to 60 days can take longer as information requests and timing can come into effect in dealing with receivables from joint venture partners. At December 31, 2017 \$0.7 million (December 31, 2016 – \$1.0 million) in receivables were over 90 days due and considered past due. Of this amount \$0.2 million (December 31, 2016 - \$0.4 million) had an allowance for doubtful accounts set up.

Cash and cash equivalents, when held, consist of cash bank balances and short-term deposits which all mature in less than 90 days. InPlay only invests cash and enters into short-term deposits and derivative contracts with large established Canadian banks and avoids complex investment vehicles with higher risk.

21(c) 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 objective is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when due.

To achieve this objective, the Company prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. The Company uses authorizations for expenditures on both operated and non-operated projects to further manage capital expenditures. To provide capital when needed, the Company has a credit facility which is reviewed semi-annually by its lenders. These facilities are described in note 10. The Company also attempts to match its payment cycle with collection of oil and natural gas revenue on the 25th of each month.

The following are the contractual maturities of non-derivative financial liabilities at December 31, 2017:

(\$'000s)	Less than one year	One to two years
Non-derivative financial liabilities:		
Accounts payable and accrued liabilities	\$ 17,764	\$ -
Bank loans – principal & interest ⁽¹⁾	654	44,888
Total	\$ 18,348	\$ 44,888

⁽¹⁾ Assumes the Credit Facility is not renewed on May 31, 2018, whereby outstanding balances become due one year later on May 31, 2019.

The following table shows the Company's accounts payable and accruals:

	Carrying Amount	
(\$'000s)	December 31, 2017	December 31, 2016
Trade payables ⁽²⁾	\$ 8,681	\$ 8,735
Joint operations partners	1,108	1,117
Accruals ⁽³⁾	7,975	5,624
Total	\$ 17,764	\$ 15,476

⁽²⁾ Includes all payables related to operations, including royalties payable.

⁽³⁾ Accruals include amounts for goods and services that have been received or supplied but have not been paid, invoiced or formally agreed with the supplier as of the reporting date. These accruals relate to both operating and capital activities.

21(d) Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises three types of risk: foreign currency risk, commodity price risk and interest rate risk. The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. Derivative instruments may be used to reduce exposure to these risks.

(i) Foreign currency exchange rate risk

The Company is exposed to the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. While substantially all of the Company's sales are denominated in Canadian dollars, the market prices in Canada for oil and natural gas are impacted by changes in the exchange rate between the Canadian dollar and the United States dollar. The Company had no forward exchange rate contracts in place as at December 31, 2017 or December 31, 2016.

(ii) Commodity price risk

The Company is exposed to the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. The reference price for buyers and sellers of crude oil relevant to the Company's oil sales is West Texas Intermediate at Cushing, Oklahoma, USA ("WTI"), and the reference price for buyers and sellers of natural gas includes deals that are conducted anywhere within TransCanada's Alberta, Canada System, otherwise known as NOVA ("AECO"). Commodity prices for petroleum and natural gas are impacted by not only the relationship between the Canadian and United States dollar, as outlined above, but also world economic events and North American processing and supply considerations that influence the levels of supply and demand.

InPlay manages the risks associated with changes in commodity prices by entering into financial derivative risk management contracts. The Company does not apply hedge accounting for these contracts. The Company does not enter into commodity contracts other than to manage the risk of commodity price fluctuation from the Company's expected commodity sales.

At December 31, 2017 the following commodity-based derivative contracts were outstanding and recorded at estimated fair value:

Type of contract: swap (natural gas pricing AECO):

Currency denomination	Volume (GJ/day)	Average swap price	Term	Fair value (\$'000 CAD)
Canadian dollar	1,000	3.055/GJ	Jan 1, 2017 – March 31, 2018	\$108
Canadian dollar	1,000	2.95 /GJ	May 1, 2017 – March 31, 2018	\$99

Type of contract: swap (crude oil pricing WTI):

Currency denomination	Volume (bpd)	Average swap price	Term	Fair value (\$'000 CAD)
US dollar	500	57.00/bbl	Jan 1, 2018 – June 30, 2018	(\$344)
US dollar	200	60.00/bbl	Jan 1, 2018 – March 31, 2018	(\$5)

Type of contract: costless collar⁽¹⁾ (crude oil pricing WTI):

Currency denomination	Volume (bpd)	Sold call price	Sold put price	Term	Fair value (\$'000 CAD)
US dollar	200	47.00/bbl	52.00/bbl	Sept 1, 2017 – March 31, 2018	(\$191)
US dollar	200	46.00/bbl	53.00/bbl	Sept 1, 2017 – June 30, 2018	(\$341)
US dollar	200	46.00/bbl	53.40/bbl	Oct 1, 2017 – June 30, 2018	(\$324)
US dollar	300	48.00/bbl	57.00/bbl	Nov 1, 2017 – Dec 31, 2018	(\$541)

⁽¹⁾ Costless collar indicates InPlay concurrently sold put and call options at strike prices such that the costs and premiums received offset each other, thereby completing the derivative contracts on a costless basis.

Type of contract: three-way collar ⁽²⁾ (crude oil pricing WTI):

Currency denomination	Volume (bpd)	Bought put price	Sold call price	Sold put price	Term	Fair value (\$'000 CAD)
US dollar	300	42.00/bbl	50.00/bbl	64.35/bbl	Jan 1, 2018 – Dec 31, 2018	(\$33)
US dollar	250	42.00/bbl	50.00/bbl	65.10/bbl	April 1, 2018 – March 31, 2019	(\$6)

⁽²⁾ The WTI three-way collars are a combination of a sold call, bought put and a sold put. The sold put price is the maximum the Company will receive for the contract volumes. The sold call price is the minimum price InPlay will receive, unless the market price falls below the bought put strike price.

