UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended June 30, 2018

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission file number 001-33578

Samson Oil & Gas Limited

(Exact Name of Registrant as Specified in its Charter)

Australia	**N/A**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
Level 16, AMP Building, **140 St Georges Terrace** **Perth, Western Australia 6000**	
(Address of principal executive offices)	(Zip Code)

+61 8 9220 9830
(Registrant's telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

American Depositary Shares* **Ordinary Shares****	**OTC MARKETS' OTCQB**
Title of Each Class	Name of Exchange on Which Registered

* American Depositary Shares evidenced by American Depository Receipts. Each American Depositary Share represents 200 Ordinary Shares.
** No par value. Not for trading, but only in connection with the listing of American Depositary Shares.

Securities Registered Pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ¨ No x

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, emerging growth company, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer”, “non-accelerated filer”, “emerging growth company” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

Large Accelerated filer ¨ Accelerated filer ¨ Non-accelerated filer x Smaller Reporting Company x Emerging Growth Company ¨

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

The aggregate market value of the registrant's ordinary shares held by non-affiliates of the registrant on December 31, 2017 was approximately $2.1 million based on the closing price of its American Depositary Shares, each of which represents 200 ordinary shares, as reported on the OTCQB over the counter trading platform (treating, for this purpose, all executive officers and directors of the registrant, as affiliates).

There were 3,283,000,444 ordinary shares outstanding as of October 10, 2018.

DOCUMENTS INCORPORATED BY REFERENCE

Part III of this Form 10-K is incorporated by reference from the registrant’s definitive proxy statement which will be filed no later than 120 days after June 30, 2018.

SAMSON OIL & GAS LIMITED
ANNUAL REPORT ON FORM 10-K

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FORWARD-LOOKING STATEMENTS

Written forward–looking statements may appear in documents filed with the Securities and Exchange Commission ("SEC"), including this annual report, documents incorporated by reference, reports to shareholders and other communications.

The U.S. Private Securities Litigation Reform Act of 1995 provides a "safe harbor" for forward–looking information to encourage companies to provide prospective information about themselves without fear of litigation so long as the information is identified as forward looking and is accompanied by meaningful cautionary statements identifying important factors that could cause actual results to differ materially from those projected in the information. We have historically relied on this safe harbor in making forward–looking statements but, as an ancillary result of the required accounting for the pending sale of substantially all of our assets, we may not be able to rely on it from the period of time between the filing of this report and the closing of that sale. Even if we cannot rely on the safe harbor to some extent, we believe that an explanation of the forward looking statements in this report is helpful disclosure and provides appropriate cautions to the reader.

Forward–looking statements appear in a number of places in this annual report and include but are not limited to management's comments regarding the anticipated outcome and timing of our efforts to sell our Foreman Butte assets; our financial and operational prospects (whether or not the sale is consummated); the potential remedies available to our senior creditor under our credit agreement and our options with respect to meeting our financial obligations; trading liquidity and other risks relating to our common stock and ADSs; business strategy, exploration and development drilling prospects and activities at our Foreman Butte and other properties; oil and gas pipeline availability and capacity; natural gas and oil reserves and production; the cost of compliance with environmental laws; our strategy to control general and administrative costs; our intentions with respect to meeting our capital raising targets and the use of proceeds; our plans, our ability to and the methods by which we may raise additional capital; our prospects for continuing as a going concern and regarding our production and future operating results; such as the following:

- our future financial position, including cash flow, debt levels and anticipated liquidity;
- the timing, effects and success of our exploration and development activities;
- uncertainties in the estimation of proved reserves and in the projection of future rates of production;
- timing, amount, and marketability of production;
- third party operational curtailment, processing plant or pipeline capacity constraints beyond our control;
- our ability to acquire and dispose of oil and gas properties at favorable prices;
- our ability to market, develop and produce new properties;
- declines in the values of our properties that may result in write-downs;
- effectiveness of management strategies and decisions;
- oil and natural gas prices and demand;
- unanticipated recovery or production problems, including cratering, explosions, fires;
- the strength and financial resources of our competitors;
- our entrance into transactions in commodity derivative instruments;
- climatic conditions; and
- effectiveness of management strategies and decisions.

Many of these factors are beyond our ability to control or predict. Neither these factors nor those included in the "Risk Factors" section of this annual report represent a complete list of the factors that may affect us. We do not undertake to update our forward–looking statements.

GLOSSARY OF TECHNICAL TERMS

Bbl. Barrel (of oil or natural gas liquids).

Bbls. Barrels of oil.

BOE. Barrel of oil equivalent., based on 6 MCF of gas conversion to 1 barrel of oil

BOEPD. Barrels of oil equivalent per day.

BOPD. Barrels of oil per day.

Developed acres. The number of acres that are allocated or held by producing wells or wells capable of production.

Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Exploratory well. A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious, strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms structural feature and stratigraphic condition are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

Fracture stimulation. The process of initiating and subsequently propagating a fracture in a rock layer, employing the pressure of a fluid as the source of energy in order to increase the extraction rates and ultimate recovery of oil and natural gas.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

MBbls. Thousand barrels of oil.

MMbo. Million barrels of oil.

MMBOE. Thousands of barrels of oil equivalent

Mcf. Thousand cubic feet (of natural gas).

Mcf/d. Thousand cubic feet (of natural gas) per day

Mcfe. Thousand cubic feet equivalent.

MMBtu. One million British Thermal Units, a common energy measurement.

Productive wells. Producing wells and wells that are capable of production, including injection wells, salt water disposal wells, service wells, and wells that are shut–in.

Proved developed reserves. Reserves which can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved properties. Properties with proved reserves.

Proved reserves. Estimated quantities of crude oil, natural gas, and natural gas liquids which, upon analysis of geologic and engineering data, can be estimated with reasonable certainty to be recoverable in the future from known oil and gas reservoirs under existing economic and operating conditions. Proved reserves are sub–classified into either proved developed reserves or proved undeveloped reserves.

Proved developed producing reserves (PDP). Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods and that are currently being produced.

Proved Developed Producing Behind Pipe (PDP BP). Those reserves expected to be recovered from completion intervals not yet open but remain behind casing in existing wells.

Proved Developed Not Producing (PDNP). Estimated proved reserves expected to recovered from existing wells where there is a requirement to achieve a workover to re-establish production.

Proved undeveloped reserves (PUD). Estimated proved reserves that are expected to be recovered from new wells on undeveloped acreage or from existing wells where a relatively major expenditure is required for recompletion.

Undeveloped acreage. Acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains estimated proved reserves.

Working interest. An operating interest that gives the owner the right to drill, produce, and conduct operating activities on the property and a share of production.

PART I

Item 1 and 2. Business and Properties

Samson Oil & Gas Limited ("we", "Samson" or the "Company") is a company limited by shares, incorporated on April 6, 1979 under the laws of Australia. Our principal business is the exploration and development of oil and natural gas properties in the United States.

Pending Asset Sale

In June 2018, we signed a purchase and sale agreement for the sale of the Foreman Butte Project, subject to our retention of a 15% working interest in a portion of the Project (the "Foreman Butte Sale"). This transaction received shareholder approval at a general meeting held on August 13, 2018. The purchase price is $40 million with an effective date of January 1, 2018. The sale is currently scheduled to close on October 15, 2018.

The Foreman Butte Project constitutes the majority of our operating assets. Upon closing of the transaction, we will retain a 15% working interest in certain wells in the Home Run Field, which consists of 15 producing wells and 20 PUD locations, the first of which is expected to be drilled soon after the sale closing.

The proceeds of the Foreman Butte Sale will be used to repay our credit facility with Mutual of Omaha Bank in full and bring our other accounts payable current. We estimate that after these repayments, we will have no outstanding debt and will retain $6.5 million in cash proceeds from the sale.

Prior Transactions

In March 2016, we acquired the Foreman Butte Project, comprised of a number of producing and non-producing, operated and non-operated properties in the Ratcliffe and Madison formations in North Dakota and Montana. The purchase price was $16.0 million (before post-closing settlement adjustments) and following a review of the fair market value of the assets and liabilities on the closing date of the transaction, we recorded a bargain purchase gain of $10.7 million. This acquisition was financed through an extension in our credit facility with Mutual of Omaha Bank of $11.5 million and a $4.0 million promissory note provided to the seller of the assets. This note was repaid in May 2017 through a term note facility from Mutual of Omaha Bank.

On June 30, 2016 we signed a purchase and sale agreement for the sale of our North Stockyard project in North Dakota. The sale price was $15 million and closed on October 31, 2016. $11.5 million of the proceeds from this transaction was used to pay down our credit facility with Mutual of Omaha Bank. The remaining proceeds were used to rebalance our hedge book, following the sale of a portion of our production, and for working capital.

In May 2017, we closed on the sale of our State GC assets in New Mexico. The sale price of $1.2 million was applied to pay down our current facility with Mutual of Omaha Bank. In June 2017, Samson and Mutual of Omaha Bank agreed to extend both the $4 million term loan and our $19.45 million reserve base facility until October 2018. The previous maturity date was October 31, 2017.

Our reserve report estimates that we had proved oil and gas reserves valued at approximately $47.7 million (before taxes) based on a present value calculation with 10% discounting rate. This present value as of June 30, 2018, utilizes an adjusted realized pricing of $57.67 per Bbl for oil and $0.91 per Mcf for natural gas. As of June 30, 2018, 92% of our proved reserves were oil and 74% was proved developed producing, 16% were proved non producing and 9% was proved undeveloped. 87% is included in the sale which is expected to be closed on October 15, 2018 according to the most recent amendment of the Purchase and Sale Agreement signed on September 28th.

Business Strategy

Before and after the Foreman Butte Sale, our business strategy is to create a competitive and sustainable rate of return to shareholders by exploring for, acquiring and developing oil and natural gas resources in the United States. Our primary financial goal is to develop profitably our oil properties while maintaining a strong balance sheet, and specifically to focus on the exploration, exploitation and development of our major project – our retained 15% working interest in the Home Run Field within the Foreman Butte Project in Montana and North Dakota.

Reporting and Financials

We became required to file our periodic reports to the SEC as a U.S. domestic issuer as of July 1, 2011. Since we remain an Australian corporation, however, we are still considered to be a domestic company in Australia as well. As a result, we are required to report our financial results in the U.S. using U.S. Generally Accepted Accounting Principles ("U.S. GAAP") and in Australia using International Financial Reporting Standards ("IFRS").

We publish our consolidated financial statements, both U.S. GAAP and IFRS, in U.S. dollars. In this annual report, unless otherwise specified, all dollar amounts are expressed in U.S. dollars, and references to "dollars," "$" or "US$" are to United States dollars. All references to "A$" are to Australian dollars.

Our registered office is located at Level 16, AMP Building, 140 St Georges Terrace, Perth, Western Australia 6000 and our telephone number at that office is +61 8-9220-9830. Our principal office in the United States is located at 1331 17th Street, Suite 710 Denver, Colorado 80202 and our telephone number at that office is +1 303-295-0344. Our website is www.samsonoilandgas.com.

Preparation of Reserves Estimates

Given the pending sale at June 30, 2018, our fiscal year-end petroleum reserves report was prepared internally by knowledgeable officers and employees of the Company for the current year. The report was based upon our internal review of the property interests being appraised, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sales of production, geoscience and engineering data, and other information we gather. We prepared our estimates by use of standard geological and engineering methods generally accepted by the petroleum industry. Reserve volumes and values were determined under the method prescribed by the SEC, which requires the application of the 12-month average price for natural gas and oil calculated as the un-weighted arithmetic average of the first-day-of-the-month price for each month within the 12-month prior period to the end of the reporting period and year-end costs. The proved reserve estimates represent our net revenue interest in our properties.

Our reserves were prepared by a practitioner with 22 years of industry experience in geologic and engineering review and analysis and a Bachelor of Science in Geological Engineering from Colorado School of Mines. Additionally, the Chief Executive Officer, Terry Barr, is responsible for overseeing the preparation of the Company's reserves report. The CEO is a petroleum geologist who holds an associateship in applied geology and has over 45 years of relevant experience in the oil and gas industry.

The reserve estimates are reported to the Board of Directors, at least annually. Our Board members have experience in reviewing and understanding reserve estimates.

According to our June 30, 2018 reserve report we had proved oil and gas reserves valued at approximately $47.7 million (before taxes) based on a present value calculation with 10% discounting rate. This present value as of June 30, 2018, utilizes an adjusted realized pricing of $57.67 per Bbl for oil and $2.91 per Mcf for natural gas. As of June 30, 2018, 92% of our proved reserves were oil and 74% was proved developed producing, 16% were proved non producing and 9% was proved undeveloped. 87% is included in the sale which is expected to be closed on October 15, 2018 according to the most recent amendment of the Purchase and Sale Agreement signed on September 28th.

Estimated Proved Reserves

The information set forth below regarding our oil and gas reserves for the fiscal year ended June 30, 2018 was prepared internally.

The information set forth below regarding our oil and gas reserves for the fiscal years ended June 30, 2017 was prepared by Netherland Sewell.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. Proved reserves are categorized as either developed or undeveloped.

The following table summarizes certain information concerning our reserves and production in fiscal years ended June 30, 2018 and 2017:

	2018			2017		
	Oil (MBbls)	Gas (Mcf)	Total (MBOE)	Oil (MBbls)	Gas (Mcf)	Total (MBOE)
Beginning of year	5,359	3,565	5,955	9,982	8,593	11,415
Revisions of previous quantity estimates	(1,654)	(2,246)	(2,028)	(2,851)	(2,474)	(3,263)
Extensions and discoveries	-	-	-	-	-	0
Sale of reserves in place	-	-	-	(1,475)	(2,396)	(1,874)
Acquisitions	-	-	-	-	-	0
Production	(190)	(27)	(195)	(297)	(158)	(323)
End of year	3,515	1,292	3,732	5,359	3,565	5,955
Proved developed producing reserves	73	60	84	3,020	1,575	3,285
Proved developed non producing	32	43	39	134	224	171
Proved undeveloped reserves	308	251	350	2,205	1,766	2,499
Proved developed producing reserves - held for sale	2,590	563	2,685	-	-	-
Proved developed non producing - held for sale	512	375	575	-	-	-
Total proved reserves	3,515	1,292	3,732	5,359	3,565	5,955

Revisions of previous quantity estimates

The downward revision recorded during the year from July 1, 2016 to June 30, 2017 related to our drilling plan for our PUD locations. During the year ended June 30, 2016, we anticipated drilling them as new 10,000 foot lateral horizontal wells. Upon further technical review, we now plan to drill the PUD wells as 5,000 foot laterals out of an existing well bore. The shortening of the lateral length lead to a decrease in the volume of reserves associated with these PUDs.

The downward movement in the current year relates to our sale of an interest in our PUDs. Due to the continued lack of capital available to drill these PUDs, the decision was made to sell substantially all of the wells in the Foreman Butte project area. We have retained a 15% working interest in certain PUDs and we have recognized that value in our reserves at June 30, 2018.

Sales of Reserves in Place

The reserves held for sale relate to the sale of the majority of our interest in the Foreman Butte project. This sale is expected to close on October 15, 2018.

The sale of reserves in place during the fiscal year ended June 30, 2017 consists of proved reserves (net of production prior to sale) in the North Stockyard field in North Dakota and the State GC field in New Mexico. All reserves were proved developed producing.

Proved Developed Producing Reserves

At June 30, 2018 our proved developed producing reserves primarily relate to our working interest in producing wells in our Foreman Butte project area in North Dakota and Montana.

Proved Developed Not Producing (PDNP)

PDNP reserves are those estimated proved reserves expected to be recovered from existing wells where a workover is required to re-establish production

As of June 30, 2017, the PDNP reserves were 171 MBOE. This primarily related to wells that require a workover to commence production again. This work will be performed as capital allows.

As of June 30, 2018, the PDNP reserves were 39 MBOE. The smaller number is attributable to our smaller retained interest in the Foreman Butte project after the proposed sale.

Proved Undeveloped Reserves

Proved undeveloped reserves (PUDs) are those reserves expected to be recovered from new wells on undeveloped acreage.

Due to the continued lack of capital available to drill these PUDs, the decision was made to sell substantially all of the wells in the Foreman Butte project area. Upon closing the proposed sale, we will retain a 15% working interest in certain PUDs and we have recognized that value in our reserves at June 30, 2018 because, following the sale, we will have the working capital available to develop these locations.

During the year ended June 30, 2017, through further technical review, we changed our plan with respect to the drilling the PUDs. This reduced the reserves volumes associated with the PUDs but did not change the reserve value associated with the PUDs due to a decrease in the estimated drilling costs. We obtained the permits to drill 4 PUDs and commenced sourcing the appropriate rig and other contractors and equipment required but did not obtain the necessary capital to develop them, leading to our decision to sell the Foreman Butte Project containing those PUDs.

While we did not convert any PUDs during the year ended June 30, 2017 and 2018, we have made considerable progress on their development through the increased technical review and the determination of the most efficient and cost effective way to drill them. The sale of a portion of the Foreman Butte project will provide us the capital in order to participate in the drilling of these PUD locations.

Production, Prices, Costs and Balance Sheet Information

Production

The results from discontinued operations are not included in the results below.

During the years ended June 30, 2018 and 2017, we produced 6,021and 61,516 barrels of oil, respectively. During the years ended June 30, 2018 and 2017 we produced 7,284 and 434,998 Mcf of gas, respectively.

For the year ended June 30, 2018 and June 30, 2017 we had one Field (as such term is used within the meaning of applicable regulations of the SEC – See Glossary of Technical Terms), excluding discontinued operations that contains more than 15% of our total proved reserves, namely our interests in the Home Runfield in North Dakota, which is part of our Foreman Butte project in North Dakota and Montana.

The following tables disclose our oil and gas production volume, revenue and expenses from the Foreman Butte field for the fiscal year ended June 30, 2018 and 2017:

	2018 Home Run Field
Oil volume – Bbls	2,191
Revenue – $	118,596
Average Price per barrel – $	54.35
Gas volume – Mcf	1,787
Revenue – $	9,093
Average price per Mcf – $	5.089
Per unit production and lease operation costs per BOE – $	$ 35.75

	2017 Home Run Field
Oil volume – Bbls	6,827
Revenue – $	280,091
Average Price per barrel – $	41.03
Gas volume – Mcf	6,821
Revenue – $	21,090
Average price per Mcf – $	3.09
Per unit production and lease operation costs per BOE – $	$ 59.20

Prices and Costs

The results of discontinued operations are not included in the results below.

The average sale price (excluding the impact of derivative instruments) we achieved for oil during the years ended June 30, 2018 and June 30, 2017 was $41.89 and $36.52 per barrel, respectively.

The average sale price we achieved for gas during the years ended June 30, 2018 and June 30, 2017 was $3.71 and $0.63 per Mcf, respectively.

The average production costs (excluding production taxes) per barrel of oil equivalent was $42.19 for the year ended June 30, 2018 and $12.42 for the year ended June 30, 2017.

Drilling Activity

	Year Ended June 30	
	2018	2017
Net productive exploratory wells drilled	Nil	Nil
Net dry exploratory wells drilled	Nil	Nil
Net productive development wells drilled	Nil	Nil
Net dry development wells drilled	Nil	Nil

Present Drilling Activity

As of October 12, 2018, we were not participating in the process of drilling or completing any wells (including wells temporarily suspended).

For a discussion of our present development activity, see “Description of Properties—Exploration / Undeveloped Properties” in “Item 1 and 2. Business and Properties” and “Recent Developments”, “2017 and 2018 Capital Expenditures” and “Estimated 2019 Capital Expenditures” in “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations”.

Oil and Natural Gas Wells and Acreage

As at October 12, 2018, our wells and acreage, excluding assets held for sale were as follows:

Gross productive oil wells	42
Net productive oil wells	7
Gross productive gas wells	-
Net productive gas wells	-
Wells with multiple completions	-
Gross Developed Acres	11,904
Net Developed Acres	1,786
Gross Undeveloped Acres	2,736
Net Undeveloped Acres	411

All of our acreage positions are located in the continental United States, with the majority located in North Dakota and Montana. We have extensive leases with a variety of remaining lease terms varying from 3 months to four years. 95% of our net developed acres are held by production. In some cases we have the ability to extend the lease term.

Standardized Measure of Discounted Future Net Cash Flows

Future hydrocarbon sales and production and development costs have been estimated using a 12-month average price for the commodity prices for June 30, 2017 and June 30, 2016 and costs in effect at the end of the periods indicated. The 12-month historical average of the first of the month prices used for natural gas for June 30, 2018 and June 30, 2017 were $2.91 and $3.01per Mcf, respectively. The 12-month historical average of the first of the month prices used for oil for June 30, 2018 and June 30, 2017 were $57.67 and $48.95 per barrel of oil, respectively. Future cash flows were reduced by estimated future development, abandonment and production costs based on period–end costs. No deductions were made for general overhead, depletion, depreciation and amortization or any indirect costs. All cash flows are discounted at 10%.

Changes in demand for hydrocarbons, inflation and other factors make such estimates inherently imprecise and subject to substantial revisions. This table should not be construed to be an estimate of current market value of the proved reserves attributable to Samson.

The following table shows the estimated standardized measure of discounted future net cash flows relating to proved reserves (in US$'000's):

	As at June 30,	
	2018	**2017**
Future cash inflows	$ 187,249	$ 237,490
Future production costs	(99,620)	(91,920)
Future development costs	(1,642)	(13,367)
Future income taxes	-	-
Future net cashflows	85,987	132,203
10 % discount	(38,325)	(66,941)
Standardized measure of discounted future net cash flows relating to proved reserves	$ 47,662	$ 65,262

The principal sources of changes in the standardized measure of discounted future net cash flows during the periods ended June 30, 2018 and June 30, 2017 are as follows (in $'000's):

	Fiscal Year Ended June 30	
	2018	2017
Beginning of year	$ 65,262	$ 66,747
Sales of oil and gas produced during the period, net of production costs	(3,902)	(3,122)
Net changes in prices and production costs	2,822	1,601
Previously estimated development costs incurred during the period	-	-
Changes in estimates of future development costs	(11,625)	22,929
Extensions and discoveries	-	-
Revisions of previous quantity estimates and other	(10,088)	(21,078)
Sale of reserves in place	-	(10,445)
Purchase of reserves in place	-	-
Change in future income taxes	-	-
Accretion of discount	6,526	6,675
Other	(1,333)	1,955
Balance at end of year	$ 47,662	$ 65,262

The impact of income taxes has not been included in the current year as the net operating losses and the tax basis of the assets exceed the future cash flows.

Description of Properties

Production information is shown net to our interests. Our net revenue interest is included in the total amount.

Developed Properties

Foreman Butte Project – Williston Basin, North Dakota and Montana
Various working interests

In March 2016, we closed on the acquisition of the Foreman Butte project. This project includes a number of producing and non producing, operated and non operated wells in the Ratcliffe and Madison formations in Montana and North Dakota.

This project consists of 131 wells (both operated and non operated) across a number of fields in Montana and North Dakota. The wells are conventional wells drilled as early as 1980 to as recently as 2010.

In June 2018, we signed a purchase and sale agreement to sell the majority of this project for $40 million, with an effective date of January 1, 2018. This transaction is currently expected to close on October 15, 2018. Under the purchase and sale agreement, we will retain a 15% working interest in certain wells within the Home Run field.

The Home Run Field (aka as the Foreman Butte Field) is the largest area oil field in our portfolio. It was developed on a 640 acre spacing pattern and our engineering and geologic analyses have determined that only 3.2% of the original oil in place has been recovered to date. Given that oil fields typically recover up to around 20% of their oil in place there would appear to be significant un-developed oil to be recovered from this field.

This has been confirmed through the use of a 3 dimensional numerical simulation of the reservoir volume, and the expected production curve for these wells has been developed from the resulting numerical model.

The current reservoir pressure has also been established using a field wide fluid level study, and the initial development wells will be located in areas of demonstrated higher pressure.

Upon closing the sale of these assets, the buyer of the project is expected to commence drilling the first of 20 identified PUD locations in the first quarter of 2019. We will have a 15% working interest in this well and any future Ratcliffe and Madison wells drilled in this field.

Currently we have 20 Ratcliffe PUD locations identified. The second lateral well expected to be drilled by the purchaser of the assets will test an undeveloped reservoir in the Mission Canyon Formation of the Mississippian Madison Group. Although we can make no assurances of the results of this drilling, we are optimistic about its prospects. It is possible that.this lateral could prove up a new oil field with the potential for many additional well locations (up to 20 vertical wells or 8 drill-out laterals), A 3,500 acre 4-way structural closure has already been mapped from the abundance of existing well control in the area.

These PUDs meet the definition of PUDS per the SPE PRMS guidelines and SEC definitions and have been risked accordingly.

In September 2017, we received approval for a water flood pilot project for the Home Run Field utilizing an existing wellbore which is located on the flank of the field and which is non-productive. This well, the Mays 1-20H has been tested and readied for injected water following the approval from the North Dakota Industrial Commission. We commenced injection in October 2017. The water flood is being used to add pressure to the reservoir which we believe should enhance the recovery of oil. The well performance in the offsetting wells will be monitored to establish the viability of the flood. The water being used is produced formation water so that there is no chemical compatibility issues, in essence the water is being returned to the reservoir from which it originated. The water is currently being trucked to the injector from the existing producing wells.

During the year ended June 30, 2018, the Foreman Butte Project, excluding discontinued operations, produced 2,191 barrels of oil.

North Stockyard Project – Williston Basin, North Dakota

On June 30, 2016 we entered into a purchase and sale agreement to sell our North Stockyard property for $15 million. This transaction closed on October 31, 2016.

State GC Oil and Gas Field, New Mexico

The State GC Oil and Gas Field, located in Lea County, New Mexico, was discovered in 1980 and covers approximately 600 acres. The field is operated by Legacy Resources.

The State GC# 1 well was drilled in 1980 and has been productive since that time.

This project was sold for $1.2 million on April 30, 2017.

Exploration / Undeveloped Properties

Hawk Springs Project, Goshen County, Wyoming
37.5% -100% working interest

Spirit of America US 34 #2-29 (Spirit of America II)
100% working interest

The Spirit of America I replacement well, Spirit of America II, was drilled to a total depth of 10,634 feet using a conservative drilling approach to penetrate the troublesome salt section along with heavy weight, oil based mud. Numerous operational difficulties were encountered and the well failed to produce economic quantities of hydrocarbons. $7.3 million in costs associated to drill this well, were written off to the Statement of Operations in the year ended June 30, 2013.

In July 2015, a workover rig was moved to the location to test the Dakota formation from 8,054 feet to 8,064 feet. This formation was found to be water saturated and no hydrocarbons were noted. All costs associated with this well have been written off to the Income Statement during the year ended June 30, 2016.

This well was plugged in October 2016.

Defender US 33 #2-29H
37.5% working interest

This well commenced production in February 2012 and has experienced numerous operational and pumping issues. In July 2012, the well was cleaned out and resumed pumping. In June 2015, the well was struck by lightning which affected the electronic controllers associated with the well. These controllers have yet to be repaired due to the well’s low productivity rate.

There was no production from this well during the year ended June 30, 2016. This well was plugged in October 2016.

Bluff 1-11 (25% working interest)

During the year ended June 30, 2014 we drilled the Bluff Prospect to test multiple targets in the Permian and Pennsylvanian sections in a 4-way structural trapping configuration. The Bluff #1-11 well reached a total depth of 8,900 feet after intersecting the pre-Cambrian basement on June 13, 2014.

To date, this well has failed to produce economic quantities of hydrocarbons and all costs associated with drilling it have been written off the Statement of Operations. The well is yet to be plugged as we are waiting on testing the upper canyon spring zone with a perforation and swab test. It is unlikely that this operation will take place and a proposal for abandonment is being prepared for consideration by the other working interest owners. It is expected that this well will be plugged during the year ended June 30, 2019.

Roosevelt Project, Roosevelt County, Montana
100% Working Interest

Australia II
100% working interest

In December 2011, we drilled Australia II in the Roosevelt Project, our first appraisal (exploratory) well in this project area. This well was drilled to a total measured depth of 14,972 feet with the horizontal lateral remaining within the target zone for the entire lateral length. Oil and gas shows were returned during the drilling of this well and approximately 3,425 barrels of oil were produced. This well was being pumped, and although this well was productive, we did not believe that we would be able to recover our costs associated with drilling it. We expensed $13.1 million of previously capitalized exploration expenditure in the Statement of Operations as deferred exploration expenditure written off, which represents 100% of the costs incurred to June 30, 2012.

This well was plugged during the year ended June 30, 2018.

Rainbow Project, Williams County, North Dakota Mississippian Bakken Formation, Williston Basin
23% -52% working interest

During the year ended June 30, 2013, we acquired, in two tranches, a net 950 acres in two 1,280 acre drilling units located in the Rainbow Project, Williams County, North Dakota. The Rainbow Project is located in Sections 17, 18, 19 and 20 in T158N R99W.

The acquisition involved an acreage trade by the parties and a future carry of the vendor by us in the initial drilling program on the Rainbow Project. We transferred 160 net acres from our 1,200 acre undeveloped acreage holding in North Stockyard and the vendor will fund its share (between 7.5% and 8.5%) of the North Stockyard initial infill program. We have acquired 950 net acres in the Rainbow Project from the vendor for this acreage trade and have paid $1 million to the vendor, in lieu of a carry as we did not spud a well within the desired time frame. $0.6 million of this payment was made prior to June 30, 2015 with the remaining $0.4 million paid during the year ended June 30, 2016.

In the western drilling unit of the acquired acreage, we hold a 52.21% working interest. In the eastern drilling unit, our interest is 23%.

Our first Rainbow well, Gladys 1-20, drilled by Continental Resources, spud on June 28, 2014 and was drilled to a total depth of 19,994 feet. The well is 1,280 acre lateral (approximately 10,000 feet) in the middle member of the Bakken formation.

There has been no further drilling activity on this lease during the prior year and 652 acres have expired.

Cane Creek Project, Grand & San Juan Counties, Utah
Pennsylvanian Paradox Formation, Paradox Basin
100% working interest

On November 5, 2014, we entered into an Other Business Arrangement ("OBA") with the Utah School and Institutional Trust Lands Administration ("SITLA") covering approximately 8,080 gross/net acres located in Grand and San Juan Counties, Utah, all of which are administered by SITLA. We were granted an option period for two years, expiring November 30th, 2016 in order to enter into a Multiple Mineral Development Agreement ("MMDA") with another company who hold leases to extract potash in an acreage position situated within our project area. Upon entering into the MMDA, SITLA would be obligated to deliver oil and gas leases covering our project area at a cost of $75 per acre to us. The MMDA has been finalized though it has not yet been executed. We paid an additional option fee in November 2016 to extend our option to November 30th, 2017. This option expired unexercised in November 2017.

Risk and Insurance Program

Our operations are subject to all the risks normally incident to the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells, including the risk of well blowouts, oil spills and other adverse events. We could be held responsible for injuries suffered by third parties, contamination, property damage or other losses resulting from these types of events. In addition, we have generally agreed to indemnify our drilling rig contractors against certain of these types of losses. Because of these risks, we maintain insurance against some, but not all, of the potential risks affecting our operations and in coverage amounts and deductible levels that we believe to be economic. Our insurance program is designed to provide us with what we believe to be an economically appropriate level of financial protection from significant unfavorable losses resulting from damages to, or the loss of, physical assets or loss of human life or liability claims of third parties, attributed to certain assets and including such occurrences as well blowouts and resulting oil spills. We regularly review our risks of loss and the cost and availability of insurance and consider the need to revise our insurance program accordingly. Our insurance coverage includes deductibles which must be met prior to recovery. Additionally, our insurance is subject to exclusions and limitations and there is no assurance that such coverage will adequately protect us against liability from all potential consequences and damages.

In general, our current insurance policies covering a blowout or other insurable incident resulting in damage to one of our oil and gas wells provide up to $20 million of well control, pollution cleanup and consequential damages coverage and $11 million of third party liability coverage for additional pollution cleanup and consequential damages, which also covers personal injury and death.

If a well blowout, spill or similar event occurs that is not covered by insurance or not fully protected by insured limits, we would be responsible for the costs, which could have a material adverse impact on our financial condition, results of operations and cash flows.

Marketing, Major Customers and Delivery Commitments

Markets for oil and natural gas are volatile and are subject to wide fluctuations depending on numerous factors beyond our control, including seasonality, economic conditions, foreign imports, political conditions in other energy producing countries, OPEC market actions, and domestic government regulations and policies. Substantially all of our production is sold pursuant to agreements with pricing based on prevailing commodity prices, subject to adjustment for regional differentials and similar factors. These contracts are generally set up on a month to month basis and can be cancelled at any time by either party giving 30 days notice. We had no material delivery commitments as of October 12, 2018.

Regulatory Environment

Our oil and gas exploration, production, and related operations are subject to numerous and frequently changing federal, state, tribal and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These regulations relate to, among other things, environmental and land-use matters, conservation, safety, pipeline use, drilling and spacing of wells, well stimulation, transportation, and forced pooling and protection of correlative rights among interest owners. Environmental laws and regulations may require the acquisition of certain permits prior to or in connection with our activities and operations. In addition, they may restrict or prohibit the types, quantities, and concentration of substances that can be released into the environment, including releases from drilling and production operations, and restrict or prohibit drilling or other operations that could impact wetlands, endangered or threatened species or other protected areas or natural resources. Following is a summary of some key statutory and regulatory programs that affect our operations.

Regulation of Oil and Gas

Certain regulations may govern the location of wells, the method of drilling and casing wells, the rates of production or “allowables,” the surface use and restoration of properties upon which wells are drilled, and the notification of surface owners and other third parties. Certain laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. We also are subject to various laws and regulations pertaining to Native American tribal surface ownership, Native American oil and gas leases and other exploration agreements, fees, taxes, or other burdens, obligations, and issues unique to oil and gas ownership and operations within Native American reservations.

Environmental and Land Use Regulation

A wide variety of environmental and land-use regulations apply to companies engaged in the production and sale of oil and natural gas. These regulations have been changed frequently in the past and, in general, these changes have imposed more stringent requirements that increase operating costs and/or require capital expenditures to remain in compliance. Failure to comply with these requirements can result in civil and/or criminal penalties and liability for non-compliance, clean-up costs and other environmental and natural resource damages. It also is possible that unanticipated developments or changes in the law could require us to make environmental expenditures significantly greater than those we currently expect.

Discharges to Waters. The Federal Water Pollution Control Act of 1972, as amended (the “Clean Water Act”), and comparable state statutes impose restrictions and controls on the discharge of “pollutants,” which include dredge and fill material, produced waters, various oil and natural gas wastes, including drilling fluids, drill cuttings, and other substances. Discharge of such pollutants into wetlands, onshore (streams, rivers, etc.), coastal and offshore waters without appropriate permits is prohibited. These controls generally have become more stringent over time, and it is possible that additional restrictions will be imposed in the future. Violation of the Clean Water Act and similar state regulatory programs can result in civil, criminal and administrative penalties for the unauthorized discharges of pollutants. Violations also put operators at risk of citizen lawsuits under the Clean Water Act, seeking both enforcement of the Clean Water Act’s provisions and civil penalties and litigation costs. Operators may also face substantial liability for the costs of removal or remediation associated with improper discharges of pollutants.

The Clean Water Act also regulates stormwater discharges from industrial properties and construction sites, and requires permits and the implementation of site-specific Stormwater Pollution Prevention Plans (“SWPPPs”), best management practices, training, and periodic monitoring of covered activities. Certain operations also are required to develop and implement Spill Prevention, Control, and Countermeasure (“SPCC”) plans, and in some circumstances, facility response plans to address potential oil and produced water spills. Certain exemptions from some Clean Water Act requirements were created or broadened pursuant to the Energy Policy Act of 2005.

The Oil Pollution Act (“OPA”) of 1990 places strict liability for oil spills on the "responsible party," which it defines for onshore facilities as the owner or operator of a facility or pipeline. Strict liability means liability without fault. The OPA provides for the recovery of cleanup and removal costs, and also recognizes as recoverable damages the loss of profits or impairment of earning capacity due to the injury to natural resources caused by an oil spill. Further, a federal, state, foreign government, or Indian tribe trustee may recover damages for injury to natural resources, including the reasonable cost of assessing the damage. Finally, federal and state governments may also recover damages for the loss of taxes, royalties, rents, fees, or profits brought about by injury to property or natural resources. We may be subject to strict liability under OPA for all or part of the costs of cleaning up oil spills from our facilities and for natural resource damages. We have not, to our knowledge, been identified as a responsible party under OPA, nor are we aware of any prior owners or operators of our properties that have been so identified with respect to their operation of those properties.

Safe Drinking Water Act – Regulation of Hydraulic Fracturing. The federal Safe Drinking Water Act, or the “SDWA”, is the main federal law that authorizes the United States Environmental Protection Agency (“EPA”) to set standards for drinking water quality and oversee the states, localities, and water suppliers who implement those standards. The Underground Injection Control (UIC) Program under the SDWA is responsible for regulating the construction, operation, permitting, and closure of injection wells that place fluids underground. The Energy Policy Act of 2005 currently excludes hydraulic fracturing from regulation by the SDWA. Hydraulic fracturing is a process that creates a fracture extending from a well bore into a low-permeability rock formation to enable oil or natural gas to move more easily to a production well. Hydraulic fractures typically are created through the injection of water, sand and chemicals into the rock formation.

The United States Congress has on multiple occasions considered, and may in the future consider, legislation such as the Fracturing Responsibility and Awareness of Chemicals Act, or the FRAC Act, to amend the SDWA to repeal this exemption. However, Congress has not taken any significant action on such legislation. A version of the FRAC Act was introduced in 2017 but remains in the first stages of the legislative process. If enacted as currently proposed, the FRAC Act would amend the definition of “underground injection” in the SDWA to encompass hydraulic fracturing activities. Such a provision could require hydraulic fracturing operations to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting, and recordkeeping obligations, including disclosure of chemicals used in the fracturing process, and meet plugging and abandonment requirements. The FRAC Act’s proposal to require the reporting and public disclosure of chemicals used in the fracturing process could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. It is not possible to predict whether a future session of Congress may act further on hydraulic fracturing legislation. Such legislation, if adopted, could establish additional regulation and permitting requirements at the federal level.

In addition, in March 2010, at the request of the U.S. Congress, EPA announced its intention to conduct a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on drinking water resources. A progress report was released in December 2012. In May 2014, the EPA indicated that as a first step, it would convene a stakeholder process to develop an approach to obtain information on chemical substances and mixtures used in hydraulic fracturing. To gather information to inform EPA's proposal, the EPA issued an advance notice of proposed rulemaking (ANPR) and initiated a public participation process to seek comment on the information that should be reported or disclosed for hydraulic fracturing chemical substances and mixtures and the mechanism for obtaining this information. EPA issued a draft report in June 2015, concluding that, although hydraulic fracturing activities have the potential to impact drinking water resources through water withdrawals, spills, fracturing directly into such resources, underground migration of liquids and gases, and inadequate treatment and discharge of wastewater, EPA did not find evidence that these mechanisms have led to widespread, systemic impacts on drinking water resources in the United States. EPA finalized the report in December 2016, after considering public comments on the draft report. The key findings remain largely unchanged from the draft report, although EPA noted in the final report that data gaps and uncertainties limited EPA's ability to fully assess the potential impacts on drinking water resources locally and nationally.

Hydraulic fracturing currently is regulated primarily at the state level. Colorado, Wyoming, Montana, North Dakota, Texas, and New Mexico recently enacted rules to regulate certain aspects of hydraulic fracturing. These regulations generally require companies to disclose the chemicals used in hydraulic fracturing operations, as well as the concentrations of those chemicals, on a well-by-well basis, either prior to or following well completion, depending on which state's regulations apply.

Air Emissions. Our operations are subject to local, state and federal regulations governing emissions of air pollutants. Major sources of air pollutants are subject to more stringent, federally based permitting requirements. Producing wells, natural gas plants and electric generating facilities all emit volatile organic compounds ("VOCs") and nitrous oxides in their normal operation. Civil and administrative enforcement actions for failure to comply strictly with air pollution regulations or permits generally are resolved by payment of monetary fines, performance of mitigation projects to offset excess emissions and the correction of any identified deficiencies. Alternatively, regulatory agencies could require us to forego construction, modification or operation of certain sources of emissions.

In April 2012, EPA issued regulations specifically applicable to the oil and gas industry that among other things, requires operators to capture 95 percent of the volatile organic compounds ("VOC") emissions from natural gas wells that are hydraulically fractured. The reduction in VOC emissions is accomplished primarily through the use of "reduced emissions completion" methods to capture natural gas that would otherwise escape into the air or be combusted. EPA also issued regulations that set requirements for VOC emissions from several types of equipment, including storage tanks, compressors, dehydrators, valves and connectors. In June 2016, EPA issued additional regulations specific to the oil and gas industry adding methane standards for equipment and processes covered by the 2012 regulations. The 2016 final regulations also add leak detection and repair (LDAR) requirements for equipment such as valves, connectors, pressure relief valves, open-ended lines, access doors, flanges, crank case vents, pump seals or diaphragms, closed vent systems, compressors, separators, dehydrators, thief hatches on storage tanks, and sweetening units at gas processing plants. On April 19, 2017, EPA announced its intent to administratively reconsider the methane rules, staying a June 3, 2017 effective date for certain provisions—such as the LDAR provisions—for 90 days. Environmental groups filed a petition to stop the administrative stay in the D.C. Circuit, and on July 3, 2017, the D.C. Circuit granted relief for the petitioners, which had the impact of making the previously-stayed rules effective. And on September 12, 2018, EPA proposed revisions to its 2016 methane regulations and sought comment on additional areas for possible revision as part of its previously noted reconsideration of those rules. While EPA continues to reconsider aspects of the methane rule, it will remain effective. These new and revised regulations, or the adoption of any other laws or regulations restricting or reducing these emissions, will increase our operating costs.

