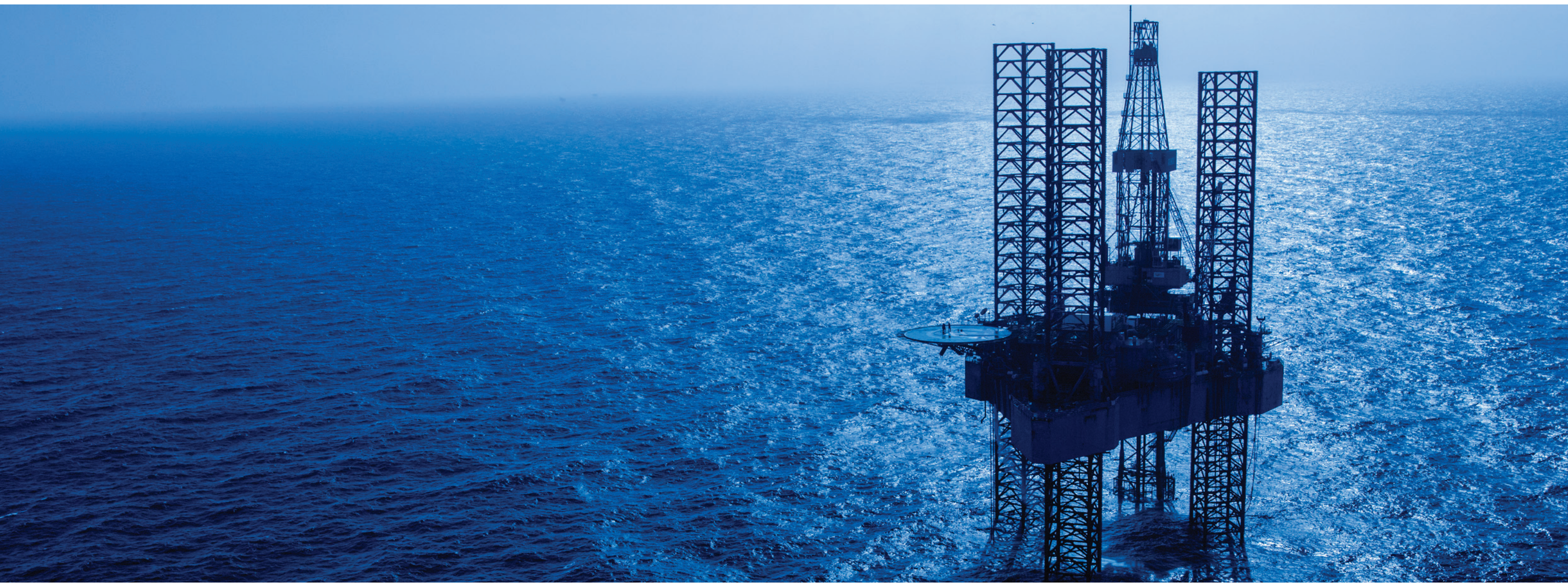


OTTO ENERGY LIMITED

2018
Annual Report

CONTENTS

CHAIRMAN'S REPORT

Dear Shareholders

It is my pleasure to present the 14th Annual Report to shareholders as Otto Energy continues to build its North American oil and gas business.

The last 12 months have been an exciting and successful period of transition for the company moving from a pure exploration play to a producer with the commissioning of SM 71, publication of a significant reserves upgrade which will underpin a stable cash flow for years to come, successful restructuring of our joint venture in Alaska thereby "unfreezing" the drilling potential in that acreage, and last but not least the successful execution of a new joint venture with Hilcorp, one of the most respected operators in the Gulf of Mexico, for an eight well drilling program. Few people would have thought at this time last year that we would make this much progress so quickly.

That having been said, we are determined not to become complacent. We know from experience that the oil and gas business is volatile and risky, and we will maintain our analytical discipline and only invest in relatively low risk projects with a 40% minimum probability of success, as well as bottom quartile production costs.

Our CEO, Matthew Allen, has completed his relocation to Houston and has been building our Houston team with local technical and commercial expertise.

Looking forward we are excited by the investment opportunities we see, particularly in the Gulf of Mexico, which will allow us to grow Otto Energy into a profitable mid-size oil and gas company whilst remaining strictly focused on what we know best, ie building a portfolio of profitable conventional oil and gas projects.

I thank you the shareholders for your continued support, the directors for their guidance, and the management and staff for their commitment.

John Jetter
Chairman

> "we are excited by the investment opportunities we see, particularly in the Gulf of Mexico"

MANAGING DIRECTOR'S REPORT

Dear Shareholders

It is my pleasure to present Otto Energy's 2018 Annual Report. The year has seen Otto return to the ranks of producing oil companies with the commencement of production at the flagship South Marsh Island 71 development occurring in March 2018. This achievement will underpin Otto's future activities within the core focus area of the Gulf of Mexico.

The energy sector globally continues to evolve and respond to changing dynamics at the macro level. A stall in the growth in supply from North American shale projects and challenges within OPEC have seen oil prices steadily climb in 2018. The timing of first production at SM 71 has occurred at the highest point in recent oil prices and has significantly strengthened Otto's financial position.

Otto has positioned itself in a counter-cyclical manner in the Gulf of Mexico by building a business that is robust for the energy business model of the future. Capturing the Gulf Coast drilling package with Hilcorp and assembling the drilling consortium for the Alaska Western Blocks prospect are examples of how Otto has positioned itself with high impact drilling opportunities.

The attraction of the Gulf of Mexico lies in the mature nature of the infrastructure and the technical understanding of the petroleum system. The use of new technology in seismic processing has enabled overlooked opportunities to be unlocked. The investment boom in shale oil projects has depleted capital available for exploration and development in conventional fields, despite the economics of conventional oil being as or more robust. There is opportunity for a company such as Otto to grow a business with key partnerships in the Gulf of Mexico whilst the focus is currently elsewhere.

The first phase of this strategy is to build a business delivering approximately 5,000 barrels of oil per day net to Otto in order to establish a cashflow generating base from which to enable growth. Otto's flagship SM 71 development is the first successful step in creating this ongoing business. We have made further major steps this year setting up the next round of exploration drilling activities.

Otto has already announced that it will participate in ten exploration wells to be drilled before the end of 2019. This is a very significant drilling program for a company of Otto's size and has the potential to create significant shareholder value and deliver upon our initial strategic goal.

At the request of the board, I have recently relocated to Houston in order to set-up our US office and look forward to being actively involved in this large drilling program. Our office and team are in place and we are already actively engaged in execution of this program as well as keeping an eye towards the next set of opportunities once we deliver our initial strategic goals.

The support of Otto's shareholders has been consistently positive in our business build phase during the last two years. I would like to thank all of Otto's shareholders for this vote of confidence in our business model.

The backing of Otto's shareholders, staff and my fellow directors throughout this period has been greatly appreciated. Thank you once again for your ongoing endorsement of Otto Energy and I look forward to reporting upon the results of our very active upcoming drilling program.

Matthew Allen
Managing Director

"Otto will participate in ten exploration wells to be drilled before the end of 2019."

STRATEGY

THE COMPANY'S CORE STRATEGIC GOAL IS TO GROW PRODUCTION IN THE GULF OF MEXICO TO 5,000 BOEPD BY THE END OF 2020.

As at the date of this report the status of execution of this strategy is as follows:

- Building a portfolio of US conventional production assets with a Gulf of Mexico focus and the capability to transition to an operator;
- Growth strategy underpinned by strong production and cash flow from our flagship Gulf of Mexico SM 71 asset;
- Exciting pipeline of ten high-impact exploration opportunities taking place over the next 15 months; and
- An experienced team with a track record of successfully growing, operating and divesting oil and gas assets globally who understand risk and capital management.

US GULF OF MEXICO STRATEGY

The Company's strategy is currently focused on growth in the Gulf of Mexico for the following reasons:

- Proven prolific hydrocarbon province where technologies such as RTM seismic processing continue to create new opportunities;
- Low sovereign risk;
- High margin oil with breakeven economics around US$20/barrel;
- Short cycle time from discovery to development of 8-18 months;
- Low cost drilling and development;
- Relatively low risk exploration;
- Deal flow is liquid and a full spectrum of opportunity size is available;
- Otto has area expertise and well-developed business relationships; and
- Otto has production in the area.

In order to deliver on the strategy, the Company's business development focus over the past year in the Gulf of Mexico has been on pursuing prospects with the following characteristics:

- Miocene/Pliocene/Oligocene geology which are amplitude supported;
- Investing capital into drilling, not seismic;
- Seeking early cashflow/ROI – Approximately 12-18 months from exploration to production;
- Shallow water (<300 feet) – keeping capex manageable; and
- High liquids yields to increase margins.

ASSET OVERVIEW

NORTH AMERICA

GULF OF MEXICO

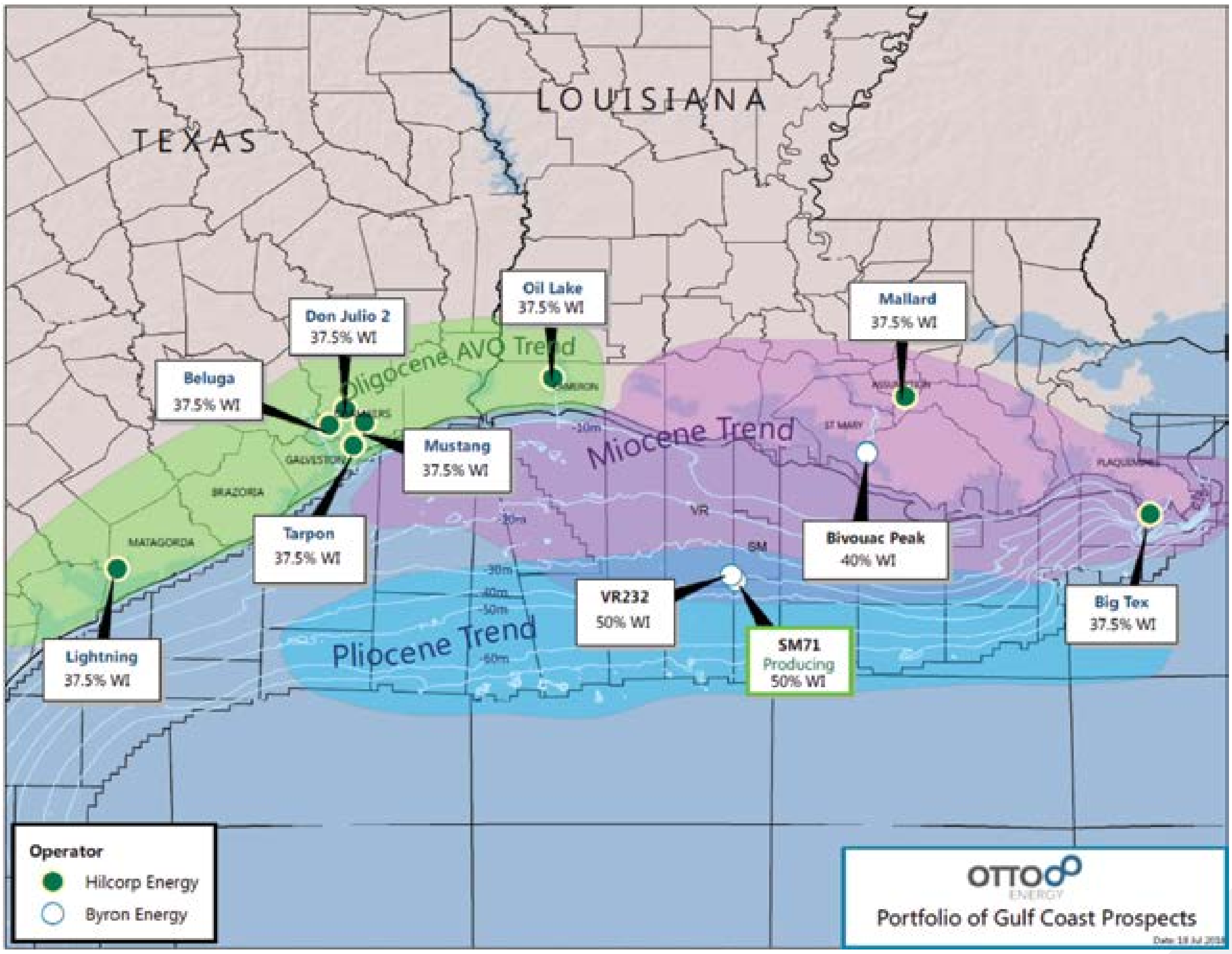
In December 2015, Otto entered into an agreement with Byron Energy giving it rights to elect to participate in up to four drilling opportunities in the Louisiana onshore and shallow water offshore continental shelf area. To date, two of these opportunities have been drilled, leading to a discovery and the booking of reserves.

The Gulf of Mexico (GOM) region is one of the most prolific oil and gas producing regions on earth. Commercial extraction of petroleum resources dates from the early decades of the 1900s, with first offshore production commencing in 1938. Today, the federally-administered GOM Outer Continental Shelf alone accounts for about a fifth of all crude oil produced in the USA.

Geologically there exists a key combination of a thick layer of evaporites (salt), rich biological deposits (which, when subjected to the right conditions, forms light producible oil and gas), and thick sand layers. Near the northern gulf margin in particular, a delta created by the Mississippi River has been building for tens of millions of years. These deltaic sand grains are well sorted and round in shape, forming the ideal high-porosity rock for a petroleum reservoir. The buoyancy and flowing effect of the underlying salt creates the structures and traps necessary for the natural collection of oil.