The estimated fair value of the financial option contracts has been determined on the amounts the Company would receive or pay for another party to assume the contracts. At December 31, 2017, the Company estimates that it would pay \$1.6 million to terminate these contracts.

The fair value of the financial commodity risk management contracts have been allocated to current and non-current liabilities on a contract by contract basis as follows:

(\$'000s)	December 31, 2017	December 31, 2016
Current asset	\$ -	\$ -
Current liability	(1,578)	(1,549)
Net asset (liability) position	\$ (1,578)	\$ (1,549)

An increase or decrease of \$5.00 per barrel WTI of oil and \$0.25 per Mcf AECO of natural gas would decrease the fair value of derivative contracts by \$2.4 million and increase the fair value of derivative contracts by \$2.3 million respectively as at December 31, 2017.

(iii) Interest rate risk

The Company is exposed to the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company's primary exposure is related to its floating interest rate credit facility. The Company estimates that an increase or decrease of 1% in interest rates would result in a change in total annual interest expense on bank debt by approximately \$0.4 million over 2017 (2016 - \$0.5 million).

21(d) Capital management

The Company's policy is to maintain a strong capital base for the objectives of maintaining financial flexibility which will allow it to execute an acquisition or to execute on its capital investment program, provide creditor and market confidence and to sustain the future development of the business.

At December 31, 2017, InPlay's capital structure includes shareholders' equity, credit facility and adjusted working capital. The Company manages its capital structure by continually monitoring its business conditions, including: changes in economic conditions, the risk profile of its drilling inventory, the efficiencies of past investments, the efficiencies of forecast investments and the timing of such investments, the forecast commodity prices and resulting cash flows.

InPlay's current capital structure is summarized below:

(\$'000s)	December 31, 2017	December 31, 2016
Current assets	\$ 11,386	\$ 10,675
Current liabilities	21,006	17,398
Working capital deficiency	9,620	6,723
Derivative contract liability	(1,578)	(1,549)
Deferred lease payments	(11)	(129)
Decommissioning obligation	(492)	-
Flow-through Share premium	(1,161)	(244)
Adjusted working capital deficiency	6,378	4,801
Credit Facility	44,888	29,755
Net debt	51,266	34,556
Shareholders' equity	190,181	187,597
Total capitalization	\$ 241,447	\$ 222,153

22. RELATED PARTY TRANSACTIONS

Key management personnel are comprised of all officers and directors of the Company. Compensation of key management personnel was as follows:

(\$'000s)	December 31, 2017	December 31, 2016
Salaries and bonuses	\$ 1,405	\$ 1,221
Stock-based compensation – expensed and capitalized	2,005	1,640
Total executive compensation	\$ 3,410	\$ 2,861

A director of the Company is an executive officer of a corporation to which the Company made office lease payments in the amount of \$0.4 million during the year ended December 31, 2016. The lease term ended in November 2016 and no amounts were outstanding as of December 31, 2016.

Several members of InPlay's board of directors and executive management participated in the InPlay Financing described in note 13. 283,402 common shares were acquired and 30,000 flow-through common shares were acquired for proceeds of \$652,500 and \$35,000 respectively. These share offerings were done under the same terms and conditions as the other participants as described in note 13.

A member of InPlay's board of directors and executive management participated in the flow-through common share issuance during 2017 as described in note 13. 55,000 flow-through common shares were acquired for proceeds of \$99,000. This share offering was done under the same terms and conditions as the other participants as described in note 13.

23. COMMITMENTS

23(a) Capital commitments

As at December 31, 2017, the Company had \$9.0 million remaining of its commitment to incur qualifying exploration and development expenditures related to the \$10.1 million raised from the issuance of flow-through shares during the year ended December 31, 2017.

23(b) Operating lease commitments

The Company has the following estimated annual obligations related to its office lease obligations.

The minimum future payments for these leases are as follows:

(\$'000s)	2018	2019
Office lease payments ^{(1) (2)}	\$ 742	\$ 34

⁽¹⁾ Net of sublease income for 2018 of \$15,000.

⁽²⁾ Both parties are entitled to terminate the lease agreement at any point after January 31, 2019 provided six months' notice is provided to the other party. This commitment table above assumes that this termination will occur on February 1, 2019.

23(c) Other commitments

The Company has entered into firm service gas transportation agreements in which the Company guarantees certain minimum volumes of natural gas will be shipped on various gas transportation systems. The terms of the various agreements expire in one to five years. If no volumes were shipped pursuant to the agreements, the maximum amounts payable under the guarantees based on current tariff rates are as follows:

(\$'000s)	2018	2019	2020	2021	Thereafter
Firm service commitment	\$ 371	\$ 220	\$ 75	\$ 56	\$ 179

24. SUBSEQUENT EVENTS

Subsequent to December 31, 2017, the Company completed the sale of a non-core processing facility and associated equipment and infrastructure for proceeds of \$10.0 million. These assets have been classified as available for sale on the statement of financial position as the carrying amounts have been recovered through a sale transaction rather than through continuing use. These assets have been measured at the lower of the carrying amount and fair value less costs of disposal and no impairment has been recognized as a result of this transfer.

Subsequent to December 31, 2017, the Company purchased producing assets, undeveloped lands and interests in various facilities in the Willesden Green area of Alberta, Canada for estimated consideration of \$5.7 million. The estimated fair value of the total consideration transferred and the amounts recognized attributed to the assets and liabilities acquired was as follows:

Consideration:	(\$'000s)
Cash consideration	\$ 5,750
Total Consideration	5,750
 Recognized amounts of assets acquired and liabilities assumed	
Exploration and evaluation	1,253
Property, plant and equipment	5,834
Decommissioning obligation	(1,337)
Total identifiable net assets	\$ 5,750