Another regulatory development that may impact our operations is EPA's notice of finding and determination that emissions of carbon dioxide, methane, and other greenhouse gases ("GHGs") present an endangerment to human health and the environment. In response to that finding, EPA has implemented GHG-related reporting, monitoring, and recordkeeping rules for petroleum and natural gas systems, among other industries, and developed a Climate Action Plan, including a Methane Strategy which formed the basis for methane regulations issued in June 2016. However, the Executive Office report calling for the Climate Action Plan and Methane Strategy was rescinded by President Trump by Executive Order 13,783, and the June 2016 methane regulations, though currently effective, are the subject of proposed and possible further reconsideration and revision, as noted above. EPA has also solicited comment on a proposed two-year stay of those methane rules. Those methane regulations remain in effect until possible revision or repeal by separate EPA rulemaking in the future, which action is also likely to be challenged in the courts. While the U.S. Congress has considered, and may in the future again consider, "cap and trade" legislation that would establish an economy-wide cap on emissions of GHGs in the United States and could require major sources of GHG emissions to obtain GHG emission "allowances" to continue their operations, the current administration's decision to withdraw from the Paris Climate accords, announced on June 1, 2017, among other factors, makes passage of such legislation less likely in the near term. Any laws or regulations that may be adopted to restrict or reduce emissions of GHGs would be likely to increase our operating costs and could also have an adverse effect on demand for our production.

Waste Disposal. We currently own or lease a number of properties that have been used for production of oil and natural gas for many years. Although we believe the prior owners and/or operators of those properties generally utilized operating and disposal practices that met applicable standards in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties we currently own or lease. State and federal laws applicable to oil and natural gas wastes have become more stringent over time. Under new and existing laws, we could be required to remediate property, including groundwater, containing or impacted by previously disposed wastes (including wastes disposed of or released by prior owners or operators) or to perform remedial well-plugging operations to prevent future, or mitigate existing, contamination.

We may generate wastes, including "solid" wastes and "hazardous" wastes that are subject to the federal Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state statutes, although certain oil and natural gas exploration and production ("E&P") wastes currently are excluded from regulation as hazardous wastes under RCRA. On May 4, 2016, several environmental groups filed a declaratory judgment action in federal district court for the District of Columbia seeking to compel the EPA to review the exemption of E&P wastes under RCRA. The groups had previously filed a Notice of Intent to Sue ("NOI") EPA in August 2015 for failure to act on a 2010 petition to review the E&P RCRA exemption. In late December 2016, EPA entered into a consent decree with the environmental groups and agreed to reconsider the Agency's current treatment of E&P wastes. The District Court approved the consent decree, binding EPA to a court-imposed timeline for determining how oil and gas wastes should be regulated under RCRA. EPA has until March 2019 to make its determination. If E&P waste becomes regulated as hazardous waste, then generators, transporters, and owners/operators of disposal and treatment facilities will be subject to RCRA regulations at significant increased cost. Thus, it is possible that certain wastes generated by our oil and natural gas operations that currently are excluded from regulation as hazardous wastes may in the future be designated as hazardous wastes, and may therefore become subject to more rigorous and costly management, disposal and clean-up requirements. State and federal oil and natural gas regulations also provide guidelines for the storage and disposal of solid wastes resulting from the production of oil and natural gas, both onshore and offshore.

Superfund. Under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended, also known as CERCLA or the Superfund law, and similar state laws, responsibility for the entire cost of cleaning up a contaminated site, as well as natural resource damages, can be imposed upon current or former site owners or operators and any party who releases or threatens to release one or more designated "hazardous substances" at the site, regardless of whether the original activities that led to the contamination were lawful at the time of disposal. This is known as strict liability, meaning liability without fault. CERCLA also authorizes EPA and, in some cases, third parties, to take actions in response to releases of hazardous substances into the environment and to seek to recover from the potentially responsible parties the costs of such response actions. Although CERCLA generally excludes petroleum from the definition of hazardous substances, in the course of our operations we may have generated and may generate other wastes that fall within CERCLA's definition of hazardous substances. We also may be an owner or operator of facilities at which hazardous substances have been released by previous owners or operators. We may be subject to joint and several liability as well as strict liability under CERCLA for all or part of the costs of cleaning up facilities at which such substances have been released and for natural resource damages. Joint and several liability is liability that may be apportioned either among two or more parties or to only one or a few select members of a group, making each party individually responsible for the entire obligation. In some situations we could be exposed to liability for clean-up costs and other damages as a result of conduct that was lawful at the time it occurred or for the conduct of third parties at, or prior operators of, properties we have acquired. This includes, in some circumstances, operators of properties in which we have an interest and parties that provide transportation services for us. If exposed to joint and several liability, we could be responsible for more than our share of costs for remediating a particular site, and potentially for the entire obligation, even where other parties were involved in the activity giving rise to the liability. We have not, to our knowledge, been identified as a potentially responsible party under CERCLA, nor are we aware of any prior owners or operators of our properties that have been so identified with respect to their ownership or operation of those properties.

BLM Venting and Flaring Proposed Rule. On January 22, 2016 the Department of Interior's Bureau of Land Management (BLM) released a proposed BLM Waste Prevention, Production Subject to Royalties, and Resource Conservation proposed rule. Comment on the proposed rule closed on April 22, 2016, and BLM issued its final rule on November 18, 2016. Petitions for judicial review of the rule were filed by industry groups and, as a result, BLM postponed compliance dates for certain sections of the rule pending judicial review. The 2016 rule was designed to replace the BLM's notice to lessees, NTL-4A, on venting and flaring at oil and gas facilities producing on federal and tribal lands by dealing with provisions related to venting and flaring of oil and natural gas, leak detection, storage tanks, pneumatic controllers and pumps, well maintenance and unloading, drilling and completions, and royalties. On September 18, 2018, however, the BLM substantially revised its 2016 Waste Prevention Rule, which had also been the subject of multiple court challenges but had become effective at certain points in the interim due to various court rulings. The 2018 rule essentially reverts the agency's regulation of venting and flaring to what existed before the 2016 Waste Prevention Rule was promulgated.

Potentially Material Costs Associated with Environmental Regulation of Our Oil and Natural Gas Operations

Significant potential costs relating to environmental and land-use regulations associated with our existing properties and operations include those relating to: (i) plugging and abandonment of facilities; (ii) clean-up costs and damages due to spills or other releases; and (iii) penalties imposed for spills, releases or non-compliance with applicable laws and regulations. As is customary in the oil and natural gas industry, we typically have contractually assumed, and may assume in the future, obligations relating to plugging and abandonment, clean-up and other environmental costs in connection with our acquisition of operating interests in fields, and these costs can be significant.

Plugging and Abandonment Costs

Our operations are subject to stringent abandonment and closure requirements imposed by the various regulatory bodies including the BLM and state agencies.

As described in Note 5 to our financial statements, we have estimated the present value of our aggregate asset retirement obligations to be $3.4 million as of June 30, 2018. This figure reflects the expected future costs associated with site reclamation, facilities dismantlement and plugging and abandonment of wells. The discount rates used to calculate the present value varied depending on the estimated timing of the obligation, but typically ranged between 4% and 13 %. Actual costs may differ from our estimates. Our financial statements do not reflect any liabilities relating to other environmental obligations. Following the sale of the Foreman Butte project this balance will be reduced by $2.5 million to reflect the abandonment liability transferred to the buyer of the property.

Competition

The oil and natural gas business is highly competitive in the search for and acquisition of additional reserves and in the sale of oil and natural gas. Our competitors consist of major and intermediate sized integrated oil and natural gas companies, independent oil and natural gas companies and individual producers and operators. The principal competitive factors in the acquisition of undeveloped oil and gas leases include the availability and quality of staff and data necessary to identify, investigate and purchase such leases, and the financial resources necessary to acquire and develop such leases. Many of our competitors have substantially greater financial resources, and more fully developed staffs and facilities than ours. In addition, the producing, processing and marketing of natural gas and crude oil are affected by a number of factors that are beyond our control, the effect of which cannot be accurately predicted. See “Item 1A. Risk Factors.” Ultimately, our future success will depend on our ability to develop or acquire additional reserves at costs that allow us to remain competitive.

Employees

At October 12, 2018, we had 4 employees in Denver, Colorado, U.S. We also have 2 part time employees and 1 full time employee located in Perth, Western Australia that are involved in facilitating the administration of the Company.

Available Information

We are subject to the informational requirements of the Securities Exchange Act of 1934 (the “Exchange Act”). We therefore file periodic reports, proxy statements and other information with the Securities and Exchange Commission (the “SEC”). Such reports may be obtained by visiting the Public Reference Room of the SEC at 100 F Street, NE, Washington, D.C. 20549, or by calling the SEC at 800-SEC-0330. In addition, the SEC maintains an internet site (www.sec.gov) that contains reports, proxy and information statements and other information.

Financial and other information can also be accessed on the investor section of our website at www.samsonoilandgas.com. We make available, free of charge, copies of our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after filing such material electronically or otherwise furnishing it to the SEC. Information on our website is not incorporated into this Form 10-K or our other securities filings and is not a part of them.

Item 1A. Risk Factors

Our business, operating or financial condition could be harmed due to any of the following risk factors. Accordingly, investors should carefully consider these risks in making a decision as to whether to purchase, sell or hold our securities. In addition, investors should note that the risks described below are not the only risks facing the Company. Additional risks not presently known to us, or risks that do not seem significant today, may also impair our business operations in the future. When determining whether to invest in our securities, you should also refer to the other information contained in this Annual Report on Form 10-K, including our consolidated financial statements and the related notes, and in our other filings with the SEC. As an Australian company, the rights of our shareholders may differ from the rights typically offered to shareholders of a company incorporated in the United States.

Risks Related to Our Business, Operations and Industry

We depend on successful exploration, development and acquisitions to maintain reserves and revenue in the future.

In general, the volume of production from natural gas and oil properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our future oil and natural gas production is highly dependent upon our level of success in finding or acquiring additional reserves that are economically feasible and in developing existing proved reserves. To the extent that cash flow from operations is reduced and external sources of capital become limited or unavailable, our ability to make the necessary capital investment to maintain or expand our asset base of natural gas and oil reserves would be impaired.

Inadequate liquidity could materially and adversely affect our business operations.

We have significant outstanding indebtedness under our credit facility with Mutual of Omaha Bank. As of June 30, 2018, we had drawn $23.5 million of the $24 million borrowing base under our credit facility. We have signed a forbearance agreement with Mutual of Omaha Bank that will expire on October 15, 2018 or when the pending asset sale closes, whichever is soonest.

Our ability to pay interest and principal on our indebtedness and to satisfy our other obligations will depend upon the completion of sale of our Foreman Butte assets, which may be beyond our control. If the sale closes as expected, our future operating performance and financial condition will be affected by prevailing economic conditions and financial, business and other factors, many of which we also cannot control. In any event, we cannot assure you that our business will generate sufficient cash flows from operations, or that future capital will be available to us under a new credit facility or otherwise, in an amount sufficient to fund our liquidity needs. In the absence of adequate cash from operations and other available capital resources, we could face substantial liquidity problems, and we might be required to seek additional debt or equity financing or to dispose of material assets or operations to meet our debt service and other obligations. We cannot assure you that we would be able to raise capital through debt or equity financings on terms acceptable to us or at all, or that we could consummate dispositions of assets or operations for fair market value, in a timely manner or at all. Furthermore, any proceeds that we could realize from any financings or dispositions may not be adequate to meet our debt service or other obligations then due.

Our auditors and management have expressed substantial doubt about our ability to continue as a going concern.

As disclosed in the financial statements, we incurred a net loss of $6.0 million for the year ended June 30, 2018. As at that date, our total current liabilities of $34.8 million (excluding discontinued operations) exceed our total current assets of $3.5 million (excluding discontinued operations). Additionally, we are in violation of our debt covenants and have suffered recurring losses from operations. We believe these circumstances raise substantial doubt about our ability to continue as a going concern.

Our ability to continue as a going concern is dependent on the pending sale of substantially all of our assets. If we are not able to generate the funds needed to cover our ongoing expenses, then we may be forced to cease operations or seek bankruptcy protection, in which event our shareholders could lose their entire investment.

We are in breach of multiple covenants under our credit agreement and we are relying on our senior lender's forbearance from exercising its rights under the credit agreement, which include the right to foreclose upon our assets.

We remain in breach of multiple covenants under our credit agreement with Mutual of Omaha Bank. There is no assurance that the Bank will not declare a default and seek immediate repayment of the entire debt borrowed under the facility because of these breaches.

We have signed a forbearance agreement with the Bank that requires us to repay our credit facility with them by October 15, 2018 through the pending sale of substantially all of our assets, currently due to close October 15, 2018. If this buyer fails to close the transaction as agreed in the purchase and sale agreement, signed on June 14, 2018 and subsequently amended, the Bank will have the right to seek other remedies to require immediate repayment of the facility. These could include the foreclosure of our assets. There can be no guarantee that the Bank will continue to its forbearance or that our pending sale will close on the terms provided in the purchase and sale agreement, as amended.

We recorded a significant impairment on the carrying value of our oil and gas assets during the fiscal years ended June 30, 2016 and 2015 and may record additional impairments in the future.

We recognized impairment expense of $11.0 million for the twelve months ended June 30, 2016, in addition to the impairment expense of $21.5 million we recognized for the twelve months ended June 30, 2015 of $21.5 million. The impairment expense recognized in both years is primarily in relation to our former North Stockyard project as a direct result of the significant fall in the oil price. Subsequent adverse changes in oil and gas prices or drilling results may result in us being unable to recover the carrying value of our long-lived assets and make it appropriate to recognize more impairments in future periods. Such impairments could materially and adversely affect our results of operations. For the fiscal year ended June 30, 2017, we recorded $0.2 million in impairments in relation to our oil inventory. While our pending sale of the Foreman Butte project and recent increases in oil and gas prices resulted in no impairment expense in the year ended June 30, 2018, a failure to close the proposed sale or a deterioration in oil and gas prices could lead to future impairment expense.

Reserve estimates are imprecise and subject to revision.

Estimates of oil and natural gas reserves are projections based on available geologic, geophysical, production and engineering data. There are uncertainties inherent in the manner of producing, and the interpretation of, this data as well as in the projection of future rates of production and the timing of development expenditures. Estimates of economically recoverable oil and natural gas reserves and future net cash flows necessarily depend upon a number of factors including:

- the quality and quantity of available data;
- the interpretation of that data;
- our ability to access the capital required to develop proved undeveloped locations;
- the accuracy of various mandated economic assumptions; and
- the judgment of the engineers preparing the estimate.

Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves will likely vary from our estimates. Any significant variance could materially affect the quantities and value of our reserves. Our reserves may also be susceptible to drainage by operators on adjacent properties. We are required to adjust our estimates of proved reserves to reflect production history, results of exploration and development and prevailing gas and oil prices. These reserve reports are necessarily imprecise and may significantly vary depending on the judgment of the reservoir engineering consulting firm.

Investors should not construe the present value of future net cash flows as the current market value of the estimated oil and natural gas reserves attributable to our properties. The estimated discounted future net cash flows from proved reserves are based on the average of the sales price on the first day of each month in the applicable year, with costs determined as of the date of the estimate, in accordance with applicable regulations, even though actual future prices and costs may be materially higher or lower. As a result of significant recent declines in commodity prices, such average sales prices are significantly in excess of more recent prices. Unless commodity prices or reserves increase, the estimated discounted future net cash flows from our proved reserves would generally be expected to decrease as additional months with lower commodity sales prices will be included in this calculation in the future. Factors that will affect actual future net cash flows include:

the amount and timing of actual production;

the price for which that oil and gas production can be sold;

supply and demand for oil and natural gas;

curtailments or increases in consumption by natural gas and oil purchasers; and

changes in government regulations or taxation.

As a result of these and other factors, we will be required to periodically reassess the amount of our reserves, which reassessment may require us to recognize a write–down of our oil and gas properties, as occurred at June 30, 2016 and June 30, 2015. We have not recorded any write downs of our oil and gas properties for the years ended June 30, 2017 and 2018. While our pending sale of the Foreman Butte project and recent increases in oil and gas prices resulted in no impairment expense in the year ended June 30, 2018, a failure to close the proposed sale or a deterioration in oil and gas prices could lead to future impairment expense.

Additionally, in recent years, there has been increased debate and disagreement over the classification of reserves, with particular focus on proved undeveloped reserves. The interpretation of SEC rules regarding the classification of reserves and their applicability in different situations remain unclear in many respects. Changing interpretations of the classification standards of reserves or disagreements with our interpretations could cause us to write-down reserves.

Unless reserves are replaced as they are produced, our reserves and production will decline, which would adversely affect our future business, financial condition and results of operations.

Producing oil and reservoirs are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. The rate of decline will change if production from existing wells declines in a different manner than we estimated. The rate can change due to other circumstances as well. Our future reserves and production and, therefore, our cash flows and income, are highly dependent on our ability to efficiently develop and exploit our current reserves and to economically find or acquire additional recoverable reserves. We may not be able to develop, discover or acquire additional reserves to replace our current and future production at acceptable costs. Our failure to do so would adversely affect our future operations, financial condition and results of operations.

Our development and exploration operations require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our production, profitability and reserves.

Our industry is capital intensive. We expect to continue to make substantial capital expenditures in our business and operations for the exploration, development, production and acquisition of crude oil and natural gas reserves. To date, we have financed capital expenditures primarily with cash generated by operations, capital markets transactions and the sale of properties. We intend to finance our future capital expenditures utilizing similar financing sources. Our cash flows from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the amount of crude oil and natural gas we are able to produce from existing wells;
- our ability to acquire, locate and produce new reserves;
- the prices at which crude oil and natural gas are sold; and
- the costs to produce crude oil and natural gas.

If our revenues or the borrowing base under our revolving credit facility decreases as a result of lower commodity prices, operating difficulties or for any other reason, our need for capital from other sources would increase. If we raise funds by issuing additional equity securities, this would have a dilutive effect on existing shareholders. If we raise funds through the incurrence of debt, the risks we face with respect to our indebtedness would increase and we would incur additional interest expense. There can be no assurance as to the availability or terms of any additional financing. Our inability to obtain additional financing, or sufficient financing on favorable terms, would adversely affect our financial condition and profitability. We have in the past funded a portion of our capital expenditures with proceeds from the sale of our properties, such as the sale of a portion of the North Stockyard properties to Slawson Exploration Company in August 2013. More recent sales of properties have been used to repay debt or provide working capital.

Petroleum exploration, drilling and development involve substantial business risks.

The business of exploring for and developing oil and gas properties involves a high degree of business and financial risk, and thus a substantial risk of investment loss that even a combination of experience, knowledge and careful evaluation may not be able to overcome. In addition, oil and gas drilling and production activities may be shortened, delayed or canceled as a result of a variety of factors, many of which are beyond our control. These factors include:

- unexpected drilling conditions;
- unexpected geological formations including abnormal pressure or irregularities in formations;
- equipment failures or accidents;
- adverse changes in prices;
- weather conditions;
- ability to fund capital necessary to develop exploration properties and producing properties;
- shortages in experienced labor; and
- shortages or delays in the delivery of equipment, including equipment needed for drilling, fracture stimulating and completing wells.

Acquisition and completion decisions generally are based on subjective judgments and assumptions that are speculative. It is impossible to predict with certainty the production potential of a particular property or well. Furthermore, the successful completion of a well does not ensure a profitable return on the investment. A variety of geological, operational, or market–related factors, including, but not limited to, unusual or unexpected geological formations, pressures, equipment failures or accidents, fires, explosions, blowouts, cratering, pollution and other environmental risks, shortages or delays in the viability of drilling rigs and the delivery of equipment, loss of circulation of drilling fluids or other conditions may substantially delay or prevent completion of any well or otherwise prevent a property or well from being profitable. A productive well may become uneconomic if water or other substances are encountered that impair or prevent the production of oil or natural gas from the well.

If the sale of the Foreman Butte Project closes, the development of substantially all of our oil and gas assets will be outside of our control until we acquire new oil and gas assets that we do control.

While we have received assurances from the purchaser of the Foreman Butte Project that it will proceed with the planned development of the Home Run Field, in which we will retain a 15% working interest, the purchaser is not legally bound to proceed with that plan or may elect to delay such development for an unspecified time. While we will retain the right, as a working interest owner, to propose and drill some of the proposed wells for our own account without the purchaser’s consent, there is no assurance that we will have the capital resources necessary to complete all or substantially all of the planned development without the active participation of the purchaser. We currently plan to use the cash remaining after the sale to acquire new oil and gas properties, but there is no assurance that we will be able to acquire suitable properties or that we will have the capital, resources or control necessary to fully develop such properties.

Oil and natural gas prices are extremely volatile, and decreases in prices have in the past, and could in the future, adversely affect our profitability, financial condition, cash flows, access to capital and ability to grow.

Our revenues, profitability and future rate of growth depend principally upon the market prices of oil and natural gas, which fluctuate widely. The markets for these commodities are unpredictable and even relatively modest drops in prices can significantly affect our financial results and impede our growth. Sustained declines in oil and gas prices may adversely affect our financial condition, liquidity and results of operations. Recently, oil prices have declined significantly. We are particularly dependent on the production and sale of oil and this recent commodity price decline has had, and may continue to have, an adverse effect on us. Further volatility in oil and gas prices or a continued prolonged period of low oil or gas prices may materially adversely affect our financial position, liquidity (including our borrowing capacity under our revolving credit facility), ability to finance planned capital expenditures and results of operations.

It is impossible to predict future oil and gas price movements with certainty. Prices for oil and gas are subject to wide fluctuation in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond our control. Factors that can cause market prices of oil and natural gas to fluctuate include:

- national and international financial market conditions;
- uncertainty in capital and commodities markets;
- the level of consumer product demand;
- weather conditions;
- U.S. and foreign governmental regulations;
- the price and availability of alternative fuels;
- political and economic conditions in oil producing countries, particularly those in the Middle East, including actions by the Organization of Petroleum Exporting Countries;
- the foreign supply of oil and natural gas;
- the price of oil and gas imports, consumer preferences; and
- overall U.S. and foreign economic conditions.

At various times, excess domestic and imported supplies have depressed oil and gas prices. Additionally, the location of our producing wells may limit our ability to take advantage of spikes in regional demand and resulting increases in price. While increased demand would normally be expected to increase the prices we receive for our oil and natural gas, other factors, such as the recent sharp downturn in worldwide economic activity, may dampen or even reverse any such positive impact on prices.

The profitability of wells are generally reduced or eliminated as commodity prices decline. In addition, certain wells that are profitable may not meet our internal return targets. Recent price declines and a lack of available capital have caused us to significantly reduce our new exploration and development activity which may adversely affect our results of operations, cash flows and our business.

Lower oil and natural gas prices may not only decrease our revenues, but also may reduce the amount of oil and natural gas that we can produce economically. Such a reduction may result in substantial downward adjustments to our estimated proved reserves and require write–downs of our properties. If this occurs, or if our development costs increase, our production data factors change or our exploration results do not meet expectations, accounting rules may require us to write down the carrying value of our oil and natural gas properties to fair value, as a non–cash charge to earnings.

If our access to markets for our oil and gas production is restricted, it could negatively impact our production, our income and ultimately our ability to retain our leases. Our ability to sell oil and natural gas and receive market prices for our oil and natural gas may be adversely affected by pipeline and gathering system capacity constraints.

Market conditions or the unavailability of satisfactory transportation arrangements may hinder our access to oil and gas markets or delay our production. The availability of a ready market for our oil and gas production depends on a number of factors, including the demand for and supply of oil and gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. Our productive properties may be located in areas with limited or no access to pipelines, thereby necessitating delivery by other means, such as trucking, or requiring compression facilities. Such restrictions on our ability to sell our oil or gas may have several adverse effects, including higher transportation costs, fewer potential purchasers (thereby potentially resulting in a lower selling price) or, in the event we were unable to market and sustain production from a particular lease for an extended time, possibly causing us to lose a lease due to lack of production. We currently own an interest in several wells that are capable of producing but may have their production curtailed from time to time at some point in the future pending gas sales contract negotiations, as well as construction of gas gathering systems, pipelines, and processing facilities.

A significant portion of our producing properties are located in geographic areas that are vulnerable to extreme seasonal weather, as well as additional environmental regulation and production constraints.

A significant portion of our operating properties are located in the Rocky Mountain region. As a result, the success of our operations and our profitability may be disproportionately exposed to the impact of adverse conditions unique to that region. Such conditions can include extreme seasonal weather, which could limit our ability to access our properties or otherwise delay or curtail our operations. Also, there could be delays or interruptions of production from existing or planned new wells by significant governmental regulation, transportation capacity constraints, curtailment of production, interruption of transportation, or fluctuations in prices of oil and natural gas produced from the wells in the region.

In addition, some of the properties that we may develop for production are located on federal lands where drilling and other related activities cannot be conducted during certain times of the year due to environmental considerations. This could adversely affect our ability to operate in those areas and may intensify competition during certain times for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs, particularly if our exploration or development activities on federal lands, or our production from federal lands increases.

Our business involves significant operating risks that could adversely affect our production and could be expensive to remedy. We do not have insurance to cover all of the risks that we may face.

Our operations are subject to all the risks normally incident to the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells, including:

- well blowouts;
- cratering and explosions;
- pipe failures and ruptures;
- pipeline accidents and failures;
- casing collapses;
- fires;
- mechanical and operational problems that affect production;
- formations with abnormal pressures;
- uncontrollable flows of oil, natural gas, brine or well fluids;
- releases of contaminants into the environment; and
- failure of subcontractors to perform or supply goods or services or personnel shortages.

These industry operating risks can result in injury or loss of life, severe damage to or destruction of property, damage to natural resources and equipment, pollution or other environmental damage, clean–up responsibilities, regulatory investigation and penalties, and suspension of operations, any of which could result in substantial losses. In addition, maintenance activities undertaken to reduce operational risks can be costly and can require exploration, exploitation and development operations to be curtailed while those activities are being completed. We may also be subject to damage claims by other oil and gas companies.

We do not maintain insurance in amounts that cover all of the losses to which we may be subject, and some risks, such as pollution and environmental risks, are not generally fully insurable. Our insurance policies and contractual rights to indemnity may not adequately cover our losses, and we do not have access to insurance coverage or rights to indemnity for all risks. If a significant accident or other event occurs and is not fully covered by insurance or contractual indemnity, it could adversely affect our financial position and results of operations.

Other business risks also include the risk of cyber security breaches. If management's systems for protecting against cyber security risk prove not to be sufficient, the company could be adversely affected such as by having its business systems compromised, its proprietary information altered, lost or stolen, or its business operations disrupted.

Competition in the oil and natural gas industry is intense, which may adversely affect our ability to succeed.

The oil and natural gas industry is highly competitive, and we compete with other companies that are significantly larger and have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay higher prices for productive oil and natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these competitors may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Our larger competitors may also be able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than we can. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in this highly competitive environment.

We may not be able to keep pace with technological developments in our industry.

The oil and gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement those new technologies at substantial cost. In addition, other oil and gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, our business, financial condition and results of operations could be materially adversely affected.

We are subject to complex environmental federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business.

Our exploration, development, and production operations are regulated extensively at the federal, state and local levels. Environmental and other governmental laws and regulations have increased the costs to plan, design, drill, install, operate and reclaim oil and natural gas wells and related production facilities. Under these laws and regulations, we also could be held liable for personal injuries, property damage, clean-up costs, and other damages. Failure to comply with these laws and regulations may result in the suspension or termination of operations and subject us to administrative, civil and criminal penalties. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects.

The environmental laws and regulations to which we are subject:

1. require applying for and receiving permits before drilling commences;
2. restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities;
3. limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, and other protected or sensitive areas; and
4. impose substantial liabilities for unpermitted releases and emissions resulting from our operations.

If any of our operations require federal permits or otherwise involve a “major federal action” that significantly impacts the environment, we may be required to prepare an environmental impact statement (“EIS”) pursuant to the National Environmental Policy Act to obtain the federal permits necessary to proceed with the development of certain oil and gas properties. There can be no assurance that we will obtain all necessary permits and, if obtained, that the costs associated with completing the EIS and obtaining such permits will not exceed those that previously had been estimated. It is possible that the costs and delays associated with compliance with such requirements could cause us to delay or abandon the further development of certain properties.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, emission controls, storage, transportation, disposal or cleanup requirements could require us to make significant expenditures to maintain compliance, and may otherwise have a material adverse effect on our earnings, results of operations, competitive position or financial condition. For example, because of its potential effect on ground water, seismic activity, and local communities, hydraulic fracturing and associated water disposal currently are the subject of regulatory scrutiny, negative press, and proposed legislative changes, particularly at the state and local level. Hydraulic fracturing is a process that creates a fracture extending from a well bore into a low-permeability rock formation to enable oil or natural gas to move more easily to a production well. Hydraulic fractures typically are created through the injection of water, sand and chemicals into the rock formation. Legislative and regulatory efforts to further regulate this process may render permitting and compliance requirements more stringent for hydraulic fracturing, which may limit or prohibit use of the process. While none of our properties are expected to be subject to any such changes, there is no assurance that this will remain the case.

President Donald Trump’s election and inauguration in January 2017 has resulted in uncertainty with respect to the future environmental regulation of the oil and natural gas industry. This uncertainty may affect how the oil and gas industry is regulated, and could also increase the level of public interest in environmental protection and safety concerns and may result in new or different pressures being exerted. For example, President Trump issued Executive Order 13,783 (March 28, 2017) entitled “Promoting Energy Independence and Economic Growth.” The stated goal is to “suspend, revise, or rescind [regulations] that unduly burden the development of domestic energy resources beyond the degree necessary to protect the public interest.” This Executive Order identified a number of Obama-era Clean Air Act and Clean Water Act regulations for reconsideration by the EPA. Public interest groups may increase their use of litigation as a means to require more stringent regulation of the oil and natural gas industry. As noted, there may be heightened litigation regarding any revision or rescission of these rules, resulting in uncertainty for the regulated community.

Over the years, we have owned or leased numerous properties for oil and gas activities upon which petroleum hydrocarbons or other materials may have been released by us or predecessor property owners or lessees who were not under our control. Under applicable environmental laws and regulations, including CERCLA, RCRA and analogous state laws, we could be held strictly liable for the removal or remediation of any such previously released contaminants at such locations, in some cases regardless of whether we were responsible for the release or whether the operations were compliant with applicable regulations or standard practice within the industry at the time they were performed.

Our operations also are subject to wildlife-protection laws and regulations such as the Migratory Bird Treaty Act (MBTA). For example, some oil companies have been charged under the MBTA with killing migratory birds that have died in reserve pits in North Dakota, where we conduct operations. Reserve pits are used during oil and gas drilling operations and can pose an attractive nuisance to migratory birds. During the cleanup phase of a reserve pit, North Dakota requires companies to cover the pit with a net if it is open for more than 90 days to reduce the risk of bird mortality.

The federal Clean Water Act and analogous state laws impose strict controls against the unpermitted discharge of pollutants and fill material, including spills and leaks of crude oil and other substances from our operations. The Clean Water Act also requires approval and/or permits prior to construction, where construction will disturb wetlands or other waters of the U.S. The Clean Water Act also regulates storm water run-off from crude oil and natural gas facilities and requires storm water discharge permits for certain activities. Spill Prevention, Control, and Countermeasure ("SPCC") plan requirements of the Clean Water Act dictate use of appropriate secondary containment loadout controls, piping controls, berms, and other measures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon spill, rupture, or leak, and that these measures be included in a written SPCC plan that is updated periodically.

The BLM had issued a final rule regulating hydraulic fracturing in 2015 (the “HF Rule”), and though never effective due to numerous court challenges, the HF Rule was rescinded by final rule of BLM published in the Federal Register December 28, 2017. That rescission was effected as part of President Trump’s goal to reduce the burden of federal regulations that hinder economic growth and energy development, and Department of Interior Secretarial Order No. 3349, “Promoting Energy Independence and Economic Growth.”

Additionally, BLM also published a final rule on September 18, 2018, substantially revising its 2016 Waste Prevention Rule, which was also the subject of multiple court challenges, and had become effective at certain points in the interim due to various court rulings. The final rule essentially reverts the agency’s regulation of venting and flaring to what existed before the 2016 Waste Prevention Rule was promulgated.

Despite the noted BLM rescissions and revisions of prior hydraulic fracturing regulations at the federal level, EPA in 2014 and 2017 issued technical permitting guidance under the Safe Drinking Water Act (“SDWA”) for the underground injection of liquids from hydraulically fractured (and other) wells where diesel fuels are used which guidance remains the agency’s current policy. Although Samson does not use diesel fuel in its hydraulic fracturing activities, continued EPA adherence to this guidance may create duplicative federal and state requirements in certain jurisdictions where Samson operates.

In April 2012, EPA issued regulations specifically applicable to the oil and gas industry that among other things, requires operators to capture 95 percent of the volatile organic compounds (“VOC”) emissions from natural gas wells that are hydraulically fractured. The reduction in VOC emissions is accomplished primarily through the use of “reduced emissions completion” methods to capture natural gas that would otherwise escape into the air or be combusted. EPA also issued regulations that set requirements for VOC emissions from several types of equipment, including storage tanks, compressors, dehydrators, valves and connectors. In June 2016, EPA issued additional regulations specific to the oil and gas industry adding methane standards for equipment and processes covered by the 2012 regulations. The 2016 final regulations also add leak detection and repair (LDAR) requirements for equipment such as valves, connectors, pressure relief valves, open-ended lines, access doors, flanges, crank case vents, pump seals or diaphragms, closed vent systems, compressors, separators, dehydrators, thief hatches on storage tanks, and sweetening units at gas processing plants. On April 19, 2017, EPA announced its intent to administratively reconsider the methane rules, staying a June 3, 2017 effective date for certain provisions—such as the LDAR provisions—for 90 days. Environmental groups filed a petition to stop the administrative stay in the D.C. Circuit, and on July 3, 2017, the D.C. Circuit granted relief for the petitioners, which had the impact of making the previously-stayed rules effective. And on September 12, 2018, EPA proposed revisions to its 2016 methane regulations and sought comment on additional areas for possible revision as part of its previously noted reconsideration of those rules. While EPA continues to reconsider aspects of the methane rule, it will remain effective. These new and revised regulations, or the adoption of any other laws or regulations restricting or reducing these emissions, will increase our operating costs.

Another regulatory development that may impact our operations is EPA’s notice of finding and determination that emissions of carbon dioxide, methane, and other greenhouse gases (“GHGs”) present an endangerment to human health and the environment. In response to that finding, EPA has implemented GHG-related reporting, monitoring, and recordkeeping rules for petroleum and natural gas systems, among other industries, and developed a Climate Action Plan, including a Methane Strategy which formed the basis for methane regulations issued in June 2016. However, the Executive Office report calling for the Climate Action Plan and Methane Strategy was rescinded by President Trump by Executive Order 13,783, and the June 2016 methane regulations, though currently effective, are the subject of proposed and possible further reconsideration and revision,, as noted above. EPA has also solicited comment on a proposed two-year stay of those methane rules. Those methane regulations remain in effect until possible revision or repeal by separate EPA rulemaking in the future, which action is also likely to be challenged in the courts. While the U.S. Congress has considered, and may in the future again consider, “cap and trade” legislation that would establish an economy-wide cap on emissions of GHGs in the United States and could require major sources of GHG emissions to obtain GHG emission “allowances” to continue their operations, the current administration’s decision to withdraw from the Paris Climate accords, announced on June 1, 2017, among other factors, makes passage of such legislation less likely in the near term. Any laws or regulations that may be adopted to restrict or reduce emissions of GHGs would be likely to increase our operating costs and could also have an adverse effect on demand for our production.

Finally, another federal regulation affecting hydraulic fracturing activities is the Occupational Safety and Health Administration’s (OSHA) final rule on Occupational Exposure to Respirable Crystalline Silica, which includes specific requirements applicable to hydraulic fracturing operations in the oil and gas industry published on March 25, 2016. . Hydraulic fracturing operations in the oil and gas industry are regulated under OSHA’s “general industry” regulations. The final silica rule establishes a new permissible exposure limit (PEL) of 50 micrograms of respirable crystalline silica per cubic meter of air (50 μg/m3) as an 8-hour, time-weighted average in all industries covered by the rule. The rule also includes other employee-protection provisions, such as requirements for exposure assessment, methods for controlling exposure, respiratory protection, medical surveillance, hazard communication, and recordkeeping. Implementation of this rule could increase operating costs. The final rule took effect on June 23, 2016, after which industries have one to five years to comply with most requirements.

We depend on key members of our management team.

The loss of key members of our management team could reduce our competitiveness and prospects for future success. We do not have any "key man" insurance policies for our Chief Executive Officer; or any other executive. Our exploratory drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced management professionals. Competition for these professionals is extremely intense.

Instability in the global financial system may have impacts on our liquidity and financial condition that we currently cannot predict.

Instability in the global financial system may have a material impact on our liquidity and our financial condition. We previously relied upon access to both our revolving credit facility and longer-term capital markets as sources of liquidity for any capital requirements not satisfied by the cash flow from operations or other sources. Our ability to access the capital markets or borrow money may be restricted or made more expensive at a time when we would like, or need, to raise capital, which could have an adverse impact on our flexibility to react to changing economic and business conditions and on our ability to fund our operations and capital expenditures in the future. The economic situation could have an impact on our lenders or customers, causing them to fail to meet their obligations to us, and on the liquidity of our operating partners, resulting in delays in operations or their failure to make required payments. Also, market conditions, including with respect to commodity prices such as for oil and gas, could have an impact on our oil and gas derivative instruments if our counterparties are unable to perform their obligations or seek bankruptcy protection. Additionally, challenges in the economy have led and could further lead to reductions in the demand for oil and gas, or further reductions in the prices of oil and gas, or both, which could have a negative impact on our financial position, results of operations and cash flows.

Failure to adequately protect critical data and technology systems could materially affect our operations.

Information technology solution failures, network disruptions and breaches of data security could disrupt our operations by causing delays or cancellation of customer orders, impeding processing of transactions and reporting financial results, resulting in the unintentional disclosure of customer, employee or our information, or damage to our reputation. There can be no assurance that a system failure or data security breach will not have a material adverse effect on our financial condition, results of operations or cash flows.

Recent and future changes to U.S. tax laws could materially adversely affect us.

On December 22, 2017, the Tax Cuts and Jobs Act (the "Tax Act") was signed into law, significantly revising the U. S. Internal Revenue Code (the "Code"). The Tax Act, among other things, reduces the backup withholding tax rate from 28% to 24% and contains significant changes to corporate taxation, including reduction of the corporate tax rate from a top marginal rate of 35% to a flat rate of 21%, limitation of the tax deduction for interest expense to 30% of adjusted earnings (except for certain small businesses), implementation of a "base erosion anti-abuse tax" which requires U.S. corporations to make an alternative determination of taxable income without regard to tax deductions for certain payments to affiliates, taxation of certain non-U.S. corporations' earnings considered to be "global intangible low taxed income" repeal of the alternative minimum tax ("AMT") for corporations and changes to a taxpayer's ability to either utilize or refund the AMT credits previously generated, revision in the attribution rules relating to shareholders of certain "controlled foreign corporations", limitation of the deduction for net operating losses to 80% of current year taxable income and elimination of net operating loss carrybacks, one-time taxation of offshore earnings at reduced rates regardless of whether they are repatriated, elimination of U.S. tax on foreign earnings (subject to certain important exceptions), immediate deductions for certain new investments instead of deductions for depreciation expense over time, and modification or elimination of many business deductions and credits. Notwithstanding the reduction in the U.S. corporate income tax rate, the overall impact of the Tax Act is uncertain and our business and financial condition could be adversely affected.

The impact of the Tax Act on our shareholders is also uncertain and could have an adverse impact on us. For example, recent changes in federal income tax law resulting in additional taxes owed by U.S. shareholders related to "controlled foreign corporations" may discourage U.S. investors from owning or acquiring (directly, indirectly or constructively) 10% or greater of our outstanding shares, whether held as ordinary shares or ADSs, which other shareholders may have previously viewed as beneficial. This change may otherwise negatively impact the trading price of our ADSs. We urge our shareholders to consult with their legal and tax advisors with respect to the Tax Act.

Risks Related to Our Securities

Currency fluctuations may adversely affect the price of our ADSs relative to the price of our ordinary shares.

The price of our ordinary shares is quoted in Australian dollars and the price of our ADSs is quoted in U.S. dollars. Movements in the Australian dollar/U.S. dollar exchange rate may adversely affect the U.S. dollar price of our ADSs and the U.S. dollar equivalent of the price of our ordinary shares. During the year ended June 30, 2018, the Australian dollar has, as a general trend, maintained its value against the U.S. dollar, though the Australian dollar began weakening relative to the U.S. dollar in the first half of 2018 and through September 2018, and the exchange rate remains volatile. As the Australian dollar weakens against the U.S. dollar, the U.S. dollar price of the ADSs could decline correspondingly, even if the price of our ordinary shares in Australian dollars increases or remains unchanged. In the unlikely event that dividends are payable, we will likely calculate and pay any cash dividends in Australian dollars and, as a result, exchange rate movements will affect the U.S. dollar amount of any dividends holders of our ADSs will receive from The Bank of New York Mellon, our depositary. While we would ordinarily expect such variances to be adjusted by inter-market arbitrage activity that accounts for the differences in currency values, there can be no assurance that such activity will in fact be an efficient offset to this risk.

The prices of our ordinary shares and ADSs have been and will likely continue to be volatile.

Trading in our ordinary shares is currently suspended on the ASX. The trading prices of our ordinary shares on the ASX and of our ADSs on the OTCQB have been volatile and will likely to continue to be volatile (in the case of our ordinary shares, assuming the resumption of trading on the ASX). Other natural resource companies have experienced similar volatility for their shares, leading us to expect that the results of exploration activities, the price of oil and natural gas, future operating results, market conditions for natural resource shares in general, and other factors beyond our control, could have a significant adverse or positive impact on the market price of our ordinary shares and ADSs. We also believe that this volatility creates opportunities for arbitrage trading between the ASX and OTCQB markets. While we recognize that arbitrage trading is an appropriate market mechanism to eliminate the differences between different trading markets resulting from the combination of volatile stock prices and inter-market inefficiencies, some of our shareholders may not be in a position to take advantage of the potential profits available to arbitrageurs in such cases.

Our ADSs may be deemed a "penny stock," which makes it more difficult for our investors to sell their shares.