Today, about half of the USA's fossil fuel refining and processing capacity is along the GOM. The high density and availability of production platforms development of primary reservoirs contributes to low production costs in this region, making projects viable even in a sustained, low oil price environment. Louisiana and the nearby shelf region are characterised by a ready market and low sovereign risk. These factors, in combination with the low-risk drilling updip of previously productive sand intervals, have led Otto to make the northern Gulf of Mexico region the focus of its forward strategy.

In late July 2018 Otto signed an agreement with Hilcorp which will see it participate in the drilling of eight gulf coast exploration wells during the next 18 months. This deal aligns perfectly with Otto's principle strategy of building a business of scale in the US Gulf of Mexico.



LOUISIANA
TEXAS
Oil Lake
37.5% WI
Don Julio 2
37.5% WI
Beluga
37.5% WI
Mallard
37.5% WI
Oligocene AVO Trend
Miocene Trend
Mustang
37.5% WI
Tarpon
37.5% WI
Bivouac Peak
40% WI
Lightning
37.5% WI
VR232
50% WI
SM71
Producing
50% WI
Big Tex
37.5% WI
Pliocene Trend
Operator
Hilcorp Energy
Byron Energy
OTTO
ENERGY
Portfolio of Gulf Coast Prospects

PRODUCTION - SOUTH MARSH ISLAND 71 (SM 71)

Location:	Louisiana - Offshore Gulf of Mexico
Area:	12.16 km^2
Otto's Working Interest:	50.00% with Byron Energy Ltd (Operator)

Otto owns a 50% Working Interest (WI) and a 40.625% Net Revenue Interest (NRI) in the South Marsh Island block 71 (SM 71), with Byron Energy Limited the Operator, holding an equivalent WI and NRI. Water depth in the area is approximately 137 feet.

Production operations at the SM 71 F platform began on 23 March 2018 when the SM 71 F1 well, completed in the D5 reservoir, was brought on line. The SM 71 F2 well, completed in the B65 Sand, was opened to the system on 25 March 2018. On 6 April 2018 production from the SM 71 F3 well was initiated. The F3 well is completed in the D5 Sand reservoir.

In the reserves report effective as of 30 June 2018, Collarini estimated an increase in 2P reserves of 4.3 MMboe net to Otto (excluding production to 30 June 2018) a near tripling of the 2017 2P reserves estimate in what is the first independent reserve report for the SM 71 project since production began in March 2018. The reserves data is set out on page 23.

The significant increase in all key reserve categories is directly due to the success of the appraisal and development drilling program in 2017/18. Both the thicker than expected net oil zones and exceptional well performance to date from the D5 producing sands in both the F1 and F3 wells are contributing factors to the positive additions and revisions to the Company's reserves. Further details on the material changes to reserves is set out on page 25.

The SM 71 F2 well, which is completed in the secondary B65 Sand, has been experiencing reservoir pressure depletion. To date 32,466 barrels of oil and 60.9 million cubic feet of gas have been recovered, without any water, from the B65 Sand in the SM 71 F2 well. This data, along with pressure data, indicates an estimated trap size of three acres, whereas the targeted seismic anomaly size is 175 acres. This provides strong evidence that the B65 Sand intersected by the F2 well is isolated from the main B65 Sand target area. In late June the F2 well was shut in to analyse the pressure build-up of the well. After flowing for approximately eight hours, the F2 well ceased production of hydrocarbons and has been shut in ever since.

As at 19 September 2018, cumulative gross production from the SM 71 field was approximately 641,737 barrels of oil and 556 million cubic feet of gas, on a gross basis with no produced formation water. The current field sales rate as of 19 September 2018, was approximately 3,600 bopd and 6.0 mmcfgpd, on a gross basis after shrinkage at the sales meter.

Recompletion of the F2 well from the B65 Sand to the B55 Sand is underway at the time of this report.

EXPLORATION - HILCORP GULF COAST PACKAGE

Location:	Inshore/Onshore Texas and Louisiana - Gulf of Mexico
Otto's Working Interest:	37.5% - Earning via staged farm-in with Hilcorp Energy (Operator)

THE DEAL

In late July 2018 Otto announced that it had entered into a joint venture with Hilcorp Energy which will see it earn a 37.5% working interest in an eight well portfolio of prospects in the Onshore/Near Shore USA Gulf Coast (Gulf of Mexico). The wells will be drilled by Hilcorp, a highly-experienced, privately-owned operator based in Houston, over the next 18 months.

Otto will earn the 37.5% working interest by paying 50.0% of the costs of drilling and either setting casing or plugging and abandoning the well plus lease acquisition costs at each of the eight prospects. The estimated cost of the commitment to Otto is US$37.5 million.

Additional Upside

Should either the Tarpon or Mustang prospects be successful then Otto has ground floor rights (ie pays only its working interest) to participate in the nearby Damsel and Corsair/Hellcat opportunities. These wells are in addition to the eight wells.

Under the agreement Otto has a right of first offer to a subsequent Gulf Coast program, if Hilcorp elect to offer such a program to third parties.

ABOUT HILCORP ENERGY

Founded in 1989, Hilcorp is one of the largest privately-held oil and natural gas companies in North America. Hilcorp specialises in reinvigorating legacy oil and gas fields across North America; including in the US Gulf Coast, Alaska and the Rockies and currently produces approximately 325,000 boepd. To put this into context, Australia's largest oil and gas company, Woodside, produces ~230,000 boepd.

Hilcorp has nearly 2,000 employees and has been consistently recognised for its strong culture, values and ethics both within the firm and in the communities in which it operates.

Otto is very pleased to be partnering with a Gulf Coast operator with proven capability to take exploration prospects into production.

IMPACT ON STRATEGY

Otto's target area for new opportunities lies within the Pliocene, Miocene and Oligocene reservoir systems of the US Gulf of Mexico shelf and Gulf Coast where capital costs are manageable and the availability of infrastructure means the time from discovery to production is short. Otto is deploying its experienced technical team to find attractive, low -risk drill opportunities in this area to provide high-margin oil and gas production growth.

The Hilcorp eight well portfolio is a significant step toward Otto's initial strategic goal of 5,000 boepd by 2020 strategy and puts Otto into a partnership with a large and well-respected operator in the region. In addition it offers further potential through follow-up drilling and a right of offer on further Hilcorp Gulf Coast farmouts.

Refer to the ASX release of 31 July 2018 for further details on the Hilcorp transaction.

DETAILS OF THE DRILLING PROGRAM

Information regarding the eight wells is set out below.

Prospect Name	Planned Spud Date	Target Depth (TVD), ft	Rig Type	Working Interest (WI) %	Net Revenue Interest (NRI) %	Stratigraphic Interval	Country/ Parish	Location
Big Tex	Sep-18	13,500	Barge	37.50	29.51	Tex	Plaquemines	Louisiana
Lighting	Nov-18	14,500	Land	37.50	28.50	Frio Tex Miss	Matagorda	Texas
Don Julio 2	Dec-18	11,500	Land	37.50	28.50	Oligocene	Chambers	Texas
Mustang	Jan-19	17,500	Land	37.50	30.00	Oligocene	Chambers	Texas
Beluga	May-19	13,000	Barge	37.50	28.50	Oligocene	Galveston Bay	Texas
Oil Lake	Jul-19	14,500	Land	37.50	29.06	Frio	Cameron	Louisiana
Tarpon	Jul-19	14,000	Barge	37.50	29.06	Oligocene	Galveston Bay	Texas
Mallard	Nov-19	11,000	Barge	37.50	29.63	Mid Miocene	Assumption	Louisiana

PROSPECTIVE RESOURCES

The range of prospective resources for each prospect is set out below.

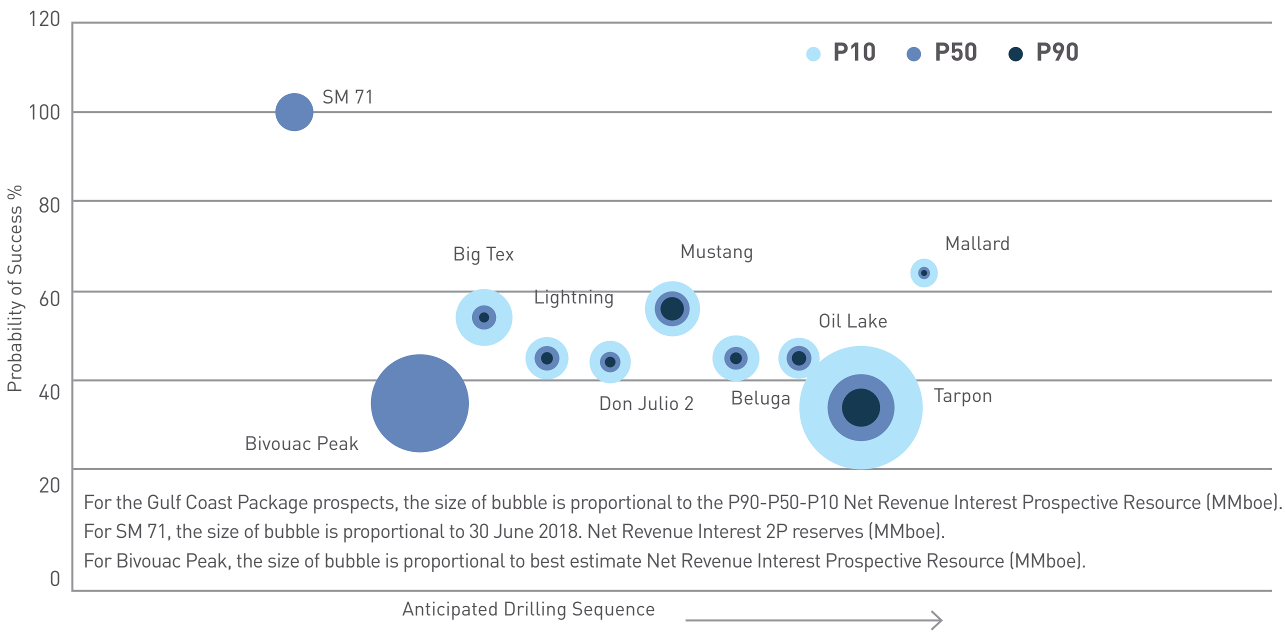
Prospect Name	Working Interest %	Net Revenue Interest %	Probability of Success %	Prospective Resources MMboe							
				100%				Otto Net Revenue Interest			
				P90	P50	Mean	P10	P90	P50	Mean	P10
Big Tex	37.50	29.51	54	0.5	3.3	6.8	16.9	0.1	1.0	2.0	5.0
Lighting	37.50	28.50	45	0.9	3.2	4.4	10.1	0.3	0.9	1.3	2.9
Don Julio 2	37.50	28.50	44	0.7	2.5	4.0	9.6	0.2	0.7	1.1	2.7
Mustang	37.50	30.00	56	2.9	6.7	8.5	16.8	0.8	1.9	2.6	4.8
Beluga	37.50	28.50	45	0.8	2.9	4.7	11.2	0.2	0.9	1.3	3.4
Oil Lake	37.50	29.06	45	1.2	3.3	4.4	9.3	0.3	1.0	1.3	2.7
Tarpon	37.50	29.06	34	7.7	24.0	35.6	81.0	2.2	7.0	10.3	23.5
Mallard	37.50	29.63	64	0.2	0.9	3.3	4.5	0.1	0.3	1.0	1.3

Prospective Resources Cautionary Statement

The estimated quantities of petroleum that may potentially be recovered by the application of future development projects relate to undiscovered accumulations. These estimates have both an associated risk of discovery and a risk of development. Further appraisal and evaluation is required to determine the existence of a significant quantity of potentially moveable hydrocarbons.

On the next page is a graphical representation showing how this portfolio fits with Otto's existing assets.

Comparison of SM 71 Reserve Base with Gulf Coast Package Prospective Resources



RISKED SUMMARY DATA - 8 WELL PORTFOLIO, GROSS (8/8THS)

Portfolio-level risked information for the eight well portfolio is set out below. These are probabilistic additions of each prospect's expectation curve, using a monte carlo approach. Refer to the ASX release of 31 July 2018 for further information on these calculations.

Metri	P90	P50	P10
Volumes, MMBOE	4.63	19.86	64.59
Peak Production Rate, BOE/d	3,270	9,990	31,300
% Hydrocarbon Liquids per BOE	13%	28%	56%
Finding cost, US$/BOE	$13.62	$3.18	$0.98
Finding & Development cost, US$/BOE	$16.40	$5.51	$2.56

Big Tex Spud

On 30 August 2018 Otto announced that the initial exploration well, SL 192 PP 031, on the Big Tex prospect had commenced drilling from a bargemounted rig.

The well will be drilled to 13,175 ft MD/12,700 ft TVD and is expected to take 55 days to reach total depth. Otto will earn a 37.5% working interest by paying 50% of the costs of drilling and either setting casing or plugging and abandoning the well, after which point Otto will pay 37.5% of all future costs. The well is expected to cost the Company US$4.23 million (50% paying interest). The exploration well on the Big Tex prospect is targeting the Tex W 16 Sand and Tex W 18 Sand that are Middle Miocene in age. This is a prolific section, having produced from the east in Hilcorp's East Bay Field, and from the west from the massive West Delta 30 Field, which has produced 562 MMBO and 934 BCF to date.