As a result of our delisting from the NYSE American and the pending sale of the Foreman Butte Project, requiring us to account for those assets as properties held for sale, our ADSs may now be subject to the "penny stock" rules adopted under Section 15(g) of the Exchange Act. The penny stock rules generally apply to companies whose common stock is not listed on a national securities exchange and trades at less than $5.00 per share, other than companies that have had average revenue of at least $6,000,000 for the last three years or that have net tangible assets worth of at least $2,000,000 if the company has been operating for three or more years. These rules require, among other things, that brokers who trade penny stock to persons other than "established customers" complete certain documentation, make suitability inquiries of investors and provide investors with certain information concerning trading in the security, including a risk disclosure document and quote information under certain circumstances. Many brokers have decided not to trade penny stocks because of the requirements of the penny stock rules and, as a result, the number of broker-dealers willing to act as market makers in such securities is limited. If we remain subject to the penny stock rules for any significant period, it could have an adverse effect on the market, if any, for our securities. If our securities are subject to the penny stock rules, investors will find it more difficult to dispose of our securities. If we close the proposed sale of the Foreman Butte Project, we expect to have net tangible assets in excess of $2,000,000 and would therefore no longer be subject to the penny stock rules.

We may issue shares of blank check preferred stock in the future that may adversely impact rights of holders of our ordinary shares and ADSs.

Our corporate constitution authorizes us to issue an unlimited amount of "blank check" preferred stock. Accordingly, our board of directors will have the authority to fix and determine the relative rights and preferences of preferred shares, as well as the authority to issue such shares, without further shareholder approval. As a result, our board of directors could authorize the issuance of a series of preferred stock that would grant to holders preferred rights to our assets upon liquidation, the right to receive dividends before dividends are declared to holders of our common stock, and the right to the redemption of such preferred shares, together with a premium, prior to the redemption of the common stock. To the extent that we do issue such additional shares of preferred stock, the rights of ordinary share and ADS holders could be impaired thereby, including, without limitation, dilution of their ownership interests in us. In addition, shares of preferred stock could be issued with terms calculated to delay or prevent a change in control or make removal of management more difficult, which may not be in the interest of holders of ordinary shares or ADSs.

Our ADSs are required to trade on the over-the-counter market and therefore selling the ADS could be more difficult.

As our ADSs on the over-the-counter market, selling them may be difficult due to reduced trading volume, transaction delays, and reduced security analyst coverage. In addition, as the ADSs have been delisted from the NYSE American, additional regulatory burdens are imposed upon broker-dealers that may discourage them from effecting transactions in such securities, as discussed in greater detail below, further limiting the liquidity of the ADSs. These factors could result in lower prices and larger spreads in the bid and ask prices for our securities. The delisting from the NYSE American exchange and continued or further declines in our share price could also greatly impair our ability to raise additional necessary capital through equity or debt financing and could significantly increase the ownership dilution to shareholders caused by our issuing equity in financing or other transactions. Any such limitations on our ability to raise debt and equity capital could prevent us from making future investments and satisfying maturing debt commitments.

We report as a U.S. domestic issuer, which means increased compliance costs notwithstanding continued eligibility for certain NYSE American rule waivers.

On July 1, 2011, we commenced reporting as a U.S. domestic issuer instead of as a "foreign private issuer" as we had in prior years. Accordingly, we are now required to comply with the reporting and other requirements imposed by U.S. securities laws on U.S. domestic issuers, which are more extensive than those applicable to foreign private issuers. We are also required to prepare financial statements in accordance with U.S. GAAP in addition to our financial statements prepared in accordance with IFRS pursuant to ASX requirements. Generating two separate sets of financial statements is a substantial burden that imposes significant administrative and accounting costs on us. As a result of becoming a U.S. domestic issuer, the legal, accounting, regulatory and compliance costs to us under U.S. securities laws are significantly higher than those that were incurred by us as a foreign private issuer.

We do not expect to pay dividends in the foreseeable future. As a result, holders of our ordinary shares and ADSs must rely on appreciation for any return on their investment.

We do not anticipate paying cash dividends on our ordinary shares in the foreseeable future. Accordingly, holders of our ordinary shares and ADSs will have to rely on capital appreciation, if any, to earn a return on their investment in our ordinary shares.

The trading prices of our ADSs may be adversely affected by short selling.

"Short selling" is the sale of a security that the seller does not own, including a sale that is completed by the seller's delivery of a "borrowed" security (i.e. the short seller's promise to deliver the security). Short sellers make a short sale because they believe that they will be able to buy the stock at a lower price than their sales price. Significant amounts of short selling, or the perception that a significant amount of short sales could occur, could depress the market price of our ADSs. The price decline could be exacerbated if sufficient "naked short selling" occurs, which is the practice by which short sellers place short sell orders for shares without first borrowing the shares to be sold, or without having first adequately located such shares and arranged for a firm contract to borrow such shares prior to the delivery date set to close the sale. The result is an artificial deluge into the market of shares for sale – shares that the seller does not own and has not even borrowed. Although there are regulations in the United States designed to address abusive short selling, the regulations may not be adequately structured or enforced.

We may be deemed to be a passive foreign investment company (a "PFIC") for U.S. federal income tax purposes. If we are or we become a PFIC, it could have adverse tax consequences to holders of our ordinary shares or ADSs.

Potential investors in our ordinary shares or ADSs should consider the risk that we could be now, or could in the future become, a PFIC for U.S. federal income tax purposes. We do not believe that we were a PFIC for the taxable year ended June 30, 2018, and do not expect to be a PFIC in the foreseeable future. However, the tests for determining PFIC status depend upon a number of factors, some of which are beyond our control and subject to uncertainties, and accordingly we cannot be certain of our PFIC status for the current, or any other, taxable year. We do not undertake an obligation to determine our PFIC status, or to advise investors in our securities as to our PFIC status, for any taxable year.

If we were to be a PFIC for any year, holders of our ordinary shares or ADSs who are U.S. persons for U.S. federal income tax purposes ("U.S. holders") whose holding period for such ordinary shares or ADSs includes part of a year in which we are a PFIC generally will be subject to a special, highly adverse, tax regime imposed on "excess distributions" made by us. This regime will continue to apply irrespective of whether we are still a PFIC in the year an "excess distribution" is made or received. "Excess distributions" for this purpose would include certain distributions received on our ordinary shares or ADSs. In addition, gains by a U.S. holder on a sale or other transfer of our ordinary shares or ADSs (including certain transfers that would otherwise be tax-free) would be treated in the same manner as excess distributions. Under the PFIC rules, excess distributions (including gains treated as excess distributions) would be allocated ratably to each day in the U.S. holder's holding period of the ordinary shares or ADSs with respect to which the excess distribution is made or received. The portion of any excess distributions allocated to the current year or prior years before the first day of the first taxable year beginning after December 31, 1986, in which we became a PFIC would be includible by the U.S. holder as ordinary income in the current year. The portion of any excess distributions allocated to prior taxable years in which we were a PFIC would be taxed to such U.S. holder at the highest marginal rate applicable to ordinary income for each such year (regardless of the U.S. holder's actual marginal rate for that year and without reduction by any losses or loss carryforwards), and any such tax owing would be subject to interest charges. In addition, dividends received from us will not be "qualified dividend income" if we are a PFIC in the year of payment, or were a PFIC in the year preceding the year of payment, and will be subject to taxation at ordinary income rates.

In certain cases, U.S. holders may make elections to mitigate the adverse tax rules that apply to PFICs (the "mark-to-market" and "qualified electing fund" or "QEF" elections), but these elections may also accelerate the recognition of taxable income and could result in the recognition of ordinary income. We have never received a request from a holder of our ordinary shares or ADSs for the annual information required to make a QEF election and we have not decided whether we would provide such information if such a request were to be received. Additional adverse tax rules would apply to U.S. holders for any year in which we are a PFIC and own or dispose of shares in another corporation that is itself a PFIC. Special adverse rules that impact certain estate planning goals could apply to our ordinary shares or ADSs if we are a PFIC.

The market price of our ordinary shares and ADSs could be adversely affected by sales of substantial amounts of shares in the public markets or the issuance of additional shares in the future, including in connection with acquisitions.

Sales of a substantial number of our ordinary shares in the public market, either directly or indirectly as the sale of ADSs, or the perception that such sales may occur, could cause the market price of our ordinary shares (and ADSs) to decline. In addition, the sale of these shares in the public market, or the possibility of such sales, could impair our ability to raise capital through the sale of additional shares or other securities. As of June 30, 2018, subject to meeting the vesting requirements we had outstanding options to purchase an aggregate of approximately 314,500,000 of our ordinary shares granted to certain of our directors, officers and employees. These option holders, subject to compliance with applicable securities laws, are permitted to sell shares they own or acquire upon the exercise of options in the public market. In addition, as of June 30, 2018, we had warrants outstanding which may be exercised by warrant holders for 314,500,000 ordinary shares. The exercise prices of the warrants and options is between 0.0055 and 0.07 cents (Australian) per share, and the warrants and options expire around November 2026. The exercise of such warrants could have similarly adverse consequences on the trading prices for our shares.

For further details on our outstanding options and warrants, see "Note 10 – Share-Based Payments" in the Notes to our Consolidated Financial Statements.

In addition, in the future, we may issue ordinary shares or ADSs including in connection with acquisitions of assets or businesses. If we use our shares for this purpose, the issuances could have a dilutive effect on the market value of our ordinary shares, depending on market conditions at the time of an acquisition, the price we pay, the value of the business or assets acquired, our success in exploiting the properties or integrating the businesses we acquire and other factors.

Our ADS holders are not shareholders and do not have shareholder rights.

The Bank of New York Mellon, as depositary, executes and delivers our ADSs on our behalf. Each ADS is represented by a certificate evidencing a specific number of ADSs. Our ADS holders are *not* required to be treated as shareholders and do not have the rights of shareholders. The depositary is the holder of the ordinary shares underlying our ADSs. Holders of our ADSs have ADS holder rights. A deposit agreement among us, the depositary and our ADS holders sets out ADS holder rights as well as the rights and obligations of the depositary. New York law governs the deposit agreement and the ADSs.

Our ADS holders do not have the right to receive notices of general meetings or to attend and vote at our general meetings of shareholders. Our practice is to give ADS holders notices of general meetings and to enable them to vote at our general meetings of shareholders, but we are not obligated to continue to do so. Our ADS holders may instruct the depositary to vote the ordinary shares underlying their ADSs, but only when we ask the depositary to ask for their instructions. Although our practice is to have the depositary ask for the instructions of ADS holders, we are not obligated to do so, and if we do not, our ADS holders would not be able to exercise their right to vote. ADS holders can exercise their right to vote the ordinary shares underlying their ADSs by withdrawing the ordinary shares. It is possible, however, that our ADS holders would not know about the meeting enough in advance to withdraw the ordinary shares.

When we do ask the depositary to seek our ADS holders' instructions, the depositary notifies our ADS holders of the upcoming vote and arranges to deliver our voting materials and form of notice to them. The depositary then tries, as far as practicable, subject to Australian law and the provisions of the depositary agreement, to vote the ordinary shares as our ADS holders instruct. The depositary does not vote or attempt to exercise the right to vote other than in accordance with the instructions of the ADS holders. We cannot assure our ADS holders that they will receive the voting materials in time to ensure that they can instruct the depositary to vote their shares. In addition, there may be other circumstances in which our ADS holders may not be able to exercise voting rights.

Similarly, while our ADS holders would generally receive the same dividends or other distributions as holders of our ordinary shares, their rights are not identical. Dividends and other distributions payable with respect to our ordinary shares generally will be paid directly to those holders. By contrast, any dividends or distributions payable with respect to ordinary shares that are held as ADSs will be paid to the depositary, which has agreed to pay to our ADS holders the cash dividends or other distributions it or the custodian receives on shares or other deposited securities, after deducting its fees and expenses. Our ADS holders will receive these distributions in proportion to the number of ordinary shares their ADSs represent. In addition, while it is unlikely, there may be circumstances in which the depositary may not pay to our ADS holders the same amounts distributed by us as a dividend or distribution, such as when it is unlawful or impractical to do so. See the next risk factor below.

There are circumstances where it may be unlawful or impractical to make distributions to the holders of our ADSs.

Our depositary, The Bank of New York Mellon, has agreed to pay to our ADS holders the cash dividends or other distributions it or the custodian receives on shares or other deposited securities, after deducting its fees and expenses. Our ADS holders will receive these distributions in proportion to the number of ordinary shares their ADSs represent.

In the case of a cash dividend, the depositary will convert any cash dividend or other cash distribution we pay on the ordinary shares into U.S. dollars if it can do so on a reasonable basis and can transfer the U.S. dollars to the United States. In the unlikely event that it is not possible to convert a cash dividend or distribution into U.S. dollars, then the deposit agreement with the depositary allows the depositary to distribute foreign currency only to those ADS holders to whom it is possible to do so. There is also a risk that, if a distribution is payable by us in Australian dollars, the depositary may hold some or all of the foreign currency for a short period of time rather than immediately converting it for the account of the ADS holders. Because the depositary will not invest the foreign currency, will not be liable for any interest on the unpaid distribution or for any fluctuation in the exchange rates during a time when the depositary has not converted the foreign currency, our ADS holders could lose some of the value of the distribution.

The depositary may determine that it is unlawful or impractical to convert foreign currency to U.S. dollars or to make a distribution to ADS holders that is made to the holders of ordinary shares. This means that, under rare circumstances, our ADS holders may not receive the same distributions we make to the holders of our ordinary shares or receive the same value for their ADSs if it is illegal or impractical for us to or the depositary to do so.

There may be difficulty in effecting service of legal process and enforcing judgments against us and our directors and management.

We are a public company limited by shares, registered and operating under the Australian Corporations Act 2001. Two of our four directors reside outside the United States. Substantially all of the assets of those persons are located outside the U.S. As a result, it may not be possible to effect service on such persons in the U.S. or to enforce, in foreign courts, judgments against such persons obtained in U.S. courts and predicated on the civil liability provisions of the federal securities laws of the U.S. There is doubt as to the enforceability in the Commonwealth of Australia, in original actions or in actions for enforcement of judgments of U.S. courts, of civil liabilities predicated solely upon federal or state securities laws of the U.S., especially in the case of enforcement of judgments of U.S. courts where the defendant has not been properly served in Australia.

Item 1B. **Unresolved Staff Comments**

None.

Item 3. **Legal Proceedings**

None.

Item 4. **Mine Safety Disclosures**

Not applicable.

PART II

Item 5. **Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities**

A. Market Information –

Our American Depositary Shares ("ADS"), were listed on the NYSE American from January 7, 2008 to November 16, 2017 under the symbol "SSN". Following our delisting from the NYSE American exchange, we began trading on the OTC QB under the symbol "SSNYY". As of October 10, 2018, 10,730,914 ADSs were outstanding and we had approximately 11,396 beneficial owners of ADS. On March 30, 2015 the ratio of ordinary shares to ADS was changed from 20 to 1, to 200 to 1.

The following table sets forth, for the periods indicated, the highest and lowest market quotations for the ADSs reported on NYSE American or OTCQB as appropriate. On October 11, 2018, the closing price of our ADSs on OTC QB was $0.18.

	NYSE American/ OTC QB American Depositary Share (ADS) Price (in USD)			
	Fiscal 2018		Fiscal 2017	
	High	Low	High	Low
First Quarter (July 1 – September 30)	$ 0.50	$ 0.33	$ 0.83	$ 0.67
Second Quarter (October 1 – December 31)	$ 0.44	$ 0.12	$ 0.78	$ 0.52
Third Quarter (January 1 – March 31)	$ 0.29	$ 0.14	$ 0.74	$ 0.54
Fourth Quarter (April 1 – June 30)	$ 0.29	$ 0.18	$ 0.59	$ 0.42

Our ordinary shares were listed on the Australian Securities Exchange Ltd. (the "ASX") beginning on April 17, 1980. As of October 12, 2018, 3,283,000,444 ordinary shares were outstanding, and we had approximately 3,821 shareholders of record. The following table sets forth, for the periods indicated, the highest and lowest market quotations for the ordinary shares reported on the Daily Official List of the ASX. Our trading on the ASX was halted on April 12, 2018, and we have requested voluntary suspension of our trading since then. On April 11, 2018, the last day the stock traded on the ASX, the closing price of our ordinary shares on the ASX was A$0.002.

	ASX Ordinary Share Price (in AUD)			
	Fiscal 2018		Fiscal 2017	
	High	Low	High	Low
First Quarter (July 1 – September 30)	$ .003	$ .001	$ .006	$ .004
Second Quarter (October 1 – December 31)	$ .002	$ .001	$ .007	$ .004
Third Quarter (January 1 – March 31)	$ .002	$ .001	$ .005	$ .003
Fourth Quarter (April 1 – June 30)	$ .002	$ .001	$ .004	$ .003

B. Holders

As of October 12, 2018 there were approximately 3,821 holders of record of our ordinary shares. Our depositary for the ADSs, The Bank of New York Mellon, constitutes the single record holder of our ADSs and there were approximately 11,396 beneficial holders of our ADS as of October 12, 2018.

C. Dividends

We have never paid dividends on our ordinary shares and do not anticipate paying any cash dividends on our ordinary shares in the foreseeable future. Under Australian law, we may not pay a dividend unless our assets exceed our liabilities immediately before the dividend is declared and the excess is sufficient for the payment of the dividend. Moreover, Australian law requires that the dividend is fair and reasonable to the holders of our ordinary shares and the payment of the dividend does not materially prejudice our ability to pay our creditors.

D. Securities Authorized for Issuance Under Equity Compensation Plans

Information regarding equity compensation plans under which our equity securities may be issued is included in Item 12 of Part III of this report through incorporation by reference to our definitive Proxy Statement to be filed in connection with our 2018 Annual General Meeting of Shareholders. In the event that our definitive Proxy Statement is not filed on or before October 29, 2018, we will amend this Form 10-K report to add the required information in Part III.

E. Taxation

The taxation discussion set forth below describes the material Australian income tax and U.S. federal income tax consequences of ownership of our ordinary shares or ADSs by a U.S. Holder (as defined below). This discussion is based on the Australian and U.S. tax laws currently in force at the date of this Annual Report. The comments do not take into account or anticipate any changes in law (by legislation or judicial decision) or any changes in administrative practice or interpretation by the relevant authorities. If there is a change, including a change having a retrospective effect, the comments would have to be considered in light of the changes. This discussion does not address any tax consequences arising under the laws of any state or local jurisdiction, nor of any foreign jurisdictions other than Australia and the United States.

These comments are not exhaustive of all income tax consequences that could apply in all circumstances of any given shareholder or ADS holder. We recommend that prospective purchasers or holders of our ordinary shares or ADSs consult their own tax advisors regarding the Australian and U.S. federal, state and local tax, and other tax consequences of, purchasing, holding, owning, disposing of or otherwise transferring our ordinary shares and ADSs in their particular circumstances. Neither the Company nor any officers accept liability or responsibility with respect of such consequences. Further, special additional rules may apply to particular shareholders, such as insurance companies, superannuation funds and financial institutions.

Australian Taxation

The following discussion of the Australian taxation implications is based on the provisions of the Income Tax Assessment Act 1936, the Income Tax Assessment Act 1997, International Tax Agreements Act 1953 (IntTAA) which includes the United States Convention as amended by the United States Protocol (USDTA), public taxation rulings and available case law current as at the date of this Annual Report on Form 10-K (all of which are collectively referred to in this section as “Australian Taxation Laws”). The Australian Taxation Laws and their interpretation are subject to change at any time.

General Principle of Taxation in Australia

This discussion only deals with two items of income that may arise from an investment in the shares or ADSs in us, namely:

- any capital gain made on a sale of the shares or ADSs; and

- any dividends which may be paid by the Company with respect to those shares (or ADSs). Please note that we have not paid any dividends to date and do not expect to pay any in the near to medium term.

The discussion is relevant only to shareholders or ADS holders that are not residents of Australia for tax purposes and are residents of the U.S. for the purposes of the USDTA (“U.S. Equity Holders”).

Capital Gains on Sale of Shares or ADSs

Under Australian law, income tax is typically not payable on the gain made on the disposal of ordinary shares or ADSs by U.S. Equity Holders unless the profit is of income in nature and sourced in Australia or the sale is subject to tax on any net capital gains, in each case as broadly summarized below.

When the Profit on Sale is Income in Nature

Where a U.S. Equity Holder:

holds its ordinary shares or ADSs as trading stock or otherwise on revenue account;

carries on a business in Australia through a permanent establishment or fixed base; and

holds the ordinary shares or ADSs as part of that business.

any profit on the sale of the ordinary shares or ADSs (as the case may be) would be required to be included in the assessable income of the relevant U.S. Equity Holders and taxed accordingly.

When the Sale is Subject to Capital Gains Tax

A U.S. Equity Holder will be required to include in its assessable income in Australia any "net capital gains" that it makes on "indirect Australian real property interests" ("IARPI"). Broadly, IARPI will exist where:

the U.S. Equity Holder and its associates have a 10% or more direct participation interest in us and owned the shareholding at the time of disposal or throughout a 12- month period beginning no earlier than 24 months before the sale of the shareholding, and ending no later than the date of sale of the shareholding; and

at the time of the sale of the shareholding more than 50% of the market value of our assets are attributable to Australian real property (broadly Australian land and interest in Australian land).

Therefore, unless a U.S. Equity Holder and its associates holds a direct participation interest of at least 10% (as described above) it should not make a taxable capital gain or capital loss for Australian tax purposes with respect to the sale of shares or ADSs, irrespective of the percentage of our assets that constitute Australian real property. There should therefore be no tax payable on any gain on the sale of the shares or ADSs.

Where a U.S. Equity Holder, with its associates holds;

a direct participation interest of at least 10% (as described above); and

at the time of sale less than 50% of the market value of our assets are attributable to Australian real property,

that U.S. Equity Holder will not be subject to Australian tax on any capital gain or loss with respect to the sale of shares or ADSs.

Where a U.S. Equity Holder, with its associates holds;

a direct participation interest of at least 10% (as described above); and

at the time of sale more than 50% of the market value of our assets are attributable to Australian real property,

that U.S. Equity Holder will be required to calculate its net capital gains for the relevant income year taking into account the capital gain or capital loss made on the sale of the shares or ADSs. The net capital gain is then included in the U.S. Holder's assessable income in Australia and will be taxed accordingly.

A summary of a method for calculating net capital gains is to:

direct participation interest of at least 10% (as described above); and

at the time of sale more than 50% of the market value of our assets are attributable to Australian real property,

Dividends

Dividends paid by Samson to U.S. Equity Holders are only subject to the withholding tax provisions of the Australian Taxation Laws.

Australia has an imputation system which allows a company which distributes profits to its members to pass on to its members a credit for the tax already paid by the company to its members. This is known as a franking credit. The amount of the franking credit attached to the dividend is at the discretion of the paying company but cannot exceed the balance of the company's franking account (broadly the net of any income tax paid less franking credits attached to previous dividends). To the extent that the dividend is franked, the dividend is not subject to withholding tax when paid to U.S. Equity Holders. This means that a fully franked dividend is not subject to any withholding tax.

Any part of a dividend paid to the U.S. Equity Holder which is not franked is subject to dividend withholding tax in Australia. The withholding tax rates under the USDTA are as follows:

generally 15% of the gross amount of the dividend, however;

this is reduced to 5% of the gross amount of the dividend if the U.S. Equity Holder who is beneficially entitled to the dividend is a company which holds at least 10% of the voting power in the company, and

this is reduced to nil if the U.S. Equity Holder who is beneficially entitled to the dividends is a company who has held shares (or ADSs) which hold a voting power of at least 80% for at least a 12-month period (subject to certain other conditions).

In the case of a U.S. Equity Holder carrying on business in Australia through a permanent establishment or performing independent personal services through a fixed base in Australia with which the holding of shares (or ADSs) is effectively connected, no withholding tax will apply, instead the dividends form part of the normal assessable income subject to tax in Australia under the USDTA.

A dividend which is unfranked is also exempt from withholding tax to the extent that it consists of certain income from foreign sources (for example dividends from foreign companies in which the shareholder owns at least a 10% interest). It may be possible to pay such dividends to U.S. Equity Holders without the imposition of withholding tax under the Australian "Conduit Foreign Income" rules. Essentially conduit foreign income is foreign income received by a non-Australian resident (you) via an Australian corporate tax entity (us).

In the unlikely event we paid a dividend we would provide Equity Holders with notices detailing the extent to which a dividend is franked or unfranked, or represents conduit foreign income, and the deduction, if any, of withholding tax. If a dividend paid is subject to withholding tax, or would be so but for being franked, no further Australian tax is payable on the dividend.

There are also additional exemptions depending on the nature of the shareholder which are designed to ensure that an entity that is otherwise exempt from tax is not subject to withholding tax, e.g., charitable institutions.

U.S. Taxation

This section describes the material U.S. federal income tax consequences to a U.S. Holder (as defined below) of owning our ordinary shares or ADSs. This summary addresses only U.S. federal income tax considerations of U.S. Holders (as defined below) that hold our ordinary shares or ADSs as capital assets for U.S. federal income tax purposes.

This summary is based on U.S. tax laws, including the Internal Revenue Code of 1986, as amended (the "Code"), Treasury Regulations promulgated thereunder, rulings, judicial decisions, administrative pronouncements, and the USDTA, all as of the date hereof, and all of which are subject to change or changes in interpretation, possibly with retroactive effect.

For purposes of this section headed "U.S. Taxation," the term "U.S. Holder" means a beneficial owner of ordinary shares or ADSs who is a U.S. person for U.S. federal income tax purposes, and generally includes:

a U.S. citizen or an individual who is a resident of the United States for U.S. federal income tax purposes;

a corporation, or an entity treated as a corporation, created or organized in or under the laws of the United States or any state thereof or the District of Columbia;

a trust that (i) is subject to (a) the primary supervision of a court within the United States and (b) the authority of one or more United States persons to control all substantial decisions or (ii) has a valid election in effect under applicable Treasury Regulations to be treated as a United States person; or,

an estate that is subject to U.S. federal income tax on its income regardless of its source.

If a partnership (including for this purpose any entity treated as a partnership for U.S. federal income tax purposes) holds our ordinary shares or ADSs, the U.S. federal income tax treatment of a partner thereof generally will depend on the status of such partner and the activities of the partnership. If you are a partner in a partnership holding our ordinary shares or ADSs, you should consult your tax advisor(s).

Holders of our ordinary shares or ADSs who are not U.S. Holders should consult with their tax advisor(s) in connection with the U.S. federal, state, local and foreign tax consequences of the matters discussed herein.

This discussion does not address all aspects of U.S. federal income taxation that may be relevant to you in light of your particular circumstances or that may be applicable to you if you are subject to special treatment under the U.S. federal income tax laws, including if you are:

a financial institution;
a tax–exempt organization;
an S corporation or other pass–through entity;
an insurance company;
a mutual fund;
a dealer in stocks and securities, or foreign currencies;
a trader in securities who elects the mark–to–market method of accounting for your securities;
subject to the alternative minimum tax provisions of the Code;
a U.S. Holder who received our ordinary shares or ADSs through the exercise of employee stock options, otherwise as compensation, or through a tax–qualified retirement plan;
a U.S. Holder who has a functional currency other than the U.S. dollar, certain expatriates, or not a U.S. Holder;
a U.S. Holder who holds our ordinary shares or ADSs as part of a hedge, straddle or constructive sale or conversion transaction; or,
a U.S. Holder who owns, or is treated as owning under certain attribution rules, 5% or more of the aggregate amount of our ordinary shares or ADSs.

This section is based in part upon the representations of the depositary and the assumption that each obligation in the deposit agreement and any related agreement will be performed in accordance with its terms.

In general, and taking into account the assumptions stated herein, for U.S. federal income tax purposes a holder of ADSs will be treated as the owner of the ordinary shares represented by those ADSs. Exchanges of ordinary shares for ADSs, and of ADSs for ordinary shares, generally will not be subject to U.S. federal income tax. This discussion (except where otherwise expressly noted) applies equally to U.S. Holders of ordinary shares and U.S. Holders of ADSs.

U.S. Holders should consult their own tax advisors regarding the specific U.S. federal, state and local tax consequences of the ownership and disposition of ordinary shares and ADSs in light of their particular circumstances as well as any consequences arising under the laws of any other taxing jurisdiction. In particular, U.S. Holders are urged to consult their own tax advisors regarding whether they are eligible for benefits under the USDTA.

This summary assumes that we are not and will not become a controlled foreign corporation for purposes of the Code and, except as otherwise indicated, that we are not and will not become a passive foreign investment company.

Sale of ordinary shares and ADSs

Subject to the passive foreign investment company rules discussed below, a U.S. Holder that sells or otherwise disposes of our ordinary shares or ADSs will recognize capital gain or loss for U.S. federal income tax purposes equal to the difference between (i) the U.S. dollar value of the amount realized on the sale or disposition and (ii) the tax basis, determined in U.S. dollars, of those ordinary shares or ADSs. Such gain or loss generally will be long-term capital gain or loss if the holding period for the ordinary shares or ADSs sold or disposed of exceeds one year at the time of disposition. The deductibility of capital losses is subject to significant limitations. The gain or loss on the sale or other disposition of our ordinary shares or ADSs by a U.S. Holder will generally be income or loss from sources within the United States for purposes of computing the foreign tax credit limitation. Capital gains may be subject to the surtax on unearned income, as discussed below under "*Surtax on Unearned Income*."

Dividends

We do not expect to pay dividends in the foreseeable future. However, subject to the passive foreign investment company rules discussed below, a U.S. Holder must include in gross income as dividend income the gross amount of any distribution (including the amount of any Australian withholding tax thereon) paid by us out of our current or accumulated earnings and profits (as determined for U.S. federal income tax purposes) with respect to ordinary shares or ADSs. Such distributions are taxable to a U.S. Holder when the U.S. Holder (in the case of ordinary shares) or the depositary (in the case of ADSs) actually or constructively receives the distribution.

Except as described below, dividends paid to a non–corporate U.S. Holder of our ordinary shares or ADSs will be "qualified dividend income" and will be taxed to such holder at the rates applicable to long–term capital gains. However, dividend income will not be qualified dividend income (and will be taxed at ordinary income rates) if (i) the holder fails to hold the ordinary shares or ADSs for at least 61 days during the 121-day period beginning 60 days before the ex–dividend date; (ii) the Internal Revenue Service determines that the USDTA is not a comprehensive income tax treaty that entitles our dividends to qualified dividend treatment and our ordinary shares or ADSs are not readily tradable on an established securities market in the United States; or (iii) we are a passive foreign investment company for the taxable year in which the dividend is paid or in the preceding taxable year. Dividends may be subject to the surtax on unearned income, as discussed below under "*Surtax on Unearned Income*."

In the case of a corporate U.S. Holder, dividends on ordinary shares and ADSs are taxed as ordinary income and will not generally be eligible for the dividends received deduction generally allowed to U.S. corporations for dividends received from other U.S. corporations.

Distributions in excess of current and accumulated earnings and profits (as determined for U.S. federal income tax purposes) will be treated as a non –taxable return of capital to the extent of the holder's tax basis in the ordinary shares or ADSs and thereafter as capital gain.

For foreign tax credit limitation purposes, at least a portion of the dividends paid by us generally would be U.S. source income if, and to the extent that, more than a de minimis amount of our earnings and profits out of which the dividends are paid is from sources within the United States. The remaining portion of the dividends paid by us will be income from sources outside the United States. The use of foreign tax credits is subject to complex conditions and limitations. In lieu of a credit, a U.S. Holder who itemizes deductions may elect to deduct all of such holder's foreign taxes in the taxable year such foreign taxes are paid or deemed paid. A deduction does not reduce U.S. tax on a dollar-for-dollar basis like a tax credit, but the deduction for foreign taxes is not subject to the same limitations applicable to foreign tax credits. U.S. Holders are urged to consult their own tax advisors regarding the availability of foreign tax credits.

The amount of any distribution paid in foreign currency (including the amount of any Australian withholding tax thereon) generally will be includible in the gross income of a U.S. Holder of ordinary shares or ADSs in an amount equal to the U.S. dollar value of the foreign currency, calculated by reference to the spot rate in effect on the date of receipt by the U.S. Holder, or, the case of ADSs, by the depositary, regardless of whether the foreign currency is converted into U.S. dollars on such date. The amount of any distribution paid in a foreign currency generally will be converted into U.S. dollars by the depositary upon its receipt. Accordingly, a U.S. Holder of ADSs generally will not be required to recognize foreign currency gain or loss in respect of the distribution. Special rules govern and specific elections are available to accrual method taxpayers to determine the U.S. dollar amount includible in income in the case of taxes withheld in a foreign currency. Accrual basis taxpayers are therefore urged to consult their own tax advisors regarding the requirements and elections applicable in this regard.

Passive Foreign Investment Company Status

A non-U.S. corporation will be classified as a PFIC in any taxable year in which, after taking into account the income and assets of certain subsidiaries, either (i) at least 75% of its gross income is passive income, or (ii) at least 50% of the average value of its assets is attributable to assets that produce or are held for the production of passive income. Whether or not we will be classified as a PFIC in any taxable year is a factual determination and will depend upon our assets, the market value of our ordinary shares, and our activities in each year and is therefore subject to change.

Although we do not believe that we were a PFIC for the taxable year ended June 30, 2018 and do not expect to be a PFIC in the foreseeable future, the tests for determining PFIC status depend upon a number of factors. Some of these factors are beyond our control and may be subject to uncertainties, and we cannot assure you that we have not been or will not be a PFIC. We have not undertaken a formal study as to our PFIC status, and we do not undertake an obligation to determine our PFIC status, or to advise investors in our securities as to our PFIC status, for any year.

If we are a classified as a PFIC for any taxable year, the so–called “excess distribution” regime of Code Section 1291 will apply to any U.S. Holder of ordinary shares or ADSs that does not make a mark–to–market or qualified electing fund election, as described below. Under the excess distribution regime, (i) any gain the U.S. Holder realizes on the sale or other disposition of the ordinary shares or ADSs (possibly including a gift, exchange in a corporate reorganization, or grant as security for a loan) and any “excess distribution” that we make to such holder (generally, any distributions to such holder in respect of the ordinary shares or ADSs during a single taxable year that are greater than 125% of the average annual distributions received by such holder in the three preceding years or, if shorter, such holder’s holding period for the ordinary shares or ADSs), will be treated as ordinary income that was earned ratably over each day in such holder’s holding period for the ordinary shares or ADSs; (ii) the portion of any excess distributions allocated to the current year or prior years before the first day of the first taxable year beginning after December 31, 1986 in which we became a PFIC would be includible by the U.S. Holder as ordinary income in the current year; (iii) the portion of such gain or distribution that is allocable to prior taxable years during which we were a PFIC will be subject to tax at the highest rate applicable to ordinary income for the relevant taxable years, regardless of the tax rate otherwise applicable to such holder and without reduction for deductions or loss carryforwards; and (iv) the interest charge generally applicable to underpayments of tax will be imposed with respect of the tax attributable to each such year.

Dividends received from us will not be “qualified dividend income” if we are a PFIC in the year of payment or were a PFIC in the year preceding the year of payment, and will be subject to taxation at ordinary income rates.

If we are classified as a PFIC for any taxable year and our ordinary shares or ADSs are treated as “marketable securities” under applicable Treasury Regulations, a U.S. Holder may avoid the excess distribution regime described above by making a valid “mark–to–market” election with respect to the ordinary shares or ADSs. If a valid mark–to–market election is made, an electing U.S. Holder generally (i) will be required to recognize as ordinary income an amount equal to the excess, if any, of the fair market value of the ordinary shares or ADSs over the holder’s adjusted tax basis in such ordinary shares or ADSs at the close of each taxable year, or (ii) if the U.S. Holder’s adjusted tax basis in the ordinary shares or ADSs exceeds their fair market value at the close of each taxable year, will be allowed to deduct the excess as an ordinary loss to the extent of the net amount of income previously included as a result of the mark–to–market election. A U.S. Holder’s basis in its ordinary shares or ADSs will be adjusted to reflect the amounts included or deducted with respect to the mark–to–market election, and any gain or loss on the disposition of ordinary shares or ADSs will generally be ordinary income, or, to the extent of previously included mark–to–market inclusions, ordinary loss. Each U.S. Holder must make their own mark–to–market election. Once made, the election cannot be revoked without the consent of the Internal Revenue Service unless the ordinary shares or ADSs cease to be marketable securities. Under applicable. Treasury Regulations, marketable securities include stock of a PFIC that is “regularly traded” on a qualified exchange or other market. Because our ordinary shares are traded on the Australian Stock Exchange and our ADSs are traded on the NYSE American, we expect that our ordinary shares and ADSs will be treated as “regularly traded,” and a U.S. Holder should be able to make a mark–to–market election. However, no assurance that our ordinary shares or ADSs are or will be marketable securities can be given.

The excess distribution regime would not apply to any U.S. Holder who is eligible for and timely makes a valid “qualified electing fund” (“QEF”) election, in which case such holder would be required to include in income on a current basis such holder’s pro rata share of our ordinary income and net capital gains. To be timely, a QEF election must be made for the U.S. Holder’s first taxable year that includes any portion of the U.S. Holder’s holding period in our ADS or ordinary shares during which we are a PFIC. For this purpose, a U.S. Holder may elect to restart the U.S. Holder’s holding period in our ADSs or ordinary shares by agreeing to recognize, and pay tax and interest on under the excess distribution regime described above, the amount of any appreciation in the ADSs or ordinary shares held. However, a U.S. Holder’s QEF election will be valid only if we provide certain annual information to our shareholders. We have not decided at this time whether we will provide such annual information and thus it is possible that U.S. Holders will not be able to make a valid QEF election with respect to our ordinary shares and ADSs.

Special rules apply with respect to the calculation of the amount of the foreign tax credit with respect to excess distributions made by a PFIC. In general, these rules allocate creditable foreign taxes over the U.S. Holder's holding period for ordinary shares or ADSs and otherwise coordinate the foreign tax credit limitation rules with the PFIC rules.

If we are a PFIC in a taxable year and own shares in another PFIC (a "lower–tier PFIC"), a U.S. Holder also will be subject to the excess distribution regime with respect to its indirect ownership of the lower–tier PFIC. The mark–to–market election would not be available for any indirect ownership of a lower–tier PFIC. A QEF election can be made for a lower–tier PFIC, but only if we provide the U.S. Holder with the annual information necessary to make such an election. We have not decided at this time whether we will provide such annual information and thus it is possible that U.S. Holders will not be able to make a valid QEF election with respect to any lower-tier PFIC.

U.S. Holders who own ordinary shares or ADSs during any year in which we are a PFIC must file Internal Revenue Service Form 8621 with their U.S. federal income tax return for each year in which such holder owns ordinary shares or ADSs. In addition to providing the information required on such form with respect to the ownership of PFIC shares, the U.S. Holder will also be required to report gain recognized on a disposition of such ordinary shares or ADSs, the receipt of certain distributions from us, or the making of elections with respect to PFIC status.

Tax Rates Applicable to Ordinary Income and Capital Gains of Non-Corporate U.S. Holders

Ordinary income and short-term capital gains of non-corporate U.S. Holders are generally subject to U.S. federal income tax at rates of up to 37%. Long-term capital gains of non-corporate U.S. Holders are generally subject to U.S. federal income tax at rates of up to 20%.

Surtax on Unearned Income

A surtax of 3.8% (the "unearned income Medicare contribution tax") is imposed on the "net investment income" of certain U.S. Holders in excess of a threshold amount. Net investment income generally includes interest, dividends, royalties, rents, gross income from a trade or business involving "passive" activities, and net gain from disposition of property (other than property held in a "non-passive" trade or business). Net investment income is reduced by deductions that are properly allocable to such income.

HIRE Act

U.S. Holders should consult their tax advisors regarding the effect, if any, of the Hiring Incentives to Restore Employment Act, signed into law on March 18, 2010, which provides disclosure and withholding rules relating to ownership by U.S. persons of financial accounts with foreign financial institutions.

U.S. Information Reporting and Backup Withholding

Dividend payments with respect to ordinary shares or ADSs and proceeds from the sale, exchange, redemption, or other disposition of ordinary shares or ADSs may be subject to information reporting to the Internal Revenue Service and U.S. backup withholding. Certain exempt recipients, including corporations, are not subject to these information reporting requirements. Backup withholding will not apply to a holder who furnishes a correct taxpayer identification number or certificate of foreign status and who makes any other required certification. U.S. persons who are required to establish their exempt status generally must provide to us or our depositary an Internal Revenue Service Form W–9 (Request for Taxpayer Identification Number and Certification).

Backup withholding is not an additional tax. Amounts withheld as backup withholding may be credited against a U.S. Holder's U.S. federal income tax liability, and a U.S. Holder may obtain a refund of any excess amounts withheld by filing the a timely claim for refund with the Internal Revenue Service and furnishing any required information.

F. Recent Sales of Unregistered Securities

None

Item 6. Selected Financial Data

Not applicable

Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with our consolidated financial statements and related notes and the other information appearing in this Annual Report on Form 10-K. As used in this report, unless the context otherwise indicates, references to “we,” “our,” “ours,” and “us” refer to Samson Oil & Gas Limited and its subsidiaries collectively.

Overview

We are an independent energy company primarily engaged in the acquisition, exploration, exploitation and development of oil and natural gas properties. Our principal business is the exploration and development of oil and natural gas properties in the United States.

Pending Asset Sale

In June 2018, we signed a purchase and sale agreement for the sale of the Foreman Butte Project, subject to our retention of a 15% working interest in a portion of the Project (the “Foreman Butte Sale”). This transaction received shareholder approval at a general meeting held on August 13, 2018. The purchase price is $40 million with an effective date of January 1, 2018.

At the purchaser’s request, the closing date was extended to October 15, 2018.

The Foreman Butte Project constitutes the majority of our operating assets. Upon closing of the transaction, we will retain a 15% working interest in certain wells in the Home Run Field.

The proceeds of the Foreman Butte Sale will be used to repay our credit facility with Mutual of Omaha Bank in full and bring our other accounts payable current. We estimate that after these repayments, we will have no outstanding debt and will retain $6.5 million cash proceeds from the sale.