EXPLORATION - BIVOUAC PEAK

Location:	Inshore Louisiana - Gulf of Mexico
Area:	11.4 km^2
Otto's Working Interest:	40.00% - Earning via farm-in with Byron Energy Ltd (Operator)

The Bivouac Peak leases cover 2,821 acres of highly prospective acreage in the transitional zone inshore southern Louisiana. The Operator has identified multiple prospects at both the Middle and Lower Miocene levels demonstrating stacked amplitude and AVO (amplitude versus offset) support. Follow-up drilling options have been identified at the Lower Miocene level that could increase the scale of the overall opportunity.

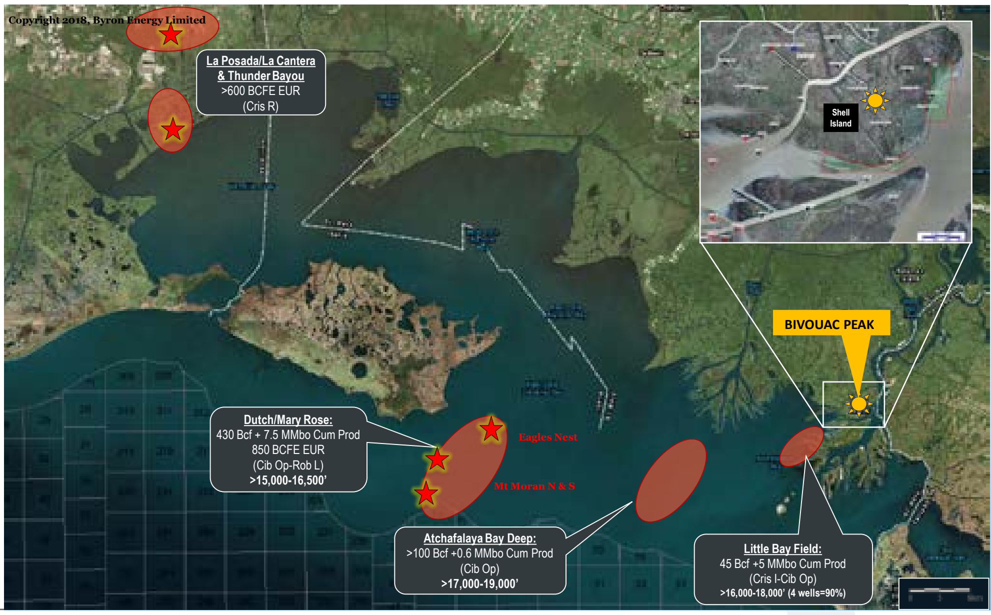
Significant production exists in the adjacent Miocene sequence at the Little Bay field (greater than 45 Bcf gas and 5 MMbbl condensate) and the Atchafalaya Bay field (greater than 100 Bcf gas and 0.6 MMbbl condensate).

On 9 July 2018 Otto announced that it had elected to participate in the initial test well, Weiss-Adler et. al. No. 1 (Weiss-Adler#1), on the Bivouac Peak East prospect. The well commenced on 25 August 2018. The Parker Drilling Company Rig #77-B Deep Drilling 3000 HP Posted Barge Rig will drill to a depth of 18,294 ft Measured Depth (MD)/18,000 ft True Vertical Depth (TVD). The well is expected to take approximately 75 days to reach total depth.

With nearby production infrastructure already in place, any successful well at Bivouac Peak would be capable of being brought into production within 8-10 months of discovery at a development cost in the range of US$9-11 million (100%).

Should a commercial discovery be made at Bivouac Peak East, additional potential at the Deep prospect will be followed up in due course.

Bivouac Peak Regional Map - LA Transition Zone



EXPLORATION - VERMILLION BLOCK 232 (VR 232)

Location:	Offshore Gulf of Mexico
Area:	18.31 km^2
Otto's Working Interest:	50.00% - Byron Energy Inc (Operator)

As reported on 19 June 2018, Byron Energy Inc, a wholly owned subsidiary of Byron Energy Limited, was advised by the Bureau of Ocean Energy Management (BOEM) that its bid for VR 232 was deemed acceptable by the BOEM and the lease was awarded to Byron. The lease is subject to a 12.5% Federal Government royalty.

VR 232 is adjacent to Otto's 50% owned SM 71 oil field and adds drilling opportunities which increase Otto's potential upside around the SM 71 facilities.

The Operator, Byron, has mapped a gas and gas condensate prospect on the block with in-house calculated gross prospective resource potential of 11 Bcf and 170,000 barrels. This prospect could be tested from Otto's SM 71 F platform. There are currently no plans to drill in VR 232 until production levels at the platform would allow a successful VR 232 well to be produced efficiently. The Operator has also identified two other prospects in VR 232 which require further geophysical evaluation before a drilling decision is made.

Byron evaluated this block with the same high-quality Reverse Time Migrated 3D seismic data and proprietary Inversion processed seismic data used in the discovery of oil and gas at SM 71 in 2016. Upon transfer, Otto's working interest will be 50% and net revenue interest will be 43.75%.

Pursuant to the terms of a Participation Agreement, effective 1 December 2015, between Byron and Otto, Otto has elected to participate in VR 232 at a fifty percent (50%) working interest.

Under that agreement, Otto must pay an amount equal to a gross one hundred thirty-three percent (133%) of Otto's fifty percent (50%) interest share of lease acquisition costs and the initial test well (dry hole costs) plus a gross fifty percent (50%) of other past costs paid by Byron.

Under Byron's bid of US$1.101 million for VR 232, Otto's share is US$734,000.

Having now elected to participate in the drilling of the East prospect at Bivouac Peak and participate in VR 232 at a 50% working interest, Otto's right to participate in new assets or projects under the December 2015 Participation Agreement has been fulfilled.

EXPLORATION - ALASKA WESTERN BLOCKS

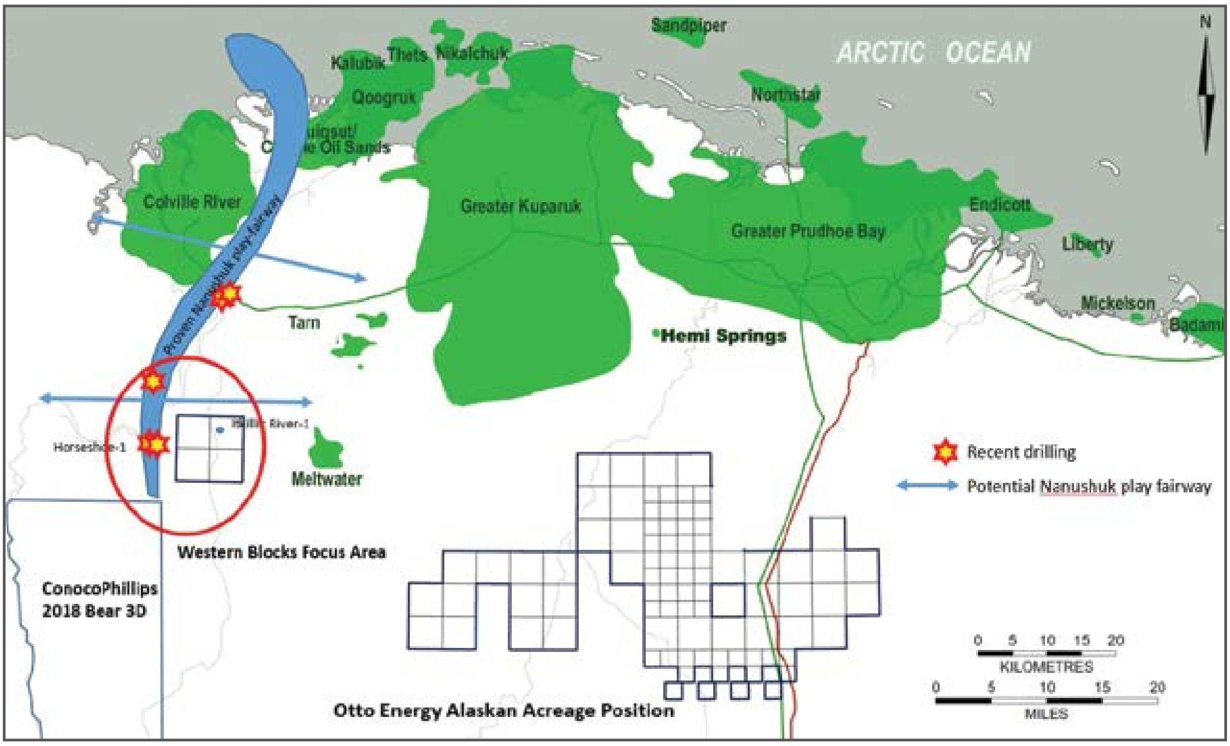
Location:	Onshore North Slope Alaska
Area:	91.9 km^2
Otto's Working Interest:	25% (before back-in) – 88 Energy Limited (Operator)

WESTERN BLOCKS - OVERVIEW

On 30 July 2018 Otto Energy Limited advised that, via its wholly owned subsidiary Borealis Alaska LLC, it had executed definitive agreements with Great Bear Petroleum, along with the Consortium Partners, 88 Energy (Captivate Energy Alaska, Inc) and Red Emperor, that will see Otto participate in the drilling of Winx-1, a highly prospective Nanushuk oil trend exploration well within its Western Blocks on the Alaska North Slope, in early 2019.

Winx-1 will test a 3D seismic defined oil prospect in the successful Nanushuk play fairway with a gross best estimate prospective resource volume of 400 MMbbls and a geological chance of success in the range of 25-30%.

NANUSHUK TOPSET OIL TREND#



Otto holds a working interest in four leases totalling over 22,710 acres located in the heart of the prolific Nanushuk oil fairway. The Horseshoe-1 well, which discovered oil in 2017, is located less than one mile to the west of Otto's Western Blocks. Horseshoe-1 extended the Nanushuk play fairway by well over 20 miles to the south of previous drilling. Repsol reports that since 2011 the Company has drilled multiple consecutive discoveries on the North Slope along with partner Armstrong.

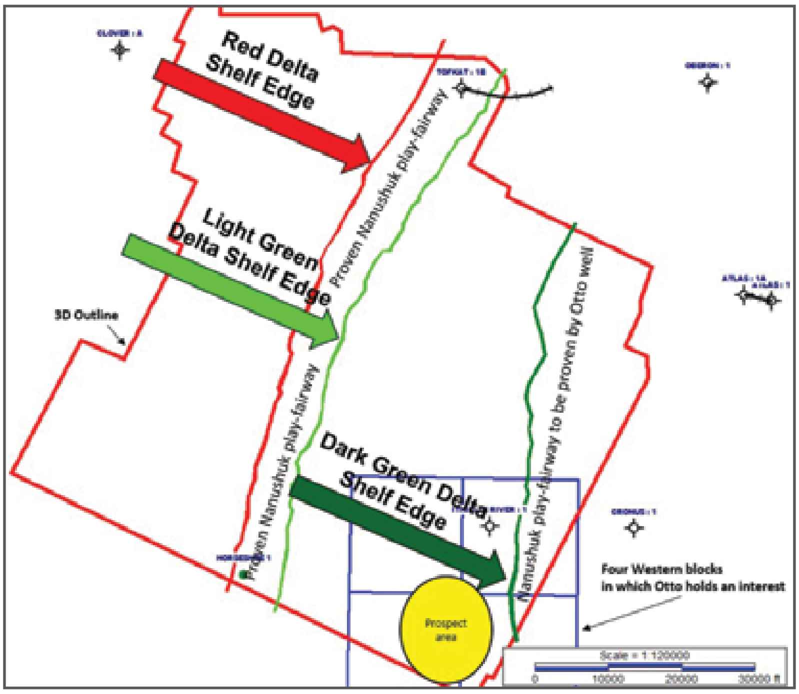
Industry sources have indicated contingent recoverable resources discovered to date in the trend could contain over 1.2 billion barrels of oil*. This places the trend as one of the most significant emerging plays on the Alaska North Slope. With ongoing drilling in 2018 it is expected that additional discoveries will be made in this emerging play trend.

The Horseshoe-1 discovery well was drilled by the Repsol-led joint venture in 2017 to a total depth of 6,000 ft. (1,828 meters) and encountered more than 150 ft. of net oil pay in several reservoir zones in the Nanushuk section. The deviated Horseshoe-1A sidetrack was drilled to a total depth of 8,215 ft. and encountered more than 100 ft. of net oil pay in the Nanushuk interval as well.

*Repsol and Oil Search (1 November 2017). Refer to Otto's ASX release of 25 June 2018.

WESTERN BLOCKS PROSPECT – WINX-1

Recent in-house technical work conducted by Otto on its Alaska acreage in the Western Blocks has resulted in the identification of an oil prospect with a gross best estimate prospective resource volume of 400 MMbbls and a geological chance of success in the range of 25-30%. The prospective resource calculation was based on a consideration of offset well information (Itkillik River-1 well completion information), seismic expression and a recovery factor of 30%. Otto's 18.75% net revenue interest (before Great Bear 10% back in) in the prospect would be 75 MMbbls.