Until the drilling program in Home Run commences we will have minimal revenue generating operations. We anticipate that our liquidity will consist of residual cash from the proceeds of the sale of our assets after repayment of our credit facility and other expenses and that our capital expenditure budget for the year ending June 30, 2019 will be approximately $1.5 million. We currently plan to deploy these funds as our share of the drilling of proved undeveloped locations in the Home Run field. We plan to fund this activity with our current cash on hand, following the sale of the majority working interest in the Foreman Butte project. We also plan on continuing to look for another project to continue to grow our production profile. It is likely that a new acquisition would be funded through a combination of new debt and the issuance of new equity. There can be no guarantee that we will be able to successfully buy another project or access the capital to fund it.

Our net oil production, excluding the results of discontinued operations was 6,021 barrels of oil for the year ended June 30, 2018 compared to 61,516 barrels of oil for the year ended June 30, 2017. Our net gas production was 7,284 Mcf for the year ended June 30, 2018 compared to 434,998 Mcf for the year ended June 30, 2017.

On June 30, 2016 we signed a purchase and sale agreement for the sale of our North Stockyard project in North Dakota. The sale price was $15 million The transaction closed on October 31, 2016.

On May 31, 2017 we closed on the sale of our State GC project in New Mexico for $1.2 million. This project consisted of two wells in Lea County, New Mexico.

Recent Developments

Operations

We are expecting to close our Foreman Butte sale on October 15, 2018. The effective date of the sale was January 1, 2018 and the sale price is $40 million. We retained a 15% working interest in certain wells, generally known as the Home Run field, within the Foreman Butte project area. We are expecting to participate in the drilling of our first well in this project in the first quarter of 2019.

In April 2016 we closed on our Foreman Butte acquisition. We were awarded operatorship of wells located in Montana by the Montana Board of Oil and Gas on April 2, 2016 and we were awarded operatorship of wells located in North Dakota by the North Dakota Industrial Commission on June 3, 2016. After we were awarded operatorship we commenced a workover program to return 32 wells that were non-producing to production prior to June 30, 2016.

The sale of the North Stockyard project closed October 31, 2016. The effective date of the transaction was the day after the sale closes. This project had a written down value of $13.8 million at June 30, 2016. It was disclosed as an asset held for sale on the Balance Sheet as at June 30, 2016.

Following the significant fall in the oil price and the below expectation drilling results seen in our exploration properties, we did not complete any significant exploration operations during our fiscal years ended June 30, 2017 or 2018.

Liquidity

Following the closure of our pending sale of our majority interest in the Foreman Butte project, we will repay our outstanding credit facility with Mutual of Omaha Bank and other accounts payable balances in full. Our ability to continue as a going concern is dependent on the closing of a sale of these assets and the successful drilling of the PUD wells in the Home Run project and the acquisition or development of further production.

Results of Operations

The results below exclude the impacts of discontinued operations for the years ended June 30, 2018 and 2017. The results also exclude the impact of closing the Foreman Butte Asset Sale, which will be effective as of January 1, 2018. The financial impact of this will be recognized during the year ended June 30, 2019. `

Net income (loss)

The result for the fiscal year ended June 30, 2018 was a net loss of $6.8 million, compared to a net loss of $1.7 million for the year ended June 30, 2017. The net loss in 2018 includes $2.7 million in loss on derivative instruments.

The net loss in 2017 included a gain in derivatives of $1.3 million and a gain on sale of assets of $2.2 million.

The following table, excluding discontinued operations, reflects the components of our oil and natural gas production and sales prices, and our operating revenues, costs and expenses, for the periods indicated.

	Fiscal Year ended June 30,	
	2018	**2017**
Production Volume:		
Oil (Bbls)	6,021	61,516
Natural gas (Mcf)	7,284	434,998
BOE	7,235	134,016
Oil Price per Bbl Produced (in dollars):		
Realized price, excluded in the impact of derivative instruments	$ 41.89	$ 36.52
Natural Gas Price per Mcf Produced (in dollars):		
Realized price	$ 3.71	$ 0.63

	Fiscal Year ended June 30, 2018	Fiscal Year ended June 30, 2017
Expense per BOE:		
Lease operating expenses	$ 38.20	$ 12.42
Production and property taxes	$ 5.61	$ 2.97
Depletion, depreciation and amortization	$ 22.95	$ 14.22
General and administrative expense	$ 572.41	$ 37.57
Interest expense, net of amounts capitalised	$ -	$ -

Comparison of Year Ended June 30, 2018 to year ended June 30, 2017

Item	Year ended June 30, 2018	Year ended June 30, 2017	Variance	% Change
Continuing Operations				
Oil and gas revenues	$ 279,282	$ 2,553,569	$ (2,274,287)	-89%
Interest income	229	411	(182)	-44%
Gain on derivative instruments	-	1,297,472	(1,297,472)	-100%
Gain on sale of assets	178,407	2,250,070	(2,071,663)	-92%
Other income	80,893	66,707	14,186	21%
Lease operating expense	(406,114)	(2,209,583)	1,749,469	-79%
Depletion, depreciation and amortization	(166,030)	(218,635)	52,605	-24%
Impairment of oil and gas properties	-	(244,480)	244,480	-100%
Exploration and evaluation expenditure	(325,304)	(78,391)	(246,913)	315%
Accretion of Asset Retirement Obligations	(34,554)	(52,801)	18,247	-35%
General and administrative cost	(4,141,399)	(5,034,746)	893,347	-18%
Abandonment expense	(128,862)	(3,055)	(125,807)	4118%
Provision for doubtful debts	(75,000)	-	(75,000)	100%
Loss on derivative instruments	(2,722,166)	-	(2,722,166)	100%
Net income (loss) from continuing operations	$ (6,782,562)	$ (1,673,462)	$ (5,109,100)	

Oil and gas revenues

Oil and gas revenues decreased from the year ended June 30, 2017 to the year ended June 30, 2018, from $2.4 million to $0.25 million. Oil production decreased from 61,516 Bbls for the year ended June 30, 2017 to 6,021 Bbls for the year ended June 30, 2018. The decrease in production is due to the sale of our North Stockyard field which closed on October 31, 2016 and our relatively small net revenue interest we have retained in our Foreman Butte project area. The average oil sale price received also increased in line with global oil prices from $36.52 per barrel for the year ended June 30, 2017 to $41.89 per barrel for the year ended June 30, 2018 (excluding the impact of derivative instruments).

Our natural gas production decreased for the year ended June 30, 2018 to 7,284 Mcf from 434,998 Mcf for the year ended June 30, 2017. The 2017 production decreased following the sale of our North Stockyard field which closed on October 31, 2016. The realized gas price increased from $0.63 per Mcf for the year ended June 30, 2017 to $3.71 per Mcf for the year ended June 30, 2018.

Impairment

Included in the loss for fiscal year ended June 30, 2017 is $0.2 million of impairment expense compared to $nil million for fiscal year ended June 30, 2018.

The impairment in the prior year relates to a write down in the value of oil inventory held on the balance sheet related to our accounting policy of holding the inventory at the lower of cost or net realizable value.

Exploration and evaluation expenditures

Exploration expenditures were slightly higher for June 30, 2018 at $0.3 million compared to $0.1 million for June 30, 2017. This was the result of previously capitalized expenditures relating to Cane Creek being written off in the current year.

Lease operating expenses

Lease operating expenses decreased from $2.2 million for fiscal year 2017 to $0.5 million in fiscal year 2018, including $0.04 million in workover costs. Costs decreased due to the sale of our interest in the North Stockyard field.

Depletion, depreciation and amortization

Depletion, depreciation and amortization expense remained consistent at $0.2 million for fiscal year 2017 to $0.2 million in fiscal year 2018. Depletion has not been charged on the assets being held for sale since March 31, 2018 when the asset was designated as held for sale.

General and administrative expense

General and administrative expense decreased from $5.0 million for the year ended June 30, 2017 to $4.1 million for the year ended June 30, 2018. Included in the cost in 2018 is $0.4 compared to $0.7 million for the financial year ended June 30, 2017 in share based payments related to warrants granted to employees and shares issued to employees in lieu of salary. Effective October 1, 2017 certain employees and directors took 25% pay cuts in order to reduce cash administrative costs while working through the asset sale process. Management intends to continue its tight cost control discipline with respect to general and administrative costs in the future.

Gain/(Loss) on derivative instruments

During the year ended June 30, 2018 we recognized a loss of $2.7 million on derivate instruments compared to a gain of $1.3 million in the year ended June 30, 2017. This is due to increase in the global oil price.

Discontinued Operations

A purchase and sale agreement to sell a substantial interest in the Foreman Butte project area was signed on June 14, 2018. The acquisition price is $40,000,000 with an effective date of January 1, 2018. If the transaction closes, we will retain a 15% working interest in certain wells in the Home Run field. The impact of this proposed sale has been treated as a discontinued operation and adjustments have been made to the fiscal year ending June 30, 2018 and 2017 to show the impact of this sale had it occurred on July 1, 2017.

Interest charges and amortization of borrowing costs have been included in the discontinued operations as the credit facility is directly related to the assets being sold.

During the year ended June 30, 2018 the discontinued operations made a net gain of $0.7 million compared to a net loss of $1.1 million for the year ended June 30, 2017. The gain in the current year is due to increased production, lower lease operating expenses and increased oil price. Lease operating expenses in the current year were $6.0 million compared to $7.8 million in the prior year.

Liquidity and Capital Resources

Cash flows

Continuing Operations	Year ended June 30 2018	2017
Cash flow (used in)/provided by operating activities	$ (4,463,003)	$ (4,847,580)
Cash flow provided by/(used in) investing activities	(161,722)	14,424,847
Cash flow (used in)/provided by financing activities	415,000	(11,088,016)

Discontinued Operations	Year ended June 30 2018	2017
Cash flow provided by operating activities	$ 6,768,727	$ 2,236,620
Cash flow used in investing activities	(445,997)	(2,718,371)
Cash flow used in financing activities	(1,350,391)	-

Capital Resources

During the year ended June 30, 2018, our main source of liquidity was cash on hand, cash from operations, and proceeds from our credit facility with Mutual of Omaha Bank. This facility is expected to be repaid in full following the closing of the pending asset sale, currently expected for October 15, 2018.

We signed an amended forbearance agreement with Mutual of Omaha Bank on September 28, 2018 in order to allow the orderly completion of the pending asset sale. We paid $0.25 million in bank fees upon the signing of the Purchase and Sale Agreement on June 14, 2018. If the asset sale fails to close as scheduled, Mutual of Omaha will be entitled to take further action to ensure payment of their outstanding credit facility.

During the year ended June 30, 2018, our main source of liquidity was cash on hand and cash from operations.

During the year ended June 30, 2017, our main source of liquidity was cash on hand, cash from operations, proceeds from our credit facility with Mutual of Omaha Bank and the sale of assets.

In March 2016, the facility was extended to $30.5 million to partly fund the Foreman Butte acquisition. As a result of this amendment to the facility agreement, the following changes were made to the original facility agreement:

- The addition of more restrictive financial covenants (including the debt to EBITDA ratio and the minimum liquidity requirement);
- Increases in the interest rate and unused facility fee;
- The addition of a minimum hedging requirement of 75% of forecasted production;
- A requirement to reduce our general and administrative costs from $6 million per year to $3 million per year;
- A requirement to raise $5 million in equity on or before September 30, 2016 (which was extended to November 15, 2016 and was achieved through the sale of the North Stockyard asset);

- A requirement to pay down at least $10 million of the loan by June 30, 2016; (which was increased to $11.5 million and completed in October 31, 2016 following the closing of the sale of our North Stockyard field for $15 million) and
- The addition of a monthly cash flow sweep whereby 50% of cash operating income will be used to repay outstanding borrowings under the Credit Agreement.

As at June 30, 2018 we were in breach of the quarterly and annual earnings and liquidity covenants and we anticipate similar breaches until the sale of our Foreman Butte assets are finalized.

2017 and 2018 Capital Expenditures

During the year ended June 30, 2018 we spent $0.1 million on oil and gas properties including recompletion activities in our Foreman Butte project area.

During the year ended June 30, 2017 we spent $2.5 million on oil and gas properties including recompletion activities in our Foreman Butte project area.

Estimated 2019 Capital Expenditures

Our capital expenditure budget for the year ending June 30, 2019 is estimated at $1.5 million, assuming the pending asset sale is completed.

We plan to deploy these funds as our share of the drilling of proved undeveloped locations in the Home Run field. We plan to fund this activity with our current cash on hand, following the sale of the majority working interest in the Foreman Butte project.

We also plan on continuing to look for another project to continue to grow our production profile. It is likely that a new acquisition would be funded through a combination of new debt and the issuance of new equity. There can be no guarantee that we will be able to successfully buy another project or access the capital to fund it.

Any capital expenditure remains dependent on us having the capital required to meet the expenditure.

Off-Balance Sheet Arrangements

At June 30, 2018, we had no existing off-balance sheet arrangements, as defined under SEC rules, that have or are reasonably likely to have a material current or future effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Acquisitions and Divestitures

Acquisitions

We had no material acquisitions in fiscal years ended June 30, 2017 or June 30, 2018.

Divestitures

On June 14, 2018 we signed a purchase and sale agreement for the sale of the majority working interest in our Foreman Butte project in Montana and North Dakota for $40 million. The effective date of the transaction was January 1, 2018 and the transaction is expected to close on October 15, 2018. We maintained a 15% working interest in the Home Run field, a smaller field in the Foreman Butte project area. This field contains a significant portion of the proved undeveloped locations in the greater project area. This project has been held for sale on the Balance Sheet at its written down value of $28.7 million, excluding the costs associated with the 15% retained assets.

On May 31, 2017 we closed on the sale of our State GC project in New Mexico for $1.2 million. This project consisted of two wells in Lea County, New Mexico.

Trends Affecting Our Results of Operation

Lease Operating Expenses

Following the decrease in global oil prices between 2014 and 2016, lease operating expenses in the U.S. significantly decreased as well. With increased oil prices in the past two years, however, lease operating expenses have ceased to decline and have in some cases materially increased. There can be no guarantee this lease operating expenses will not increase further nor that we will be able to access lower prices for such services. Prior to the Foreman Butte acquisition, we were the operator of the majority of our wells. These wells are older wells that may have higher operating costs than more recently drill wells. Following the completion of our pending asset sale, we will no longer be the operator of the majority of assets and as such we will be subject to the operating costs of the operator, which will be largely outside of our control.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon financial statements that have been prepared in accordance with U.S. GAAP. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. We have identified certain accounting policies as being of particular importance to the presentation of our financial position and results of operations and which require the application of significant judgment by our management. We analyze our estimates, including those related to oil and natural gas revenues, oil and natural gas properties, exploration and valuation expenditure, share based payments, income taxes and contingencies, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies and estimates affect our more significant judgments and estimates used in the preparation of our financial statements.

Reserves Estimates

Our estimates of proved reserves are based on the quantities of oil and gas that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation, and judgment. For example, Samson must estimate the amount and timing of future operating costs, production, and property taxes, development costs, and workover costs, all of which may in fact vary considerably from actual results. In addition, as prices and cost levels change from year to year, the estimate of proved reserves also changes. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves. Despite the inherent imprecision in these engineering estimates, our reserves are used throughout our financial statements. For example, we use the units–of–production method to amortize our oil and gas properties, which means that the quantity of reserves could significantly impact our depletion, depreciation and amortization expense. The value of our reserves also impacts any impairment expense recognized.

Successful efforts

The Company’s oil and gas exploration and production activities are accounted for using the successful efforts method. Under this method, all property acquisition costs and costs of drilling exploratory wells are capitalized when incurred, pending determination of whether the well has found proved reserves. Costs of drilling development wells are capitalized regardless of the success of the well. Exploratory dry hole costs, lease rentals and geological and geophysical costs are charged to expense as incurred. Upon surrender of undeveloped properties, the original cost of such properties is charged against income.

Exploration and Evaluation Expense

Exploration and evaluation assets are assessed for impairment when facts and circumstances indicate that the carrying amount of an exploration and evaluation asset may exceed its recoverable amount. When assessing for impairment consideration is given to but not limited to the following:

- the period for which Samson has the right to explore;
- planned and budgeted future exploration expenditure;
- activities incurred during the year; and
- activities planned for future periods.

If, after having capitalized expenditure under our policy, we conclude that we are unlikely to recover the expenditure by future exploitation or sale, then the relevant capitalized amount will be written off to the income statement.

During the year ended June 30, 2018 we expensed $0.2 million in exploration expenditure written off in relation to the Paradox project in Utah.

During the year ended June 30, 2017 we incurred exploration expenditure of $0.08 million in relation to delay rentals and other permitting.

Depreciation, Depletion and Amortization for Oil and Gas Properties

The quantities of estimated proved oil and gas reserves are a significant component of our calculation of depletion expense, so revisions in such estimates may alter the rate of future expense. Holding all other factors constant, if reserves were revised upward or downward, earnings would increase or decrease respectively.

Depreciation, depletion and amortization of the cost of proved oil and gas properties are calculated using the unit–of–production method. The reserve base used to calculate depletion, depreciation or amortization is the sum of proved developed reserves and proved undeveloped reserves for leasehold acquisition costs and the cost to acquire proved properties. With respect to lease and well equipment costs, which include development costs and successful exploration drilling costs, the reserve base includes only proved developed reserves. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are taken into account. Certain other assets are depreciated on a straight –line basis.

Amortization rates are updated four times a year to reflect: the addition of capital costs, reserve revisions (upwards or downwards) and additions, property acquisitions or dispositions, and impairments.

Assets held for sale have not been depreciated for the period they are held for sale

Impairments

The Company reviews its proved oil and gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. The Company estimates the expected future cash flows of its oil and gas properties and compares these undiscounted future cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the oil and gas properties to fair value. The factors used to determine fair value include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of reserves, future commodity pricing, future production estimates, anticipated capital expenditures and various discount rates commensurate with the risk associated with realizing the projected cash flows.

We recorded impairment charges of $nil and $0.2 million for the years ended June 30, 2018 and 2017 respectively.

Asset Retirement Obligations

The accounting standards set forth by the FASB with respect to accounting for asset retirement obligations provide that, if the fair value for asset retirement obligations can be reasonably estimated, the liability should be recognized in the period when it is incurred. Oil and natural gas producing companies incur this liability upon acquiring or drilling a well. Under this method, the retirement obligation is recorded as a liability at its estimated present value at the asset's inception, with the offsetting increase to property cost. Periodic accretion of discount of the estimated liability is recorded in the income statement. Our asset retirement obligation primarily represents the estimated present value of the amount we will incur to plug, abandon and remediate our properties at the end of their productive lives, in accordance with applicable laws. We have determined our asset retirement obligation by calculating the present value of estimated cash flows related to each liability. The discount rates used to calculate the present value vary depending on the estimated timing of the relevant obligation, but typically ranged between 4% and 10%. We periodically review the estimate of costs to plug, abandon and remediate our properties at the end of their productive lives. This includes a review of both the estimated costs and the expected timing to incur such costs. We believe most of these costs can be estimated with reasonable certainty based upon existing laws and regulatory requirements and based upon wells and facilities currently in place. Any changes in regulatory requirements, which changes cannot be predicted with reasonable certainty, could result in material changes in such costs. Changes in reserve estimates and the economic life of oil and natural gas properties could affect the timing of such costs and accordingly the present value of such costs.

Asset retirement obligations for assets held for sale, are included on the Balance Sheet in current liabilities.

Share Based Payments

We measure the cost of equity settled transactions by reference to the fair value of the equity instruments at the date they are granted. Where the fair value of the equity instrument cannot be readily determined in reference to the market price of our ordinary shares, the fair value is determined using the Black Scholes option pricing model. The use of the Black Scholes option pricing model requires Samson to make estimates in regard to certain inputs required by the model, in particular in regard to the time to expiry of the option and the volatility of our share price. We review inputs to this model each time a valuation is performed with reference to inputs used in the past and recent developments.

Income Taxes and Uncertain Tax Positions

Income taxes reflect the tax effects of transactions reported in the financial statements and consist of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income tax assets and liabilities represent the future tax return consequences of those differences, which will either be taxable or deductible when assets are recovered or settled. Deferred income taxes are also recognized for tax credits that are available to offset future income taxes. Deferred income taxes are measured by applying current tax rates to the differences between financial statement and income tax reporting. We have recognized a valuation allowance against our net deferred taxes because we cannot conclude that it is more likely than not that the net deferred tax assets will be realized as a result of estimates of our future operating income based on current oil and natural gas commodity pricing. In assessing the realization of deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. We consider the scheduled reversal of deferred tax liabilities, available taxes in carryback periods, projected future taxable income and tax planning strategies in making this assessment. We will continue to evaluate whether the valuation allowance is needed in future reporting periods. We are subject to taxation in many jurisdictions, and the calculation of our income tax liabilities involves dealing with uncertainties in the application of complex income tax laws and regulations in various taxing jurisdictions. We recognize certain income tax positions that meet a more-likely-than not recognition threshold. If we ultimately determine that the payment of these liabilities will be unnecessary, we will reverse the liability and recognize an income tax benefit during the period in which we determine the liability no longer applies.

Derivatives

The Company has elected not to apply hedge accounting to any of its derivative transactions and, consequently, the Company recognizes mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income for those commodity derivatives that would qualify as cash flow hedges. All derivative instruments are recorded on the balance sheet at fair value.

Recently Adopted Accounting Standards

There have been no recently adopted accounting standards that would impact our business.

Recently Issued Accounting Pronouncements

ASU 2016-02, *Leases (Topic 842)* This ASU, among other provisions, requires lessees to recognize right of use assets and leases liabilities for all leases not considered short term leases. The ASU is effective for public business entities for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. We not expect this to have significant impact on our accounting for leases but may require additional disclosures.

ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)* Accounting Standards Update (ASU) 2014-09 provides a new framework for addressing revenue recognition issues and upon its effective date, replaces almost all existing revenue recognition guidance. While the revenue recognition policies of all entities will be impacted by this standards, we do not expect the impact to be significant. For public business entities, the guidance is effective for annual reporting periods beginning after December 15, 2017, including interim period’s within that reporting period. We do not expect this standard to have significant impact on our revenue recognition but may require additional disclosures.

Item 8. Financial Statements and Supplementary Data

See “Index to Consolidated Financial Statements” on page 57 of this report.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. We conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the “Exchange Act ”) as of June 30, 2018. This evaluation was conducted under the supervision and with the participation of management, including our Chief Executive Officer (“CEO”) and Chief Financial Officer (“CFO”). Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the rules and forms of the SEC, and that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Control weakness – Accounts Payable processing

The Company took over operatorship of the Foreman Butte field in May and June of 2016. This change necessitated a review of our accounts payable procedures. During the course of this review we noted that the design of one process was not sufficient to adequately capture all invoices in a timely fashion. The impact of this was stated in Note 2 to our Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 15, 2017. At that time, we concluded that this control was not operating effectively for the quarter ended March 31, 2017. We have since revised and redesigned our accounts payable procedures and controls with particular emphasis on ensuring the accuracy and completeness of this Annual Report on Form 10-K. We have implemented these new controls however they have not been in place long enough to fully assess their control design and effectiveness.

As of June 30, 2018, we have carried out an evaluation under the supervision of, and with the participation of, our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 under the Exchange Act.

Our Chief Executive Officer and Chief Financial Officer have concluded that, as of June 30, 2018, because of the deficiency noted above, our disclosure controls and procedures were not effective to ensure that the information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Management’s Annual Report on Internal Control over Financial Reporting. Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of financial statements for external reporting purposes in accordance with generally accepted accounting principles. Internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of assets of the company, (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company’s assets that could have a material effect on the financial statements.

Under the supervision and with the participation of our management, including our CEO and CFO, we assessed the effectiveness of our internal control over financial reporting as of June 30, 2018, the end of our fiscal year. This assessment was based on criteria established in *Internal Control—Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on our assessment, for the reasons noted above, management has concluded that, as of June 30, 2018, our internal control over financial reporting is not effective based upon these criteria.

Inherent Limitations on Effectiveness of Controls

A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Accordingly, our disclosure controls and procedures are designed to provide reasonable, not absolute, assurance that the objectives of our disclosure system are met. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Changes in Internal Control over Financial Reporting

Other than as discussed above, there were no changes in our internal control over financial reporting during the quarter ended June 30, 2018, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information relating to this item will be in the proxy statement for our 2018 annual shareholders' meeting and is incorporated by reference in this report or, if necessary, will be included in an amendment to this report.

Item 11. Executive Compensation

Information relating to this item will be in the proxy statement for our 2018 annual shareholders' meeting and is incorporated by reference in this report or, if necessary, will be included in an amendment to this report.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information relating to this item will be in the proxy statement for our 2018 annual shareholders' meeting and is incorporated by reference in this report or, if necessary, will be included in an amendment to this report.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information relating to this item will be in the proxy statement for our 2018 annual shareholders' meeting and is incorporated by reference in this report or, if necessary, will be included in an amendment to this report.

Item 14. Principal Accounting Fees and Services

Information relating to this item will be in the proxy statement for our 2018 annual shareholders' meeting and is incorporated by reference in this report or, if necessary, will be included in an amendment to this report.

PART IV

Item 15. Exhibits and Financial Statement Schedules

Financial Statements and Financial Statement Schedules

See "Index to Consolidated Financial Statements" on page 57.

Exhibits

Number	Description
3.1	Constitution of Samson Oil & Gas Limited dated November 30, 2017 (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on February 14, 2018)
4.1	Form of Deposit Agreement between Samson Oil & Gas Limited and The Bank of New York (incorporated by reference to Exhibit 1 to the Registration Statement on Form F-6EF filed on April 29, 2010).
4.2	Terms and Conditions of Warrants, included in the Form of Subscription Agreement filed as Exhibit 10.1 hereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on August 22, 2013).
10.4	Employment Agreement between Samson Oil and Gas USA, Inc. and Terence Barr, dated as of January 1, 2011 (incorporated by reference to Exhibit 10.4 to the Annual Report on Form 10-K filed on September 13, 2012).+

10.5	Amendment to Employment Agreement between Samson Oil and Gas USA, Inc. and Terence Barr, dated as of December 20, 2011 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on December 27, 2011).+
10.6	Employment Agreement between Samson Oil and Gas USA, Inc. and Robyn Lamont, dated as of January 1, 2011 (incorporated by reference to Exhibit 10.5 to the Annual Report on Form 10-K filed on September 13, 2012).+
10.7	Employment Agreement between Samson Oil and Gas USA, Inc. and David Ninke, dated as of January 1, 2011 (incorporated by reference to Exhibit 10.6 to the Annual Report on Form 10-K filed on September 13, 2012).+
10.8	Employment Agreement between Samson Oil and Gas USA, Inc. and Daniel Gralla, dated as of January 1, 2011 (incorporated by reference to Exhibit 10.7 to the Annual Report on Form 10-K filed on September 13, 2012).+
10.9	Samson Oil & Gas Limited Stock Option Plan (incorporated by reference to Exhibit 4.1 to the Registration Statement on Form S-8 of Samson Oil & Gas Limited filed on April 21, 2011).+
10.10	Purchase and Sale Agreement with Slawson Exploration Company, Inc. dated August 15, 2013 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on March 20, 2013).
10.11	Form of Subscription Agreement dated March 20, 2013 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on March 22, 2013).
10.12	Form of Subscription Agreement dated August 19, 2013 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on August 22, 2013).
10.13	Term Loan Credit Agreement dated January 27, 2014 among Samson Oil and Gas USA, Inc. as borrower, Samson Oil & Gas Limited and Samson Oil and Gas Montana, Inc. as guarantors, and Mutual of Omaha Bank as lender and administrative agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on January 31, 2014).
10.14	Farmout Agreement dated February 28, 2014, among Samson Oil and Gas USA Montana, Inc., Fort Peck Energy Company, LLC and Momentus Energy LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on March 6, 2014).
10.15	Form of Subscription Agreement dated April 16, 2014, among Samson Oil & Gas Limited and each of the purchasers party thereto (incorporated by reference to Exhibit 1.1 to the Current Report on Form 8-K filed on April 17, 2014).
10.16	First Amendment to Mutual of Omaha Credit Agreement dated November 24, 2014 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed on February 9, 2015).
10.17	Purchase and Sale Agreement dated December 31, 2015 between Samson Oil and Gas USA, Inc. and Oasis Petroleum North America LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on January 7, 2016).
10.18	First Amendment to Purchase and Sale Agreement dated March 31, 2016 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on April 6, 2016).
10.19	Secured Promissory Note dated March 31, 2016 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on April 6, 2016).

10.20	Third Amendment to Credit Agreement dated March 31, 2016 (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed on April 6, 2016).
10.21	Form of Subscription Agreement (incorporated by reference to Exhibit 1.1 to the Current Report on Form 8-K filed on April 14, 2016).
10.22	Engagement Agreement dated February 22, 2016 between Samson and Euro-Pacific (incorporated by reference to Exhibit 1.2 to the Current Report on Form 8-K filed on April 14, 2016).
10.23	Amendment to Employment Agreement dated May 6, 2016 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on May 9, 2016).+
10.24	Purchase and Sale Agreement dated June 30, 2016 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on July 7, 2016).
10.25	Fourth Amendment to Credit Agreement (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on July 18, 2016).
10.26	Fifth Amendment to Credit Agreement (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on October 3, 2016).
10.27	Letter dated April 3, 2017 modifying payment terms of Secured Promissory Note dated March 31, 2016 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on April 7, 2017).
10.28	Amended and Restated Employment Agreement, by and between Samson Oil and Gas USA and Terence Barr, dated January 1, 2011 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on April 26, 2017).+
10.29	Amended and Restated Employment Agreement, by and between Samson Oil and Gas USA and Robyn Lamont, dated January 1, 2017 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on April 26, 2017).+
10.30	Amended and Restated Employment Agreement, by and between Samson Oil and Gas USA and David Ninke, dated January 1, 2017 (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on April 26, 2017).+
10.31	Employment Agreement, by and between Samson Oil and Gas USA and Mark Ulmer, dated April 1, 2016 (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on April 26, 2017).+
10.32	Sixth Amendment to Credit Agreement dated May 5, 2017 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on May 8, 2017)
10.33	Term Note for the benefit of Mutual of Omaha Bank dated May 5, 2017 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on May 8, 2017)
10.44	Purchase and Sale Agreement dated May 1, 2017 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on May 15, 2017)

10.45	Seventh Amendment to Credit Agreement dated July 14, 2017 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on July 20, 2017)
10.46	2016 Stock Option Plan (incorporated by reference to Exhibit 10.46 to the Annual Report on Form 10-K filed with the Securities and Exchange Commission on September 28, 2017)+
10.47	Amended & Restated Employment Agreement dated as of January 1, 2018 between Samson Oil and Gas USA, Inc. and Terence M. Barr (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on February 5, 2018) +
10.48	Agreement, dated as of February 9, 2018, between Samson Oil and Gas, USA, Inc., Samson Oil & Gas Limited, Samson Oil and Gas USA Montana, Inc., and Mutual of Omaha Bank (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on February 14, 2018).
10.49	Subscription Agreement dated March 30, 2018 between the Company and DynEvolve Capital, LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on April 5, 2018).
10.50	Stockholders Agreement dated March 30, 2018 between the Company, DynEvolve Capital Group and future stockholders party thereto (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on April 5, 2018).
10.51	Purchase and Sale Agreement dated June 12, 2018 between Samson Oil and Gas USA, Inc., and Eagle Energy Partners I, LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on June 20, 2018).
10.52	Agreement dated June 14, 2018 between Samson Oil and Gas, USA, Inc., Samson Oil & Gas Limited, Samson Oil and Gas USA Montana, Inc., and Mutual of Omaha Bank (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on June 20, 2018).
10.53	Amendment to Purchase and Sale Agreement dated September 28, 2018 between Samson Oil and Gas USA, Inc., and Eagle Energy Partners I, LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on October 4, 2018).
10.54	Amendment to Agreement dated September 28, 2018 between Samson Oil and Gas, USA, Inc., Samson Oil & Gas Limited, Samson Oil and Gas USA Montana, Inc., and Mutual of Omaha Bank (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on October 4, 2018).
21.1	List of Subsidiaries (incorporated by reference to Exhibit 21 to the Annual Report on Form 10-K filed on September 13, 2011).
23.1	Consent of Moss Adams LLP*
23.2	Consent of Hein & Associates LLP*
23.3	Consent of Netherland, Sewell & Associates, Inc*

31.1	Certification of the Principal Executive Officer pursuant to Rule 13a–14(a) and Rule 15d–14(a) of the Securities Exchange Act of 1934, as amended.*
31.2	Certification of the Principal Financial Officer pursuant to Rule 13a–14(a) and Rule 15d–14(a) of the Securities Exchange Act of 1934, as amended. *
32.1	Certifications of the Principal Executive Officer and Principal Financial Officer pursuant to 18 USC 1350, as adopted, pursuant to Section 906 of the Sarbanes–Oxley Act of 2002. **
101.INS	XBRL Instance Document
	XBRL Taxonomy Extension Schema Document
	XBRL Taxonomy Extension Calculation Linkbase Document
	XBRL Taxonomy Extension Definition Linkbase Document
	XBRL Taxonomy Extension Label Linkbase Document
	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith
**Furnished herewith
+ Management contract or compensatory plan or arrangement

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Samson Oil and Gas Limited

By: /s/ Terence Barr
Name: Terence Barr
Title: Managing Director, President and Chief Executive Officer
Date: October 15, 2018

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Terence Barr Terence Barr	Managing Director, President and Chief Executive Officer (Principal Executive Officer)	October 15, 2018
/s/ Robyn Lamont Robyn Lamont	Chief Financial Officer (Principal Financial Officer)	October 15, 2018
/s/ Peter Hill Peter Hill	Director	October 15, 2018
/s/ Greg Channon Greg Channon	Director	October 15, 2018
/s/ Denis Rakich Denis Rakich	Director	October 15, 2018

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of
Samson Oil & Gas Limited

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of Samson Oil & Gas Limited and subsidiaries (the "Company") as of June 30, 2018, the related consolidated statements of operations and comprehensive loss, changes in stockholders' equity (deficit) and cash flows for the year then ended, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 2018, and the consolidated results of its operations and its cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States of America.

Going Concern Uncertainty

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 1 to the consolidated financial statements, the Company is in violation of its debt covenants, has suffered recurring losses from operations, and its current liabilities exceed its current assets. These conditions raise substantial doubt about its ability to continue as a going concern. Management's plans in regard to these matters are also described in Note 1. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audit. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audit we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audit included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audit provides a reasonable basis for our opinion.

/s/ Moss Adams LLP

Denver, Colorado
October 15, 2018

We have served as the Company's auditor since 2017.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Samson Oil & Gas Limited

We have audited the accompanying consolidated balance sheet of Samson Oil & Gas Limited and subsidiaries (collectively, the "Company") as of June 30, 2017 and the related consolidated statements of operations and comprehensive loss, changes in stockholders' equity and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Samson Oil & Gas Limited and subsidiaries as of June 30, 2017 and the results of their operations and their cash flows for the years then ended in conformity with U.S. generally accepted accounting principles.

The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 1 to the financial statements, the Company is in violation of its debt covenants, has suffered recurring losses from operations and its current liabilities exceed its current assets. These conditions raise substantial doubt of the ability of the Company to continue as a going concern. Management's plans in regard to these matters also are described in Note 1. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

/s/ Hein & Associates LLP

Denver, Colorado
September 28, 2017

SAMSON OIL & GAS LIMITED AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	June 30	
	2018	**2017**
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 1,376,676	$ 628,778
Accounts receivable, net of allowance for doubtful accounts of $75,000 and $nil respectively	1,759,461	1,550,438
Oil Inventory	219,288	219,288
Prepayments	137,342	54,519
Oil and gas properties held for sale	28,675,890	-
Total current assets	32,168,657	2,453,023
PROPERTY, PLANT AND EQUIPMENT, AT COST		
Oil and gas properties, successful efforts method of accounting, less accumulated depreciation, depletion and impairment of $12,606,419 and $12,440,389 at June 30, 2018 and June 30, 2017, respectively	1,744,951	1,814,772
Oil and gas properties held for sale	-	29,682,501
Other property and equipment, net of accumulated depreciation and amortization of $775,057 and $693,945 at June 30, 2018 and June 30, 2017, respectively	242,822	296,077
Net property, plant and equipment	1,987,773	31,793,350
OTHER ASSETS		
Unproved capitalized acreage	-	271,078
Capitalized exploration expense	-	0
Fair value of derivative instruments	-	99,603
Restricted cash - collateral for bonds	450,000	450,000
Deferred tax asset	732,056	-
Other	134,644	291,181
TOTAL ASSETS	$ 35,473,130	$ 35,358,235
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 8,383,570	$ 4,287,955
Accrued liabilities	1,088,338	821,319
Provision for annual leave	250,826	249,060
Amounts due for current repayment from the credit facility	23,867,557	23,419,749
Asset retirement obligation related to assets held for sale	2,509,981	2,475,427
Fair value of derivative instruments	1,210,795	363,960
Total current liabilities	37,311,067	31,617,470
Fair value of derivative instruments	-	-
Asset retirement obligations	834,131	680,809
Total liabilities	38,145,198	32,298,279
Commitments and contingencies (Note 12)	-	-
STOCKHOLDERS' EQUITY (DEFICIT)		
Common stock, 3,282,000,444 and 3,282,000,444 shares issued and outstanding at June 30, 2017 and 2016, respectively	106,743,167	106,390,864
Accumulated other comprehensive income	846,556	892,017
Accumulated deficit	(110,261,791)	(104,222,925)
Total stockholders' equity (deficit)	(2,672,068)	3,059,956
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)	$ 35,473,130	$ 35,358,235

See accompanying Notes to Consolidated Financial Statements.

SAMSON OIL & GAS LIMITED AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE LOSS

	Fiscal year ended June 30,	
	2018	**2017**
REVENUES AND OTHER INCOME:		
Oil sales	$ 252,233	$ 2,246,725
Gas sales	27,042	273,816
Other liquids	7	33,028
Interest income	229	411
Gain on derivative instruments	-	1,297,472
Gain on sale of assets	178,407	2,250,070
Other	80,893	66,707
TOTAL REVENUE AND OTHER INCOME	538,811	6,168,229
EXPENSES:		
Lease operating expense	(460,114)	(2,209,583)
Depletion, depreciation and amortization	(166,030)	(218,635)
Impairment of oil and natural gas properties and oil inventory	-	(244,480)
Exploration and evaluation expenditure	(325,304)	(78,391)
Accretion of asset retirement obligations	(34,554)	(52,801)
General and administrative	(4,141,399)	(5,034,746)
Abandonment Expense	(128,862)	(3,055)
Loss on derivative instruments	(2,722,166)	-
Provision for doubtful debts	(75,000)	-
TOTAL EXPENSES	(8,053,429)	(7,841,691)
Loss before income tax	(7,514,618)	(1,673,462)
Income tax (provision)/ benefit	732,056	-
Net loss from continuing operations	$ (6,782,562)	$ (1,673,462)
Income/(loss) from discontinued operations, net of tax of zero	743,696	(1,094,034)
Net loss	(6,038,866)	(2,767,496)
OTHER COMPREHENSIVE LOSS		
Foreign Currency Translation loss	(45,461)	(35,701)
Total comprehensive loss for the period	$ (6,084,327)	$ (2,803,197)
Net loss from continuing operations per common share:		
Basic – cents per share	(0.22)	(0.05)
Diluted – cents per share	(0.22)	(0.05)
Net income/(loss) from discontinued operations per common share:		
Basic – cents per share	0.04	(0.04)
Diluted – cents per share	0.04	(0.04)
Net gain(loss) per common share:		
Basic – cents per share	(0.18)	(0.09)
Diluted – cents per share	(0.18)	(0.09)
Weighted average common shares outstanding:		
Basic	3,283,000,444	3,257,194,847
Diluted	3,283,000,444	3,257,194,847

See accompanying Notes to Consolidated Financial Statements.

SAMSON OIL & GAS LIMITED AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY/(DEFICIT)

	Issued Capital	Retained Earnings/(Accumulated Deficit)	Accumulated Other Comprehensive Income	Total Equity/Deficit
Balance at July 1, 2016	$ 105,719,184	$ (101,455,429)	$ 927,718	$ 5,191,473
Net loss	-	(2,767,496)	-	(2,767,496)
Foreign currency translation	-	-	(35,701)	(35,701)
Total comprehensive loss for the period	-	(2,767,496)	(35,701)	(2,803,197)
Stock based compensation	711,493	-	-	711,493
Issue of share capital	4,516	-	-	4,516
Share issue costs	(44,329)	-	-	(44,329)
Balance at June 30, 2017	$ 106,390,864	$ (104,222,925)	$ 892,017	$ 3,059,956
Net loss	-	(6,038,866)	-	(6,038,866)
Foreign currency translation	-	-	(45,461)	(45,461)
Total comprehensive loss for the period	-	(6,038,866)	(45,461)	(6,084,327)
Stock based compensation	352,303	-	-	352,303
Issue of share capital	-	-	-	-
Share issue costs	-	-	-	-
Balance at June 30, 2018	$ 106,743,167	$ (110,261,791)	$ 846,556	$ (2,672,068)

See accompanying Notes to Consolidated Financial Statements.

SAMSON OIL & GAS LIMITED AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Fiscal year ended June 30,	
	2018	**2017**
Cash flows from continuing operating activities		
Receipts from customers	$ 1,498,741	$ 2,093,069
Net cash (paid)/received from commodity derivative financial instruments	(1,625,866)	(1,342,901)
Payments to suppliers & employees	(4,044,829)	(5,553,017)
Interest received	228	411
Interest paid	-	-
Income taxes paid	-	-
Payments for abandonment costs	(291,277)	(45,142)
Proceeds from legal settlement	-	-
Net cash flows used in operating activities	(4,463,003)	(4,847,580)
Cash flows from investing activities		
Proceeds from sale of oil and gas properties	-	15,150,000
Payments for plant & equipment	(28,805)	(106,726)
Payments for exploration and evaluation	(54,212)	(138,715)
Payments for oil and gas properties	(78,705)	(479,712)
Net cash flows (used in)/provided by investing activities	(161,722)	14,424,847
Cash flows from financing activities		
Proceeds from issue of share capital	-	3,198
Proceeds from borrowings	450,000	-
Repayments of borrowings	(35,000)	(11,047,443)
Payments for costs associated with borrowings	-	(40,000)
Payments for costs associated with capital raising	-	(3,771)
Net cash flows provided by/(used in) financing activities	415,000	(11,088,016)
Net change in cash and cash equivalents	(4,209,725)	(1,510,749)
Cash and cash equivalents at the beginning of the year	628,778	2,654,812
Net cashflows provided by operations - discontinued operations	6,768,727	2,236,620
Net cashflows used in investing actvities - discontinued operations	(445,997)	(2,718,371)
Net cashflows used in financing operations -discontinued operations	(1,350,391)	-
Effects of exchange rate changes on cash and cash equivalents	(14,716)	(33,534)
Cash and cash equivalents at end of year	$ 1,376,676	628,778

See accompanying Notes to Consolidated Financial Statements.