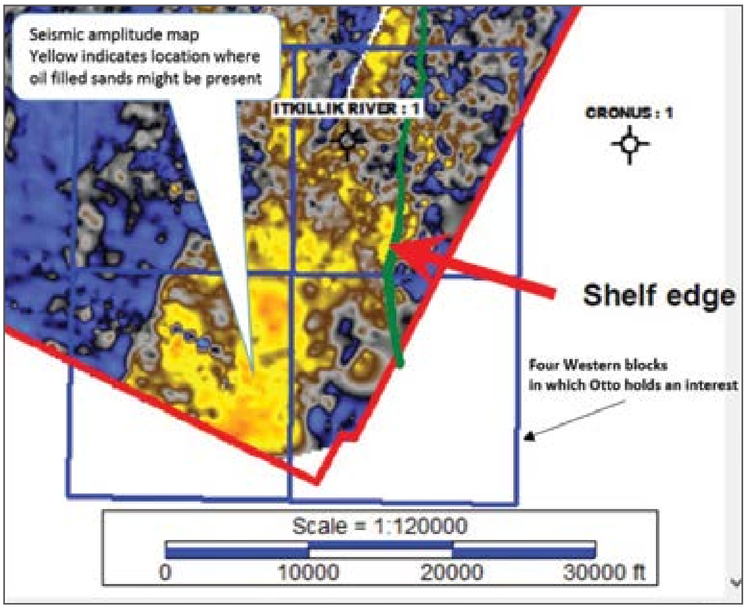


The prospect, identified on modern 3D seismic data obtained through the Alaska Department of Natural Resources, Division of Oil and Gas, is illustrated above in the context of the four graticular leases that comprise the Western Blocks in which Otto holds an interest.

On the above-mentioned seismic data the prospect shares many of the positive attributes seen at the Horseshoe-1 discovery which found light oil reservoired in more than 150ft of net oil sand of the Nanushuk delta sequence.

The discovery at Horseshoe-1 has extended the known accumulation of Nanushuk oil some 20 miles south of earlier discoveries such as those at Qugruk 8 and Qugruk 301 which flowed 30 degree gravity crude at rates as much as 2,160 and 4,600 bbls/d respectively (Repsol press release 2 June 2015).

The Horseshoe-1 discovery has signalled the presence of an extensive previously overlooked hydrocarbon province which is in now attracting major development capital including the recent acquisition by Oil Search Limited of operatorship of the Pikka Unit and a number of oil exploration assets on the Alaska North Slope.



Exploration success in the Nanushuk play-fairway is now being driven by the understanding that when reservoir quality top set sands are present anomalously high amplitudes are seen on seismic data.

This type of positive amplitude response has also been seen on seismic over the Western Blocks as illustrated above. Otto presently calculates a best estimate gross prospective resource of 400 MMbbls in the prospect area mainly on the basis of this amplitude work.

As can be seen, some of the block area to the south is not covered by 3D data and as yet uncalculated upside potential is likely to exist in this area as well.

Further encouragement that the prospect will be found oil bearing is provided by the presence of oil shows seen in the adjacent Itkillik River-1 well drilled in 1978 (from publicly available well data at the Alaska DNR). Here oil was observed during drilling at multiple levels within fine grained sediments.

If 3D data had been available at the time Itkillik River-1 had been drilled, the well would likely have been moved further south to intersect a better reservoir quality and more continuous sand interval. This higher quality sand interval is the key target for the proposed Otto well.

OFFTAKE OPTIONS

With the Oil Search operated Pikka unit development activities occurring to the west and the Conoco-Phillips Meltwater unit facility some 10 miles to the east, any oil found within the Western Blocks will find a cost effective, commercially attractive route to market. Project economics will be further enhanced by the shallow nature of the oil pool.

DRILLING PLANNING

88 Energy Ltd will manage the drilling of the initial test well in the Western Blocks on behalf of the joint venture and consortium partners. Since year end a rig contract has been signed. Given that the location is only accessible through an ice road, drilling will be undertaken during the winter operational months once the Alaska North Slope is opened for operations.

EXPLORATION - ALASKA CENTRAL BLOCKS

Location:	Onshore North Slope Alaska
Area:	1,163 km^2
Otto's Working Interest:	8%-10.8% – Great Bear Petroleum Operating (Operator)

Through its agreements with Great Bear Petroleum Operating (Great Bear) in 2015, Otto has between an 8% and 10.8% working interest in 90 leases (covering 287,425 gross acres) held by Great Bear on the Alaskan North Slope (Central Blocks).

Great Bear is a private exploration company focused exclusively on exploring and developing conventional and unconventional resources in this highly prospective basin. The leases are in a major play fairway south of the Prudhoe Bay and Kuparuk giant oil fields.

Great Bear has undertaken significant exploration work on the acreage since 2011 including:

- Acquisition and processing of approximately 2,970 km2 of 3D seismic data (1,170 km2 in 2016);
- Drilling of two unconventional stratigraphic test wells which cored three primary unconventional targets; and
- Drilling of a conventional exploration well (Alkaid-1) which specifically targeted a 3D defined Brookian reservoir. The Alkaid well results are under evaluation.

The extensive, modern 3D seismic coverage, existing well control and proximity to the all-weather Dalton Highway and Trans-Alaskan Pipeline System (TAPS), means the acreage is well positioned for exploration.

Existing 3D seismic has allowed development of an extensive prospect portfolio which includes at least four well locations.

Otto's exposure on the first two wells is limited to US$2.6m/well.

SUMMARY OF ASSETS

AS AT 30 JUNE 2018

Asset	Otto working interest	Otto net revenue interest	Joint venture partners		Notes
Louisiana/Gulf of Mexico * **					
South Marsh Island 71 (SM 71), Outer Continental Shelf	50%	40.625%	Byron Energy (Operator)	50% WI	Producing field
Vermillion 232 (VR 232)	50%*	43.75%	Byron Energy (Operator)	50% WI	Block adjacent to SM 71
Bivouac Peak, Louisiana Near-shore	45% Earning via staged farm-in with Byron Energy Ltd (Operator)**	33.525%	Byron Energy (Operator)	40% WI	Initial well commenced on 25 August 2018
			Metgasco	10% WI	
			Private US Company	5% WI	
Alaska					
Alaska North Slope (Western Blocks)	22.5%	18.75%	88 Energy (Drilling Management)	36.0% WI	4 leases covering 91.9 km² make up the Alaskan North Slope Western Blocks Acreage
			Red Emperor	31.5% WI	
			Great Bear Petroleum Ventures II LLC (Operator)	10% WI	
Alaska North Slope (Central Blocks)	8 – 10.8%	6.67 – 9.45%	Great Bear Petroleum Ventures I/II LLC (Operator)	67.0% -89.2% WI	90 leases covering 1,163.1 km² make up the Alaskan North Slope Central Blocks Acreage
			Haliburton Energy Services, Inc	0.0% - 25.0% WI	Capped contribution to two wells

Notes:

* Otto has elected to acquire a 50% working interest/43.75% net revenue interest for an amount equal to a gross one hundred and thirty-three percent (133%) of Otto's fifty percent (50%) interest share of certain acquisition costs, including the Dry Hole Costs of an Initial Test Well (as defined in the Participation Agreement between Byron and Otto) incurred by Byron plus an amount equal to a gross fifty percent (50%) of certain other acquisition expenses (as defined in the Participation Agreement) incurred and paid by Byron. Refer to page 16.

** On 6 July 2018 Otto elected to participate in the initial test well at 40% working interest (29.8% net revenue interest).

*** On 31 July 2018 Otto farmed into an 8 well Gulf Coast package with Hilcorp. These assets are not reflected in the above table as they were subsequent to 30 June 2018.

RESERVES & PROSPECTIVE RESOURCES

AS AT 30 JUNE 2018

RESERVES AND PROSPECTIVE RESOURCES AS AT 30 JUNE 2017

Otto Energy Working Interest (WI) %

Reserves	Oil (Mbbls)	Gas (Mmscf)	Mboe (6:1)
SM 71, WI (50%)			
Proved Producing	1,733	1,065	1,910
Proved Behind Pipe	305	191	337
Proved Undeveloped	702	433	774
Proved (1P)	**2,740**	**1,689**	**3,021**
Probable Reserves	4,514	3,487	5,096
Proved and Probable (2P)	**7,254**	**5,175**	**8,117**
Possible Reserves	2,326	1,985	2,657
Proved, Probable and Possible (3P)	**9,580**	**7,161**	**10,774**
Prospective Resource (Best Estimate, Unrisked)* **	**Oil (Mbbls)**	**Gas (MMscf)**	**Mboe (6:1)**
SM 71, WI (50%)	476	23,844	4,450
Alaska (Western Blocks) WI (22.5%)	90,000	0	90,000
Alaska (Central Blocks) WI (10.8%)	70,000	0	70,000
Bivouac Peak WI (45%) **	7,196	79,950	20,520

Otto Energy Net Revenue Interest (NRI) %

Reserves	Oil (Mbbls)	Gas (Mmscf)	Mboe (6:1)
SM 71, NRI (40.625%)			
Proved Producing	1,408	865	1,552
Proved Behind Pipe	248	155	274
Proved Undeveloped	570	352	629
Proved (1P)	**2,226**	**1,372**	**2,455**
Probable Reserves	3,668	2,833	4,140
Proved and Probable (2P)	**5,894**	**4,205**	**6,595**
Possible Reserves	1,890	1,613	2,159
Proved, Probabale and Possible (3P)	**7,784**	**5,818**	**8,754**
Prospective Resource (Best Estimate, Unrisked)* **	**Oil (Mbbls)**	**Gas (MMscf)**	**Mboe (6:1)**
SM 71, NRI (40.625%)	387	19,373	3,616
Alaska (Western Blocks) NRI (18.75%)	75,000	0	75,000
Alaska (Central Blocks) NRI (9-9.45%)*	58,333 - 61,250	0	58,333 - 61,250
Bivouac Peak NRI (33.525%) **	5,361	59,562	15,288

* Precise weighted average royalty split unknown, volumetric range provided based on 12.5 to 16.67% royalty range

** On 6 July 2018 Otto elected to participate in the initial test well at 40% working interest (29.8% net revenue interest).

*** On 31 July 2018 Otto farmed into an 8 well Gulf Coast package with Hilcorp. These assets are not reflected in the above table as they were subsequent to 30 June 2018.

RESERVES RECONCILIATION

The following table shows a spilt of Otto's remaining reserves, as at 30 June 2018, into developed and undeveloped categories by project and by product. All reserves relate to SM 71 which is in the shallow water Gulf of Mexico, USA.

SM 71					
	Developed		Undeveloped		Total
	Oil (Mbbl)	Gas (MMscf)	Oil (Mbbl)	Gas (MMscf)	MBoe
Proven (1P)	**1,656**	**1,020**	**570**	**352**	**2,455**
Probable	2,605	1,726	1,064	1,107	4,141
Proven Plus Probable (2P)	**4,261**	**2,746**	**1,634**	**1,459**	**6,596**
Possible	-	-	1,890	1,613	2,159
Proven Plus Probable Plus Possible (3P)	**4,261**	**2,746**	**3,524**	**3,072**	**8,755**

The following table reconciles the movement in Otto's SM 71 reserves between 30 June 2017 and 30 June 2018.The numbers below are based on Otto's Working Interest of 50% and Net Revenue Interest (NRI) of 40.625%.

Otto Energy Working Interest (WI) %

RESERVES	OIL (MBBL)					GAS (MMSCF)				
SM 71 Otto (50% WI)	30 June 2018	Production	Farm-in	Revisions	30 June 2017	30 June 2018	Production	Farm-in	Revisions	30 June 2017
Proved (1P)	**2,740**	**(175)**	**-**	**1,850**	**715**	**1,689**	**(148)**	**-**	**1,045**	**496**
Probable Reserves	4,514	-	-	2,736	1,778	3,487	-	-	2,185	1,302
Proved and Probable (2P)	**7,254**	**(175)**	**-**	**4,586**	**2,494**	**5,175**	**(148)**	**-**	**3,230**	**1,798**
Possible Reserves	2,326	-	-	1,666	660	1,985	-	-	1,530	455
Proved, Probable and Possible (3P)	**9,580**	**(175)**	**-**	**6,252**	**3,153**	**7,161**	**(148)**	**-**	**4,759**	**2,254**

Otto Energy Net Revenue Interest (NRI) %

RESERVES	OIL (MBBL)					GAS (MMSCF)				
SM 71 Otto (40.625%)	30 June 2018	Production	Farm-in	Revisions	30 June 2017	30 June 2018	Production	Farm-in	Revisions	30 June 2017
Proved (1P)	**2,226**	**(142)**	**-**	**1,503**	**581**	**1,372**	**(120)**	**-**	**849**	**403**
Probable Reserves	3,668	-	-	2,223	1,445	2,833	-	-	1,775	1,058
Proved and Probable (2P)	**5,894**	**(142)**	**-**	**3,726**	**2,026**	**4,205**	**(120)**	**-**	**2,624**	**1,461**
Possible Reserves	1,890	-	-	1,354	536	1,613	-	-	1,243	370
Proved, Probable and Possible (3P)	**7,784**	**(142)**	**-**	**5,080**	**2,562**	**5,818**	**(120)**	**-**	**3,867**	**1,831**

MATERIAL CHANGES TO RESERVES

Proved and Probable Reserves - Net of Actual Production

The increase in proved and probable reserves is due to the successful SM 71 F2 ("F2") appraisal well drilled in December 2017 and the SM 71 F3 ("F3") development well drilled in January 2018. Significantly thicker than predicted oil bearing sands were logged in the drilling of the SM 71 F2 and F3 wells in the D5 Sand which has resulted in reserve additions and upgrades. Additionally, flow rates from the F1 and F3 wells have continued to exceed pre-start-up predictions resulting in positive revisions to expected recoveries.

Drilling of the B65 Sand in the SM 71 F2 well resulted in a positive reclassification of a portion of Prospective Resources to the Proved and Probable Reserves categories. Although the SM 71 F2 well has experienced premature pressure depletion, suggesting the well is in an isolated compartment, the reservoir is mapped well beyond the small drainage area of the SM 71 F2 well.

72% of the remaining proved and probable reserves are classified as developed or behind pipe with the balance classified as undeveloped.