SAMSON OIL & GAS LIMITED AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of Operations. Samson Oil & Gas Limited along with its consolidated subsidiaries ("Samson" or the "Company"), is engaged in the acquisition, exploration, exploitation and development of oil and natural gas properties with a focus on properties in North Dakota and Montana.

Going concern. These financial statements have been prepared on the going concern basis, which contemplates the continuity of normal business activities and the realisation of assets and settlement of liabilities in the normal course of business.

We incurred a net loss of $6.0 million. the year ended June 30, 2018. As at that date, our total current liabilities of $34.8 (excluding discontinued operations million exceed our total current assets of $3.5 million (excluding discontinued operations). Additionally, we are in violation of our debt covenants and have suffered recurring losses from operations. These factors raise substantial doubt over our ability to continue as a going concern and therefore whether we will realize our assets and extinguish our liabilities in the normal course of business and at the amounts stated in the financial report.

To address these concerns, we have undertaken the following plan:

- We have signed a purchase and sale agreement for the sale of substantially all of our interest in the Foreman Butte project for $40 million. The effective date of this sale is January 1, 2018 and the sale is expected to close October 15, 2018.
- We have entered into a forbearance agreement with Mutual of Omaha Bank in order to allow the orderly closing of the pending asset sale
- We are continuing to operate the properties in a such a way so as to maximize value should we be required to enter into a sale agreement with another party.

While management believes that we will successfully close the pending asset sale transaction or a similarly valued alternative sale transaction there can be no assurances that our efforts will be successful. In addition, given our current financial situation we may be forced to accept terms on these transactions that are less favorable than would be otherwise available.

The financial report does not include any adjustments relating to the amounts or classification of recorded assets or liabilities that might be necessary if the Company does not continue as a going concern.

Comparatives. These statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP).

Principles of Consolidation. The consolidated financial statements include the accounts of the Company and its subsidiaries, all of which are wholly owned. Significant intercompany balances and transactions have been eliminated in consolidation.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Items subject to such estimates and assumptions include (1) oil and gas reserves; (2) cash flow estimates used in impairment tests of long–lived assets; (3) depreciation, depletion and amortization; (4) asset retirement obligations; (5) assigning fair value and allocating purchase price in connection with business combinations; (6) accrued revenue and related receivables; (7) valuation of commodity and interest derivative instruments; (8) certain accrued liabilities; (9) valuation of share-based payments, (10) income taxes and (11) carrying value of exploration and evaluation expenditure. Although management believes these estimates are reasonable, actual results could differ from these estimates. The Company has evaluated subsequent events and transactions through the date of this report for matters that may require recognition or disclosure in these financial statements.

Business Segment Information. The Company has evaluated how it is organized and managed and has identified only one operating segment, which is the exploration and production of crude oil, natural gas and natural gas liquids. All of the Company's operations and assets are located in the United States, and all of its revenues are attributable to United States customers.

Revenue Recognition and Gas Imbalances. Revenues from the sale of natural gas and crude oil are recognized when the product is delivered at a fixed or determinable price, title has transferred and collectability is reasonably assured and evidenced by a contract. This generally occurs when oil or natural gas has been delivered to a refinery or a pipeline, or has otherwise been transferred to a customer's facilities or possession. Oil revenues are generally recognized based on actual volumes of completed deliveries where title has transferred. Title to oil sold is typically transferred at the wellhead.

The Company uses the entitlement method of accounting for natural gas revenues. Under this method, revenues are recognized based on actual production of natural gas. The Company incurs production gas volume imbalances in the ordinary course of business. Net deliveries in excess of entitled amounts are recorded as liabilities, while net under–deliveries are reflected as assets. Imbalances are reduced either by subsequent recoupment of over– and under– deliveries or by cash settlement, as required by applicable contracts. The Company's production imbalances were not material at June 30, 2018 or 2017.

Cash and Cash Equivalents. The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents. The Company's cash management process provides for the daily funding of checks as they are presented to the bank.

Accounts Receivable. The components of accounts receivable include the following:

	June 30	
	2018	**2017**
Oil and natural gas sales	$ 1,005,217	$ 894,523
Cost recovery from partners	734,912	572,082
Less provision for doubtful debts	(75,000)	-
Other	94,332	83,833
Total accounts receivable, net of nil allowance for doubtful accounts for June 30, 2018 and 2017	$ 1,759,461	$ 1,550,438

The Company's accounts receivable result from (i) oil and natural gas sales to oil and intrastate gas pipeline companies and (ii) billings to joint working interest partners in properties operated by the Company. The Company's trade and accrued production receivables are primarily from the operators of our various projects, who negotiate the sale of oil and gas to third parties on our behalf.

Oil and Gas Properties.

Oil and gas properties and equipment consist of the following at June 30:

	2018	**2017**
Proved properties	$ 13,181,514	$ 13,114,851
Lease and well equipment	1,169,856	1,140,310
Less accumulated depreciation, depletion and impairment	(12,606,419)	(12,440,389)
	$ 1,744,951	$ 1,814,772
Assets held for sale	28,675,890	-
Unproved acreage	$ -	$ 271,078

The Company accounts for its oil and gas exploration and development costs using the successful efforts method. Geological and geophysical costs are expensed as incurred. Exploratory well costs are capitalized pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. All exploratory wells are evaluated for economic viability within one year of well completion, and the related capitalized costs are reviewed quarterly.

Exploratory wells that discover potentially economic reserves in areas where a major capital expenditure would be required before production could begin and where the economic viability of that major capital expenditure depends upon the successful completion of further exploratory work in the area remain capitalized if the well finds a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

The costs of development wells are capitalized whether productive or nonproductive. The provision for depletion of oil and gas properties is calculated on a field–by–field basis using the unit–of–production method. Mineral interests and leasehold acquisition costs are depleted over total proved reserves while cost of completed wells and related facilities and equipment are depleted over proved developed producing reserves.

If the estimates of total proved or proved developed reserves decline, the rate at which the Company records depreciation, depletion and amortization (DD&A) expense increases, which in turn reduces net earnings. Such a decline in reserves may result from lower commodity prices, which may make it uneconomic to drill for and produce higher cost fields. The Company is unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of its development program, as well as future economic conditions. Changes in reserves are applied on a prospective basis.

As wells are drilled in a field with proved undeveloped reserves or unproved reserves, a portion of the acquisition costs are either re–designated as proved developed or expensed, as appropriate. In fields with multiple potential drilling sites, the Company determines the amount of the acquisition cost to re–designate or expense through a systematic and rational basis that considers the total expected wells to be drilled in that field.

The Company reviews its proved oil and gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. The Company estimates the expected future cash flows of its oil and gas properties and compares these undiscounted future cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the oil and gas properties to fair value. The factors used to determine fair value include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of reserves, future commodity pricing, future production estimates, anticipated capital expenditures and various discount rates commensurate with the risk associated with realizing the projected cash flows. Unproved oil and gas properties are assessed periodically for impairment on a field by field (consistent with the fields used for the calculation of depletion, depreciation and amortization) basis based on remaining lease terms, drilling results, reservoir performance, commodity price outlooks or future plans to develop acreage and allocate capital. When the Company has allocated fair values to significant unproved property (probable reserves) as the result of a business combination or other purchase of proved and unproved properties, it uses a future cash flow analysis to assess the property for impairment.

Gains on sales of proved and unproved properties are only recognized when there is no uncertainty about the recovery of costs applicable to any interest retained or where there is no substantial obligation for future performance by the Company. Impairment on properties sold is recognized when incurred or when the properties are held for sale and the fair value of the properties is less than the carrying value.

In determining whether an unproved property is impaired, the Company considers numerous factors including, but not limited to, current development and exploration drilling plans, favorable or unfavorable exploration activity on adjacent leaseholds, in-house geologists' evaluation of the lease, future reserve cash flows and the remaining lease term.

Assets held for sale

In June 2018, we signed a purchase and sale agreement for the sale of the Foreman Butte Project, subject to our retention of a 15% working interest in a portion of the Project (the “Foreman Butte Sale”). This transaction received shareholder approval at a general meeting held on August 13, 2018. The purchase price is $40 million with an effective date of January 1, 2018.

The Foreman Butte Project constitutes the majority of our operating assets. Upon closing of the transaction, we will retain a 15% working interest in certain wells in the Home Run Field, which consists of 15 producing wells and 20 PUD locations.

The proceeds of the Foreman Butte Sale will be used to repay our credit facility with Mutual of Omaha Bank in full and bring our other accounts payable current. We estimate that after these repayments, we will have no outstanding debt and will retain approximately $6.5 million in cash proceeds from the sale.

Exploration and evaluation costs including capitalized exploration written off and dry hole expenses

Exploration and evaluation assets are assessed for impairment when facts and circumstances indicate that the carrying amount of an exploration and evaluation asset may exceed its recoverable amount. When assessing for impairment consideration is given to but not limited to the following:

- the period for which Samson has the right to explore;
- planned and budgeted future exploration expenditure;
- activities incurred during the year; and
- activities planned for future periods.

If, after having capitalized expenditure under our policy, the Company concludes that it is unlikely to recover the expenditure by future exploitation or sale, then the relevant capitalized amount will be written off to the income statement.

During the fiscal year ended June 30, 2018, we expensed $0.2 million in deferred exploration expense in relation to our Cane Creek project area.

Impairment

The Company recorded impairment charges of $nil million and $0.2 million for the years ended June 30, 2018 and 2017 respectively.

The charges in the fiscal year ended June 30, 2017 related to the write down of the value in our oil inventory to lower of cost or net realizable value.

Other Property and Equipment.

Other property and equipment, which includes leasehold improvements, office and other equipment, are stated at cost. Depreciation and amortization are calculated using the straight–line method over the estimated useful lives of the related assets, ranging from 3 to 25 years.

Depreciation and amortization expense for the years ended June 30, 2018 and 2017 was $0.2 million and $0.2 million, respectively.

Other property and equipment consist of the following at June 30:

	2018	2017
Furniture, fittings and equipment	$ 1,017,879	$ 990,022
Less accumulated depreciation	(775,057)	(693,945)
	$ 242,822	$ 296,077

Derivative Financial Instruments. The Company enters into derivative contracts, primarily collars, swaps and option contracts, to hedge future crude oil and natural gas production in order to mitigate the risk of market price fluctuations. All derivative instruments are recorded on the balance sheet at fair value. All of the Company's derivative counterparties are major oil companies. The Company has elected not to apply hedge accounting to any of its derivative transactions and consequently, the Company recognizes mark-to-market gains and losses in earnings currently, rather than deferring such amounts in other comprehensive income for those commodity derivatives that qualify as cash flow hedges.

Asset Retirement Obligations. The Company recognizes estimated liabilities for future costs associated with the abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long–lived asset are recorded at the time the well is spud or acquired.

Environmental. The Company is subject to extensive federal, state and local environmental laws and regulations. These laws and regulations, which regularly change, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a non–capital nature are recorded when environmental assessment and/or remediation is probable and the costs can be reasonably estimated. Such liabilities are generally recorded at their undiscounted amounts unless the amount and timing of payments is fixed or reliably determinable. The Company is not aware of any material noncompliance with existing laws and regulations.

Income Taxes. Deferred income tax assets and liabilities are recognized for the future income tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective income tax bases. Deferred income tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred income tax assets and liabilities of a change in income tax rates is recognized in income in the period that includes the enactment date. The measurement of deferred income tax assets is reduced, if necessary, by a valuation allowance if management believes that it is more likely than not that some portion or all of the net deferred tax assets will not be fully realized on future income tax returns. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, available taxes in carryback periods, projected future taxable income and tax planning strategies in making this assessment.

The Company recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement.

Earnings per Share. Basic earnings (loss) per share are calculated by dividing net earnings (loss) attributable to common stock by the weighted average number of shares outstanding for the period. Under the treasury stock method, diluted earnings per share is calculated by dividing net earnings (loss) by the weighted average number of shares outstanding including all potentially dilutive common shares. In the event of a net loss, no potential common shares are included in the calculation of shares outstanding since the impact would be anti-dilutive. When the Company records a net loss, none of the loss is allocated to the unexercised stock options since the securities are not obligated to share in Company losses. Consequently, in periods of net loss, outstanding options will have no dilutive impact to the Company's basic earnings per share.

The following potential common shares relating to options and warrants have been excluded from the calculation of diluted earnings per share as the related impact was anti-dilutive.

	Year ended June 30,	
	2018	**2017**
Dilutive	-	-
Anti–dilutive	314,500,000	287,956,323

Stock-Based Compensation. Stock-based compensation is measured at the estimated grant date fair value of the awards and is recognized on a straight-line basis over the requisite service period (usually the vesting period). The Company recognizes stock-based compensation net of an estimated forfeiture rate, and recognizes compensation expense only for shares that are expected to vest. Compensation expense is then adjusted based on the actual number of awards for which the requisite service period is rendered.

Foreign Currency Translation. The functional currency of Samson Oil & Gas Limited (Parent Entity) is Australian dollars, the reason for this being the majority of cash flows of the Parent Entity are denominated in Australian dollars. The functional and presentation currency of Samson Oil & Gas USA, Inc. (subsidiary) is U.S. dollars. The presentation currency of the Consolidated Entity is U.S. dollars.

Transactions in foreign currencies are initially recorded in the functional currency by applying the exchange rates ruling at the date of the transaction. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at year ended exchange rates of monetary assets and liabilities denominated in foreign currencies are recognized in profit and loss

Translation differences on assets and liabilities carried at fair value are reported as part of the fair value gain or loss. Translation differences on non -monetary assets and liabilities are recognized in other comprehensive income.

Business Combinations Samson applies the acquisition method in accounting for business combinations. The consideration transferred by the Company is calculated as the sum of the acquisition date fair value of assets transferred, liabilities incurred and any equity interests issued by the Company, which includes the fair value of any asset or liability arising from any contingent consideration arrangements. Acquisition costs are expensed as incurred. The Company treats the acquisition of oil and gas assets as a business combination.

The Company recognizes identifiable assets acquired and liabilities assumed in a business combination regardless of whether they have been previously recognized in the acquiree's financial statements prior to the acquisition. Assets acquired and liabilities assumed are generally measured at their acquisition date fair values.

If the fair values of identifiable net assets exceeds the sum calculated has the fair value transferred, the excess amount, a gain on bargain purchase) is recognized in the statement of operations immediately.

Impact of Recently Adopted Accounting Standards.

There have been no recently adopted accounting standards that would impact our business.

Recently Issued Accounting Pronouncements

In August 2014, the FASB issued new guidance related to the disclosures around going concern. The new standard provides guidance around management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and to provide related footnote disclosures. The new guidance becomes effective for fiscal years beginning after December 15, 2016, and interim periods within those years, with early adoption permitted. This standard has been adopted and the Company has added the appropriate disclosures.

In November 2014, the FASB issued ASU No. 2014-16, which updates authoritative guidance for derivatives and hedging instruments, specifically in determining whether the host contract in a hybrid financial instrument issued in the form of a share is more akin to debt or to equity. This guidance is effective for the annual period beginning after December 15, 2015; early adoption is permitted. The Company has adopted this standard and it did not have a material impact on its consolidated financial statements.

ASU 2016-02, *Leases (Topic 842)* This ASU, among other provisions, requires lessees to recognize right of use assets and leases liabilities for all leases not considered short term leases. The ASU is effective for public business entities for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years This standard is not expected to have a significant impact on the Company as it does not currently engage in significant leasing activity.

ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)* Accounting Standards Update (ASU) 2014-09 provides a new framework for addressing revenue recognition issues and upon its effective date, replaces almost all existing revenue recognition guidance. While the revenue recognition policies of all entities will be impacted by this standard, we do not expect the impact to be significant. For public business entities, the guidance is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period.

We do expect this standard to have a significant impact on our financial reporting of the standards disclosed above that have not yet taken effect. However, we do expect these changes to have an impact with additional disclosures contained in the 10Q for the period ended September 30, 2018 expected.

2. DISCONTINUED OPERATIONS

As of June 30, 2018 the majority of our interest in the wells in the Foreman Butte project were held for sale and therefore have been recognized as discontinued operations for the years ended June 30, 2018 and 2017. .

Discontinued Operations

	Year ended June 30,	
	2018	**2017**
Major line items constituting pretax gain (loss) of discontinued operations		
Oil sales	9,678,832	10,336,307
Gas sales	91,742	162,546
Other liquids	8,864	5,261
Lease operating expense	(6,031,983)	(7,751,072)
Depletion, depreciation and amortization	(1,071,959)	(1,770,500)
Accretion of asset retirement obligations	(216,229)	(263,964)
Amortization of borrowing costs	(440,434)	(219,810)
Interest expense	(1,275,137)	(1,592,802)
Gain/(loss) from discontinued operations	743,696	(1,094,034)
Cashflows from Discontinued Operations		
Cashflows from Operating Activities	6,768,727	2,236,620
Cashflows from Investing Activities	(445,997)	(2,718,371)
Cashflows from Financing Activities	(1,350,391)	0

3. HEDGING AND DERIVATIVE FINANCIAL INSTRUMENTS

Commodity Derivative Agreements. The Company utilizes swap and collar option contracts to hedge the effect of price changes on a portion of its future oil and natural gas production. The objective of the Company's hedging activities and the use of derivative financial instruments is to achieve more predictable cash flows. While the use of these derivative instruments limits the downside risk of adverse price movements, they also may limit future revenues from favorable price movements. The Company may, from time to time, opportunistically restructure existing derivative contracts or enter into new transactions to effectively modify the terms of current contracts in order to improve the pricing parameters in existing contracts or realize the current value of the Company's existing positions. The Company may use the proceeds from such transactions to secure additional contracts for periods in which the Company believes it has additional unmitigated commodity price risk.

The use of derivatives involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. The Company's derivative contracts are with a single major oil company with no history of default with the Company. The derivative contracts may be terminated by a non-defaulting party in the event of default by one of the parties to the agreement.

The Company has elected not to apply hedge accounting to any of its derivative transactions and, consequently, the Company recognizes mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income for those commodity derivatives that would qualify as cash flow hedges. All derivative instruments are recorded on the balance sheet at fair value.

At June 30, 2018, the Company's commodity derivative contracts consisted of collars and fixed price swaps, which are described below:

Collar	Collars contain a fixed floor price (put) and fixed ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, the Company receives the fixed price rather than the market price. If the market price is between the call and the put strike price, no payments are due from either party.
Fixed price swap	The Company receives a fixed price for the contract and pays a floating market price to the counterparty over a specified period for a contracted volume.

All of the Company's derivative contracts are with the same counterparty and are shown on a net basis on the Balance Sheet. The Company's counterparty has entered into an inter-creditor agreement with Mutual of Omaha Bank, the provider of the Company's credit facility. As such no collateral is required by the counterparty.

At June 30, 2018 the Company's open derivative contracts consisted of the following:

Collar

Product	Start Date	End Date	Volume (BO/Mmbtu)	Floor	Ceiling
WTI	1-Jul-18	31-Dec-18	80,960	$ 45.00	56.00
Henry Hub	1-May-18	31-Dec-18	50,490	$ 2.65	2.90

During the year ended June 30, 2017, the Company recorded a gain of $1.3 million in the Statement of Operations in in derivative instruments. As of June 30, 2017, the derivative instruments were valued at $0.26 million of which, $0.1 million is recorded as a current liability and $0.36 million is recorded as a non-current asset.

During the year ended June 30, 2018, the Company recognized $2.7 million in the Statement of Operations in loss in derivative instruments. As of June 30, 2018, its derivative instruments were valued at $1.2 million recorded as current liability. See Note 4 for additional fair value disclosures about the Company's oil and gas derivatives.

Price risk

Price risk arises from the Company's exposure to oil and gas prices. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond the control of the Company. Sustained weakness in oil and natural gas prices may adversely affect the Company's financial condition.

The Company manages this risk by continually monitoring the oil and gas price and the external factors that may affect it. The Board reviews the risk profile associated with commodity price risk periodically to ensure that it is appropriately managing this risk. Derivatives are used to manage this risk where appropriate. The Board must approve any derivative contracts that are entered into by the Company.

4. FAIR VALUE MEASUREMENTS

Fair value is defined as the price that would be received in the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. The Company classifies fair value balances based on the observability of those inputs. The FASB has established a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement).

The three levels of the fair value hierarchy are as follows:

Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2—Pricing inputs are other than quoted prices in active markets included in level 1, but are either directly or indirectly observable as of the reported date and for substantially the full term of the instrument. Inputs may include quoted prices for similar assets and liabilities. Level 2 includes those financial instruments that are valued using models or other valuation methodologies.

Level 3—Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The following table sets forth by level within the fair value hierarchy the Company's financial assets and liabilities that were accounted for at fair value as of June 30, 2018 and 2017.

	Fair Value at June 30, 2018				
	Level 1	**Level 2**	**Level 3**	**Netting [1]**	**Total**
Current Assets:					
Cash and cash equivalents	$ 1,376,676	$ -	$ -	$ -	$ 1,376,676
Derivative Instruments	-	4,218	-	(4,218)	-
Non Current Assets:					
Derivative Instruments	-	-	-	-	-
Current Liabilities					
Derivative Instruments	-	1,215,013	-	(4,218)	1,210,795
Non Current Liabilities:					
Derivative Instruments		-		-	-

	Fair Value at June 30, 2017				
	Level 1	Level 2	Level 3	Netting [1]	Total
Current Assets:					
Cash and cash equivalents	$ 628,778	$ -	$ -	$ -	$ 628,778
Derivative Instruments	-	167,307	-	(167,307)	-
Non Current Assets:					
Derivative Instruments	-	370,494	-	(270,891)	99,603
Current Liabilities					
Derivative Instruments	-	531,267	-	(167,307)	363,960
Non Current Liabilities:					
Derivative Instruments		270,891		(270,891)	-

(1) **Netting** In accordance with the Company's standard practice, its commodity derivatives are subject to counterparty netting under agreements governing such derivatives and therefore the risk of loss is somewhat mitigated.

The following methods and assumptions were used to estimate the fair value of the assets and liabilities in the table above:

Commodity Derivative Contracts. The Company's commodity derivative instruments consisted of collars and swap contracts for oil. The Company values the derivative contracts using industry standard models, based on an income approach, which considers various assumptions including quoted forward prices and contractual prices for the underlying commodities, time value and volatility factors, as well as other relevant economic measures. Substantially all of the assumptions can be observed throughout the full term of the contracts, can be derived from observable data or are supportable by observable levels at which transactions are executed in the marketplace and are therefore designated as level 2 within the fair value hierarchy. The discount rates used in the assumptions include consideration of non-performance risk. The Company accounts for its commodity derivatives at fair value (see Note 3) on a recurring basis.

Fair Value of Financial Instruments. The Company's financial instruments consist primarily of cash and cash equivalents, accounts receivable and payable, investments and derivatives (discussed above). The carrying values of cash equivalents and accounts receivable and payable are representative of their fair values due to their short–term maturities.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis. The Company also applies fair value accounting guidance to measure non–financial assets and liabilities such as business acquisitions proved oil and gas properties, and asset retirement obligations. These assets and liabilities are subject to fair value adjustments only in certain circumstances and are not subject to recurring revaluations. These items are primarily valued using the present value of estimated future cash inflows and/or outflows. Given the unobservable nature of these inputs, they are deemed to be Level 3.

Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two. The Company utilizes the discounted cash flow method; estimated future cash flows are based on management's expectations for the future and include estimates of future oil and gas production, commodity prices based on published forward commodity price curves as of the date of the estimate, operational costs, and a risk–adjusted discount rate. The fair value measurement was based on Level 3 inputs.

5. ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations primarily represent the estimated present value of the amounts expected to be incurred to plug, abandon and remediate producing and shut–in properties at the end of their productive lives in accordance with applicable state and federal laws. The Company determines the estimated fair value of its asset retirement obligations by calculating the present value of estimated cash flows related to plugging and abandonment liabilities. The significant inputs used to calculate such liabilities include estimates of costs to be incurred; the Company's credit adjusted discount rates, inflation rates and estimated dates of abandonment. The asset retirement liability is accreted to its present value each period and the capitalized asset retirement cost is depleted using the units–of–production method.

The following table summarizes the activities for the Company's asset retirement obligations for the years ended June 30, 2017 and 2016:

	2018	2017
Asset retirement obligations at beginning of period	$ 3,456,236	$ 3,750,245
Liabilities incurred or acquired	-	226,123
Liabilities settled	(73,667)	(427,214)
Disposition of properties	(73,011)	(409,683)
Accretion expense	34,554	316,765
Asset retirement obligations at end of period	3,344,112	3,456,236
Less: current asset retirement obligations (classified with accounts payable and accrued liabilities)	-	(300,000)
Less current asset retirement obligatons related to assets held for sale	(2,509,981)	
Long-term asset retirement obligations	$ 834,131	$ 3,156,236

Discount rates used to calculate the present value vary depending on the estimated timing of the obligation, but typically range between 4% and 13%.

The liabilities incurred in the prior year relate to the liabilities acquired in relation to the Foreman Butte acquisition.

6. INCOME TAXES

The Company accounts for income taxes under the asset and liability approach prescribed by GAAP, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been recognized in the Company's consolidated financial statements or tax returns.

The Company's income tax provision (benefit) is composed of the following:

	June 30	
	2018	**2017**
Current:		
Federal	$ (732,056)	$ -
State	-	-
	(732,056)	-
Deferred:		
Federal	-	-
State	-	-
Less income tax benefit allocated to discontinued operations		
Total income tax provision (benefit)	$ (732,056)	$ -

A reconciliation of the income tax provision (benefit) computed by applying the Australian federal statutory rate of 30% to the Company's income tax provision (benefit) is as follows (in thousands):

	June 30	
	2018	**2017**
Income tax expense (benefit) at federal statutory rate	$ (1,956,277)	$ (787,563)
Effect of permanent differences and other - US	115,616	-
State income taxes	(123,694)	(34,997)
Change in tax rate	11,207,430	
US income taxed at a different rate	116,777	
Foreign exchange	282,557	
Other adjustments - true up of deferred balances	(10,819)	
Alternative minimum tax	-	-
Other - change in deferred tax rate	-	(239,200)
Other	23,507	112,867
Valuation allowance	(10,387,153)	948,893
	$ (732,056)	$ -

The components of deferred tax assets and (liabilities) are as follows (in thousands):

	June 30	
	2018	**2017**
Deferred income tax assets:		
Net operating losses	$ 23,674,591	$ 34,581,318
Asset retirement obligation	737,875	1,212,151
Annual leave	51,837	81,130
Abandonment limitation	554,685	554,685
Allowance for doubtful debts	17,560	-
Accrued bonus	-	-
Charitable contributions	-	882
AMT credit	780,443	780,443
Share based compensation	500,844	500,844
Oil and Gas Property	-	-
Derivative liability	283,458	98,175
Valuation allowance	(23,951,026)	(34,286,029)
Deferred income tax liabilities:		
Commodity liability	-	-
Amortization - loan costs	-	-
Oil and gas property	(1,908,395)	(3,523,599)
Net deferred income tax assets (liabilities)	732,506	-

	June 30	
	2018	2017
Deferred Income Tax Valuation Allowance		
Balance at July 1	34,286,029	33,337,136
Additions (reductions) to deferred income tax expense	(10,387,153)	948,893
Balance at June 30	23,898,876	34,286,029

The Company has tax losses carried forward arising in Australia of $15,509,399 (2017: $15,949,783). The benefit of these losses of $4,652,820 (2017: $4,784,935) will only be obtained in future years if:

(i) the Parent Entity derive future assessable income of a nature and an amount sufficient to enable the benefit from the deduction for the losses to be realized; and
(ii) the Parent Entity have complied and continue to comply with the conditions for deductibility imposed by law; and
(iii) no changes in tax legislation adversely affect the Parent Entity in realizing the benefit from deduction for the losses.

The Company has federal net operating tax losses in the United States of approximately $84,932,621 (2017: $82,341,738). The current year utilization carried back to prior years, is approximately $nil (2017: $nil). The 2000-2005 years are limited to $403,194 per year as a result of a change in ownership of the one of the subsidiaries which occurred in January 2005. NOLs generated after this ownership change are not limited due to any known ownership changes. If not utilized, the tax net operating losses will expire during the period from 2020 to 2036.

In addition to the above-mentioned Federal carried forward losses in the United States, the Company also has approximately $ 49,189,363 (2017: $47,582,073) of State carried forward tax losses, with expiry dates between June 2015 and June 2033. A deferred income tax asset in relation to these losses has not been recognized as realization of the benefit is not regarded as probable.

The change in federal corporate income tax rate from 35% to 21% was enacted in 2017 and effective 1/1/18. For 2017, the rate change does impact the calculation of current income tax liability and requires the future rate to be applied to deferred income tax assets and liabilities that exist at 6/30/18. An expense of $11,140,774 was recorded to deferred income tax expense for this change. An adjustment to the effective tax rate is also required to reflect the different rates (35% and 21%) applied to currently arising temporary differences for current tax and deferred tax. There is no P&L impact of these adjustments as the valuation allowance will have a corresponding adjustment to offset any changes to the deferred tax asset.

In assessing the realizeability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which the use of such net operating losses are allowed. Among other items, Management considers the scheduled reversal of deferred tax liabilities, tax planning strategies and projected future taxable income. As of the current year end, the company does not believe the realizeablity of the deferred tax assets to be more likely than not. As such, the company has a full valuation allowance offsetting the deferred tax asset.

The Company adopted the uncertainty provision of FASB ASC Topic 740, "Income Taxes" and has analyzed filing positions in all federal and state jurisdictions where it is required to file income tax returns, as well as all open tax years in this jurisdiction. Most uncertain tax positions relate primarily to timing differences and management does not believe any such uncertain tax positions will materially impact the Company's effective tax rate in future periods. The Company anticipates that no additional uncertain tax positions will be recognized within the next twelve months. Our policy is to recognize any interest and penalties related to the unrecognized tax benefits in income tax expense. In our major tax jurisdictions, the earliest years remaining open to examination are as follows US - 6/30/1996 due to the usage of net operating losses from that period. If recognized, these uncertain tax positions would impact the Company's effective income tax rate. The company currently has no unrecognized positions.

7. COMMON STOCK

	Consolidated Entity	
	2018	**2017**
3,283,000,444 ordinary fully paid shares including shares to be issued	$ 106,743,167	$ 106,390,864

(2017 –3,283,000,444 ordinary fully paid shares including shares to be issued)

Movements in contributed equity for the year	**2018**		**2017**	
	No. of shares	**$**	**No. of shares**	**$**
Opening balance	3,283,000,444	106,390,864	3,215,854,701	105,719,184
Shares issued upon exercise of options (i)	-	-	140,143	4,516
Stock based compensation - shares issued	-	-	67,005,600	159,506
Stock based compensation - warrants issued	-	352,303	-	551,987
Transaction costs incurred	-	-	-	(44,329)
Shares on issue at balance date	3,283,000,444	106,743,167	3,283,000,444	106,390,864

(i) During the course of the prior year the Company issued 140,143 ordinary shares upon the exercise of 140,143 options.

The exercise price of 140,143 of the options exercised was A$0.038 cents per share/US$0.032 cents per shares (average price based on the exchange rate on the date of exercise) to raise US$4,516.

8. CASH FLOW STATEMENT

A reconciliation of the net loss to the net cash provided by operations is as follows:

	Year ended June 30	
	2018	2017
Net loss after tax	$ (6,038,866)	$ (2,767,496)
Depreciation	1,237,989	1,989,135
Accretion of asset retirement obligations	250,783	316,765
Share based payments	352,303	711,493
Exploration and evaluation expenditures	325,304	78,391
Impairment losses of oil and gas properties	-	244,480
Borrowing costs	440,434	219,810
Change in fair value of derivative instruments	946,438	(2,640,373)
Bargain purchase on acquisition	-	-
Profit on sale of assets	(178,407)	(2,250,070)
Provision for doubtful debts	75,000	-
Income tax benefit	(732,056)	
Non cash other income	-	(126,265)
Changes in assets and liabilities:		
Decrease in receivables	(121,193)	743,041
Increase/(decrease) in employee benefits	1,766	54,563
Increase in payables	5,746,229	815,566
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	**$ 2,305,724**	**$ (2,610,960)**

9. CREDIT FACILITY

	June 30,	
	2018	2017
Credit facility at beginning of period	$ 23,419,749	$ 30,500,000
Cash advanced under facility	450,000	-
Assumption of promissory note	-	4,000,000
Repayments	(2,192)	(11,080,251)
Credit facility at end of period	$ 23,867,557	$ 23,419,749
Funds available for drawdown under the facility	-	$ 580,251

In March 2016, the facility was extended to $30.5 million to partly fund the Foreman Butte acquisition. $11.5 million was repaid in October 2016, following the closing of the sale of the North Stockyard asset. As a result of this amendment to the facility agreement, the following changes were made to the original facility agreement:

- The addition of more restrictive financial covenants (including the debt to EBITDA ratio and the minimum liquidity requirement);
- Increases in the interest rate and unused facility fee;
- The addition of a minimum hedging requirement of 75% of forecasted production;
- A requirement to reduce our general and administrative costs from $6 million per year to $3 million per year;
- A requirement to raise $5 million in equity on or before September 30, 2016 (which was extended to November 15, 2016 and completed in October 31, 2016);
- A requirement to pay down at least $10 million of the loan by June 30, 2016 (which was increased to $11.5 million and extended to and completed in October 31, 2016 following the agreement to sell our interest in the North Stockyard field for $15 million); and
- The addition of a monthly cash flow sweep whereby 50% of cash operating income will be used to repay outstanding borrowings under the Credit Agreement.

The current borrowing base is $24 million and is fully drawn as at September 28, 2018. We have entered into a forbearance agreement with Mutual of Omaha to allow the closure of the orderly pending asset sale, expected to be October 15, 2018. Should that sale not close in a timely fashion, Mutual of Omaha bank will have the right to seek alternative remedies to facilitate the repayment of the facility.

In January 2014, we entered into a $25.0 million credit facility with Mutual of Omaha Bank. The current borrowing base is $24.0 million, of which $23.5 million was drawn at June 30, 2017. In June 2017, the facility was extended to October 31, 2018 and the interest was changed to the prime rate plus between 1% and 2.5%. This equates to between 5.25% and 6.75%.

All of our assets are pledged as collateral under this facility.

As at June 30, 2017 and June 30, 2018, we were in breach of earnings and liquidity covenants with respect to the facility.

We incurred $0.4 million in borrowing costs when we completed the first drawdown, which have were deferred, however have now been written off to Discontinued Operations following the entering of the original forbearance agreement.

10. SHARE-BASED PAYMENTS (all figures are in Australian dollars in this note unless noted otherwise)

To convert June 30, 2018 balances denominated in Australian dollars to U.S. dollars, we used the June 30, 2018 and 2017 Federal Reserve Bank of Australia (www.rba.gov.au) closing exchange rates of 0.7692 and 0.768. U.S. dollars per Australian dollar, respectively. All dollars in this footnote are Australian dollars, except where stated otherwise.

During the year ended June 30, 2011, the Company registered a Form S-8 with the Securities Exchange Commission. The Form S-8 is a registration statement used by U.S. public companies to register securities to be offered pursuant to employee benefit plans; in this case the ordinary shares issuable and reserved for issuance underlying the options which may be issued pursuant to the Samson Oil & Gas Limited Stock Option Plan were registered.

All incentive options issued by the Company are valued using a Black-Scholes pricing model which requires inputs for the share price at grant date, exercise price, time to expiry, risk free interest rate, share price volatility and dividend yield. The risk free interest rate is based on the interest rate applicable to Australian Government Bonds with a similar remaining life to the options on the day of grant. The dividend yield is the expected annual dividend yield over the expected life of the option. The volatility factors are based on historic volatility of the Company's stock. Estimates of fair value are not intended to predict actual future events or the value ultimately realized by certain employees who receive stock options, and subsequent events are indicative of the reasonableness of the original fair value estimates.

During the year ended June 30, 2017 320,000,000 options were issued to certain employees and directors. The options vest on November 16 and 17, 2017 and expire on November 17, 2026. The exercise price of 48,000,000 options is A$0.7 cents and the exercise price on 272,000,000 is $0.55 cents.

Based on the following assumptions, the options have fair market value on grant date of A$0.38 cents.

Share price at grant date (cents – Australian)	0.4
Exercise price (cents - Australian)	0.70
Time to expiry (years)	10
Risk free rate (%)	2.72
Share price volatility (%)	119.96

Based on the following assumptions, the options have a fair market value on grant date of A$0.37 cents

Share price at grant date (cents – Australian)	0.4
Exercise price (cents - Australian)	0.55
Time to expiry (years)	10
Risk free rate (%)	2.72
Share price volatility (%)	119.96

No options were issued during the year ended June 30, 2018 as share based payments.

As of June 30, 2017, there was US$0.4 million in unrecognized compensation cost related to stock options. This was expensed during the period from July 1, 2017 to the vesting date of the options on November 17, 2017. 5,500,000 options were cancelled as an employee resigned prior to meeting the vesting condition.

The following summarizes the Company's stock option and warrant activity for the years ended June 30, 2018 and 2017 (all values in AUD unless otherwise noted):

	2018			2017	
	Number	Weighted Average Exercise Price – cents (AUD)	Aggregate Intrinsic Value of Options/Warrants cents (AUD) (1)	Number	Weighted Average Exercise Price – cents (AUD)
Outstanding, start of period	411,033,246	1.18		320,615,486	4.60
Granted	-			320,000,000	0.57
Exercised	-			(140,143)	3.80
Cancelled/expired	(96,533,246)	3.80		(229,442,097)	3.80
Outstanding, end of period	314,500,000	0.5700	-	411,033,246	1.18
Exercisable, end of period	314,500,000	0.5700		91,033,246	3.80

(1) The intrinsic value of a stock option is the amount by which the market value is (less than)/exceeds the exercise price at the Balance Date.

The aggregate intrinsic value of options exercised in 2017 was (AUD4,747). No options were exercised during 2018.

Additional information related to options and warrants outstanding at June 30, 2018 is as follows (outstanding):

	Options/Warrants Outstanding and Exercisable		
Range of Exercise Prices	**Number Outstanding**	**Weighted Average Remaining Contractual Life - years**	**Weighted Average Exercise Prices Cents per share**
0.7 cents	48,000,000	8.42	0.7
0.55 cents	266,500,000	8.42	0.55
	314,500,000		

11. RELATED PARTY TRANSACTIONS

There were no related party transactions during the years ended June 30, 2018 and 2017.

12. COMMITMENTS

Lease commitments over the next five years are as follows:

	Total	**2019**	**2020**	**2021**	**2022**	**2023**	**Thereafter**
Leases	391,974	123,873	127,845	131,309	8,947	-	-

(2) Leases relate primarily to obligations associated with our office facilities in Denver, Colorado and Perth, Western Australia.

Leases –The Company has entered into lease agreements for office space in Denver, Colorado and Perth, Western Australia. As of June 30, 2018, future minimum lease payments under operating leases that have initial or remaining non–cancelable terms in excess of one year are $123,873 in 2019, $127,845 in 2020, $131,309 in 2021, $8,947 in 2022. Net rent expense incurred for office space was $214,650 and $153,375 in 2018 and 2017, respectively.

13. CONTINGENCIES

Samson may be subject to various other lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, and claims for underpayment of royalties, property damage claims and contract actions.

The Company records an associated liability when a loss is probable and the amount is reasonably estimable. Although the outcome of litigation cannot be predicted with certainty, management is of the opinion that no pending or threatened lawsuit or dispute incidental to its business operations is likely to have a material adverse effect on the company's consolidated financial position, results of operations or cash flows. The final resolution of such matters could exceed amounts accrued, however, and actual results could differ materially from management's estimates.

14. SUBSEQUENT EVENTS

There have been no material subsequent events through the date of filing.

15. SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES, INCLUSIVE OF DISCONTINUED OPERATIONS (UNAUDITED)

Oil and Gas Reserves

Given the pending sale at June 30, 2018, our fiscal year-end petroleum reserves report was prepared internally by knowledgeable officers and employees of the Company for the current year. The report was based upon our internal review of the property interests being appraised, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sales of production, geoscience and engineering data, and other information we gather. We prepared our estimates by use of standard geological and engineering methods generally accepted by the petroleum industry. Reserve volumes and values were determined under the method prescribed by the SEC, which requires the application of the 12-month average price for natural gas and oil calculated as the un-weighted arithmetic average of the first-day-of-the-month price for each month within the 12-month prior period to the end of the reporting period and year-end costs. The proved reserve estimates represent our net revenue interest in our properties.

Our reserves were prepared by a practitioner with 22 years of industry experience in geologic engineering and a Bachelor of Science in Geological Engineering from Colorado School of Mines. Additionally, our Chief Executive Officer is responsible for overseeing the preparation of the Company's reserves report. The CEO is a petroleum geologist who holds an associateship in applied geology and has over 45 years of relevant experience in the oil and gas industry.

Estimated Proved Reserves

Proved reserves are those quantities of hydrocarbons which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods and government regulations. As commodity prices decline, the commercially viability of wells change and reserve quantities may decrease. Proved reserves can be categorized as developed or undeveloped.

Capitalized Costs Incurred

Costs incurred for oil and natural gas exploration, development and acquisition are summarized below.

	Year ended June 30,	
	2018	**2017**
Development	13,272	2,458,276
Discontinued Operations	68,865	-
Undeveloped capitalized acreage	-	50,375
Total costs incurred	$ 82,137	$ 2,508,651

Estimated Proved Reserves

Proved reserves are those quantities of hydrocarbons which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods and government regulations. As commodity prices decline, the commercially viability of wells change and reserve quantities may decrease. Proved reserves can be categorized as developed or undeveloped.