Possible Reserves

The increase in possible reserves at SM 71 is mainly due to: -

(a) Potential upside recoveries and drainage areas from the producing D5 reserves

(b) The reclassification to possible reserves of a material proportion of the prospective resource previously attributed to the B65 Sand, and

(c) the addition of the possible reserves attributed to the B65, J1 and D5 sands as result of the development drilling in 2017/18.

NOTES TO RESERVES AND RESOURCES STATEMENT

Reserves and Resources Governance

Otto's reserves estimates are compiled annually. The operator of SM 71, Byron Energy, engages Collarini and Associates, a qualified external petroleum engineering consultant, to conduct an independent assessment of the SM 71 reserves on behalf of the joint venture. Collarini and Associates is an independent petroleum engineering consulting firm that has been providing petroleum consulting services in the USA for more than fifteen years. Collarini and Associates does not have any financial interest or own any shares in the Company. The fees paid to Collarini and Associates are not contingent on the reserves outcome of the reserves report.

Competent Persons Statement

The information in this report that relates to oil and gas reserves and resources for SM 71 and Bivouac Peak was compiled by technical employees of independent consultants Collarini and Associates, under the supervision of Mr Mitch Reece BSc PE. Mr Reece is the President of Collarini and Associates and is a registered professional engineer in the State of Texas and a member of the Society of Petroleum Evaluation Engineers (SPEE), Society of Petroleum Engineers (SPE), and American Petroleum Institute (API). The reserves and resources included in this report have been prepared using definitions and guidelines consistent with the 2007 Society of Petroleum Engineers (SPE)/World Petroleum Council (WPC)/American Association of Petroleum Geologists (AAPG)/ Society of Petroleum Evaluation Engineers (SPEE) Petroleum Resources Management System (PRMS). The reserves and resources information reported in this Statement are based on, and fairly represents, information and supporting documentation prepared by, or under the supervision of, Mr Reece. Mr Reece is qualified in accordance with the requirements of ASX Listing Rule 5.41 and consents to the inclusion of the information in this report of the matters based on this information in the form and context in which it appears.

The information in this report that relates to oil and gas resources in relation to the Alaska Western Blocks was compiled by Mr Paul Senycia BSc (Hons) (Mining Engineering), MAppSc (Exploration Geophysics), who has consented to the inclusion of such information in this report in the form and context in which it appears.

The information in this report that relates to oil and gas resources in relation to Alaska Central Blocks was compiled by technical employees of Great Bear Petroleum, the Operator of the Alaska acreage, and subsequently reviewed by Mr Paul Senycia BSc (Hons) (Mining Engineering), MAppSc (Exploration Geophysics), who has consented to the inclusion of such information in this report in the form and context in which it appears.

Mr Senycia is an employee of the Company, with more than 30 years relevant experience in the petroleum industry and is a member of The Society of Petroleum Engineers (SPE). The resources included in this report have been prepared using definitions and guidelines consistent with the 2007 Society of Petroleum Engineers (SPE)/World Petroleum Council (WPC)/ American Association of Petroleum Geologists (AAPG)/ Society of Petroleum Evaluation Engineers (SPEE) Petroleum Resources Management System (PRMS). The resources information included in this report are based on, and fairly represents, information and supporting documentation reviewed by Mr Senycia. Mr Senycia is qualified in accordance with the requirements of ASX Listing Rule 5.41 and consents to the inclusion of the information in this report of the matters based on this information in the form and context in which it appears.

Reserves Cautionary Statement

Oil and gas reserves and resource estimates are expressions of judgment based on knowledge, experience and industry practice. Estimates that were valid when originally calculated may alter significantly when new information or techniques become available. Additionally, by their very nature, reserve and resource estimates are imprecise and depend to some extent on interpretations, which may prove to be inaccurate. As further information becomes available through additional drilling and analysis, the estimates are likely to change. This may result in alterations to development and production plans which may, in turn, adversely impact the Company's operations. Reserves estimates and estimates of future net revenues are, by nature, forward looking statements and subject to the same risks as other forward looking statements.

Prospective Resources Cautionary Statement

The estimated quantities of petroleum that may potentially be recovered by the application of future development projects relate to undiscovered accumulations. These estimates have both an associated risk of discovery and a risk of development. Further appraisal and evaluation is required to determine the existence of a significant quantity of potentially moveable hydrocarbons.

ASX Reserves and Resources Reporting Notes

(i) The reserves and prospective resources information in this document is effective as at 30 June, 2018 (Listing Rule (LR) 5.25.1)

(ii) The reserves and prospective resources information in this document has been estimated and is classified in accordance with SPE-PRMS (Society of Petroleum Engineers - Petroleum Resources Management System) (LR 5.25.2)

(iii) The reserves and prospective resources information in this document is reported according to the Company's economic interest in each of the reserves and prospective resource net of royalties (LR 5.25.5)

(iv) The reserves and prospective resources information in this document has been estimated and prepared using the deterministic method (LR 5.25.6)

(v) The reserves and prospective resources information in this document has been estimated using a ratio of 6,000 cubic feet of natural gas to one barrel of oil. This conversion ratio is based on an energy equivalency conversion method and does not represent value equivalency (LR 5.25.7)

(vi) The reserves and prospective resources information in this document has been estimated on the basis that products are sold on the spot market with delivery at the sales point on the production facilities (LR 5.26.5)

(vii) The method of aggregation used in calculating estimated reserves was the arithmetic summation by category of reserves. As a result of the arithmetic aggregation of the field totals, the aggregate 1P may be a very conservative estimate and the aggregate 3P may be a very optimistic estimate due to the portfolio effects of arithmetic summation (LR 5.26.7 & 5.26.8)

(viii) Prospective resources are reported on a best estimate basis (LR 5.28.1)

(ix) The reserve numbers assume some investment over the life of the field which goes out to 2037. Proved (1P) reserves assume no wells but some re-completions and a sidetrack. Proved and Probable (2P) reserves assume some re-completions and two sidetracks Proved, Probable and possible (3P) reserves assume a new well in addition to some recompletions and sidetracks.

(x) Otto has controls in place to provide assurance for reserves estimation and reporting, including staff competency, staff accreditation and external reserves evaluations (LR 5.39.5).

(xi) Reserves are as originally announced to the ASX on 6 August 2018, and Otto is not aware of any new information or data that materially affects the information included in the referred market announcement and all the material assumptions and technical parameters underpinning the estimates in the relevant market announcement continue to apply and have not materially changed (LR 5.43.2).

(xii) All of Otto's reserves and prospective resources (except for those prospective resources designated as Alaska) are located in the Gulf Coast or shallow water of the Gulf of Mexico, offshore Louisiana, USA.

GLOSSARY

Bbl = barrels

bcf = billion cubic feet

boe = barrels of oil equivalent

Bopd = barrels of oil per day

Btu = British Thermal Units

Mcfg = thousand cubic of gas

Mcfgpd = thousand cubic feet of gas per day

MMcf = million cubic feet

Mbbl = thousand barrels of oil

MMbbl = million barrels of oil

Mboe = thousand barrels of oil equivalent

MMboe = million barrels of oil equivalent

Mcf = thousand cubic feet

MMcf = million cubic feet

mmbtu = million British Thermal Units

OTTO ENERGY
FINANCIAL REPORT 2018

FINANCIAL REPORT 2018

FINANCIAL REPORT 2018 CONTENTS

Annual General Meeting

The Annual General Meeting of Otto Energy Limited will be held on 15 November 2018.

CORPORATE DIRECTORY

Directors	Mr John Jetter – Non-Executive Chairman Mr Matthew Allen – Managing Director and Chief Executive Officer Mr Ian Macliver – Non-Executive Director Mr Ian Boserio – Non-Executive Director Mr Paul Senycia – Executive Director
Company Secretary	Mr David Rich
Key Executives	Mr Matthew Allen – Managing Director and Chief Executive Officer Mr Paul Senycia – Vice President Exploration and New Ventures Mr David Rich – Chief Financial Officer and Company Secretary
Principal registered office in Australia	32 Delhi Street West Perth WA 6005 Tel: + 61 8 6467 8800 Fax: + 61 8 6467 8801
Share Registry	Link Market Services Limited Level 12 QV1 Building 250 St Georges Terrace Perth WA 6000 Tel: + 61 8 9211 6670 Fax: + 61 2 9287 0303
Auditors	BDO Audit (WA) Pty Ltd 38 Station Street Subiaco WA 6008 Tel: + 61 8 6382 4600 Fax: + 61 8 6382 4601
Securities Exchange Listing	Australian Securities Exchange ASX Code: OEL
Website address	www.ottoenergy.com
ABN	56 107 555 046

DIRECTORS' REPORT
FOR THE YEAR ENDED 30 JUNE 2018

The Directors present their report together with the consolidated financial statements of the Group comprising Otto Energy Limited (referred to as 'Otto' or the 'Company') and its subsidiaries for the financial year ended 30 June 2018 and the auditors' report thereon.

Directors

The Directors in office at any time during the financial year and until the date of this report are set out below. All Directors were in office for the entire period except for Mr Paul Senycia who was appointed on 24 April 2018.

Mr John Jetter BLaw, BEcon, INSEAD
Chairman (Independent Non-Executive)
Appointed Non-Executive Director 10 December 2007, Non-Executive Chairman 25 November 2015
Mr John Jetter is the former Managing Director, CEO and head of investment banking of JP Morgan in Germany and Austria, and a member of the European Advisory Council, JP Morgan London. Mr Jetter has held senior positions with JP Morgan throughout Europe, focusing his attention on major corporate clients advising on some of Europe's largest corporate transactions. Mr Jetter has been a non-executive Director of Venture Minerals Limited since June 2010 and Peak Resources Limited since April 2015 and is a member of the Remuneration and Nomination Committee.

Mr Matthew Allen BBus, FCA, F Fin, GAICD
Managing Director and Chief Executive Officer
Appointed 24 June 2015
Mr Matthew Allen was appointed Chief Executive Officer in February 2014 and Managing Director in June 2015. Mr Allen joined Otto Energy in 2009 as Chief Financial Officer and has played an integral role in implementing Otto's strategy since joining Otto. Prior to joining Otto, Mr Allen worked for Woodside Energy for over 8 years in leadership roles in a number of Woodside business units, including within Woodside's overseas businesses in Africa.

Mr Allen's experience lies in the operation and management of oil & gas companies with particular focus on strategic, commercial and financial aspects of the business. Mr Allen has global upstream experience in the USA, Asia, Africa, Australia and the Middle East. He is a Fellow of Chartered Accountants Australia and New Zealand, Fellow of the Financial Services Institute of Australasia and Graduate Member of the Australian Institute of Company Directors.

Mr Ian Macliver BCom, FCA, SF Fin, FAICD
Director (Independent Non-Executive)
Appointed 7 January 2004
Mr Ian Macliver is Managing Director of Grange Consulting Group Pty Ltd, which provides specialist corporate advisory services to listed and unlisted companies. Mr Macliver has held senior executive and Director roles in both resource and industrial companies, specifically responsible for capital raising and other corporate initiatives. Mr Macliver has been the non-executive Chairman of Western Areas Limited since November 2013, and non-executive Director since October 2011. Mr Macliver was a non-executive Director of Rent.com.au Limited (formerly Select Exploration Limited) from September 2010 to June 2015 and a non-executive Director of Range Resources Limited from June to August 2014. Mr Macliver is a member of the Audit and Risk Management Committee and the Remuneration and Nomination Committee.

Mr Ian Boserio BSc Hons First Class (Geophysics), BSc (Geology)
Director (Independent Non-Executive)
Appointed 2 September 2010
Mr Ian Boserio brings to the Otto Board more than 30 years international experience in the oil and gas business, focused predominantly on exploration and management. Mr Boserio was formerly at Shell as the Australian New Business Manager, prior to that he led the Shell Australia and New Zealand exploration team developing its gas portfolio for LNG development. Mr Boserio also worked with Shell internationally, including roles in Australia, North Sea, Middle East, India and Indonesia, including a five year secondment into Woodside. He is currently co-owner and technical director of private oil and gas company Pathfinder Energy Pty Ltd. Mr Boserio is a member of the Audit and Risk Management Committee.

Mr Paul Senycia BSc (Hons), MAppSc
Director (Executive)
Appointed 24 April 2018
Mr Paul Senycia is an exploration geoscientist with over 35 years of international oil and gas experience in both commercial and technical aspects of the business. Mr Senycia has held senior roles in large and small companies worldwide including Shell, Woodside and Beach Petroleum. Over the last twenty years Paul has accumulated substantial Gulf of Mexico expertise both on the shelf and in the deep water. This has included deal capture, asset management and project divestment activities. Outside the Gulf of Mexico, Paul has worked in Europe, Asia, Africa and Australasia both on and offshore.

Company Secretary

Mr David Rich BCom, FCA, GAICD, AGIA, Grad.Dip.CSP
Appointed 31 January 2017
Mr Rich is an experienced public company CFO and Company Secretary with over 15 years as CFO of ASX listed upstream oil and gas companies with international interests including Australia, Europe, Asia, Africa and the USA.

Director's interests

As at the date of this report, the interests of the Directors in the shares and rights of Otto Energy Limited were:

Director	Number of ordinary shares	Number of convertible notes	Number of rights
Mr J Jetter	21,607,020	200,000	1,033,000
Mr M Allen	7,666,667	-	6,227,000
Mr I Macliver	6,007,627	-	703,000
Mr I Boserio	2,803,968	-	620,000
Mr P Senycia	3,661,468	-	5,450,000

Principal activities

The principal activity of the Group is oil and gas exploration, development, production and sales in North America.

Dividends

No dividend has been declared for the year ended 30 June 2018.

Strategy

The Company's core strategic goal is to grow production in the Gulf of Mexico to 5,000 boepd by the end of 2020.

As at the date of this report the status of execution of this strategy is as follows:

- Building a portfolio of US conventional production assets with a Gulf of Mexico focus and the capability to transition to an operator;
- Growth strategy underpinned by strong production and cash flow from flagship Gulf of Mexico SM 71 asset;
- Exciting pipeline of ten high-impact exploration opportunities taking place over the next 15 months; and
- An experienced team with a track record of successfully growing, operating and divesting oil and gas assets globally who understand risk and capital management.

Gulf of Mexico

The Company's strategy is currently focused on growth in the Gulf of Mexico for the following reasons:

- Proven prolific hydrocarbon province where technologies such as RTM seismic processing continue to create new opportunities;
- Low sovereign risk;
- High margin oil with breakeven economics around US$20/barrel;
- Short cycle time from discovery to development of 8-18 months;
- Low cost drilling and development;
- Relatively low risk exploration;
- Deal flow is liquid and a full spectrum of opportunity size is available;
- Otto has area expertise and well developed business relationships; and
- Otto has production in the area.

In order to deliver on the strategy, the Company's business development focus over the past year in the Gulf of Mexico has been on pursuing prospects with the following characteristics:

- Miocene/Pliocene/Oligocene geology which are amplitude supported;
- Investing capital into drilling, not seismic;
- Seeking early cashflow/ROI – Approximately 12-18 months from exploration to production;
- Shallow water (<300 feet) – keeping capex manageable; and
- High liquids yields to increase margins.

Review of operations

A review of the operations of the Group during the financial year and the results of those operations are set out below.

South Marsh Island 71 (SM 71)

Through the drilling of the SM 71 #1 discovery well ("SM 71 F1") in April-May 2016, Otto earned a 50% participating interest (equal to a 40.625% net revenue interest) in the SM 71 licence. Byron Energy Inc, a wholly owned subsidiary of Byron Energy Limited ("Byron") (ASX: BYE) is the operator, holding an equivalent participating and net revenue interest. Water depth in the area is approximately 137 feet.

Facilities

The platform jacket and deck modifications were completed at Laredo's onshore facility in Galveston, Texas and all major decks stacked by October 2017 in preparation for load out to the SM 71 location.

In late November 2017 the Tetra Hedron derrick barge was de-mobilised off location after successfully placing the jacket and decks over the SM 71 F1 well and securing the structure with pilings. The installation of the jacket and decks comprising the SM 71 F Platform was completed without any safety or operational issues.

Operations to lay the 500 foot 4-inch oil and 7,000 foot 6-inch gas pipelines were completed during October 2017. Each pipeline was initially laid and buried to within tie-in distance of the SM 71 F platform location and their respective sales lines. Final tie-in work at the platform and sales lines was completed in December 2017 by dive crews soon after the jacket and decks were installed at the platform location in SM 71.

Development Drilling

In early December 2017 the Ensco 68 jack-up rig spudded the first development well, the OCS G-34266 #F-2 well ("SM 71 F2"), on SM 71.

On 27 December 2017 Otto reported that the SM 71 F2 appraisal well encountered four discrete hydrocarbon bearing sands, including the B65 and D5, with an estimated combined net oil pay of true vertical thickness of 190 feet (58 metres). The drill pipe became stuck approximately 214 feet below the bottom of the D5 sand. Attempts were made to free the stuck drill pipe whilst evaluating various alternatives including the optimization of the F2 wellbore and the drilling of a future F3 well. Consequently, it was decided to case the F2 well to a depth of 7,700 feet measured depth ("MD"), 130 feet MD below the base of the B65 sand. By doing so, the B65 sand logged in the well was preserved as a take point in that reservoir. The F2 well can also be used to produce the J1 sand and B55 sand.

Real time "log-while drilling" porosity data indicated the porosity of both the B65 and D5 Sands to be consistent with other wells in the area with porosities ranging up to 31% with a high net to gross sand ratio in each zone.

Given the high quality and thickness of the D5 sand encountered in the F2 well and the fact that the joint venture had a one-time option to drill a second well under the existing Ensco drilling contract, it was decided to drill OCS G-34266 #F-3 well ("SM 71 F3") well immediately following the casing of the SM 71 F2 well using the Ensco 68 rig, rather than releasing it.

The F3 well spudded on 9 January 2018 USA Central Standard time and reached a final total depth of 7,717 feet MD on 26 January 2018. Logs indicated 211 measured depth feet of oil pay (175 feet TVT net oil pay) in the D5 Sand and exhibited excellent rock properties with porosities in the 32% range. With the base of the D5 Sand in the F3 well 150 feet below the base of D5 Sand in the F2 well, the D5 Sand oil column has been further extended downdip.

Because of the northerly well bore trajectory of the F3 well, the very updip portions of the three other oil sands were penetrated. The J1, B55 and B65 Sands each logged approximately 5 feet TVT net oil pay in the F3 well, consistent with pre-drill expectations. The data points of these three sands will serve to help delineate the size of each reservoir for future reserve determinations.

In addition to the J1, B55 and B65 zones, the F3 well also intersected 12 feet TVT net oil pay in the C10 which is productive in other parts of the dome but, to date, not productive at SM 71. Pre-drill mapping did indicate that the F3 would be at the very updip edge of the C10 in this well bore and this result sets up a further opportunity to be exploited in future well bores or in the F3 wellbore.

Following drilling of the F3 well, the Ensco 68 drilling rig was repositioned over the SM 71 F1 well and operations to complete the wells for production commenced. On 22 February 2018 Otto reported that the F1 well was completed for production in the D5 sand. On 5 March 2018 Otto reported that the F2 well was completed for production in the B65 sand. On 3 April 2018 the F3 well was completed for production in the D5 sand after delays due to downhole issues.

Production

Production operations at the SM 71 F platform began on 23 March when the SM 71 F1 well was brought on line. The F1 well is completed in the D5 Sand. The SM 71 F2 well, completed in the B65 Sand, was opened to the system on 25 March. On 6 April 2018 production from the SM 71 F3 well was initiated. The F3 well is completed in the D5 Sand reservoir.

The SM 71 F1 and F3 wells continue to produce strongly and are being managed to ensure maximum recovery from the field's primary D5 Sand reservoir.

After initial high flow rates, the F2 well which is completed in the secondary B65 Sand experienced premature pressure depletion, suggesting the well is in an isolated compartment, the reservoir is mapped well beyond the small drainage area of the SM 71 F2 well.

The Operator has confirmed that the B65 Sand is one of many focus areas to be targeted by the seismic processing project Byron is undertaking with Schlumberger's subsidiary WesternGeco, These data will help determine the placement of any sidetrack and future wells noting the significant remaining potential in the B65 Sand as evidenced by the reserves upgrade at 30 June 2018.

On 6 August 2018 Otto released the updated independent reserves numbers as at 30 June 2018. These include production data and the development drilling results. The report confirmed gross (100%) 2P reserves have increased by 10.6 MMboe, nearly threefold, to 16.2 MMboe since 30 June 2017. Otto's NRI share of 2P reserves is 6.6 MMboe and 1P is 2.5 MMboe as at 30 June 2018. Refer to the subsequent events section below for details on the independent reserves report.

Production and revenue details to 30 June 2018 are set out below:

SM 71 Production Volumes	To 30 June 2018
Gross (100%)	
SM 71 – Oil (bbls)	348,581
SM 71 – Oil (bopd)	3,486
SM 71 – Gas (Mscf)	240,438
Otto WI Share (50%)	
SM 71 – Oil (bbls)	174,291
SM 71 – Oil (bopd)	1,743
SM 71 – Gas (Mscf)	120,219
Otto NRI Share (40.625%)	
SM 71 – Oil (bbls)	141,611
SM 71 – Oil (bopd)	1,416
SM 71 – Gas (Mscf)	97,678

SM 71 Sales Revenue – Otto 50% WI share (before royalties)	To 30 June 2018
SM 71 – Oil - US$'million	11.31
SM 71 – Oil - US$ per bbl	64.91
SM 71 – Gas - US$'000	432
SM 71 – Gas – US$ per MMbtu	$3.68

Notes

1. Otto sells its high quality Louisiana Light Sweet crude ("LLS") produced at SM 71 at premium to West Texas Intermediate ("WTI") based on current LLS versus WTI price differentials. Deductions are then applied for transportation, oil shrinkage, basic sediment & water (BS&W), and other applicable adjustments.
2. Gas revenues include NGLs. 1 Mscf = 1.09 MMbtu in June for SM 71 production. The thermal content of SM 71 gas may vary over time.

South Timbalier 224 (ST 224)

In July 2017 Otto farmed-in to the ST 224 licence in the Gulf of Mexico shelf area. The block contained a large amplitude supported, high condensate to gas ratio (CGR) gas condensate prospect delineated by 3D seismic. Several existing production platforms fell within tie-back distance of the proposed well, making development of any discovered hydrocarbons both quick and cost effective.

The well, operated by respected and experienced operator, W&T Offshore Inc,.commenced on 19 October 2017 and was drilled to a total measured depth of 10,900 feet (3,322 metres). The targeted BN sand interval was intersected close to prognosis at 10,330 feet (3,149 metres) measured depth, however based on log observations the sand was considered to be water bearing. The well was plugged and abandoned in December 2017.

The joint venture, through Houston Energy, had also bid and won ST 235 which is the lease adjoining with and immediately south of ST 224. ST 235 was relinquished on 21 May 2018.

Bivouac Peak

The Bivouac Peak leases cover 2,821 acres of highly prospective acreage in the transitional zone inshore southern Louisiana. The Operator has identified multiple prospects at both the Middle and Lower Miocene levels demonstrating stacked amplitude and AVO (amplitude versus offset) support. Follow-up drilling options have been identified at the Lower Miocene level that could increase the scale of the overall opportunity.

Significant production exists in the adjacent Miocene sequence at the Little Bay field (greater than 45 Bcf gas and 5 MMbbl condensate) and the Atchafalaya Bay field (greater than 100 Bcf gas and 0.6 MMbbl condensate).

During the year the operator, Byron, negotiated the extension of the term of the original Bivouac Peak lease with the private landowners through 1 September 2019, to facilitate likely permit approval and anticipated drilling activity.

Permitting and well planning activities on Bivouac Peak continued including site specific survey work, pre-application geologic review, and the submission of the joint application coastal use permit to the Louisiana Coastal Management and the US Army Corps of Engineers for review.

On 6 July 2018 Otto elected to participate in the initial test well, Weiss Adler et al No. 1, on the Bivouac Peak East prospect. The well commenced on 25 August 2018. Refer to the subsequent events section below for further details.

With nearby production infrastructure already in place, any successful well at Bivouac Peak would be capable of being brought into production within 8-10 months of discovery at a development cost in the range of US$9-11 million (100%).

Should a commercial discovery be made at Bivouac Peak East additional potential at the Deep prospect will be followed up in due course.

Vermillion 232 (VR 232)

VR 232 is adjacent to Otto's 50% owned SM 71 oil field and adds drilling opportunities which increase Otto's potential upside around the SM 71 facilities.

In June 2018 Byron Energy Inc, a wholly owned subsidiary of Byron Energy Limited was advised by the Bureau of Ocean Energy Management ("BOEM") that its bid for VR 232 was deemed acceptable by the BOEM and the lease was awarded to Byron. The lease is subject to a 12.5% Federal Government royalty.

The Operator, Byron, has mapped a gas and gas condensate prospect on the block with in-house calculated gross prospective resource potential of 11 Bcf and 170,000 barrels. This prospect could be tested from Otto's SM 71 F platform. There are currently no plans to drill VR 232 until production levels at the platform would allow a successful VR 232 well to be produced efficiently. The Operator has also identified two other prospects in VR 232 which require further geophysical evaluation before a drilling decision is made.

Byron evaluated this block with the same high-quality Reverse Time Migrated 3D seismic data and proprietary Inversion processed seismic data used in the discovery of oil and gas at SM 71 in 2016. Upon transfer, Otto's working interest will be 50% and net revenue interest will be 43.75%.

Pursuant to the terms of a Participation Agreement, effective 1 December 2015, between Byron and Otto, Otto has elected to participate in VR 232 at a fifty percent (50%) working interest.

Under that agreement, Otto must pay an amount equal to a gross one hundred thirty-three percent (133%) of Otto's fifty percent (50%) interest share of lease acquisition costs and the initial test well (dry hole costs) plus a gross fifty percent (50%) of other past costs paid by Byron.

Under Byron's bid of US$1.101 million for VR 232, Otto's share was US$734,000.

Having now elected to participate in the drilling of the East prospect at Bivouac Peak and participate in VR 232 at a 50% working interest, Otto's right to participate in new assets or projects under the December 2015 Participation Agreement with Byron has been fulfilled.

Alaska Western Blocks

On 25 June 2018 Otto, along with 88 Energy Limited (ASX:88E) and Red Emperor Resources NL (ASX:RMP) (collectively the "Consortium Partners"), announced they had executed a binding term sheet agreement with Great Bear Petroleum Ventures II LLC ("Great Bear") to acquire the majority of Great Bear's working interest in four leases comprising the "Western Blocks" (ADL#s 391718, 391719, 319720 and 391721). Refer to the ASX release of 25 June 2018 for the full details.