	Year ended June 30, 2018			Year ended June 30, 2017		
	Oil Mbbls	Gas MMcf	Total MBOE	Oil Mbbls	Gas MMcf	Total MBOE
Beginning of year	5,359	3,565	5,955	9,982	8,593	11,415
Revisions of previous quantity estimates	(1,654)	(2,246)	(2,028)	(2,851)	(2,474)	(3,263)
Extensions and discoveries	-	-	-	-	-	-
Sale of reserves in place	-	-	-	(1,475)	(2,396)	(1,874)
Acquisitions	-	-	-	-	-	-
Production	(190)	(27)	(195)	(297)	(158)	(323)
End of year	3,515	1,292	3,732	5,359	3,565	5,955
Proved developed producing reserves	73	60	84	3,020	1,575	3,285
Proved developed non producing	32	43	39	134	224	171
Proved undeveloped reserves	308	251	350	2,205	1,766	2,499
Proved developed producing reserves - held for sale	2,590	563	2,685	-	-	-
Proved developed non producing - held for sale	512	375	575	-	-	-
Total proved reserves	3,515	1,292	3,732	5,359	3,565	5,955

Revisions of previous quantity estimates

The downward revision recorded for the year ended June 30, 2017 relates to our current drilling plan for our PUD locations. In the prior year, we anticipated drilling them as new 10,000 foot lateral horizontal wells. Upon further technical review, we now plan to drill the PUD wells as 5,000 foot laterals out of an existing well bore. The shortening of the lateral length lead to a decrease in the volume of reserves associated with these PUDs.

The downward revision in the current year relates to our recognition of PUDs. Due to the continued lack of capital available to drill these PUDs, the decision was made to sell substantially all of the wells in the Foreman Butte project area. We have retained a 15% working interest in certain PUDs and we have recognized that value in our reserves at June 30, 2018.

Sales of Reserves in Place

The reserves held for sale relate to the sale of the majority of our interest in the Foreman Butte project. This sale is expected to close on October 15, 2018.

The sale of reserves in place during the fiscal year ended June 30, 2017 consists of proved reserves (net of production prior to sale) in the North Stockyard field in North Dakota and the State GC field in New Mexico. All reserves were proved developed producing.

Developed Reserves

Developed reserves are those reserves expected to be recovered from existing wells, with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved Developed Producing Reserves

At June 30, 2018 our proved developed producing reserves primarily relate to our working interest in producing wells in our Foreman Butte project area in North Dakota and Montana.

Proved Developed Not Producing (PDNP)

PDNP reserves are those estimated proved reserves expected to be recovered from existing wells where a workover is required to re-establish production. As of June 30, 2017, the PDNP reserves were 171 MBOEAs of June 30, 2018, the PDNP reserves were 39 MBOE. These primarily related to our retained interest in the Foreman Butte project. This work is expected to be performed as capital allows.

Proved Undeveloped Reserves

Proved undeveloped reserves (PUD) are those reserves expected to be recovered from new wells on undeveloped acreage.

Due to the continued lack of capital available to drill these PUDs, the decision was made to sell substantially all of the wells in the Foreman Butte project area. We have retained a 15% working interest in certain PUDs and we have recognized that value in our reserves at June 30, 2018 as following the sale, we will have the working capital available to develop these locations.

During the year ended June 30, 2017 through further technical review, we changed our plan with respect to the drilling the PUDs. This reduced the reserves volumes associated with the PUDs but did not change the reserve value associated with the PUDs due to a decrease in the estimated drilling costs. We currently have the permits to drill 4 PUDs and have commenced sourcing the appropriate rig and other contractors and equipment required.

While we did not convert any PUDs during the year ended June 30, 2018, we have made considerable progress on their development through the pending sale.

Standardized Measure of Discounted Future Net Cash Flows

Future hydrocarbon sales and production and development costs have been estimated using a 12 month average price for the commodity prices for June 30, 2018 and 2017 and costs in effect at the end of the periods indicated. The average 12 month historical average of the first of the month prices used for natural gas for June 30, 2018 and 2017 were $2.95 and $3.01 per Mcf, respectively. The 12-month historical average of the first of the month prices used for oil for June 30, 2018 and 2017 were $57.67 and $48.95per barrel of oil, respectively. Future cash flows were reduced by estimated future development, abandonment and production costs based on period–end costs. No deductions were made for general overhead, depletion, depreciation and amortization or any indirect costs. All cash flows are discounted at 10%.

Changes in demand for hydrocarbons, inflation and other factors make such estimates inherently imprecise and subject to substantial revisions. This table should not be construed to be an estimate of current market value of the proved reserves attributable to Samson.

Samson has not disclosed the impact of taxes in the future cash flows for the years ended June 30, 2018 and 2017 as given Samson's extensive net operating losses carried forward, its history of loss making and the significant value of intangible costs incurred when developing its proved undeveloped locations, for which an immediate tax deduction is currently available, it is unlikely Samson will pay tax in the future based on current commodity pricing.

The following table shows the estimated standardized measure of discounted future net cash flows relating to proved reserves (in US$'000's):

	As at June 30,	
	2018	2017
Future cash inflows	$ 187,249	$ 237,490
Future production costs	(99,620)	(91,920)
Future development costs	(1,642)	(13,367)
Future income taxes	-	-
Future net cashflows	85,987	132,203
10 % discount	(38,325)	(66,941)
Standardized measure of discounted future net cash flows relating to proved reserves	$ 47,662	$ 65,262

The principal sources of changes in the standardized measure of discounted future net cash flows during the periods ended June 30, 2018 and June 30, 2017 are as follows (in US$'000's):

	Fiscal Year Ended June 30	
	2018	2017
Beginning of year	$ 65,262	$ 66,747
Sales of oil and gas produced during the period, net of production costs	(3,902)	(3,122)

Net changes in prices and production costs	2,822	1,601
Previously estimated development costs incurred during the period	-	-
Changes in estimates of future development costs	(11,625)	22,929
Extensions and discoveries	-	-
Revisions of previous quantity estimates and other	(10,088)	(21,078)
Sale of reserves in place	-	(10,445)
Purchase of reserves in place	-	-
Change in future income taxes	-	-
Accretion of discount	6,526	6,675
Other	(1,333)	1,955
Balance at end of year	$ 47,662	$ 65,262

The impact of income taxes has not been included in the current year as the Company's net operating losses, the tax basis of oil and gas assets and future expected deductions, exceed the future cashflows.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statements (Form S-3 Nos. 333-183327 and 333-207306 and Form S-8 No. 333-173647) of Samson Oil & Gas Limited of our report dated October 15, 2018, relating to the consolidated financial statements, (which report expresses an unqualified opinion and includes an explanatory paragraph regarding Samson Oil & Gas Limited's going concern uncertainty) appearing in this Annual Report (Form 10-K) for the year ended June 30, 2018.

/s/ Moss Adams LLP

Denver, Colorado
October 15, 2018

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statements on Form S-3 (Nos. 333-183327 and 333-207306) and Form S-8 (No. 333-173647) of Samson Oil & Gas Limited of our report dated September 28, 2017, relating to our audit of the consolidated financial statements (which report expresses an unqualified opinion and includes an explanatory paragraph regarding Samson Oil & Gas Limited's going concern uncertainty), which appears in this Annual Report on Form 10-K of Samson Oil & Gas Limited for the year ended June 30, 2018.

/s/ Hein & Associates LLP

Denver, Colorado
October 15, 2018

Exhibit 23.3

NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the use of the name Netherland, Sewell & Associates, Inc., to the inclusion of information taken from the reserves report dated August 21, 2017, as attached as Exhibit 99.1 to the Annual Report on Form 10-K for the year ended June 30, 2017, of Samson Oil & Gas Limited, prepared by us relating to the estimated quantities of Samson Oil & Gas Limited's proved reserves of oil and gas for the year ended June 30, 2017, in this Form 10-K for the year ended June 30, 2018. We also consent to the incorporation by reference of information from our report in Samson Oil & Gas Limited's Registration Statements on Form S-3 (No. 333-183327 and No. 333-207306) and Form S-8 (No. 333-173647) and related prospectuses.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

Dallas, Texas
October 15, 2018

Exhibit 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Terence M. Barr, certify that:

1. I have reviewed this annual report on Form 10-K of Samson Oil & Gas Limited;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the company as of, and for, the periods presented in this report;

4. The company's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the company and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the company's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the company's internal control over financial reporting that occurred during the company's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the company's internal control over financial reporting; and

5. The company's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the company's auditors and the audit committee of the company's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the company's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the company's internal control over financial reporting.

/s/ Terence M. Barr
Terence M. Barr
President, Chief Executive Officer and Managing Director
October 15, 2018

Exhibit 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Robyn Lamont, certify that:

1. I have reviewed this annual report on Form 10-K of Samson Oil & Gas Limited;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the company as of, and for, the periods presented in this report;

4. The company's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the company and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the company's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the company's internal control over financial reporting that occurred during the company's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the company's internal control over financial reporting; and

5. The company's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the company's auditors and the audit committee of the company's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the company's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the company's internal control over financial reporting.

/s/ Robyn Lamont
Robyn Lamont
Chief Financial Officer
October 15, 2018

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code), the undersigned officers of Samson Oil & Gas Limited (the “Company”), do hereby certify, to such officer’s knowledge, that:

(1) The Annual Report on Form 10-K for the year ended June 30, 2018 (the “Report”) fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Terence M Barr
Terence M. Barr
President, Chief Executive Officer and Managing Director
October 15, 2018

/s/ Robyn Lamont
Robyn Lamont
Chief Financial Officer
October 15, 2018

Document And Entity Information - USD ($) $ in Thousands	12 Months Ended		
	Jun. 30, 2018	Sep. 28, 2018	Dec. 29, 2017
Document And Entity Information [Abstract]			
Document Type	10-K		
Amendment Flag	false		
Document Period End Date	Jun. 30, 2018		
Document Fiscal Year Focus	2018		
Document Fiscal Period Focus	FY		
Trading Symbol	SSN		
Entity Registrant Name	Samson Oil & Gas LTD		
Entity Central Index Key	0001404079		
Current Fiscal Year End Date	--06-30		
Entity Voluntary Filers	No		
Entity Well-known Seasoned Issuer	No		
Entity Current Reporting Status	Yes		
Entity Filer Category	Smaller Reporting Company		
Entity Common Stock, Shares Outstanding		3,283,000,444	
Entity Public Float			$ 2,100

Consolidated Balance Sheets - USD ($)	Jun. 30, 2018	Jun. 30, 2017
CURRENT ASSETS		
Cash and cash equivalents	$ 1,376,676	$ 628,778
Accounts receivable, net of allowance for doubtful accounts of $nil and $nil respectively	1,759,461	1,550,438
Energy Related Inventory, Crude Oil and Natural Gas Liquids	219,288	219,288
Prepayments	137,342	54,519
Assets Held-for-sale, Not Part of Disposal Group, Current	28,675,890	
Total current assets	32,168,657	2,453,023
PROPERTY, PLANT AND EQUIPMENT, AT COST		
Oil and gas properties, successful efforts method of accounting, less accumulated depreciation, depletion and impairment of $44,273,976 and $21,219,361 at June 30, 2015 and June 30, 2014, respectively	1,744,951	1,814,772
Oil and gas properties held for sale		29,682,501
Other property and equipment, net of accumulated depreciation and amortization of $553,428 and $421,443 at June 30, 2015 and June 30, 2014, respectively	242,822	296,077
Net property, plant and equipment	1,987,773	31,793,350
OTHER ASSETS		
Undeveloped capitalized acreage		271,078
Fair value of derivative instruments		99,603
Malpractice Loss Contingency, Letters of Credit and Surety Bonds	450,000	450,000
Deferred tax asset	732,056	
Other	134,644	291,181
TOTAL ASSETS	35,473,130	35,358,235
CURRENT LIABILITIES		
Accounts payable	8,383,570	4,287,955
Accrued liabilities	1,088,338	821,319
Provision for annual leave	250,826	249,060
Fair value of derivative instruments	1,210,795	363,960
Asset retirement obligations related to assets held for sale	2,509,981	2,475,427
Short term repayment of long term debt	23,867,557	23,419,749
Total current liabilities	37,311,067	31,617,470
Asset retirement obligations	834,131	680,809
Total liabilities	38,145,198	32,298,279
Commitments and Contingencies		
STOCKHOLDERS' EQUITY - nil par value		
Common stock, 2,837,756,933 (equivalent to 141,887,847 ADRs) and 2,229,165,163 (equivalent to 111,458,258 ADRs) shares issued and outstanding at June 30, 2014 and 2013, respectively)	106,743,167	106,390,864
Other comprehensive income	846,556	892,017
Retained earnings (accumulated deficit)	(110,261,791)	(104,222,925)
Total stockholders' equity	(2,672,068)	3,059,956
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 35,473,130	$ 35,358,235

Consolidated Balance Sheets (Parenthetical) - USD ($)	Jun. 30, 2018	Jun. 30, 2017	Jun. 30, 2014	Jun. 30, 2013
Consolidated Balance Sheets [Abstract]				
Accounts receivable, allowance for doubtful accounts	$ 75,000			
Oil and Gas Property, Successful Effort Method, Accumulated Depreciation, Depletion Amortization and Impairment	12,606,419	$ 12,440,389		
Other property and equipment, accumulated depreciation and amortization	$ 775,057	$ 693,945		
Common stock, par value				
Common stock, shares issued	3,282,000,444	3,282,000,444		
Common stock, shares outstanding	3,282,000,444	3,282,000,444		

Consolidated Statements Of Operations - USD ($)	12 Months Ended	
	Jun. 30, 2018	Jun. 30, 2017
REVENUES AND OTHER INCOME:		
Interest income	$ 229	$ 411
Gain on derivative instruments		1,297,472
Gain on sale of exploration acreage	178,407	2,250,070
Other	80,893	66,707
TOTAL REVENUE AND OTHER INCOME	538,811	6,168,229
EXPENSES:		
Lease operating expense	(460,114)	(2,209,583)
Depletion, depreciation and amortization	(166,030)	(218,635)
Impairment of oil and natural gas properties		(244,480)
Exploration and evaluation expenditure	(325,304)	(78,391)
Accretion of asset retirement obligations	(34,554)	(52,801)
General and administrative	(4,141,399)	(5,034,746)
Abandonment Expense	(128,862)	(3,055)
Loss on derivative instruments	(2,722,166)	
Borrowing costs	(440,434)	(219,810)
Provision for doubtful debts	75,000	
TOTAL EXPENSES	(8,053,429)	(7,841,691)
Loss before income tax	(7,514,618)	(1,673,462)
Income tax (provision)/benefit	732,056	
Net loss from continuing operations	(6,782,562)	(1,673,462)
Income/(loss) from discontinued operations	743,696	(1,094,034)
Net loss from operations	(6,038,866)	(2,767,496)
OTHER COMPREHENSIVE LOSS		
Foreign currency translation	(45,461)	(35,701)
Total comprehensive loss for the period	$ (6,084,327)	$ (2,803,197)
Net earnings per common share from continuing operations:		
Basic loss per common share - cents per share	$ (0.21)	$ (0.05)
Diluted earnings per common share - cents per share	(0.21)	(0.05)
Net earnings per common share from discontinued operations:		
Basic - cents per share	0.02	(0.03)
Diluted - cents per share	0.02	(0.03)
Net gain(loss) from operations per common share:		
Basic - cents per share	(0.19)	(0.08)
Diluted - cents per share	$ (0.19)	$ (0.08)
Weighted average common shares outstanding:		
Basic	3,283,000,444	3,257,194,847
Diluted	3,283,000,444	3,257,194,847
Oil [Member]		
REVENUES AND OTHER INCOME:		
TOTAL REVENUE AND OTHER INCOME	$ 252,233	$ 2,246,725
Natural Gas [Member]		
REVENUES AND OTHER INCOME:		

TOTAL REVENUE AND OTHER INCOME	27,042	273,816
Other Liquids [Member]		
REVENUES AND OTHER INCOME:		
TOTAL REVENUE AND OTHER INCOME	$ 7	$ 33,028

Consolidated Statements Of Changes In Stockholders' Equity - USD ($)	Issued Capital [Member]	Retained Earnings/ (Accumulated Deficit) [Member]	Other Comprehensive Income (Loss) [Member]	Total
Beginning Balance, value at Jun. 30, 2016	$ 105,719,184	$ (101,455,429)	$ 927,718	$ 5,191,473
Net loss		(2,767,496)		(2,767,496)
Foreign currency translation			(35,701)	(35,701)
Total comprehensive loss for the period		(2,767,496)	(35,701)	(2,803,197)
Share based payment, value	159,506			
Stock based compensation	711,493			711,493
Issue of share capital	4,516			4,516
Share issue costs				(44,329)
Ending Balance, value at Jun. 30, 2017	106,390,864	(104,222,925)	892,017	3,059,956
Net loss		(6,038,866)		(6,038,866)
Foreign currency translation			(45,461)	(45,461)
Total comprehensive loss for the period		(6,038,866)	(45,461)	(6,084,327)
Total stock based compensation	352,303			352,303
Ending Balance, value at Jun. 30, 2018	$ 106,743,167	$ (110,261,791)	$ 846,556	$ (2,672,068)

Consolidated Statements Of Cash Flows - USD ($)	12 Months Ended	
	Jun. 30, 2018	Jun. 30, 2017
Cash flows from operating activities		
Receipts from customers	$ 1,498,741	$ 2,093,069
Cash received from commodity derivative financial instruments	(1,625,866)	(1,342,901)
Payments to suppliers & employees	(4,044,829)	(5,553,017)
Interest received	228	411
Cash payments for abandonment costs	(291,277)	(45,142)
Net Cash Provided by (Used in) Operating Activities, Continuing Operations, Total	(4,463,003)	(4,847,580)
Cash flows from investing activities		
Proceeds from sale of oil and gas properties		15,150,000
Payments for plant & equipment	(28,805)	(106,726)
Payments for exploration and evaluation	(54,212)	(138,715)
Payments for oil and gas properties	(78,705)	(479,712)
Net cash flows (used in)/ provided by investing activities	(161,722)	14,424,847
Cash flows from financing activities		
Proceeds from issue of share capital		3,198
Proceeds from borrowings	450,000	
Repayment of borrowings	(35,000)	(11,047,443)
Payments for costs associated with borrowings		(40,000)
Payments for costs associated with capital raising		(3,771)
Net cash flows (used in)/ provided by financing activities	415,000	(11,088,016)
Net (decrease)/increase in cash and cash equivalents	(4,209,725)	(1,510,749)
Cash and cash equivalents at the beginning of the year	628,778	2,654,812
Net cashflows provided by operations - discontinued operations	6,768,727	2,236,620
Net cashflows used in investing actvities - discontinued operations	(445,997)	(2,718,371)
Net cashflows used in financing operations -discontinued operations	(1,350,391)	
Effects of exchange rate changes on cash and cash equivalents	(14,716)	(33,534)
Cash and cash equivalents at end of year	$ 1,376,676	$ 628,778

Summary Of Significant Accounting Policies	12 Months Ended
	Jun. 30, 2018
Summary Of Significant Accounting Policies [Abstract]	
Summary Of Significant Accounting Policies	

1. **SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES**

Description of Operations. Samson Oil & Gas Limited along with its consolidated subsidiaries (“Samson” or the “Company”), is engaged in the acquisition, exploration, exploitation and development of oil and natural gas properties with a focus on properties in North Dakota and Montana.

Going concern. These financial statements have been prepared on the going concern basis, which contemplates the continuity of normal business activities and the realisation of assets and settlement of liabilities in the normal course of business.

We incurred a net loss of $6.0 million. the year ended June 30, 2018. As at that date, our total current liabilities of $34.8 million (excluding discontinued operations million exceed our total current assets of $3.5 million (excluding discontinued operations). Additionally, we are in violation of our debt covenants and have suffered recurring losses from operations. These factors raise substantial doubt over our ability to continue as a going concern and therefore whether we will realize our assets and extinguish our liabilities in the normal course of business and at the amounts stated in the financial report.

To address these concerns, we have undertaken the following plan:

- We have signed a purchase and sale agreement for the sale of substantially all of our interest in the Foreman Butte project for $40 million. The effective date of this sale is January 1, 2018 and the sale is expected to close October 15, 2018.
- We have entered into a forbearance agreement with Mutual of Omaha Bank in order to allow the orderly closing of the pending asset sale
- We are continuing to operate the properties in a such a way so as to maximize value should we be required to enter into a sale agreement with another party.

While management believes that we will successfully close the pending asset sale transaction or a similarly valued alternative sale transaction there can be no assurances that our efforts will be successful. In addition, given our current financial situation we may be forced to accept terms on these transactions that are less favorable than would be otherwise available.

The financial report does not include any adjustments relating to the amounts or classification of recorded assets or liabilities that might be necessary if the Company does not continue as a going concern.

Comparatives. These statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP).

Principles of Consolidation. The consolidated financial statements include the accounts of the Company and its subsidiaries, all of which are wholly owned. Significant intercompany balances and transactions have been eliminated in consolidation.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Items subject to such estimates and assumptions include (1) oil and gas reserves; (2) cash flow estimates used in impairment tests of long–lived assets; (3) depreciation, depletion and amortization; (4) asset retirement obligations; (5) assigning fair value and allocating purchase price in connection with business combinations; (6) accrued revenue and related receivables; (7) valuation of commodity and interest derivative instruments; (8) certain accrued liabilities; (9) valuation of share-based payments, (10) income taxes and (11) carrying value of exploration and evaluation expenditure. Although management believes these estimates are reasonable, actual results could differ from these estimates. The Company has evaluated subsequent events and transactions through the date of this report for matters that may require recognition or disclosure in these financial statements.

Business Segment Information. The Company has evaluated how it is organized and managed and has identified only one operating segment, which is the exploration and production of crude oil, natural gas and natural gas liquids. All of the Company's operations and assets are located in the United States, and all of its revenues are attributable to United States customers.

Revenue Recognition and Gas Imbalances. Revenues from the sale of natural gas and crude oil are recognized when the product is delivered at a fixed or determinable price, title has transferred and collectability is reasonably assured and evidenced by a contract. This generally occurs when oil or natural gas has been delivered to a refinery or a pipeline, or has otherwise been transferred to a customer's facilities or possession. Oil revenues are generally recognized based on actual volumes of completed deliveries where title has transferred. Title to oil sold is typically transferred at the wellhead.

The Company uses the entitlement method of accounting for natural gas revenues. Under this method, revenues are recognized based on actual production of natural gas. The Company incurs production gas volume imbalances in the ordinary course of business. Net deliveries in excess of entitled amounts are recorded as liabilities, while net under–deliveries are reflected as assets. Imbalances are reduced either by subsequent recoupment of over– and under– deliveries or by cash settlement, as required by applicable contracts. The Company's production imbalances were not material at June 30, 2018 or 2017.

Cash and Cash Equivalents. The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents. The Company’s cash management process provides for the daily funding of checks as they are presented to the bank.

Accounts Receivable. The components of accounts receivable include the following:

	June 30	
	2018	**2017**
Oil and natural gas sales	$ 1,005,217	$ 894,523
Cost recovery from partners	734,912	572,082
Less provision for doubtful debts	(75,000)	-
Other	94,332	83,833
Total accounts receivable, net of nil allowance for doubtful accounts for June 30, 2018 and 2017	$ 1,759,461	$ 1,550,438

The Company's accounts receivable result from (i) oil and natural gas sales to oil and intrastate gas pipeline companies and (ii) billings to joint working interest partners in properties operated by the Company. The Company's trade and accrued production receivables are primarily from the operators of our various projects, who negotiate the sale of oil and gas to third parties on our behalf.

Oil and Gas Properties.

Oil and gas properties and equipment consist of the following at June 30:

	2018	**2017**
Proved properties	$ 13,181,514	$ 13,114,851

Lease and well equipment	1,169,856	1,140,310
Less accumulated depreciation, depletion and impairment	(12,606,419)	(12,440,389)
	$ 1,744,951	$ 1,814,772
Assets held for sale	28,675,890	-
Unproved acreage	$ -	$ 271,078

The Company accounts for its oil and gas exploration and development costs using the successful efforts method. Geological and geophysical costs are expensed as incurred. Exploratory well costs are capitalized pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. All exploratory wells are evaluated for economic viability within one year of well completion, and the related capitalized costs are reviewed quarterly.

Exploratory wells that discover potentially economic reserves in areas where a major capital expenditure would be required before production could begin and where the economic viability of that major capital expenditure depends upon the successful completion of further exploratory work in the area remain capitalized if the well finds a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

The costs of development wells are capitalized whether productive or nonproductive. The provision for depletion of oil and gas properties is calculated on a field–by–field basis using the unit–of–production method. Mineral interests and leasehold acquisition costs are depleted over total proved reserves while cost of completed wells and related facilities and equipment are depleted over proved developed producing reserves.

If the estimates of total proved or proved developed reserves decline, the rate at which the Company records depreciation, depletion and amortization (DD&A) expense increases, which in turn reduces net earnings. Such a decline in reserves may result from lower commodity prices, which may make it uneconomic to drill for and produce higher cost fields. The Company is unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of its development program, as well as future economic conditions. Changes in reserves are applied on a prospective basis.

As wells are drilled in a field with proved undeveloped reserves or unproved reserves, a portion of the acquisition costs are either re–designated as proved developed or expensed, as appropriate. In fields with multiple potential drilling sites, the Company determines the amount of the acquisition cost to re–designate or expense through a systematic and rational basis that considers the total expected wells to be drilled in that field.

The Company reviews its proved oil and gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. The Company estimates the expected future cash flows of its oil and gas properties and compares these undiscounted future cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the oil and gas properties to fair value. The factors used to determine fair value include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of reserves, future commodity pricing, future production estimates, anticipated capital expenditures and various discount rates commensurate with the risk associated with realizing the projected cash flows. Unproved oil and gas properties are assessed periodically for impairment on a field by field (consistent with the fields used for the calculation of depletion, depreciation and amortization) basis based on remaining lease terms, drilling results, reservoir performance, commodity price outlooks or future plans to develop acreage and allocate capital. When the Company has allocated fair values to significant unproved property (probable reserves) as the result of a business combination or other purchase of proved and unproved properties, it uses a future cash flow analysis to assess the property for impairment.

Gains on sales of proved and unproved properties are only recognized when there is no uncertainty about the recovery of costs applicable to any interest retained or where there is no substantial obligation for future performance by the Company. Impairment on properties sold is recognized when incurred or when the properties are held for sale and the fair value of the properties is less than the carrying value.

In determining whether an unproved property is impaired, the Company considers numerous factors including, but not limited to, current development and exploration drilling plans, favorable or unfavorable exploration activity on adjacent leaseholds, in-house geologists' evaluation of the lease, future reserve cash flows and the remaining lease term.

Assets held for sale

In June 2018, we signed a purchase and sale agreement for the sale of the Foreman Butte Project, subject to our retention of a 15% working interest in a portion of the Project (the "Foreman Butte Sale"). This transaction received shareholder approval at a general meeting held on August 13, 2018. The purchase price is $40 million with an effective date of January 1, 2018.

The Foreman Butte Project constitutes the majority of our operating assets. Upon closing of the transaction, we will retain a 15% working interest in certain wells in the Home Run Field, which consists of 15 producing wells and 20 PUD locations.

The proceeds of the Foreman Butte Sale will be used to repay our credit facility with Mutual of Omaha Bank in full and bring our other accounts payable current. We estimate that after these repayments, we will have no outstanding debt and will retain approximately $6.5 million in cash proceeds from the sale.

Exploration and evaluation costs including capitalized exploration written off and dry hole expenses

Exploration and evaluation assets are assessed for impairment when facts and circumstances indicate that the carrying amount of an exploration and evaluation asset may exceed its recoverable amount. When assessing for impairment consideration is given to but not limited to the following:

- the period for which Samson has the right to explore;
- planned and budgeted future exploration expenditure;
- activities incurred during the year; and
- activities planned for future periods.

If, after having capitalized expenditure under our policy, the Company concludes that it is unlikely to recover the expenditure by future exploitation or sale, then the relevant capitalized amount will be written off to the income statement.

During the fiscal year ended June 30, 2018, we expensed $0.2 million in deferred exploration expense in relation to our Cane Creek project area.

Impairment

The Company recorded impairment charges of $nil million and $0.2 million for the years ended June 30, 2018 and 2017 respectively.

The charges in the fiscal year ended June 30, 2017 related to the write down of the value in our oil inventory to lower of cost or net realizable value.

Other Property and Equipment.

Other property and equipment, which includes leasehold improvements, office and other equipment, are stated at cost. Depreciation and amortization are calculated using the straight–line method over the estimated useful lives of the related assets, ranging from 3 to 25 years.

Depreciation and amortization expense for the years ended June 30, 2018 and 2017 was $0.2 million and $0.2 million, respectively.

Other property and equipment consist of the following at June 30:

	2018	2017
Furniture, fittings and equipment	$ 1,017,879	$ 990,022
Less accumulated depreciation	(775,057)	(693,945)
	$ 242,822	$ 296,077

Derivative Financial Instruments. The Company enters into derivative contracts, primarily collars, swaps and option contracts, to hedge future crude oil and natural gas production in order to mitigate the risk of market price fluctuations. All derivative instruments are recorded on the balance sheet at fair value. All of the Company's derivative counterparties are major oil companies. The Company has elected not to apply hedge accounting to any of its derivative transactions and consequently, the Company recognizes mark-to-market gains and losses in earnings currently, rather than deferring such amounts in other comprehensive income for those commodity derivatives that qualify as cash flow hedges.

Asset Retirement Obligations. The Company recognizes estimated liabilities for future costs associated with the abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long–lived asset are recorded at the time the well is spud or acquired.

Environmental. The Company is subject to extensive federal, state and local environmental laws and regulations. These laws and regulations, which regularly change, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a non–capital nature are recorded when environmental assessment and/or remediation is probable and the costs can be reasonably estimated. Such liabilities are generally recorded at their undiscounted amounts unless the amount and timing of payments is fixed or reliably determinable. The Company is not aware of any material noncompliance with existing laws and regulations.

Income Taxes. Deferred income tax assets and liabilities are recognized for the future income tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective income tax bases. Deferred income tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred income tax assets and liabilities of a change in income tax rates is recognized in income in the period that includes the enactment date. The measurement of deferred income tax assets is reduced, if necessary, by a valuation allowance if management believes that it is more likely than not that some portion or all of the net deferred tax assets will not be fully realized on future income tax returns. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, available taxes in carryback periods, projected future taxable income and tax planning strategies in making this assessment.

The Company recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement.

Earnings per Share. Basic earnings (loss) per share are calculated by dividing net earnings (loss) attributable to common stock by the weighted average number of shares outstanding for the period. Under the treasury stock method, diluted earnings per share is calculated by dividing net earnings (loss) by the weighted average number of shares outstanding including all potentially dilutive common shares. In the event of a net loss, no potential common shares are included in the calculation of shares outstanding since the impact would be anti-dilutive. When the Company records a net loss, none of the loss is allocated to the unexercised stock options since the securities are not obligated to share in Company losses. Consequently, in periods of net loss, outstanding options will have no dilutive impact to the Company's basic earnings per share.

The following potential common shares relating to options and warrants have been excluded from the calculation of diluted earnings per share as the related impact was anti-dilutive.

	Year ended June 30,	
	2018	**2017**
Dilutive	-	-
Anti–dilutive	314,500,000	287,956,323

Stock-Based Compensation. Stock-based compensation is measured at the estimated grant date fair value of the awards and is recognized on a straight-line basis over the requisite service period (usually the vesting period). The Company recognizes stock-based compensation net of an estimated forfeiture rate, and recognizes compensation expense only for shares that are expected to vest. Compensation expense is then adjusted based on the actual number of awards for which the requisite service period is rendered.

Foreign Currency Translation. The functional currency of Samson Oil & Gas Limited (Parent Entity) is Australian dollars, the reason for this being the majority of cash flows of the Parent Entity are denominated in Australian dollars. The functional and presentation currency of Samson Oil & Gas USA, Inc. (subsidiary) is U.S. dollars. The presentation currency of the Consolidated Entity is U.S. dollars.

Transactions in foreign currencies are initially recorded in the functional currency by applying the exchange rates ruling at the date of the transaction. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at year ended exchange rates of monetary assets and liabilities denominated in foreign currencies are recognized in profit and loss

Translation differences on assets and liabilities carried at fair value are reported as part of the fair value gain or loss. Translation differences on non-monetary assets and liabilities are recognized in other comprehensive income.

Business Combinations Samson applies the acquisition method in accounting for business combinations. The consideration transferred by the Company is calculated as the sum of the acquisition date fair value of assets transferred, liabilities incurred and any equity interests issued by the Company, which includes the fair value of any asset or liability arising from any contingent consideration arrangements. Acquisition costs are expensed as incurred. The Company treats the acquisition of oil and gas assets as a business combination.

The Company recognizes identifiable assets acquired and liabilities assumed in a business combination regardless of whether they have been previously recognized in the acquiree's financial statements prior to the acquisition. Assets acquired and liabilities assumed are generally measured at their acquisition date fair values.

If the fair values of identifiable net assets exceeds the sum calculated has the fair value transferred, the excess amount, a gain on bargain purchase) is recognized in the statement of operations immediately.

Impact of Recently Adopted Accounting Standards.
There have been no recently adopted accounting standards that would impact our business.

Recently Issued Accounting Pronouncements

In August 2014, the FASB issued new guidance related to the disclosures around going concern. The new standard provides guidance around management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and to provide related footnote disclosures. The new guidance becomes effective for fiscal years beginning after December 15, 2016, and interim periods within those years, with early adoption permitted. This standard has been adopted and the Company has added the appropriate disclosures.

In November 2014, the FASB issued ASU No. 2014-16, which updates authoritative guidance for derivatives and hedging instruments, specifically in determining whether the host contract in a hybrid financial instrument issued in the form of a share is more akin to debt or to equity. This guidance is effective for the annual period beginning after December 15, 2015; early adoption is permitted. The Company has adopted this standard and it did not have a material impact on its consolidated financial statements.

ASU 2016-02, *Leases (Topic 842)* This ASU, among other provisions, requires lessees to recognize right of use assets and leases liabilities for all leases not considered short term leases. The ASU is effective for public business entities for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years This standard is not expected to have a significant impact on the Company as it does not currently engage in significant leasing activity.

ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)* Accounting Standards Update (ASU) 2014-09 provides a new framework for addressing revenue recognition issues and upon its effective date, replaces almost all existing revenue recognition guidance. While the revenue recognition policies of all entities will be impacted by this standard, we do not expect the impact to be significant. For public business entities, the guidance is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period.

We do expect this standard to have a significant impact on our financial reporting of the standards disclosed above that have not yet taken effect. However, we do expect these changes to have an impact with additional disclosures contained in the 10Q for the period ended September 30, 2018 expected.

Discontinued Operations	12 Months Ended Jun. 30, 2018
Discontinued Operations [Abstract]	
Discontinued Operations	**2. DISCONTINUED OPERATIONS** As of June 30, 2018 the majority of our interest in the wells in the Foreman Butte project were held for sale and therefore have been recognized as discontinued operations for the years ended June 30, 2018 and 2017. .

Discontinued Operations

	Year ended June 30,	
	2018	**2017**
Major line items constituting pretax gain (loss) of discontinued operations		
Oil sales	9,678,832	10,336,307
Gas sales	91,742	162,546
Other liquids	8,864	5,261
Lease operating expense	(6,031,983)	(7,751,072)
Depletion, depreciation and amortization	(1,071,959)	(1,770,500)
Accretion of asset retirement obligations	(216,229)	(263,964)
Amortization of borrowing costs	(440,434)	(219,810)
Interest expense	(1,275,137)	(1,592,802)
Gain/(loss) from discontinued operations	743,696	(1,094,034)
Cashflows from Discontinued Operations		
Cashflows from Operating Activities	6,768,727	2,236,620
Cashflows from Investing Activities	(445,997)	(2,718,371)
Cashflows from Financing Activities	(1,350,391)	-

Hedging And Derivative Financial Instruments	12 Months Ended Jun. 30, 2018
Hedging And Derivative Financial Instruments [Abstract]	
Hedging And Derivative Financial Instruments	(see below)

3. HEDGING AND DERIVATIVE FINANCIAL INSTRUMENTS

Commodity Derivative Agreements. The Company utilizes swap and collar option contracts to hedge the effect of price changes on a portion of its future oil and natural gas production. The objective of the Company's hedging activities and the use of derivative financial instruments is to achieve more predictable cash flows. While the use of these derivative instruments limits the downside risk of adverse price movements, they also may limit future revenues from favorable price movements. The Company may, from time to time, opportunistically restructure existing derivative contracts or enter into new transactions to effectively modify the terms of current contracts in order to improve the pricing parameters in existing contracts or realize the current value of the Company's existing positions. The Company may use the proceeds from such transactions to secure additional contracts for periods in which the Company believes it has additional unmitigated commodity price risk.

The use of derivatives involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. The Company's derivative contracts are with a single major oil company with no history of default with the Company. The derivative contracts may be terminated by a non-defaulting party in the event of default by one of the parties to the agreement.

The Company has elected not to apply hedge accounting to any of its derivative transactions and, consequently, the Company recognizes mark-to-market gains and losses in earnings currently, rather than deferring such amounts in accumulated other comprehensive income for those commodity derivatives that would qualify as cash flow hedges. All derivative instruments are recorded on the balance sheet at fair value.

At June 30, 2018, the Company's commodity derivative contracts consisted of collars and fixed price swaps, which are described below:

Collar *Collars contain a fixed floor price (put) and fixed ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, the Company receives the fixed price rather than the market price. If the market price is between the call and the put strike price, no payments are due from either party.*

Fixed price swap *The Company receives a fixed price for the contract and pays a floating market price to the counterparty over a specified period for a contracted volume.*

All of the Company's derivative contracts are with the same counterparty and are shown on a net basis on the Balance Sheet. The Company's counterparty has entered into an inter-creditor agreement with Mutual of Omaha Bank, the provider of the Company's credit facility. As such no collateral is required by the counterparty.

At June 30, 2018 the Company's open derivative contracts consisted of the following:

Collar

Product	*Start Date*	*End Date*	*Volume (BO/Mmbtu)*	*Floor*	*Ceiling*
WTI	*1-Jul-18*	*31-Dec-18*	*80,960*	*$ 45.00*	*56.00*
Henry Hub	*1-May-18*	*31-Dec-18*	*50,490*	*$ 2.65*	*2.90*

During the year ended June 30, 2017, the Company recorded a gain of $1.3 million in the Statement of Operations in in derivative instruments. As of June 30, 2017, the derivative instruments were valued at $0.26 million of which, $0.1 million is recorded as a current liability and $0.36 million is recorded as a non-current asset.

During the year ended June 30, 2018, the Company recognized $2.7 million in the Statement of Operations in loss in derivative instruments. As of June 30, 2018, its derivative instruments were valued at $1.2 million recorded as current liability. See Note 4 for additional fair value disclosures about the Company's oil and gas derivatives.

Price risk

Price risk arises from the Company's exposure to oil and gas prices. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond the control of the Company. Sustained weakness in oil and natural gas prices may adversely affect the Company's financial condition.

The Company manages this risk by continually monitoring the oil and gas price and the external factors that may affect it. The Board reviews the risk profile associated with commodity price risk periodically to ensure that it is appropriately managing this risk. Derivatives are used to manage this risk where appropriate. The Board must approve any derivative contracts that are entered into by the Company.

Fair Value Measurements	12 Months Ended Jun. 30, 2018

Fair Value Measurements [Abstract]

Fair Value Measurements

4. FAIR VALUE MEASUREMENTS

Fair value is defined as the price that would be received in the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. The Company classifies fair value balances based on the observability of those inputs. The FASB has established a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement).

The three levels of the fair value hierarchy are as follows:

- Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

- Level 2—Pricing inputs are other than quoted prices in active markets included in level 1, but are either directly or indirectly observable as of the reported date and for substantially the full term of the instrument. Inputs may include quoted prices for similar assets and liabilities. Level 2 includes those financial instruments that are valued using models or other valuation methodologies.

- Level 3—Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management’s best estimate of fair value.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company’s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The following table sets forth by level within the fair value hierarchy the Company’s financial assets and liabilities that were accounted for at fair value as of June 30, 2018 and 2017.

	Fair Value at June 30, 2018				
	Level 1	**Level 2**	**Level 3**	**Netting** [(1)]	**Total**
Current Assets:					
Cash and cash equivalents	$ 1,376,676	$ -	$ -	$ -	$ 1,376,676
Derivative Instruments	-	4,218	-	(4,218)	-
Non Current Assets:					
Derivative Instruments	-	-	-	-	-
Current Liabilities					

Derivative Instruments	-	1,215,013	-	(4,218)	1,210,795
Non Current Liabilities:					
Derivative Instruments		-		-	-

	Fair Value at June 30, 2017				
	Level 1	**Level 2**	**Level 3**	**Netting [1]**	**Total**
Current Assets:					
Cash and cash equivalents	$ 628,778	$ -	$ -	$ -	$ 628,778
Derivative Instruments	-	167,307	-	(167,307)	-
Non Current Assets:					
Derivative Instruments	-	370,494	-	(270,891)	99,603
Current Liabilities					
Derivative Instruments	-	531,267	-	(167,307)	363,960
Non Current Liabilities:					
Derivative Instruments		270,891		(270,891)	-

(1) **Netting** In accordance with the Company's standard practice, its commodity derivatives are subject to counterparty netting under agreements governing such derivatives and therefore the risk of loss is somewhat mitigated.

The following methods and assumptions were used to estimate the fair value of the assets and liabilities in the table above:

Commodity Derivative Contracts. The Company's commodity derivative instruments consisted of collars and swap contracts for oil. The Company values the derivative contracts using industry standard models, based on an income approach, which considers various assumptions including quoted forward prices and contractual prices for the underlying commodities, time value and volatility factors, as well as other relevant economic measures. Substantially all of the assumptions can be observed throughout the full term of the contracts, can be derived from observable data or are supportable by observable levels at which transactions are executed in the marketplace and are therefore designated as level 2 within the fair value hierarchy. The discount rates used in the assumptions include consideration of non-performance risk. The Company accounts for its commodity derivatives at fair value (see Note 3) on a recurring basis.