In consideration for acquiring the leases, the consortium partners agreed to undertake the following:

- Provide a performance bond of US$3.0 million to the State of Alaska by 31 July 2018 (Otto's share is US$750,000); and
- Drill an exploration well in the Western Blocks by 31 May 2019.

The consortium partners agreed to provide the following consideration to Great Bear:

- Free carry Great Bear for a 10% working interest in the leases for the drilling, completion and production testing of an initial test well, including all associated costs such as permitting, ice road access and test production disposition;
- Pay US$500,000 upon execution of the definitive agreements;
- Pay US$500,000 upon receipt of final permits necessary to drill the initial test well, in any case by no later than 31 December 2018; and
- Provide an option for Great Bear to acquire a further 10% working interest prior to the spud of the initial test well by paying its pro-rata share of all costs of the initial test well or if exercised within 6 months of completing the initial test well, by paying 200% of its pro-rata share of all costs of the initial test well.

The relevant interests in the Western Blocks following the commercial agreements are as follows (subject to regulatory approval by the State of Alaska):

	Working Interest (before back-in)	Paying Interest (before back-in)	Net Revenue Interest* (before back-in)	Working Interest (after back-in)
Otto Energy	22.5%	25.0%	18.75%	20.0%
88 Energy (Drilling Management)	36.0%	40.0%	30.00%	32.0%
Red Emperor	31.5%	35.0%	26.25%	28.0%
Great Bear Petroleum**	10.0%	-	8.33%	20.0%
State of Alaska	-	-	16.67%	
	100.0%	100%	100%	100%

*Government royalty of 16.67%. **Currently Operator of record on leases.

The initial test well will satisfy Otto's first participation obligation under Otto's Purchase and Development Agreement with Great Bear dated 29 May 2015. Refer to the Otto announcement of 1 October 2015.

Otto holds a working interest in four leases totalling over 22,710 acres located in the heart of the prolific Nanushuk oil fairway. The Horseshoe-1 well, which discovered oil in 2017, is located less than one mile to the west of Otto's Western Blocks. Horseshoe-1 extended the Nanushuk play fairway by well over 20 miles to the south of previous drilling. Repsol reports that since 2011 the Company has drilled multiple consecutive discoveries on the North Slope along with partner Armstrong.

Industry sources have indicated contingent recoverable resources discovered to date in the trend could contain over 1.2 billion barrels of oil. This places the trend as one of the most significant emerging plays on the Alaska North Slope. With ongoing drilling in 2018 it is expected that additional discoveries will be made in this emerging play trend.

The Horseshoe-1 discovery well was drilled by the Repsol-led joint venture in 2017 to a total depth of 6,000 ft. (1,828 meters) and encountered more than 150 ft. of net oil pay in several reservoir zones in the Nanushuk section. The deviated Horseshoe-1A sidetrack was drilled to a total depth of 8,215 ft. and encountered more than 100 ft. of net oil pay in the Nanushuk interval as well.

Western Blocks Prospect

Recent in-house technical work conducted by Otto on its Alaska acreage in the Western Blocks has resulted in the identification of an oil prospect with a gross best estimate prospective resource volume of 400 MMbbls and a geological chance of success in the range of 25-30%. The prospective resource calculation was based on a consideration of offset well information (Itkillik River-1 well completion information), seismic expression and a recovery factor of 30%. Otto's 18.75% net revenue interest (before Great Bear 10% back in – refer table above) in the prospect would be 75 MMbbls. The prospective resource information was first released to ASX on 25 June 2018.

The prospect was identified on modern 3D seismic data obtained through the Alaska Department of Natural Resources, Division of Oil and Gas. On this seismic data the prospect shares many of the positive attributes seen at the Horseshoe-1 discovery which found light oil reservoired in more than 150ft of net oil sand of the Nanushuk delta sequence.

The discovery at Horseshoe-1 has extended the known accumulation of Nanushuk oil some 20 miles south of earlier discoveries such as those at Qugruk 8 and Qugruk 301 which flowed 30 degree gravity crude at rates as much as 2,160 and 4,600 bbls/d respectively.

The Horseshoe-1 discovery has signalled the presence of an extensive previously overlooked hydrocarbon province which is in now attracting major development capital including the recent acquisition by Oil Search Limited (ASX: OSH) of operatorship of the Pikka Unit and a number of oil exploration assets on the Alaska North Slope.

Exploration success in the Nanushuk play-fairway is now being driven by the understanding that when reservoir quality top set sands are present anomalously high amplitudes are seen on seismic data.

This type of positive amplitude response has also been seen on seismic over the Western Blocks. Otto presently calculates a best estimate gross prospective resource of 400 MMbbls in the prospect area mainly on the basis of this amplitude work.

Some of the block area to the south is not covered by 3D data and as yet uncalculated upside potential is likely to exist in this area as well.

Further encouragement that the prospect will be found oil bearing is provided by the presence of oil shows seen in the adjacent Itkillik River-1 well drilled in 1978 (from publicly available well data at the Alaska DNR). Here oil was observed during drilling at multiple levels within fine grained sediments.

If 3D data had been available at the time Itkillik River-1 had been drilled, the well would likely have been moved further south to intersect a better reservoir quality and more continuous sand interval. This higher quality sand interval is the key target for the proposed Otto well.

Offtake Options

With the Oil Search operated Pikka unit development activities occurring to the west and the Conoco-Phillips Meltwater unit facility some 10 miles to the east, any oil found within the Western Blocks will find a cost effective, commercially attractive route to market. Project economics will be further enhanced by the shallow nature of the oil pool.

Drilling Planning

88 Energy Ltd will manage the drilling of the initial test well in the Western Blocks on behalf of the joint venture and consortium partners. Since year end a rig contract has been signed. Given that the location is only accessible through an ice road, drilling will be undertaken during the winter operational months once the Alaska North Slope is opened for operations.

Lease Terms

The four North Slope leases comprising the Western Blocks have recently been extended by three years with the term now expiring on 30 April 2021. During this period the joint venture is required to post a US$3.0 million performance bond and undertake the drilling and testing of an initial test well by no later than 31 May 2019. This bond has been posted subsequent to year end. The leases have an annual rental of US$10.00 per acre or fraction thereof.

Alaska Central Blocks

Through its agreements with Great Bear Petroleum Operating ("Great Bear") in 2015, Otto has between an 8% and 10.8% working interest in 90 leases (covering 287,425 gross acres) held by Great Bear on the Alaskan North Slope ("Central Blocks").

Great Bear is a private exploration company focused exclusively on exploring and developing conventional and unconventional resources in this highly prospective basin. The leases are in a major play fairway south of the Prudhoe Bay and Kuparuk giant oil fields.

Great Bear has undertaken significant exploration work on the acreage since 2011 including:

- Acquisition and processing of approximately 2,970 km2 of 3D seismic data (1,170 km2 in 2016);
- Drilling of two unconventional stratigraphic test wells which cored three primary unconventional targets; and
- Drilling of a conventional exploration well (Alkaid-1) which specifically targeted a 3D defined Brookian reservoir. The Alkaid well results are under evaluation.

The extensive, modern 3D seismic coverage, existing well control and proximity to the all-weather Dalton Highway and Trans-Alaskan Pipeline System (TAPS) means the acreage is well positioned for exploration.

Existing 3D seismic has allowed development of an extensive prospect portfolio which includes at least 4 well locations.

Otto's exposure on the first two wells is limited to US$2.6m/well.

During the year 54 leases expired or were relinquished. The key prospects have been retained in the 90 leases held after this review and relinquishment process.

Houston Office

To support the pursuit of Otto's strategic goal of 5,000 boepd in the US, the Company is in the process of moving its operational office to Houston, Texas. Managing Director, Mr Matthew Allen, has relocated to Houston since year-end.

In addition, Otto has recruited an exploration team led by Will Armstrong, who has more than 30 years of experience across the Gulf of Mexico. Full background information on the team can be found in the ASX release dated 16 July 2018.

Otto has opened its office located at Two Allen Center in Houston Downtown.

Financial summary

The Group recognised a loss after income tax for the year of $5.2 million (2017: loss $5.2 million). Net revenue from SM 71 production was US$9.5 million generating a gross profit of US$7.9 million noting production only commenced on 23 March 2018 (2017: Nil). Costs of production included US$877,000 for amortization of oil and gas properties (2017: Nil). The net loss for the financial year ended 30 June 2018 included exploration expenses of US$4.8 million (2017: US$0.9 million) which was predominantly for the ST 224 well (US$3.6 million).

Administration costs were US$4.0 million, down from US$4.4 million in 2017. This includes business development costs of US$0.5 million (2017: US$0.5 million) and the costs of establishing the office in Houston.

Finance costs totaled US$4.4 million (2017: Nil) which included non-cash items of accretion of effective interest on convertible notes (US$0.3 million), fair value adjustment on embedded derivative element of convertible note US$2.4 million) and amortisation of borrowing costs (US$0.2 million). The other components of finance costs were success fee accrual (US$0.2 million) and interest on convertible note (US$1.2 million).

Significant changes in the state of affairs

Significant changes in the state of affairs of the Group during the financial year were as follows:

- On 23 March 2018 production commenced from the Company's 50% owned SM 71 oil field in the Gulf of Mexico. As at 30 June 2018 Otto had generated revenue from the SM 71 field of US$11.7 million before royalties from 174,291 bbls of oil and 120 MMscf of gas (Otto' share). This equates to net revenue of US$9.5 million after federal royalties.
- On 2 August 2017, following shareholder approval at a general meeting, the Company raised $8.2 million via an issue of secured convertible notes to Molton Holdings Limited, a major Otto shareholder ($8 million), and Mr John Jetter, Otto's Chairman ($0.2 million). Key terms of the convertible notes are set out in the notice of meeting released to the ASX on 23 June 2017. Funds raised via the issue were used to develop Otto's SM 71 oil project.
- On 25 October 2017 the Company announced that it has successfully raised A$8.5 million through a placement at A$0.035 per share, attracting strong interest from new and existing institutional and sophisticated investors. The heavily oversubscribed placement was strongly supported by the Company's larger shareholders, including all of the company's directors, as well as several new professional and sophisticated investors.

  The first tranche of the Placement, comprising 236.8 million shares (A$8.3 million) was issued utilising Otto's available placement capacity under ASX Listing Rules 7.1 and 7.1A respectively on 1 November 2017. The second tranche of the Placement, comprising 6.1 million shares(A$0.2 million) was issued to Otto directors (or their nominees) on 1 December 2017 following shareholder approval at the Company's Annual General Meeting held on 29 November 2017.

  The Company also announced on 25 October 2017 it was undertaking a Share Purchase Plan to its existing eligible shareholders, providing them with the opportunity to subscribe for up to a maximum of $15,000 worth of shares at the placement price of $0.035 per share. The Company was aiming to raise up to $1 million with the ability to determine to raise a higher amount or scale back applications at its discretion. The SPP opened on Monday 30 October 2017 and closed at 5.00pm (AWST) on Friday 17 November 2017.

  The SPP closed with applications of A$6.2 million, well in excess of the A$1 million Directors had been aiming to raise from the SPP. As a result of the significant oversubscription, the Board approved an increase in the total amount to be accepted to A$3.5 million of the A$6.2 million SPP applications received. The balance of A$2.7 million was refunded and 100 million shares were issued on 27 November 2017.

Significant events after the balance date

No matters or circumstances have arisen since 30 June 2018 that have significantly affected, or may significantly affect the Group's operations, the results of those operations, or the Group's state of affairs in future financial years apart from those listed below:

Appointment of US technical team

The Company has completed the establishment of its Houston office and appointment of a US-based technical team. Managing Director Matthew Allen has relocated to Houston to lead the team. In addition, Otto is pleased to announce the following technical appointments in Houston:

Will Armstrong – Vice President, Exploration and New Ventures

Philip Trajanovich – Senior Commercial Manager

Mark Sunwall – Senior Exploration Consultant

Kevin Small – Senior Exploration Consultant

The exploration team will be led by Will Armstrong, who has more than 30 years of experience across the Gulf of Mexico. Will's exploration work has seen the drilling of 162 prospects across his career at a commercial success rate in excess of 66%.

The exploration team have been engaged as consultants inside the Otto business since early 2018. This has involved the screening of a number of prospects and investment opportunities including the Hilcorp Gulf Coast package. As a result of this consulting work, and past experience, the exploration team are very familiar with the Company's current portfolio, screening criteria and focus area for potential prospects.

In addition, Otto has opened its office located at Two Allen Center in Houston Downtown. Refer to the ASX release of 16 July 2018 for further details.

Alaska Western Blocks

On 30 July 2018 Otto advised that, via its wholly owned subsidiary Borealis Alaska LLC, it had executed definitive agreements with Great Bear Petroleum Operating LLC, along with the Consortium Partners, 88 Energy Limited (Captivate Energy Alaska, Inc) and Red Emperor Resources NL, to acquire the majority of Great Bear's working interest in exchange for drilling a commitment well on the Western Blocks prior to 30 May 2019. Refer to the operational update above and Otto's ASX release of 25 June 2018 for the details of the agreement and Western Blocks opportunity.

On 29 August 2018 the Company announced that the operator Captivate Energy Alaska, Inc, (a 100% owned subsidiary of 88 Energy Limited) had executed a rig contract for the drilling of the Winx Prospect, located on the Western Blocks, North Slope of Alaska.

The Winx Prospect is a 3D seismic defined oil prospect in the successful Nanushuk play fairway with a gross mean unrisked prospective resource of 400MMbbls (75MMbbls net to Otto) and a geological chance of success in the range of 25-30%.