Fair Value of Financial Instruments. The Company's financial instruments consist primarily of cash and cash equivalents, accounts receivable and payable, investments and derivatives (discussed above). The carrying values of cash equivalents and accounts receivable and payable are representative of their fair values due to their short–term maturities.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis. The Company also applies fair value accounting guidance to measure non–financial assets and liabilities such as business acquisitions proved oil and gas properties, and asset retirement obligations. These assets and liabilities are subject to fair value adjustments only in certain circumstances and are not subject to recurring revaluations. These items are primarily valued using the present value of estimated future cash inflows and/or outflows. Given the unobservable nature of these inputs, they are deemed to be Level 3.

Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two. The Company utilizes the discounted cash flow method; estimated future cash flows are based on management’s expectations for the future and include estimates of future oil and gas production, commodity prices based on published forward commodity price curves as of the date of the estimate, operational costs, and a risk–adjusted discount rate. The fair value measurement was based on Level 3 inputs.

Asset Retirement Obligations	12 Months Ended Jun. 30, 2018
Asset Retirement Obligations [Abstract]	
Asset Retirement Obligations	

5. ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations primarily represent the estimated present value of the amounts expected to be incurred to plug, abandon and remediate producing and shut–in properties at the end of their productive lives in accordance with applicable state and federal laws. The Company determines the estimated fair value of its asset retirement obligations by calculating the present value of estimated cash flows related to plugging and abandonment liabilities. The significant inputs used to calculate such liabilities include estimates of costs to be incurred; the Company's credit adjusted discount rates, inflation rates and estimated dates of abandonment. The asset retirement liability is accreted to its present value each period and the capitalized asset retirement cost is depleted using the units–of–production method.

The following table summarizes the activities for the Company's asset retirement obligations for the years ended June 30, 2017 and 2016:

	2018	2017
Asset retirement obligations at beginning of period	$ 3,456,236	$ 3,750,245
Liabilities incurred or acquired	-	226,123
Liabilities settled	(73,667)	(427,214)
Disposition of properties	(73,011)	(409,683)
Accretion expense	34,554	316,765
Asset retirement obligations at end of period	3,344,112	3,456,236
Less: current asset retirement obligations (classified with accounts payable and accrued liabilities)	-	(300,000)
Less current asset retirement obligatons related to assets held for sale	(2,509,981)	
Long-term asset retirement obligations	$ 834,131	$ 3,156,236

Discount rates used to calculate the present value vary depending on the estimated timing of the obligation, but typically range between 4% and 13%.

The liabilities incurred in the prior year relate to the liabilities acquired in relation to the Foreman Butte acquisition.

Income Taxes	12 Months Ended Jun. 30, 2018
Income Taxes [Abstract]	
Income Taxes	

6. INCOME TAXES

The Company accounts for income taxes under the asset and liability approach prescribed by GAAP, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been recognized in the Company's consolidated financial statements or tax returns.

The Company's income tax provision (benefit) is composed of the following:

	June 30	
	2018	2017
Current:		
Federal	$ (732,056)	$ -
State	-	-
	(732,056)	-
Deferred:		
Federal	(732,056)	-
State	-	-
Less income tax benefit allocated to discontinued operations		
Total income tax provision (benefit)	$ (1,464,112)	$ -

A reconciliation of the income tax provision (benefit) computed by applying the Australian federal statutory rate of 30% to the Company's income tax provision (benefit) is as follows (in thousands):

	June 30	
	2018	2017
Income tax expense (benefit) at federal statutory rate	$ (1,956,277)	$ (787,563)
Effect of permanent differences and other - US	115,616	-
State income taxes	(123,694)	(34,997)
Change in tax rate	11,207,430	
US income taxed at a different rate	116,777	
Foreign exchange	282,557	
Other adjustments - true up of deferred balances	(10,819)	
Alternative minimum tax	-	-
Other - change in deferred tax rate	-	(239,200)
Other	23,507	112,867
Valuation allowance	(10,387,153)	948,893
	$ (732,056)	$ -

The components of deferred tax assets and (liabilities) are as follows (in thousands):

	June 30	
	2018	2017
Deferred income tax assets:		
Net operating losses	$ 23,674,591	$ 34,581,318
Asset retirement obligation	737,875	1,212,151

Annual leave	51,837	81,130
Abandonment limitation	554,685	554,685
Allowance for doubtful debts	17,560	-
Accrued bonus	-	-
Charitable contributions	-	882
AMT credit	780,443	780,443
Share based compensation	500,844	500,844
Oil and Gas Property	-	-
Derivative liability	283,458	98,175
Valuation allowance	(23,951,026)	(34,286,029)
Deferred income tax liabilities:		
Commodity liability	-	-
Amortization - loan costs	-	-
Oil and gas property	(1,908,395)	(3,523,599)
Net deferred income tax assets (liabilities)	732,506	-

	June 30	
	2018	**2017**
Deferred Income Tax Valuation Allowance		
Balance at July 1	34,286,029	33,337,136
Additions (reductions) to deferred income tax expense	(10,387,153)	948,893
Balance at June 30	23,898,876	34,286,029

The Company has tax losses carried forward arising in Australia of $15,509,399 (2017: $15,949,783). The benefit of these losses of $4,652,820 (2017: $4,784,935) will only be obtained in future years if:

(i) the Parent Entity derive future assessable income of a nature and an amount sufficient to enable the benefit from the deduction for the losses to be realized; and
(ii) the Parent Entity have complied and continue to comply with the conditions for deductibility imposed by law; and
(iii) no changes in tax legislation adversely affect the Parent Entity in realizing the benefit from deduction for the losses.

The Company has federal net operating tax losses in the United States of approximately $84,932,621 (2017: $82,341,738). The current year utilization carried back to prior years, is approximately $nil (2017: $nil). The 2000-2005 years are limited to $403,194 per year as a result of a change in ownership of the one of the subsidiaries which occurred in January 2005. NOLs generated after this ownership change are not limited due to any known ownership changes. If not utilized, the tax net operating losses will expire during the period from 2020 to 2036.

In addition to the above-mentioned Federal carried forward losses in the United States, the Company also has approximately $ 49,189,363 (2017: $47,582,073) of State carried forward tax losses, with expiry dates between June 2015 and June 2033. A deferred income tax asset in relation to these losses has not been recognized as realization of the benefit is not regarded as probable.

The change in federal corporate income tax rate from 35% to 21% was enacted in 2017 and effective 1/1/18. For 2017, the rate change does impact the calculation of current income tax liability and requires the future rate to be applied to deferred income tax assets and liabilities that exist at 6/30/18. An expense of $11,140,774 was recorded to deferred income tax expense for this change. An adjustment to the effective tax rate is also required to reflect the different rates (35% and 21%) applied to currently arising temporary differences for current tax and deferred tax. There is no P&L impact of these adjustments as the valuation allowance will have a corresponding adjustment to offset any changes to the deferred tax asset.

In assessing the realizeability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which the use of such net operating losses are allowed. Among other items, Management considers the scheduled reversal of deferred tax liabilities, tax planning strategies and projected future taxable income. As of the current year end, the company does not believe the realizeablity of the deferred tax assets to be more likely than not. As such, the company has a full valuation allowance offsetting the deferred tax asset.

The Company adopted the uncertainty provision of FASB ASC Topic 740, "Income Taxes" and has analyzed filing positions in all federal and state jurisdictions where it is required to file income tax returns, as well as all open tax years in this jurisdiction. Most uncertain tax positions relate primarily to timing differences and management does not believe any such uncertain tax positions will materially impact the Company's effective tax rate in future periods. The Company anticipates that no additional uncertain tax positions will be recognized within the next twelve months. Our policy is to recognize any interest and penalties related to the unrecognized tax benefits in income tax expense. In our major tax jurisdictions, the earliest years remaining open to examination are as follows US - 6/30/1996 due to the usage of net operating losses from that period. If recognized, these uncertain tax positions would impact the Company's effective income tax rate. The company currently has no unrecognized positions.

Capital Stock Contributed Equity	12 Months Ended Jun. 30, 2018
Capital Stock Contributed Equity [Abstract]	
Capital Stock Contributed Equity	**7. COMMON STOCK**

	Consolidated Entity	
	2018	**2017**
3,283,000,444 ordinary fully paid shares including shares to be issued (2017 –3,283,000,444 ordinary fully paid shares including shares to be issued)	$ 106,743,167	$ 106,390,864

Movements in contributed equity for the year	**2018**		**2017**	
	No. of shares	**$**	**No. of shares**	**$**
Opening balance	3,283,000,444	106,390,864	3,215,854,701	105,719,184
Capital raising (i)	-	-	-	-
Shares issued upon exercise of options (ii)	-	-	140,143	4,516
Stock based compensation - shares issued	-	-	67,005,600	159,506
Stock based compensation - warrants issued	-	352,303	-	551,987
Transaction costs incurred	-	-	-	(44,329)
Shares on issue at balance date	3,283,000,444	106,743,167	3,283,000,444	106,390,864

i)

(ii) During the course of the prior year the Company issued 140,143 ordinary shares upon the exercise of 140,143 options.
The exercise price of 140,143 of the options exercised was A$0.038 cents per share/US$0.032 cents per shares (average price based on the exchange rate on the date of exercise) to raise US$4,516.

Cash Flow Statement	12 Months Ended Jun. 30, 2018
Cash Flow Statement [Abstract]	
Cash Flow Statement	**8. CASH FLOW STATEMENT**

	Year ended June 30	
	2018	**2017**
A reconciliation of the net loss to the net cash provided by operations is as follows:		
Net loss after tax	$ (6,038,866)	$ (2,767,496)
Depreciation	1,237,989	1,989,135
Accretion of asset retirement obligations	250,783	316,765
Share based payments	352,303	711,493
Exploration and evaluation expenditures	325,304	78,391
Impairment losses of oil and gas properties	-	244,480
Borrowing costs	440,434	219,810
Change in fair value of derivative instruments	946,438	(2,640,373)
Bargain purchase on acquisition	-	-
Profit on sale of assets	(178,407)	(2,250,070)
Provision for doubtful debts	75,000	-
Income tax benefit	(732,056)	
Non cash other income	-	(126,265)
Changes in assets and liabilities:		
Decrease in receivables	(121,193)	743,041
Increase/(decrease) in employee benefits	1,766	54,563
Increase in payables	5,746,229	815,566
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	**$ 2,305,724**	**$ (2,610,960)**

Credit Facility	12 Months Ended
	Jun. 30, 2018
Credit Facility [Abstract]	
Credit Facility	9.CREDIT FACILITY

	June 30,			
	2018		2017	
Credit facility at beginning of period	$	23,419,749	$	30,500,000
Cash advanced under facility		450,000		-
Assumption of promissory note		-		4,000,000
Repayments		(2,192)		(11,080,251)
Credit facility at end of period	$	23,867,557	$	23,419,749
Funds available for drawdown under the facility		-		580,251

In March 2016, the facility was extended to $30.5 million to partly fund the Foreman Butte acquisition. $11.5 million was repaid in October 2016, following the closing of the sale of the North Stockyard asset. As a result of this amendment to the facility agreement, the following changes were made to the original facility agreement:

- The addition of more restrictive financial covenants (including the debt to EBITDA ratio and the minimum liquidity requirement);
- Increases in the interest rate and unused facility fee;
- The addition of a minimum hedging requirement of 75% of forecasted production;
- A requirement to reduce our general and administrative costs from $6 million per year to $3 million per year;
- A requirement to raise $5 million in equity on or before September 30, 2016 (which was extended to November 15, 2016 and completed in October 31, 2016);
- A requirement to pay down at least $10 million of the loan by June 30, 2016 (which was increased to $11.5 million and extended to and completed in October 31, 2016 following the agreement to sell our interest in the North Stockyard field for $15 million); and
- The addition of a monthly cash flow sweep whereby 50% of cash operating income will be used to repay outstanding borrowings under the Credit Agreement.

The current borrowing base is $24 million and is fully drawn as at September 28, 2018. We have entered into a forbearance agreement with Mutual of Omaha to allow the closure of the orderly pending asset sale, expected to be October 15, 2018. Should that sale not close in a timely fashion, Mutual of Omaha bank will have the right to seek alternative remedies to facilitate the repayment of the facility.

In January 2014, we entered into a $25.0 million credit facility with Mutual of Omaha Bank. The current borrowing base is $24.0 million, of which $23.5 million was drawn at June 30, 2017. In June 2017, the facility was extended to October 31, 2018 and the interest was changed to the prime rate plus between 1% and 2.5%. This equates to between 5.25% and 6.75%.

All of our assets are pledged as collateral under this facility.

As at June 30, 2017 and June 30, 2018, we were in breach of earnings and liquidity covenants with respect to the facility.

We incurred $0.4 million in borrowing costs when we completed the first drawdown, which have were deferred, however have now been written off to Discontinued Operations following the entering of the original forbearance agreement.

Share-Based Payments	12 Months Ended Jun. 30, 2018
Share-Based Payments [Abstract]	
Share-Based Payments	**10. SHARE-BASED PAYMENTS (all figures are in Australian dollars in this note unless noted otherwise)** To convert June 30, 2018 balances denominated in Australian dollars to U.S. dollars, we used the June 30, 2018 and 2017 Federal Reserve Bank of Australia (www.rba.gov.au) closing exchange rates of 0.7692 and 0.768. U.S. dollars per Australian dollar, respectively. All dollars in this footnote are Australian dollars, except where stated otherwise. During the year ended June 30, 2011, the Company registered a Form S-8 with the Securities Exchange Commission. The Form S-8 is a registration statement used by U.S. public companies to register securities to be offered pursuant to employee benefit plans; in this case the ordinary shares issuable and reserved for issuance underlying the options which may be issued pursuant to the Samson Oil & Gas Limited Stock Option Plan were registered. All incentive options issued by the Company are valued using a Black-Scholes pricing model which requires inputs for the share price at grant date, exercise price, time to expiry, risk free interest rate, share price volatility and dividend yield. The risk free interest rate is based on the interest rate applicable to Australian Government Bonds with a similar remaining life to the options on the day of grant. The dividend yield is the expected annual dividend yield over the expected life of the option. The volatility factors are based on historic volatility of the Company's stock. Estimates of fair value are not intended to predict actual future events or the value ultimately realized by certain employees who receive stock options, and subsequent events are indicative of the reasonableness of the original fair value estimates. During the year ended June 30, 2017 320,000,000 options were issued to certain employees and directors. The options vest on November 16 and 17, 2017 and expire on November 17, 2026. The exercise price of 48,000,000 options is A$0.7 cents and the exercise price on 272,000,000 is $0.55 cents. Based on the following assumptions, the options have fair market value on grant date of A$0.38 cents.

Share price at grant date (cents – Australian)	0.4
Exercise price (cents - Australian)	0.70
Time to expiry (years)	10
Risk free rate (%)	2.72
Share price volatility (%)	119.96

Based on the following assumptions, the options have a fair market value on grant date of A$0.37 cents

Share price at grant date (cents – Australian)	0.4
Exercise price (cents - Australian)	0.55
Time to expiry (years)	10
Risk free rate (%)	2.72
Share price volatility (%)	119.96

No options were issued during the year ended June 30, 2018 as share based payments.

As of June 30, 2017, there was US$0.4 million in unrecognized compensation cost related to stock options. This was expensed during the period from July 1, 2017 to the vesting date of the options on November 17, 2017. 5,500,000 options were cancelled as an employee resigned prior to meeting the vesting condition.

The following summarizes the Company's stock option and warrant activity for the years ended June 30, 2018 and 2017 (all values in AUD unless otherwise noted):

	2018			2017	
	Number	**Weighted Average Exercise Price – cents (AUD)**	**Aggregate Intrinsic Value of Options/Warrants cents (AUD) (1)**	**Number**	**Weighted Average Exercise Price – cents (AUD)**
Outstanding, start of period	411,033,246	1.18		320,615,486	4.60
Granted	-			320,000,000	0.57
Exercised	-			(140,143)	3.80
Cancelled/expired	(96,533,246)	3.80		(229,442,097)	3.80
Outstanding, end of period	314,500,000	0.5700	-	411,033,246	1.18
Exercisable, end of period	314,500,000	0.5700		91,033,246	3.80

(1) The intrinsic value of a stock option is the amount by which the market value is (less than)/exceeds the exercise price at the Balance Date.

The aggregate intrinsic value of options exercised in 2017 was (AUD4,747). No options were exercised during 2018.

Additional information related to options and warrants outstanding at June 30, 2018 is as follows (outstanding):

	Options/Warrants Outstanding and Exercisable		
Range of Exercise Prices	**Number Outstanding**	**Weighted Average Remaining Contractual Life - years**	**Weighted Average Exercise Prices Cents per share**
0.7 cents	48,000,000	8.42	0.7
0.55 cents	266,500,000	8.42	0.55
	314,500,000		

Related Party Transactions	12 Months Ended Jun. 30, 2018
Related Party Transactions [Abstract]	
Related Party Transactions	**11. RELATED PARTY TRANSACTIONS** There were no related party transactions during the years ended June 30, 2018 and 2017.

Commitments	12 Months Ended Jun. 30, 2018
Commitments [Abstract]	
Commitments	**12. COMMITMENTS**

Lease commitments over the next five years are as follows:

	Total	2019	2020	2021	2022	2023	Thereafter
Leases	391,974	123,873	127,845	131,309	8,947	-	-

(2) Leases relate primarily to obligations associated with our office facilities in Denver, Colorado and Perth, Western Australia.
Leases –The Company has entered into lease agreements for office space in Denver, Colorado and Perth, Western Australia. As of June 30, 2018, future minimum lease payments under operating leases that have initial or remaining non–cancelable terms in excess of one year are $123,873 in 2019, $127,845 in 2020, $131,309 in 2021, $8,947 in 2022. Net rent expense incurred for office space was $214,650 and $153,375 in 2018 and 2017, respectively.

Contingencies	12 Months Ended Jun. 30, 2018
Contingencies [Abstract]	
Contingencies	**13. CONTINGENCIES** Samson may be subject to various other lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, and claims for underpayment of royalties, property damage claims and contract actions. The Company records an associated liability when a loss is probable and the amount is reasonably estimable. Although the outcome of litigation cannot be predicted with certainty, management is of the opinion that no pending or threatened lawsuit or dispute incidental to its business operations is likely to have a material adverse effect on the company’s consolidated financial position, results of operations or cash flows. The final resolution of such matters could exceed amounts accrued, however, and actual results could differ materially from management’s estimates.

Subsequent Events	12 Months Ended Jun. 30, 2018
Subsequent Events [Abstract]	
Subsequent Events	**14. SUBSEQUENT EVENTS** There have been no material subsequent events through the date of filing.

Supplemental Information On Oil And Natural Gas Exploration, Development And Production Activities, Inclusive Of Discontinued Operations	12 Months Ended
	Jun. 30, 2018
Supplemental Information On Oil And Natural Gas Exploration, Development And Production Activities, Inclusive Of Discontinued Operations [Abstract]	
Supplemental Information On Oil And Natural Gas Exploration, Development And Production Activities, Inclusive Of Discontinued Operations	(see below)

15. SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES, INCLUSIVE OF DISCONTINUED OPERATIONS (UNAUDITED)

Oil and Gas Reserves

Given the pending sale at June 30, 2018, our fiscal year-end petroleum reserves report was prepared internally by knowledgeable officers and employees of the Company for the current year. The report was based upon our internal review of the property interests being appraised, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sales of production, geoscience and engineering data, and other information we gather. We prepared our estimates by use of standard geological and engineering methods generally accepted by the petroleum industry. Reserve volumes and values were determined under the method prescribed by the SEC, which requires the application of the 12-month average price for natural gas and oil calculated as the un-weighted arithmetic average of the first-day-of-the-month price for each month within the 12-month prior period to the end of the reporting period and year-end costs. The proved reserve estimates represent our net revenue interest in our properties.

Our reserves were prepared by a practitioner with 22 years of industry experience in geologic engineering and a Bachelor of Science in Geological Engineering from Colorado School of Mines. Additionally, our Chief Executive Officer is responsible for overseeing the preparation of the Company's reserves report. The CEO is a petroleum geologist who holds an associateship in applied geology and has over 45 years of relevant experience in the oil and gas industry.

Estimated Proved Reserves

Proved reserves are those quantities of hydrocarbons which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods and government regulations. As commodity prices decline, the commercially viability of wells change and reserve quantities may decrease. Proved reserves can be categorized as developed or undeveloped.

Capitalized Costs Incurred

Costs incurred for oil and natural gas exploration, development and acquisition are summarized below.

	Year ended June 30,	
	2018	**2017**
Development	13,272	2,458,276
Discontinued Operations	68,865	-
Undeveloped capitalized acreage	-	50,375
Total costs incurred	$ 82,137	$ 2,508,651

Estimated Proved Reserves

Proved reserves are those quantities of hydrocarbons which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods and government regulations. As commodity prices decline, the commercially viability of wells change and reserve quantities may decrease. Proved reserves can be categorized as developed or undeveloped.

	Year ended June 30, 2018			Year ended June 30, 2017		
	Oil	**Gas**	**Total**	**Oil**	**Gas**	**Total**
	Mbbls	**MMcf**	**MBOE**	**Mbbls**	**MMcf**	**MBOE**
Beginning of year	5,359	3,565	5,955	9,982	8,593	11,415
Revisions of previous quantity estimates	(1,654)	(2,246)	(2,028)	(2,851)	(2,474)	(3,263)
Extensions and discoveries	-	-	-	-	-	-
Sale of reserves in place	-	-	-	(1,475)	(2,396)	(1,874)
Acquisitions	-	-	-	-	-	-
Production	(190)	(27)	(195)	(297)	(158)	(323)
End of year	3,515	1,292	3,732	5,359	3,565	5,955
Proved developed producing reserves	73	60	84	3,020	1,575	3,285
Proved developed non producing	32	43	39	134	224	171
Proved undeveloped reserves	308	251	350	2,205	1,766	2,499
Proved developed producing reserves - held for sale	2,590	563	2,685	-	-	-
Proved developed non producing - held for sale	512	375	575	-	-	-
Total proved reserves	3,515	1,292	3,732	5,359	3,565	5,955

Revisions of previous quantity estimates

The downward revision recorded for the year ended June 30, 2017 relates to our current drilling plan for our PUD locations. In the prior year, we anticipated drilling them as new 10,000 foot lateral horizontal wells. Upon further technical review, we now plan to drill the PUD wells as 5,000 foot laterals out of an existing well bore. The shortening of the lateral length lead to a decrease in the volume of reserves associated with these PUDs.

The downward revision in the current year relates to our recognition of PUDs. Due to the continued lack of capital available to drill these PUDs, the decision was made to sell substantially all of the wells in the Foreman Butte project area. We have retained a 15% working interest in certain PUDs and we have recognized that value in our reserves at June 30, 2018.

Sales of Reserves in Place

The reserves held for sale relate to the sale of the majority of our interest in the Foreman Butte project. This sale is expected to close on October 15, 2018.

The sale of reserves in place during the fiscal year ended June 30, 2017 consists of proved reserves (net of production prior to sale) in the North Stockyard field in North Dakota and the State GC field in New Mexico. All reserves were proved developed producing.

Developed Reserves

Developed reserves are those reserves expected to be recovered from existing wells, with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved Developed Producing Reserves

At June 30, 2018 our proved developed producing reserves primarily relate to our working interest in producing wells in our Foreman Butte project area in North Dakota and Montana.

Proved Developed Not Producing (PDNP)

PDNP reserves are those estimated proved reserves expected to be recovered from existing wells where a workover is required to re-establish production. As of June 30, 2017, the PDNP reserves were 171 MBOEAs of June 30, 2018, the PDNP reserves were 39 MBOE. These primarily related to our retained interest in the Foreman Butte project. This work is expected to be performed as capital allows.

Proved Undeveloped Reserves

Proved undeveloped reserves (PUD) are those reserves expected to be recovered from new wells on undeveloped acreage.

Due to the continued lack of capital available to drill these PUDs, the decision was made to sell substantially all of the wells in the Foreman Butte project area. We have retained a 15% working interest in certain PUDs and we have recognized that value in our reserves at June 30, 2018 as following the sale, we will have the working capital available to develop these locations.

During the year ended June 30, 2017 through further technical review, we changed our plan with respect to the drilling the PUDs. This reduced the reserves volumes associated with the PUDs but did not change the reserve value associated with the PUDs due to a decrease in the estimated drilling costs. We currently have the permits to drill 4 PUDs and have commenced sourcing the appropriate rig and other contractors and equipment required.

While we did not convert any PUDs during the year ended June 30, 2018, we have made considerable progress on their development through the pending sale.

Standardized Measure of Discounted Future Net Cash Flows

Future hydrocarbon sales and production and development costs have been estimated using a 12 month average price for the commodity prices for June 30, 2018 and 2017 and costs in effect at the end of the periods indicated. The average 12 month historical average of the first of the month prices used for natural gas for June 30, 2018 and 2017 were $2.95 and $3.01 per Mcf, respectively. The 12-month historical average of the first of the month prices used for oil for June 30, 2018 and 2017 were $57.67 and $48.95per barrel of oil, respectively. Future cash flows were reduced by estimated future development, abandonment and production costs based on period–end costs. No deductions were made for general overhead, depletion, depreciation and amortization or any indirect costs. All cash flows are discounted at 10%.

Changes in demand for hydrocarbons, inflation and other factors make such estimates inherently imprecise and subject to substantial revisions. This table should not be construed to be an estimate of current market value of the proved reserves attributable to Samson.

Samson has not disclosed the impact of taxes in the future cash flows for the years ended June 30, 2018 and 2017 as given Samson’s extensive net operating losses carried forward, its history of loss making and the significant value of intangible costs incurred when developing its proved undeveloped locations, for which an immediate tax deduction is currently available, it is unlikely Samson will pay tax in the future based on current commodity pricing.

The following table shows the estimated standardized measure of discounted future net cash flows relating to proved reserves (in US$'000's):

	As at June 30,	
	2018	2017
Future cash inflows	$ 187,249	$ 237,490
Future production costs	(99,620)	(91,920)
Future development costs	(1,642)	(13,367)
Future income taxes	-	-
Future net cashflows	85,987	132,203
10 % discount	(38,325)	(66,941)
Standardized measure of discounted future net cash flows relating to proved reserves	$ 47,662	$ 65,262

The principal sources of changes in the standardized measure of discounted future net cash flows during the periods ended June 30, 2018 and June 30, 2017 are as follows (in US$'000's):

	Fiscal Year Ended June 30	
	2018	2017
Beginning of year	$ 65,262	$ 66,747
Sales of oil and gas produced during the period, net of production costs	(3,902)	(3,122)
Net changes in prices and production costs	2,822	1,601
Previously estimated development costs incurred during the period	-	-
Changes in estimates of future development costs	(11,625)	22,929
Extensions and discoveries	-	-
Revisions of previous quantity estimates and other	(10,088)	(21,078)
Sale of reserves in place	-	(10,445)
Purchase of reserves in place	-	-
Change in future income taxes	-	-
Accretion of discount	6,526	6,675
Other	(1,333)	1,955
Balance at end of year	$ 47,662	$ 65,262

The impact of income taxes has not been included in the current year as the Company's net operating losses, the tax basis of oil and gas assets and future expected deductions, exceed the future cashflows.

Summary Of Significant Accounting Policies (Policy)	12 Months Ended Jun. 30, 2018	Jun. 30, 2017	Jun. 30, 2015
Summary Of Significant Accounting Policies [Abstract]			
Description Of Operations	**Description of Operations.** Samson Oil & Gas Limited along with its consolidated subsidiaries ("Samson" or the "Company"), is engaged in the acquisition, exploration, exploitation and development of oil and natural gas properties with a focus on properties in North Dakota and Montana. **Going concern.** These financial statements have been prepared on the going concern basis, which contemplates the continuity of normal business activities and the realisation of assets and settlement of liabilities in the normal course of business. We incurred a net loss of $6.0 million. the year ended June 30, 2018. As at that date, our total current liabilities of $34.8 million (excluding discontinued operations million exceed our total current assets of $3.5 million (excluding discontinued operations). Additionally, we are in violation of our debt covenants and have suffered recurring losses from operations. These factors raise substantial doubt over our ability to continue as a going concern and therefore whether we will realize our assets and extinguish our liabilities in the normal course of business and at the amounts stated in the financial report. To address these concerns, we have undertaken the following plan: - We have signed a purchase and sale agreement for the sale of substantially all of our interest in the Foreman Butte project for $40 million. The effective date of this sale is January 1, 2018 and the sale is expected to close October 15, 2018. - We have entered into a forbearance agreement with Mutual of Omaha Bank in order to allow the orderly closing of the pending asset sale - We are continuing to operate the properties in a such a way so as to maximize value should we be required to enter into a sale agreement with another party. While management believes that we will successfully close the pending asset sale transaction or a similarly valued alternative sale transaction there can be no assurances that our efforts will be successful. In addition, given our current financial situation we may be forced to accept terms on these transactions that are less favorable than would be otherwise available. The financial report does not include any adjustments relating to the amounts or classification of recorded		

assets or liabilities that might be necessary if the Company does not continue as a going concern.

Comparatives. These statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP).

Principles Of Consolidation

Principles of Consolidation. The consolidated financial statements include the accounts of the Company and its subsidiaries, all of which are wholly owned. Significant intercompany balances and transactions have been eliminated in consolidation.

Use Of Estimates

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Items subject to such estimates and assumptions include (1) oil and gas reserves; (2) cash flow estimates used in impairment tests of long–lived assets; (3) depreciation, depletion and amortization; (4) asset retirement obligations; (5) assigning fair value and allocating purchase price in connection with business combinations; (6) accrued revenue and related receivables; (7) valuation of commodity and interest derivative instruments; (8) certain accrued liabilities; (9) valuation of share-based payments, (10) income taxes and (11) carrying value of exploration and evaluation expenditure. Although management believes these estimates are reasonable, actual results could differ from these estimates. The Company has evaluated subsequent events and transactions through the date of this report for matters that may require recognition or disclosure in these financial statements.

Business Segment Information

Business Segment Information. The Company has evaluated how it is organized and managed and has identified only one operating segment, which is the exploration and production of crude oil, natural gas and natural gas liquids. All of the Company's operations and assets are located in the United States, and all of its revenues are attributable to United States customers.

Revenue Recognition And Gas Imbalances

Revenue Recognition and Gas Imbalances. Revenues from the sale of natural gas and crude oil are recognized when the product is delivered at a fixed or determinable price, title has transferred and collectability is reasonably assured and evidenced by a contract. This generally occurs when oil or natural gas has been delivered to a refinery or a pipeline, or has otherwise been transferred to a customer's facilities or possession. Oil revenues are generally recognized based on actual volumes of completed deliveries where title has transferred. Title to oil sold is typically transferred at the wellhead.

The Company uses the entitlement method of accounting for natural gas revenues. Under this method, revenues are recognized based on actual production of natural gas. The Company incurs production gas volume imbalances in the ordinary course of business. Net deliveries in excess of entitled amounts are recorded as liabilities, while net under–deliveries are reflected as assets. Imbalances are reduced either by subsequent recoupment of over– and under– deliveries or by cash settlement, as required by applicable contracts. The Company's production imbalances were not material at June 30, 2018 or 2017.

Cash And Cash Equivalents

Cash and Cash Equivalents. The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents. The Company's cash management process provides for the daily funding of checks as they are presented to the bank.

Accounts Receivable

Accounts Receivable. The components of accounts receivable include the following:

	June 30	
	2018	**2017**
Oil and natural gas sales	$1,005,217	$ 894,523
Cost recovery from partners	734,912	572,082
Less provision for doubtful debts	(75,000)	-
Other	94,332	83,833
Total accounts receivable, net of nil allowance for doubtful accounts for June 30, 2018 and 2017	$1,759,461	$1,550,438

The Company's accounts receivable result from (i) oil and natural gas sales to oil and intrastate gas pipeline companies and (ii) billings to joint working interest partners in properties operated by the Company. The Company's trade and accrued production receivables are primarily from the operators of our various projects, who negotiate the sale of oil and gas to third parties on our behalf.

Oil And Natural Gas Properties

Oil and Gas Properties.

Oil and gas properties and equipment consist of the following at June 30:

	2018	**2017**
Proved properties	$ 13,181,514	$ 13,114,851
Lease and well equipment	1,169,856	1,140,310

Less accumulated depreciation, depletion and impairment	(12,606,419)	(12,440,389)
	$ 1,744,951	$ 1,814,772
Assets held for sale	28,675,890	-
Unproved acreage	$ -	$ 271,078

The Company accounts for its oil and gas exploration and development costs using the successful efforts method. Geological and geophysical costs are expensed as incurred. Exploratory well costs are capitalized pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. All exploratory wells are evaluated for economic viability within one year of well completion, and the related capitalized costs are reviewed quarterly.

Exploratory wells that discover potentially economic reserves in areas where a major capital expenditure would be required before production could begin and where the economic viability of that major capital expenditure depends upon the successful completion of further exploratory work in the area remain capitalized if the well finds a sufficient quantity of reserves to justify its completion as a producing well and the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

The costs of development wells are capitalized whether productive or nonproductive. The provision for depletion of oil and gas properties is calculated on a field–by–field basis using the unit–of–production method. Mineral interests and leasehold acquisition costs are depleted over total proved reserves while cost of completed wells and related facilities and equipment are depleted over proved developed producing reserves.

If the estimates of total proved or proved developed reserves decline, the rate at which the Company records depreciation, depletion and amortization (DD&A) expense increases, which in turn reduces net earnings. Such a decline in reserves may result from lower commodity prices, which may make it uneconomic to drill for and produce higher cost fields. The Company is unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of its development program, as well as future economic conditions. Changes in reserves are applied on a prospective basis.

As wells are drilled in a field with proved undeveloped reserves or unproved reserves, a portion of the acquisition costs are either re–designated as proved developed or expensed, as appropriate. In fields with multiple potential drilling sites, the Company determines the amount of the acquisition cost to re–designate or expense through a systematic and rational basis that considers the total expected wells to be drilled in that field.

The Company reviews its proved oil and gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. The Company estimates the expected future cash flows of its oil and gas properties and compares these undiscounted future cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the oil and gas properties to fair value. The factors used to determine fair value include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of reserves, future commodity pricing, future production estimates, anticipated capital expenditures and various discount rates commensurate with the risk associated with realizing the projected cash flows. Unproved oil and gas properties are assessed periodically for impairment on a field by field (consistent with the fields used for the calculation of depletion, depreciation and amortization) basis based on remaining lease terms, drilling results, reservoir performance, commodity price outlooks or future plans to develop acreage and allocate capital. When the Company has allocated fair values to significant unproved property (probable reserves) as the result of a business combination or other purchase of proved and unproved properties, it uses a future cash flow analysis to assess the property for impairment.

Gains on sales of proved and unproved properties are only recognized when there is no uncertainty about the recovery of costs applicable to any interest retained or where there is no substantial obligation for future performance by the Company. Impairment on properties sold is recognized when incurred or when the properties are held for sale and the fair value of the properties is less than the carrying value.

In determining whether an unproved property is impaired, the Company considers numerous factors including, but not limited to, current development and exploration drilling plans, favorable or unfavorable exploration activity on adjacent leaseholds, in-house geologists' evaluation of the lease, future reserve cash flows and the remaining lease term.

Assets held for sale

In June 2018, we signed a purchase and sale agreement for the sale of the Foreman Butte Project, subject to our retention of a 15% working interest in a portion of the Project (the “Foreman Butte

Sale"). This transaction received shareholder approval at a general meeting held on August 13, 2018. The purchase price is $40 million with an effective date of January 1, 2018.

The Foreman Butte Project constitutes the majority of our operating assets. Upon closing of the transaction, we will retain a 15% working interest in certain wells in the Home Run Field, which consists of 15 producing wells and 20 PUD locations.

The proceeds of the Foreman Butte Sale will be used to repay our credit facility with Mutual of Omaha Bank in full and bring our other accounts payable current. We estimate that after these repayments, we will have no outstanding debt and will retain approximately $6.5 million in cash proceeds from the sale.

Exploration Written Off, Including Dry Hole Expenses

Exploration and evaluation costs including capitalized exploration written off and dry hole expenses

Exploration and evaluation assets are assessed for impairment when facts and circumstances indicate that the carrying amount of an exploration and evaluation asset may exceed its recoverable amount. When assessing for impairment consideration is given to but not limited to the following:

- the period for which Samson has the right to explore;
- planned and budgeted future exploration expenditure;
- activities incurred during the year; and
- activities planned for future periods.

If, after having capitalized expenditure under our policy, the Company concludes that it is unlikely to recover the expenditure by future exploitation or sale, then the relevant capitalized amount will be written off to the income statement.

During the fiscal year ended June 30, 2018, we expensed $0.2 million in deferred exploration expense in relation to our Cane Creek project area.

Impairment

Impairment

The Company recorded impairment charges of $nil million and $0.2 million for the years ended June

30, 2018 and 2017 respectively.

The charges in the fiscal year ended June 30, 2017 related to the write down of the value in our oil inventory to lower of cost or net realizable value.

Other Property And Equipment

Other Property and Equipment.

Other property and equipment, which includes leasehold improvements, office and other equipment, are stated at cost. Depreciation and amortization are calculated using the straight–line method over the estimated useful lives of the related assets, ranging from 3 to 25 years.

Depreciation and amortization expense for the years ended June 30, 2018 and 2017 was $0.2 million and $0.2 million, respectively.

Other property and equipment consist of the following at June 30:

	2018	2017
Furniture, fittings and equipment	$1,017,879	$ 990,022
Less accumulated depreciation	(775,057)	(693,945)
	$ 242,822	$ 296,077

Derivative Financial Instruments

Derivative Financial Instruments. The Company enters into derivative contracts, primarily collars, swaps and option contracts, to hedge future crude oil and natural gas production in order to mitigate the risk of market price fluctuations. All derivative instruments are recorded on the balance sheet at fair value. All of the Company's derivative counterparties are major oil companies. The Company has elected not to apply hedge accounting to any of its derivative transactions and consequently, the Company recognizes mark-to-market gains and losses in earnings currently, rather than deferring such amounts in other comprehensive income for those commodity derivatives that qualify as cash flow hedges.

Asset Retirement Obligations

Asset Retirement Obligations. The Company recognizes estimated liabilities for future costs associated with the abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long–lived asset are recorded at the time the well is spud or acquired.

Environmental

Environmental. The Company is subject to extensive federal, state and local environmental laws and regulations. These laws and regulations, which regularly change, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a non–capital nature are recorded when environmental assessment and/or remediation is probable and the costs can be reasonably estimated. Such liabilities are generally recorded at their undiscounted amounts unless the amount and timing of payments is fixed or reliably determinable. The Company is not aware of any material noncompliance with existing laws and regulations.

Income Taxes

Income Taxes. Deferred income tax assets and liabilities are recognized for the future income tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective income tax bases. Deferred income tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred income tax assets and liabilities of a change in income tax rates is recognized in income in the period that includes the enactment date. The measurement of deferred income tax assets is reduced, if necessary, by a valuation allowance if management believes that it is more likely than not that some portion or all of the net deferred tax assets will not be fully realized on future income tax returns. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, available taxes in carryback periods, projected future taxable income and tax planning strategies in making this assessment.

The Company recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement.

Earnings Per Share

Earnings per Share. Basic earnings (loss) per share are calculated by dividing net earnings (loss) attributable to common stock by the weighted average number of shares outstanding for the period. Under the treasury stock method, diluted earnings per share is calculated by dividing net earnings (loss) by the weighted average number of shares outstanding including all potentially dilutive common shares. In the event of a net loss, no potential common shares are included in the calculation of shares outstanding since the impact would be anti-dilutive. When the Company records a net loss, none of the loss is allocated to the unexercised stock options since the securities are not obligated to share in Company losses. Consequently, in periods of net loss, outstanding options will have no dilutive impact to the Company's basic earnings per share.

The following potential common shares relating to options and warrants have been excluded from the calculation of diluted earnings per share as the related impact was anti-dilutive.

	Year ended June 30,	
	2018	**2017**
Dilutive	-	-
Anti–dilutive	314,500,000	287,956,323

Stock-Based Compensation

Stock-Based Compensation. Stock-based compensation is measured at the estimated grant date fair value of the awards and is recognized on a straight-line basis over the requisite service period (usually the vesting period). The Company recognizes stock-based compensation net of an estimated forfeiture rate, and recognizes compensation expense only for shares that are expected to vest. Compensation expense is then adjusted based on the actual number of awards for which the requisite service period is rendered.

Foreign Currency Translation

Foreign Currency Translation. The functional currency of Samson Oil & Gas Limited (Parent Entity) is Australian dollars, the reason for this being the majority of cash flows of the Parent Entity are denominated in Australian dollars. The functional and presentation currency of Samson Oil & Gas USA, Inc. (subsidiary) is U.S. dollars. The presentation currency of the Consolidated Entity is U.S. dollars.

Transactions in foreign currencies are initially recorded in the functional currency by applying the exchange rates ruling at the date of the transaction. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at year ended exchange rates of monetary assets and liabilities denominated in foreign currencies are recognized in profit and loss

Translation differences on assets and liabilities carried at fair value are reported as part of the fair value gain or loss. Translation differences on non-monetary assets and liabilities are recognized in other comprehensive income.

New Accounting Pronouncements, Policy [Policy Text Block]

Impact of Recently Adopted Accounting Standards.
There have been no recently adopted accounting standards that would impact our business.

Recently Issued Accounting Pronouncements
In August 2014, the FASB issued new guidance related to the disclosures around going concern. The new standard provides guidance around management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and to provide related footnote disclosures. The new guidance becomes effective for fiscal years beginning after December 15, 2016, and interim periods within those years, with early adoption permitted.

This standard has been adopted and the Company has added the appropriate disclosures.

In November 2014, the FASB issued ASU No. 2014-16, which updates authoritative guidance for derivatives and hedging instruments, specifically in determining whether the host contract in a hybrid financial instrument issued in the form of a share is more akin to debt or to equity. This guidance is effective for the annual period beginning after December 15, 2015; early adoption is permitted. The Company has adopted this standard and it did not have a material impact on its consolidated financial statements.

Impact of Recently Adopted Accounting Standards.

There have been no recently adopted accounting standards that would impact our business.

Recently Issued Accounting Pronouncements

ASU 2016-02, *Leases (Topic 842)* This ASU, among other provisions, requires lessees to recognize right of use assets and leases liabilities for all leases not considered short term leases. The ASU is effective for public business entities for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years This standard is not expected to have a significant impact on the Company as it does not currently engage in significant leasing activity.

ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)* Accounting Standards Update (ASU) 2014-09 provides a new framework for addressing revenue recognition issues and upon its effective date, replaces almost all existing revenue recognition guidance. While the revenue recognition policies of all entities will be impacted by this standard, we do not expect the impact to be significant. For public business entities, the guidance is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period.

We do expect this standard to have a significant impact on our financial reporting of the standards disclosed above that have not yet taken effect. However, we do expect these changes to have an impact with additional disclosures contained in the 10Q for the period ended September 30, 2018 expected.

Summary Of Significant Accounting Policies (Tables)	12 Months Ended Jun. 30, 2018
Summary Of Significant Accounting Policies [Abstract]	
Schedule Of Components Of Accounts Receivable	

	June 30	
	2018	**2017**
Oil and natural gas sales	$ 1,005,217	$ 894,523
Cost recovery from partners	734,912	572,082
Less provision for doubtful debts	(75,000)	-
Other	94,332	83,833
Total accounts receivable, net of nil allowance for doubtful accounts for June 30, 2018 and 2017	$ 1,759,461	$ 1,550,438

Schedule Of Other Property And Equipment

	2018	**2017**
Furniture, fittings and equipment	$ 1,017,879	$ 990,022
Less accumulated depreciation	(775,057)	(693,945)
	$ 242,822	$ 296,077

Schedule Of Weighted Average Dilutive And Anti-Dilutive Securities

	Year ended June 30,	
	2018	**2017**
Dilutive	-	-
Anti–dilutive	314,500,000	287,956,323

Discontinued Operations (Tables)	12 Months Ended Jun. 30, 2018
Discontinued Operations [Abstract]	
Schedule Of Earnings From Discontinued Operations, Net Of Income Tax	Discontinued Operations

	Year ended June 30,	
	2018	**2017**
Major line items constituting pretax gain (loss) of discontinued operations		
Oil sales	9,678,832	10,336,307
Gas sales	91,742	162,546
Other liquids	8,864	5,261
Lease operating expense	(6,031,983)	(7,751,072)
Depletion, depreciation and amortization	(1,071,959)	(1,770,500)
Accretion of asset retirement obligations	(216,229)	(263,964)
Amortization of borrowing costs	(440,434)	(219,810)
Interest expense	(1,275,137)	(1,592,802)
Gain/(loss) from discontinued operations	743,696	(1,094,034)
Cashflows from Discontinued Operations		
Cashflows from Operating Activities	6,768,727	2,236,620
Cashflows from Investing Activities	(445,997)	(2,718,371)
Cashflows from Financing Activities	(1,350,391)	-

Hedging And Derivative Financial Instruments (Tables)	12 Months Ended
	Jun. 30, 2018
Hedging And Derivative Financial Instruments [Abstract]	
Schedule Of Open Derivative Contracts	During the year ended June 30, 2017, the Company recorded a gain of $1.3 million in the Statement of Operations in in derivative instruments. As of June 30, 2017, the derivative instruments were valued at $0.26 million of which, $0.1 million is recorded as a current liability and $0.36 million is recorded as a non-current asset.

Fair Value Measurements (Tables)	12 Months Ended Jun. 30, 2018
Fair Value Measurements [Abstract]	
Schedule Of Fair Value, Assets And Liabilities Measured On Recurring And Nonrecurring Basis	see tables below

Fair Value at June 30, 2018

	Level 1	Level 2	Level 3	Netting [(1)]	Total
Current Assets:					
Cash and cash equivalents	$1,376,676	$ -	$ -	$ -	$1,376,676
Derivative Instruments	-	4,218	-	(4,218)	-
Non Current Assets:					
Derivative Instruments	-	-	-	-	-
Current Liabilities					
Derivative Instruments	-	1,215,013	-	(4,218)	1,210,795
Non Current Liabilities:					
Derivative Instruments		-		-	-

Fair Value at June 30, 2017

	Level 1	Level 2	Level 3	Netting [(1)]	Total
Current Assets:					
Cash and cash equivalents	$ 628,778	$ -	$ -	$ -	$ 628,778
Derivative Instruments	-	167,307	-	(167,307)	-
Non Current Assets:					
Derivative Instruments	-	370,494	-	(270,891)	99,603
Current Liabilities					
Derivative Instruments	-	531,267	-	(167,307)	363,960
Non Current Liabilities:					
Derivative Instruments		270,891		(270,891)	-

Asset Retirement Obligations (Tables)

12 Months Ended Jun. 30, 2018

Asset Retirement Obligations [Abstract]

Summary Of Activities Of Asset Retirement Obligations

	2018	2017
Asset retirement obligations at beginning of period	$ 3,456,236	$ 3,750,245
Liabilities incurred or acquired	-	226,123
Liabilities settled	(73,667)	(427,214)
Disposition of properties	(73,011)	(409,683)
Accretion expense	34,554	316,765
Asset retirement obligations at end of period	3,344,112	3,456,236
Less: current asset retirement obligations (classified with accounts payable and accrued liabilities)	-	(300,000)
Less current asset retirement obligatons related to assets held for sale	(2,509,981)	
Long-term asset retirement obligations	$ 834,131	$ 3,156,236

Income Taxes (Tables)	12 Months Ended	
	Jun. 30, 2018	Jun. 30, 2017
Income Taxes [Abstract]		
Schedule Of Components Of Income Tax Provision (Benefit)	(table below)	

	June 30	
	2018	2017
Current:		
Federal	$ (732,056)	$ -
State	-	-
	(732,056)	-
Deferred:		
Federal	(732,056)	-
State	-	-
Less income tax benefit allocated to discontinued operations		
Total income tax provision (benefit)	$(1,464,112)	$ -

Schedule Of Effective Income tax Rate Reconciliation

	June 30	
	2018	2017
Income tax expense (benefit) at federal statutory rate	$ (1,956,277)	$(787,563)
Effect of permanent differences and other - US	115,616	-
State income taxes	(123,694)	(34,997)
Change in tax rate	11,207,430	
US income taxed at a different rate	116,777	
Foreign exchange	282,557	
Other adjustments - true up of deferred balances	(10,819)	
Alternative minimum tax	-	-
Other - change in deferred tax rate	-	(239,200)
Other	23,507	112,867
Valuation allowance	(10,387,153)	948,893
	$ (732,056)	$ -

Schedule Of Components Of Deferred Tax Assets and (Liabilities)

	June 30	
	2018	2017
Deferred income tax assets:		
Net operating losses	$ 23,674,591	$ 34,581,318
Asset retirement obligation	737,875	1,212,151
Annual leave	51,837	81,130
Abandonment limitation	554,685	554,685
Allowance for doubtful debts	17,560	-
Accrued bonus	-	-
Charitable contributions	-	882
AMT credit	780,443	780,443
Share based compensation	500,844	500,844
Oil and Gas Property	-	-
Derivative liability	283,458	98,175

Valuation allowance	(23,951,026)	(34,286,029)
Deferred income tax liabilities:		
Commodity liability	-	-
Amortization - loan costs	-	-
Oil and gas property	(1,908,395)	(3,523,599)
Net deferred income tax assets (liabilities)	732,506	-

Summary Of Valuation Allowance

	June 30	
	2018	**2017**
Deferred Income Tax Valuation Allowance		
Balance at July 1	34,286,029	33,337,136
Additions (reductions) to deferred income tax expense	(10,387,153)	948,893
Balance at June 30	23,898,876	34,286,029

Reconciliation Of Gross Uncertain Tax Positions

Capital Stock Contributed Equity (Tables)	12 Months Ended Jun. 30, 2018
Capital Stock Contributed Equity [Abstract]	
Contributed Equity	(table below)

	Consolidated Entity	
	2018	**2017**
3,283,000,444 ordinary fully paid shares including shares to be issued (2017 –3,283,000,444 ordinary fully paid shares including shares to be issued)	$ 106,743,167	$ 106,390,864

Movements In Contributed Equity For The Year

Movements in contributed equity for the year	**2018**		**2017**	
	No. of shares	**$**	**No. of shares**	**$**
Opening balance	3,283,000,444	106,390,864	3,215,854,701	105,719,184
Capital raising (i)	-	-	-	-
Shares issued upon exercise of options (ii)	-	-	140,143	4,516
Stock based compensation - shares issued	-	-	67,005,600	159,506
Stock based compensation - warrants issued	-	352,303	-	551,987
Transaction costs incurred	-	-	-	(44,329)
Shares on issue at balance date	3,283,000,444	106,743,167	3,283,000,444	106,390,864

i)

(ii) During the course of the prior year the Company issued 140,143 ordinary shares upon the exercise of 140,143 options.

Cash Flow Statement (Tables)

	12 Months Ended Jun. 30, 2018

Cash Flow Statement [Abstract]

Schedule Of Cash Flow Statement

	Year ended June 30	
	2018	2017
A reconciliation of the net loss to the net cash provided by operations is as follows:		
Net loss after tax	$ (6,038,866)	$ (2,767,496)
Depreciation	1,237,989	1,989,135
Accretion of asset retirement obligations	250,783	316,765
Share based payments	352,303	711,493
Exploration and evaluation expenditures	325,304	78,391
Impairment losses of oil and gas properties	-	244,480
Borrowing costs	440,434	219,810
Change in fair value of derivative instruments	946,438	(2,640,373)
Bargain purchase on acquisition	-	-
Profit on sale of assets	(178,407)	(2,250,070)
Provision for doubtful debts	75,000	-
Income tax benefit	(732,056)	
Non cash other income	-	(126,265)
Changes in assets and liabilities:		
Decrease in receivables	(121,193)	743,041
Increase/(decrease) in employee benefits	1,766	54,563
Increase in payables	5,746,229	815,566
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	**$ 2,305,724**	**$ (2,610,960)**

Credit Facility (Tables)	12 Months Ended Jun. 30, 2018
Credit Facility [Abstract]	
Schedule of Credit Facilities	

	June 30, 2018	June 30, 2017
Credit facility at beginning of period	$ 23,419,749	$ 30,500,000
Cash advanced under facility	450,000	-
Assumption of promissory note	-	4,000,000
Repayments	(2,192)	(11,080,251)
Credit facility at end of period	$ 23,867,557	$ 23,419,749
Funds available for drawdown under the facility	-	580,251

Share-Based Payments (Tables)	12 Months Ended Jun. 30, 2018
Share-Based Payments [Abstract]	
Schedule Of Additional Information Related To Options Outstanding	

	Options/Warrants Outstanding and Exercisable		
Range of Exercise Prices	**Number Outstanding**	**Weighted Average Remaining Contractual Life - years**	**Weighted Average Exercise Prices Cents per share**
0.7 cents	48,000,000	8.42	0.7
0.55 cents	266,500,000	8.42	0.55
	314,500,000		

Commitments (Tables)	12 Months Ended Jun. 30, 2018
Commitments [Abstract]	
Contractual Obligations	

	Total	2019	2020	2021	2022	2023	Thereafter
Leases	391,974	123,873	127,845	131,309	8,947	-	-

Supplemental Information On Oil And Natural Gas Exploration, Development And Production Activities, Inclusive Of Discontinued Operations (Tables)	12 Months Ended	
	Jun. 30, 2018	Jun. 30, 2017
Supplemental Information On Oil And Natural Gas Exploration, Development And Production Activities, Inclusive Of Discontinued Operations [Abstract]		
Summary Of Costs Incurred For Oil And Natural Gas Exploration, Development And Acquisition		

	Year ended June 30,	
	2018	2017
Development	13,272	2,458,276
Discontinued Operations	68,865	-
Undeveloped capitalized acreage	-	50,375
Total costs incurred	$ 82,137	$ 2,508,651

Schedule Of Proved Developed And Undeveloped Oil And Gas Reserve Quantities

	Year ended June 30, 2018			Year ended June 30, 2017		
	Oil	Gas	Total	Oil	Gas	Total
	Mbbls	MMcf	MBOE	Mbbls	MMcf	MBOE
Beginning of year	5,359	3,565	5,955	9,982	8,593	11,415
Revisions of previous quantity estimates	(1,654)	(2,246)	(2,028)	(2,851)	(2,474)	(3,263)
Extensions and discoveries	-	-	-	-	-	-
Sale of reserves in place	-	-	-	(1,475)	(2,396)	(1,874)
Acquisitions	-	-	-	-	-	-
Production	(190)	(27)	(195)	(297)	(158)	(323)
End of year	3,515	1,292	3,732	5,359	3,565	5,955
Proved developed producing reserves	73	60	84	3,020	1,575	3,285
Proved developed non producing	32	43	39	134	224	171
Proved undeveloped reserves	308	251	350	2,205	1,766	2,499
Proved developed producing						

reserves - held for sale	2,590	563	2,685	-	-	-
Proved developed non producing - held for sale	512	375	575	-	-	-
Total proved reserves	3,515	1,292	3,732	5,359	3,565	5,955

Schedule Of Estimated Standardized Measure Of Discounted Future Net Cash Flows Relating To Proved Reserves

	As at June 30,	
	2018	**2017**
Future cash inflows	$187,249	$237,490
Future production costs	(99,620)	(91,920)
Future development costs	(1,642)	(13,367)
Future income taxes	-	-
Future net cashflows	85,987	132,203
10 % discount	(38,325)	(66,941)
Standardized measure of discounted future net cash flows relating to proved reserves	$ 47,662	$ 65,262

Schedule Of Changes In Standardized Measure Of Discounted Future Net Cash Flows

	Fiscal Year Ended June 30	
	2018	**2017**
Beginning of year	$ 65,262	$ 66,747
Sales of oil and gas produced during the period, net of production costs	(3,902)	(3,122)
Net changes in prices and production costs	2,822	1,601
Previously estimated development costs incurred during the period	-	-
Changes in estimates of future development costs	(11,625)	22,929
Extensions and discoveries	-	-
Revisions of previous quantity estimates		

and other	(10,088)	(21,078)
Sale of reserves in place	-	(10,445)
Purchase of reserves in place	-	-
Change in future income taxes	-	-
Accretion of discount	6,526	6,675
Other	(1,333)	1,955
Balance at end of year	$ 47,662	$ 65,262

Summary Of Significant Accounting Policies (Narrative) (Details)	12 Months Ended	
	Jun. 30, 2018 USD ($) segment	Jun. 30, 2017 USD ($)
Significant Accounting Policies [Line Items]		
Number of operating segments | segment	1	
Impairment of oil and natural gas properties		$ 244,480
Depreciation and amortization	$ 166,030	218,635
Minimum percentage of likelihood tax benefits recognized from uncertain tax position, reasonably possible upon settlement	50.00%	
Proved properties	$ 13,181,514	13,114,851
Other Property And Equipment [Member]		
Significant Accounting Policies [Line Items]		
Depreciation and amortization	$ 200,000	$ 200,000
Other Property And Equipment [Member] | Minimum [Member]		
Significant Accounting Policies [Line Items]		
Estimated useful life	3 years	
Other Property And Equipment [Member] | Maximum [Member]		
Significant Accounting Policies [Line Items]		
Estimated useful life	25 years	

Summary Of Significant Accounting Policies (Schedule Of Components Of Accounts Receivable) (Details) - USD ($)	Jun. 30, 2018	Jun. 30, 2017	Jun. 30, 2014	Jun. 30, 2013
Accounts, Notes, Loans and Financing Receivable [Line Items]				
Accounts receivable	$ 1,759,461	$ 1,550,438		
Less provision for doubtful debts	(75,000)			
Accounts receivable, allowance for doubtful accounts	75,000			
Oil And Natural Gas Sales Related Receivable [Member]				
Accounts, Notes, Loans and Financing Receivable [Line Items]				
Accounts receivable	1,005,217	894,523		
Cost Recovery From JV Partner Receivable [Member]				
Accounts, Notes, Loans and Financing Receivable [Line Items]				
Accounts receivable	734,912	572,082		
Other Receivable [Member]				
Accounts, Notes, Loans and Financing Receivable [Line Items]				
Accounts receivable	$ 94,332	$ 83,833		

Summary Of Significant Accounting Policies (Schedule Of Oil And Gas Properties And Equipment) (Details) - USD ($)	Jun. 30, 2018	Jun. 30, 2017
Summary Of Significant Accounting Policies [Abstract]		
Proved properties	$ 13,181,514	$ 13,114,851
Lease and well equipment	1,169,856	1,140,310
Less accumulated depreciation, depletion and impairment	(12,606,419)	(12,440,389)
Total oil and gas properties and equipment	1,744,951	1,814,772
Assets Held-for-sale, Not Part of Disposal Group, Current	$ 28,675,890	
Undeveloped capitalized acreage		$ 271,078

Summary Of Significant Accounting Policies (Schedule Of Other Property And Equipment) (Details) - USD ($)	Jun. 30, 2018	Jun. 30, 2017
Summary Of Significant Accounting Policies [Abstract]		
Furniture, fittings and equipment	$ 1,017,879	$ 990,022
Less accumulated depreciation	(775,057)	(693,945)
Total other property and equipment	$ 242,822	$ 296,077

Summary Of Significant Accounting Policies (Schedule Of Weighted Average Dilutive And Anti-Dilutive Securities) (Details) - shares	12 Months Ended	
	Jun. 30, 2018	Jun. 30, 2017
Diluted weighted average common shares outstanding	3,283,000,444	3,257,194,847
Options And Warrants [Member]		
Anit-dilutive weighted average common shares outstanding	314,500,000	287,956,323

Discontinued Operations (Schedule Of Earnings From Discontinued Operations, Net Of Income Tax) (Details) - USD ($)	12 Months Ended	
	Jun. 30, 2018	Jun. 30, 2017
Income Statement, Balance Sheet and Additional Disclosures by Disposal Groups, Including Discontinued Operations [Line Items]		
Earnings from discontinued operations, net of income taxes	$ 743,696	$ (1,094,034)
Cashflows from Operating Activities	6,768,727	2,236,620
Cashflows from Investing Activities	(445,997)	(2,718,371)
Cashflows from Financing Activities	(1,350,391)	
Discontinued Operations [Member]		
Income Statement, Balance Sheet and Additional Disclosures by Disposal Groups, Including Discontinued Operations [Line Items]		
Lease operating expense	(6,031,983)	(7,751,072)
Depletion, amortization and impairment	(1,071,959)	(1,770,500)
Accretion of asset retirement obligations	(216,229)	(263,964)
Amortization of borrowing costs	(440,434)	(219,810)
Interest expense	(1,275,137)	(1,592,802)
Earnings from discontinued operations, net of income taxes	(743,696)	1,094,034
Cashflows from Operating Activities	6,768,727	2,236,620
Cashflows from Investing Activities	(445,997)	(2,718,371)
Cashflows from Financing Activities	(1,350,391)	
Oil [Member] | Discontinued Operations [Member]		
Income Statement, Balance Sheet and Additional Disclosures by Disposal Groups, Including Discontinued Operations [Line Items]		
Sales	9,678,832	10,336,307
Natural Gas [Member] | Discontinued Operations [Member]		
Income Statement, Balance Sheet and Additional Disclosures by Disposal Groups, Including Discontinued Operations [Line Items]		
Sales	91,742	162,546
Other Liquids [Member] | Discontinued Operations [Member]		
Income Statement, Balance Sheet and Additional Disclosures by Disposal Groups, Including Discontinued Operations [Line Items]		
Sales	$ 8,864	$ 5,261

Hedging And Derivative Financial Instruments (Narrative) (Details) - USD ($)	12 Months Ended	
	Jun. 30, 2018	Jun. 30, 2017
Hedging And Derivative Financial Instruments [Abstract]		
Fair value of derivative instruments		$ 99,603
Derivative Liability, Current	$ 1,210,795	363,960
Loss on Derivative Instruments, Pretax	$ 2,722,166	
Gain on derivative instruments		$ 1,297,472

Hedging And Derivative Financial Instruments (Schedule Of Open Derivative Contracts) (Details)	3 Months Ended Sep. 30, 2016 bbl / MMBTU $ / bbl
Derivative Contract Seven [Member]	
Derivative [Line Items]	
Derivative inception	Jul. 01, 2018
Derivative maturity	Dec. 31, 2018
Volume (BO/Mmbtu) | bbl / MMBTU	80,960
Floor price	45.00
Ceiling price	56.00
Derivative Contract Eight [Member]	
Derivative [Line Items]	
Derivative inception	May 01, 2018
Derivative maturity	Dec. 31, 2018
Volume (BO/Mmbtu) | bbl / MMBTU	50,490
Floor price	2.65
Ceiling price	2.90

Fair Value Measurements (Schedule Of Fair Value, Assets And Liabilities Measured On Recurring And Nonrecurring Basis) (Details) - USD ($)		Jun. 30, 2018	Jun. 30, 2017
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]			
Cash and cash equivalents		$ 1,376,676	$ 628,778
Non Current Assets, Derivative Instruments			99,603
Current Liabilities, Derivative Instruments		1,210,795	363,960
Level 1 [Member]			
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]			
Cash and cash equivalents		1,376,676	628,778
Level 2 [Member]			
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]			
Cash and cash equivalents			
Current Assets, Derivative Instruments		4,218	167,307
Non Current Assets, Derivative Instruments			370,494
Current Liabilities, Derivative Instruments		1,215,013	531,267
Non Current Liabilities, Derivative Instruments			270,891
Level 3 [Member]			
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]			
Cash and cash equivalents			
Current Assets, Derivative Instruments			
Non Current Assets, Derivative Instruments			
Current Liabilities, Derivative Instruments			
Non Current Liabilities, Derivative Instruments			
Netting [Member]			
Fair Value, Assets and Liabilities Measured on Recurring and Nonrecurring Basis [Line Items]			
Current Assets, Derivative Instruments	[1]	(4,218)	(167,307)
Non Current Assets, Derivative Instruments	[1]		(270,891)
Current Liabilities, Derivative Instruments	[1]	$ (4,218)	(167,307)
Non Current Liabilities, Derivative Instruments	[1]		$ (270,891)

[1] Netting In accordance with the Company's standard practice, its commodity derivatives are subject to counterparty netting under agreements governing such derivatives and therefore the risk of loss is somewhat mitigated.

Asset Retirement Obligations (Details) - USD ($)	12 Months Ended	
	Jun. 30, 2018	Jun. 30, 2017
Asset Retirement Obligations [Line Items]		
Asset retirement obligations at beginning of period	$ 3,456,236	$ 3,750,245
Liabilities incurred or acquired		226,123
Liabilities settled	73,667	427,214
Disposition of properties	(73,011)	(409,683)
Accretion expense	34,554	316,765
Asset retirement obligations at end of period	3,344,112	3,456,236
Less: current asset retirement obligation (classified with accounts payable and accrued liabilities)		(300,000)
Less current asset retirement obligatons related to assets held for sale	2,509,981	
Long-term asset retirement obligations	$ 834,131	$ 3,156,236
Minimum [Member]		
Asset Retirement Obligations [Line Items]		
Asset Retirement Obligations, Discount Rate		4.00%
Maximum [Member]		
Asset Retirement Obligations [Line Items]		
Asset Retirement Obligations, Discount Rate		13.00%

Income Taxes (Narrative) (Details)	12 Months Ended				
	Jun. 30, 2018 USD ($)	Jun. 30, 2017 USD ($)	Jun. 30, 2017 AUD ($)	Jun. 30, 2017 USD ($)	Jun. 30, 2016 USD ($)
Income Taxes [Line Items]					
Tax losses carried forward	$ 15,509,399		$ 15,949,783		
Benefit of tax losses carried forward	4,652,820	$ 4,784,935			
Net operating tax losses				$ 82,341,738	
Tax expense (benefit)	(732,056)				
Internal Revenue Service (IRS) [Member]					
Income Taxes [Line Items]					
Net operating tax losses	84,932,621				
Limitation per year	$ 403,194				
State and Local Jurisdiction [Member]					
Income Taxes [Line Items]					
Net operating tax losses				$ 49,189,363	$ 47,582,073
Minimum [Member] | Internal Revenue Service (IRS) [Member]					
Income Taxes [Line Items]					
Net operating losses, expiration year		Jan. 01, 2020			
Minimum [Member] | State and Local Jurisdiction [Member]					
Income Taxes [Line Items]					
Net operating losses, expiration year		Jun. 01, 2015			
Maximum [Member] | Internal Revenue Service (IRS) [Member]					
Income Taxes [Line Items]					
Net operating losses, expiration year		Dec. 31, 2036			
Maximum [Member] | State and Local Jurisdiction [Member]					
Income Taxes [Line Items]					
Net operating losses, expiration year		Jun. 01, 2033			

Income Taxes (Schedule Of Components Of Income Tax Provision (Benefit)) (Details)	12 Months Ended Jun. 30, 2018 USD ($)
Income Taxes [Abstract]	
Current Federal	$ (732,056)
Current	(732,056)
Deferred Federal	(732,056)
Total income tax provision (benefit)	$ (1,464,112)

Income Taxes (Schedule Of Effective Income tax Rate Reconciliation) (Details) - USD ($)	12 Months Ended		
	Jun. 30, 2018	Jun. 30, 2017	Jun. 30, 2014
Income Taxes [Abstract]			
Federal statutory rate			30.00%
Income tax expense (benefit) at federal statutory rate	$ (1,956,277)	$ (787,563)	
Effect of permanent differences and other - US	115,616		
State income taxes	(123,694)	(34,997)	
Change in tax rate	11,207,430		
US income taxed at a different rate	116,777		
Foreign exchange	282,557		
Other adjustments - true up deferred balances	(10,819)		
Other - change in deferred tax rate		(239,200)	
Other	23,507	112,867	
Valuation allowance	(10,387,153)	948,893	
Income Tax Expense (Benefit), Total	$ (732,056)		

Income Taxes (Schedule Of Components Of Deferred Tax Assets and (Liabilities)) (Details) - USD ($)	Jun. 30, 2018	Jun. 30, 2017
Income Taxes [Abstract]		
Net operating losses	$ 23,674,591	$ 34,581,318
Asset retirement obligation	737,875	1,212,151
Annual leave	51,837	81,130
Abandonment limitation	554,685	554,685
Allowance for doubtful debts	17,560	
Accrued bonus		
Charitable contributions		882
AMT Credit	780,443	780,443
Share based compensation	500,844	500,844
Derivative liability	283,458	98,175
Valuation allowance	(23,951,026)	(34,286,029)
Commodity liability		
Amortization - loan costs		
Oil and gas property	(1,908,395)	(3,523,599)
Net deferred income tax assets (liabilities)	732,506	
Noncurrent deferred tax liability	$ 732,056	

Income Taxes (Summary Of Valuation Allowance) (Details) - USD ($)	12 Months Ended	
	Jun. 30, 2018	Jun. 30, 2017
Valuation Allowance [Line Items]		
Balance	$ 34,286,029	
Balance	23,951,026	$ 34,286,029
Deferred Income Tax [Member]		
Valuation Allowance [Line Items]		
Balance	34,286,029	33,337,136
Additions (reductions) to deferred income tax expense	(10,387,153)	948,893
Balance	$ 23,898,876	$ 34,286,029

Capital Stock Contributed Equity (Narrative) (Details)	12 Months Ended			
	Jun. 30, 2018 shares	Jun. 30, 2017 $ / shares shares	Jun. 30, 2017 $ / shares shares	Jun. 30, 2015 AUD ($)
Shares issued upon exercise of options, shares	140,143	140,143.00	140,143.00	
Weighted average exercise price - cents (AUD), exercised | (per share)		$ 0.038	$ 3.800	
Aggregate intrinsic value of options exercised | $				$ 4,747
1.5 Cents [Member]				
Shares issued upon exercise of options, shares		140,143	140,143	

Capital Stock Contributed Equity (Contributed Equity) (Details) - USD ($)	Jun. 30, 2018	Jun. 30, 2017
Capital Stock Contributed Equity [Abstract]		
2,837,756,933 ordinary fully paid shares including shares to be issued (2013 - 2,229,165,163 ordinary fully paid shares including shares to be issued)	$ 106,743,167	$ 106,390,864
Common stock outstanding and to be issued	3,283,000,444	3,283,000,444

Capital Stock Contributed Equity (Movements In Contributed Equity For The Year) (Details) - USD ($)	12 Months Ended		
	Jun. 30, 2018	Jun. 30, 2017	Jun. 30, 2016
Beginning Balance, shares	3,283,000,444	3,215,854,701	
Opening balance, value	$ 106,390,864	$ 105,719,184	
Shares issued upon exercise of options, shares	140,143	140,143.00	
Shares issued upon exercise of options, value		$ 4,516	
Stock based compensation (options issued), value		711,493	
Transaction costs incurred, value		$ (44,329)	$ (44,329)
Ending Balance, shares	3,283,000,444	3,283,000,444	3,215,854,701
Shares on issue at balance date, value	$ 106,743,167	$ 106,390,864	$ 105,719,184
Issued Capital [Member]			
Share based payment, shares		67,005,600	
Share based payment, value		$ 159,506	
Stock based compensation (options issued), value		711,493	
Transaction costs incurred, value			$ (44,329)
Warrant [Member]			
Share based payment, value	$ 352,303	$ 551,987	

Cash Flow Statement (Details) - USD ($)	12 Months Ended	
	Jun. 30, 2018	Jun. 30, 2017
Cash Flow Statement [Abstract]		
Net loss after tax	$ (6,038,866)	$ (2,767,496)
Net loss after tax	(6,038,866)	(2,767,496)
Net (gain)/loss recognized on re-measurement to fair-value of investments held for trading	946,438	(2,640,373)
Depreciation	1,237,989	1,989,135
Accretion of asset retirement obligations	250,783	316,765
Share Based payments and options issued	352,303	711,493
Borrowing costs	440,434	219,810
Exploration expense	325,304	78,391
Impairment losses of oil and gas properties		244,480
Abandonment expense	128,862	3,055
Gain on sale of assets	(178,407)	(2,250,070)
Provision for doubtful debts	75,000	
Income tax benefit	(732,056)	
Non cash other income		(126,265)
(Increase)/decrease in receivables	(121,193)	743,041
Increase/(decrease) in employee benefits	1,766	54,563
Increase/(decrease) in payables	5,746,229	815,566
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 2,305,724	$ (2,610,960)

Credit Facility (Narrative) (Details) - USD ($)	3 Months Ended	12 Months Ended				
	Sep. 30, 2016	Jun. 30, 2017	Jun. 30, 2016	Jun. 30, 2018	Jun. 30, 2015	Jan. 31, 2014
Credit Facility [Abstract]						
Line of credit facility, maximum borrowing capacity						$ 25,000,000
Line of credit facility, current borrowing capacity		$ 24,000,000				
Line of credit facility, amount outstanding		23,419,749	$ 23,419,749	$ 23,867,557	$ 30,500,000	
Line of credity facility, cap on general and administrative expenditure		3,000,000			$ 6	
Minimum hedging		$ 75	75			
Equity to be raised	$ 5		5,000,000			
Debt paydown required	$ 11,500,000		$ 10,000,000			

Credit Facility (Schedule of Credit Facilities) (Details) - USD ($)	12 Months Ended	
	Jun. 30, 2018	Jun. 30, 2017
Credit Facility [Abstract]		
Credit facility at beginning of period	$ 23,419,749	$ 23,419,749
Cash advanced under facility	450,000	
Assumption of promissory note		4,000,000
Repayments	(2,192)	(11,080,251)
Credit facility at end of period	23,867,557	23,419,749
Funds available for drawdown under the facility		$ 580,251

Share-Based Payments (Narrative) (Details)	12 Months Ended				
	Jun. 30, 2018 shares	Jun. 30, 2017 $ / shares shares	Jun. 30, 2017 $ / shares shares	Jun. 30, 2015 AUD ($)	Jun. 30, 2015 USD ($)
Share-based Compensation Arrangement by Share-based Payment Award [Line Items]					
Exchange rate	0.7692	0.7680	0.7680		
Options granted		320,000,000	320,000,000		
Exercise price (Australian cents) | (per share)		$ 0.038	$ 3.800		
Options exercised	140,143	140,143.00	140,143.00		
Unrecognized compensation cost related to stock options | $					$ 0.400
Aggregate intrinsic value of options exercised | $				$ 4,747	
1.5 Cents [Member]					
Share-based Compensation Arrangement by Share-based Payment Award [Line Items]					
Options exercised		140,143	140,143		

Share-Based Payments (Schedule Of Assumption Used In Black-Scholes Model) (Details) - 12 months ended Jun. 30, 2017	$ / shares	$ / shares
Share-Based Payments [Abstract]		
Exercise price (Australian cents) | (per share)	$ 0.038	$ 3.800

Share-Based Payments (Summary Of Stock Option Activity) (Details)	12 Months Ended		
	Jun. 30, 2018 $ / shares shares	Jun. 30, 2017 $ / shares shares	Jun. 30, 2017 $ / shares shares
Share-Based Payments [Abstract]			
Outstanding, start of period	411,033,246	320,615,486	320,615,486
Granted		320,000,000	320,000,000
Exercised	(140,143)	(140,143.00)	(140,143.00)
Cancelled/expired	(96,533,246)	(229,442,097)	(229,442,097)
Outstanding, end of period	314,500,000	411,033,246	411,033,246
Exercisable, end of period	314,500,000	91,033,246	91,033,246
Weighted average exercise price - cents (AUD), outstanding, start of period | $ / shares	$ 1.180	$ 4.600	
Weighted average exercise price - cents (AUD), granted | $ / shares		0.570	
Weighted average exercise price - cents (AUD), exercised | (per share)		0.038	$ 3.800
Weighted average exercise price - cents (AUD), cancelled/expired | $ / shares	3.800	3.800	
Weighted average exercise price - cents (AUD), outstanding, end of period | $ / shares	0.5700	1.180	
Weighted average exercise price - cents (AUD), exercisable, end of period | $ / shares	$ 0.5700	$ 3.800	

Share-Based Payments (Schedule Of Additional Information Related To Options Outstanding) (Details)	12 Months Ended				
	Jun. 30, 2017 $ / shares shares	Jun. 30, 2017 $ / shares $ / shares shares	Jun. 30, 2016 $ / shares shares	Jun. 30, 2013 $ / shares	Jun. 30, 2018 $ / shares shares
Share-based Compensation Arrangement by Share-based Payment Award [Line Items]					
Exercise price (Australian cents) | (per share)	$ 0.038	$ 3.800			
Options outstanding, number outstanding | shares	411,033,246	411,033,246	320,615,486		314,500,000
Options outstanding, weighted average exercise prices	$ 1.180	$ 1.180	$ 4.600		$ 0.5700
Options exercisable, number exercisable | shares	91,033,246	91,033,246			314,500,000
Options exercisable, weighted average exercise prices	$ 3.800	$ 3.800			$ 0.5700
3.9 Cents [Member]					
Share-based Compensation Arrangement by Share-based Payment Award [Line Items]					
Exercise price (Australian cents)				$ 0.0055	
Options outstanding, number outstanding | shares			266,500,000		
Options outstanding, weighted average remaining contractual life - years			8 years 5 months 1 day		
Options outstanding, weighted average exercise prices			$ 0.0055		

Commitments (Narrative) (Details) - USD ($)	12 Months Ended					
	Jun. 30, 2016	Jun. 30, 2015	Jun. 30, 2020	Jun. 30, 2019	Jun. 30, 2017	Jun. 30, 2014
Commitments [Abstract]						
Operating leases, 2018				$ 123,873	$ 123,873	
Operating leases, 2019			$ 127,845		127,845	
Operating leases, 2020					131,309	
Operating Leases, 2021					8,947	
Operating Leases, 2022						
Operating leases, Thereafter						
Net rent expense	$ 214,650	$ 153,375				

Commitments (Contractual Obligations) (Details) - USD ($)	Jun. 30, 2020	Jun. 30, 2019	Jun. 30, 2018	Jun. 30, 2017	Jun. 30, 2016	Jun. 30, 2014
Commitments [Abstract]						
Asset retirement obligations, Total			$ 3,344,112	$ 3,456,236	$ 3,750,245	
Operating leases, Total				391,974		
Operating leases, 2018		$ 123,873		123,873		
Operating leases, 2019	$ 127,845			127,845		
Operating leases, 2020				131,309		
Operating leases, 2021				8,947		
Operating leases, 2022						
Operating leases, Thereafter						

Contingencies (Details)	Jun. 30, 2013 USD ($)
Contingencies [Abstract]	
Contingent assets	
Contingent liabilities	

Supplemental Information On Oil And Natural Gas Exploration, Development And Production Activities, Inclusive Of Discontinued Operations (Narrative) (Details) - USD ($)	12 Months Ended		
	Jun. 30, 2018	Jun. 30, 2017	Jun. 30, 2014
Supplemental Information On Oil And Natural Gas Exploration, Development And Production Activities, Inclusive Of Discontinued Operations [Abstract]			
12 month historical average price per Mcf	$ 2.95	$ 3.01	
12 month historical average price per barrel of oil	$ 57.67	$ 48.95	
Discount factor of future net cash flows			10.00%

Supplemental Information On Oil And Natural Gas Exploration, Development And Production Activities, Inclusive Of Discontinued Operations (Summary Of Costs Incurred For Oil And Natural Gas Exploration, Development And Acquisition) (Details) - USD ($)	12 Months Ended	
	Jun. 30, 2018	Jun. 30, 2017
Supplemental Information On Oil And Natural Gas Exploration, Development And Production Activities, Inclusive Of Discontinued Operations [Abstract]		
Development costs	$ 13,272	$ 2,458,276
Exploration costs	68,865	
Undeveloped capitalized acreage		50,375
Total costs incurred	$ 82,137	$ 2,508,651

Supplemental Information On Oil And Natural Gas Exploration, Development And Production Activities, Inclusive Of Discontinued Operations (Schedule Of Proved Developed And Undeveloped Oil And Gas Reserve Quantities) (Details)	12 Months Ended	
	Jun. 30, 2018 MBoe MBbls MMcf	Jun. 30, 2017 MBoe MBbls MMcf
Reserve Quantities [Line Items]		
Proved Developed Reserves ProductionBOE | MBoe	(195)	(323)
Beginning of year (BOE) | MBoe	5,955	11,415
Revisions of previous quantity estimates (BOE) | MBoe	(2,028)	(3,263)
Sales of reserves in place (BOE) | MBoe		(1,874)
End of year (BOE) | MBoe	3,732	5,955
Proved developed producing reserves (BOE) | MBoe	84	3,285
Proved undeveloped reserves (BOE) | MBoe	350	2,499
Proved Developed Non Producing (BOE) | MBoe	39	171
Proved developed producing reserves - held for sale (BOE) | MBoe	2,685	
Proved developed non producing - held for sale (BOE) | MBoe	575	
Proved reserves (BOE) | MBoe	3,732	5,955
Oil [Member]		
Reserve Quantities [Line Items]		
Beginning of year (Volume) | MBbls	5,359	9,982
Revisions of previous quantity estimates (Volume) | MBbls	(1,654)	(2,851)
Sales of reserves in place (Volume) | MBbls		(1,475)
Production (Volume) | MBbls	(190)	(297)
End of year (Volume) | MBbls	3,515	5,359
Proved developed producing reserves (Volume) | MBbls	73	3,020
Proved Developed Non Producing (Volume) | MBbls	32	134
Proved undeveloped reserves (Volume) | MBbls	308	2,205
Proved developed producing reserves - held for sale (Volume) | MBbls	2,590	
Proved developed non producing - held for sale (Volume) | MBbls	512	
Proved reserves (Volume) | MBbls	3,515	5,359
Natural Gas [Member]		
Reserve Quantities [Line Items]		
Beginning of year (Volume) | MMcf	3,565	8,593
Revisions of previous quantity estimates (Volume) | MMcf	(2,246)	(2,474)
Sales of reserves in place (Volume) | MMcf		(2,396)
Production (Volume) | MMcf	(27)	(158)
End of year (Volume) | MMcf	1,292	3,565
Proved developed producing reserves (Volume) | MMcf	60	1,575
Proved Developed Non Producing (Volume) | MMcf	43	224
Proved undeveloped reserves (Volume) | MMcf	251	1,766
Proved developed producing reserves - held for sale (Volume) | MMcf	563	
Proved developed non producing - held for sale (Volume) | MMcf	375	

Proved reserves (Volume) | MMcf	1,292	3,565

Supplemental Information On Oil And Natural Gas Exploration, Development And Production Activities, Inclusive Of Discontinued Operations (Estimated Standard Measure Of Discounted Future Net CF Relating To Proved Reserves) (Details) - USD ($) $ in Thousands	Jun. 30, 2018	Jun. 30, 2017	Jun. 30, 2016
Supplemental Information On Oil And Natural Gas Exploration, Development And Production Activities, Inclusive Of Discontinued Operations [Abstract]			
Future cash inflows	$ 187,249	$ 237,490	
Future production costs	(99,620)	(91,920)	
Future development costs	(1,642)	(13,367)	
Future net cashflows	85,987	132,203	
10% discount	(38,325)	(66,941)	
Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves, Total	$ 47,662	$ 65,262	$ 66,747

Supplemental Information On Oil And Natural Gas Exploration, Development And Production Activities, Inclusive Of Discontinued Operations (Schedule Of Changes In Standardized Measure Of Discounted Future Net Cash Flows) (Details) - USD ($) $ in Thousands	12 Months Ended	
	Jun. 30, 2018	Jun. 30, 2017
Supplemental Information On Oil And Natural Gas Exploration, Development And Production Activities, Inclusive Of Discontinued Operations [Abstract]		
Beginning of year	$ 65,262	$ 66,747
Sales of oil and gas produced during the period, net of production costs	(3,902)	(3,122)
Net changes in prices and production costs	2,822	1,601
Changes in estimates of future development costs	(11,625)	22,929
Revisions of previous quantity estimates and other	(10,088)	(21,078)
Sale of reserves in place		(10,445)
Accretion of discount	6,526	6,675
Other	(1,333)	1,955
Balance at end of year	$ 47,662	$ 65,262