Hilcorp eight well farmin

On 31 July 2018 Otto advised that it had entered into a joint venture with Hilcorp Energy which will see it earn a 37.5% working interest in an eight well portfolio of prospects in the Onshore/Near Shore USA Gulf Coast (Gulf of Mexico). The wells will be drilled by Hilcorp, a highly experienced, privately-owned operator based in Houston, over the next 15 months

Details of the Agreement

Under a Joint Exploration and Development Agreement (JEDA) with Hilcorp Energy Otto has committed to an eight well drilling program with an estimated cost of US$75 million (100%).

Otto will earn a 37.5% working interest by paying 50.0% of the costs of drilling and either setting casing or plugging and abandoning the well plus lease acquisition costs at each of the eight prospects. The estimated cost of the commitment to Otto is US$37.5 million. US$4 million was paid immediately to cover initial land and other costs.

Well Cap - Otto has the option to discontinue participation in each prospect well if actual costs exceed the approved expenditure budget by 20%. If Otto elects to not continue, it will forfeit rights to that prospect. If Otto proceeds, costs from then on will be at working interest percentages.

Program Cap - Once Otto has incurred a total amount relating to the initial eight wells of US$42.5m, it will have the option to elect (but not the obligation) to participate in the remaining undrilled prospects in the initial eight well program at working interest percentages. If Otto elects to not participate in any undrilled prospects, it will forfeit rights in those prospects.

Minimum Commitment – Should Otto not participate in one or more of the eight wells, it shall be liable for liquidated damages in the sum of US$1 million per prospect.

Additional Upside

Should either the Tarpon or Mustang prospects be successful then Otto has ground floor rights (ie pays only its working interest) to participate in the nearby Damsel and Corsair/Hellcat opportunities. These wells are in addition to the eight wells.

Under the JEDA Otto has a right of first offer to a subsequent Gulf Coast program, if Hilcorp elect to offer such a program to third parties.

About Hilcorp Energy

Founded in 1989, Hilcorp is one of the largest privately held oil and natural gas companies in North America. Hilcorp specializes in reinvigorating legacy oil and gas fields across North America; including in the US Gulf Coast, Alaska and the Rockies and currently produces approximately 325,000 boepd. To put this into context, Australia's largest oil and gas company, Woodside, produces ~230,000 boepd.

Hilcorp has nearly 2,000 employees and has been consistently recognized for its strong culture, values and ethics both within the firm and in the communities in which it operates.

Otto is very pleased to be partnering with a Gulf Coast operator with proven capability to take exploration prospects into production.

Impact on Strategy

Otto has a clear strategy to grow production in the Gulf of Mexico to 5,000 boepd by the end of 2020. More specifically Otto's target area for new opportunities lies within the Pliocene, Miocene and Oligocene reservoir systems of the US Gulf of Mexico shelf and Gulf Coast where capital costs are manageable for Otto and the availability of infrastructure means the time from discovery to production is short. Otto is deploying its experienced technical team to find attractive, low risk drill opportunities in this area to provide high-margin oil and gas production growth.

This growth strategy is underpinned by the strong production and cashflow from Otto's 50% owned SM 71 oil field in the Gulf of Mexico shelf.

The Hilcorp eight well portfolio is a significant step toward the 5,000 boepd and puts Otto into partnership a large and well-respected operator in the region. In addition it offers further potential through follow-up drilling and a right of offer on further Hilcorp Gulf Coast farmouts.

Details of the Drilling Program

Information regarding the eight wells is set out in the table below. Note that on 30 August 2018 Otto announced that the Big Tex well commenced drilling. Further details are set out later in this subsequent events note.

Prospect Name	Planned Spud Date	Target Depth (TVD), ft	Rig Type	Working Interest (WI)	Net Revenue Interest (NRI)	Stratigraphic Interval	County/ Parish	Location
Big Tex	Sep-18	13,500	Barge	37.50%	29.51%	Tex	Plaquemines	Louisiana
Lightning	Oct-18	14,500	Land	37.50%	28.50%	Frio Tex Miss	Matagorda	Texas
Don Julio 2	Dec-18	11,500	Land	37.50%	28.50%	Oligocene	Chambers	Texas
Mustang	Jan-19	17,500	Land	37.50%	30.00%	Oligocene	Chambers	Texas
Beluga	May-19	13,000	Barge	37.50%	28.50%	Oligocene	Galveston Bay	Texas
Oil Lake	Jul-19	14,500	Land	37.50%	29.06%	Frio	Cameron	Louisiana
Tarpon	Jul-19	14,000	Barge	37.50%	29.06%	Oligocene	Galveston Bay	Texas
Mallard	Nov-19	11,000	Barge	37.50%	29.63%	Mid Miocene	Assumption	Louisiana

Prospective Resources

The range of prospective resources for each prospect is set out below.

Prospect Name	Working Interest	Net Revenue Interest	Probability of Success	Prospective Resources MMboe							
				100%				Otto Net Revenue Interest			
				P90	P50	Mean	P10	P90	P50	Mean	P10
Big Tex	37.50%	29.51%	54%	0.5	3.3	6.8	16.9	0.1	1.0	2.0	5.0
Lightning	37.50%	28.50%	45%	0.9	3.2	4.4	10.1	0.3	0.9	1.3	2.9
Don Julio 2	37.50%	28.50%	44%	0.7	2.5	4.0	9.6	0.2	0.7	1.1	2.7
Mustang	37.50%	30.00%	56%	2.9	6.7	8.5	16.8	0.8	1.9	2.6	4.8
Beluga	37.50%	28.50%	45%	0.8	2.9	4.7	11.2	0.2	0.9	1.3	3.4
Oil Lake	37.50%	29.06%	45%	1.2	3.3	4.4	9.3	0.3	1.0	1.3	2.7
Tarpon	37.50%	29.06%	34%	7.7	24.0	35.6	81.0	2.2	7.0	10.3	23.5
Mallard	37.50%	29.63%	64%	0.2	0.9	3.3	4.5	0.1	0.3	1.0	1.3

Equity raising

On 31 July 2018 the Company announced it was undertaking a capital raising of approximately A$20 million via an institutional Placement and a fully-underwritten, accelerated non-renounceable Entitlement Offer to fund its US$37.5 million share of the drilling program. Refer above and to the ASX release of 31 July 2018 for details on the Gulf Coast Package of eight wells with Hilcorp.

The offer price of A$0.059 represented a:

- 7.8% discount to the last close of A$0.064 on Monday 30 July 2018;
- 9.5% discount to the 30 day VWAP; and
- 6.5% discount to TERP.

Placement

The Placement raised a total of A$10m through the issue of approximately 169.5 million shares at A$0.059 per share.

Institutional Entitlement Offer

The Institutional Entitlement Offer raised a total of A$3m through the issue of approximately 51.6 million shares at A$0.059 per share

The Institutional Entitlement Offer shortfall was strongly oversubscribed by institutional shareholders. Shares issued under the placement and Institutional Entitlement Offer were allotted on Friday 10 August 2018.

Retail Entitlement Offer

The retail component of the Entitlement Offer (Retail Entitlement Offer) provided eligible retail shareholders in Otto the opportunity to acquire 1 new share for every 9 shares held at the record date of 7.00pm (AEST) on 2 August 2018.

A$5.5 million (78%) of Entitlements were taken up leaving a Shortfall of A$1.5 million. A further A$6.0 million in subscriptions were received for Additional New Shares which was A$4.5 million in excess of the Shortfall of A$1.5 million, hence the A$4.5 million was refunded. The scale back was determined based on the pro-rata of the Additional New Shares applied for to the shareholder's entitlement as at the Record Date. Accordingly, given the Retail Entitlement Offer was oversubscribed, there was no allocation to underwriters.

A total of A$7 million was raised from the Retail Entitlement Offer through the issue of 118.5 million shares at A$0.059 per share.

New shares issued under the Retail Entitlement Offer were allotted on 29 August 2018.

As a result of the entitlement offer, the conversion price for the convertible notes reduced from A$0.055 to A$0.05484.

Bivouac Peak

On 9 July 2018 Otto announced that it had elected to participate in the initial test well, Weiss-Adler et. al. No. 1 ("Weiss-Adler#1"), on the Bivouac Peak East prospect.

The estimated cost for the 18,294 ft MD/18,000 ft TVD well is US$10.8 million (100% dry hole cost). Otto will earn a 40% working interest by paying 53.33% of the costs of the well to reach the earning depth or up to a cap of US$5.33 million, whichever occurs first, after which Otto will revert back to paying 40% of all future costs.

The Bivouac Peak project area comprises two prospects, the East Prospect and the Deep Prospect. The total mapped gross 8/8ths prospective resources for the two combined prospects at Bivouac Peak are estimated at 16.0 million barrels of oil ("Mmbo") and 177.7 billion cubic feet of gas ("Bcf "), or 45.6 million barrels oil equivalent ("Mmboe")1 .

The Weiss-Adler #1 well is designed to test the Bivouac Peak East Prospect, targeting the regionally productive Miocene Cib Op section, with a mapped gross 8/8ths prospective resource of 11.3 MMbbls and 125.6 Bcf, or a combined 32.2MMboe. Although the East and the Deep prospects are independent, success at the East Prospect would provide positive seismic calibration, potentially reducing risk at the Deep Prospect as well.

On 27 August 2018 Otto announced that the Weiss-Adler #1 exploration well had commenced. The Parker Drilling Company Rig #77-B Deep Drilling 3000 HP Posted Barge Rig will drill to a depth of 18,294 ft Measured Depth ("MD")/18,000 ft True Vertical Depth ("TVD"). The well is expected to take approximately 75 days to reach total depth.

In case of success, completion and development costs to first production are currently estimated in the range of US$9.0-11.0 million (gross). Should the well be productive, it is currently estimated that this well would commence production within 8-10 months following drilling of the initial test well.

Big Tex spud

On 30 August 2018 Otto announced that the initial exploration well, SL 192 PP 031, on the Big Tex prospect had commenced drilling from a bargemounted rig.

The well will be drilled to 13,175 ft MD/12,700 ft TVD and is expected to take 55 days to reach total depth. Otto will earn a 37.5% working interest by paying 50% of the costs of drilling and either setting casing or plugging and abandoning the well, after which point Otto will pay 37.5% of all future costs. The well is expected to cost the Company US$4.23 million (50% paying interest). The exploration well on the Big Tex prospect is targeting the Tex W 16 Sand and Tex W 18 Sand that are Middle Miocene in age. This is a prolific section, having produced from the east in Hilcorp's East Bay Field, and from the west from the massive West Delta 30 Field, which has produced 562 MMBO and 934 BCF to date.

The success case development concept will be a flowline tieback to an existing platform. The prospect has been assessed as having a probability of success of 54%.

Nearly threefold reserve increase at SM 71

On 6 Aug 2018 Otto provided an update on the Company's reserves and resources position for its 50% owned South Marsh Island Block 71 ("SM 71") oil producing project, in the shallow waters of the Gulf of Mexico as independently assessed by Collarini Associates ("Collarini").

The SM 71 reserves and resources as at 30 June 2018 are as follows:

SM 71	Gross (100%)			Otto Net (40.625%)		
	Oil (Mbbl)	Gas (MMscf)	MBoe	Oil (Mbbl)	Gas (MMscf)	MBoe
Proved Producing	3,466	2,130	3,821	1,408	865	1,552
Proved Behind Pipe	609	380	672	248	155	274
Proved Undeveloped	1,404	868	1,549	570	352	629
Proven (1P)	**5,479**	**3,378**	**6,042**	**2,226**	**1,372**	**2,455**
Probable	9,030	6,974	10,192	3,668	2,833	4,140
Proven Plus Probable (2P)	**14,509**	**10,352**	**16,234**	**5,894**	**4,205**	**6,595**
Possible	4,651	3,970	5,313	1,890	1,613	2,159
Proven Plus Probable Plus Possible (3P)	**19,160**	**14,322**	**21,547**	**7,784**	**5,818**	**8,754**
Total Prospective Resource (best estimate, unrisked)	954	47,687	8,902	387	19,373	3,616

The Collarini report is effective as of 30 June 2018 and is the first independent reserve report for the SM 71 project since production began in March 2018. All reserves quoted below are remaining reserves, excluding production of approximately 349,000 barrels of oil and 240 MMcf of gas (gross) through 30 June 2018.

Collarini has estimated an increase in 2P reserves of 4.3 MMboe net to Otto (excluding production to 30 June 2018) a near tripling of the 2017 2P reserves estimate.

The significant increase in all key reserve categories is directly due to the success of the appraisal and development drilling program in 2017/18. Both the thicker than expected net oil zones and exceptional well performance to date from the D5 producing sands in both the F1 and F3 wells are contributing factors to the positive additions and revisions to the Company's reserves. Further details on the material changes to reserves is set out below.

Proved and Probable Reserves - Net of Actual Production

The increase in proved and probable reserves is due to the successful SM 71 F2 ("F2") appraisal well drilled in December 2017 and the SM 71 F3 ("F3") development well drilled in January 2018. Significantly thicker than predicted oil bearing sands were logged in the drilling of the SM 71 F2 and F3 wells in the D5 Sand which has resulted in reserve additions and upgrades. Additionally, flow rates from the F1 and F3 wells have continued to exceed pre-start-up predictions resulting in positive revisions to expected recoveries.

Drilling of the B65 Sand in the SM 71 F2 well resulted in a positive reclassification of a portion of Prospective Resources to the Proved and Probable Reserves categories. Although the SM 71 F2 well has experienced premature pressure depletion, suggesting the well is in an isolated compartment, the reservoir is mapped well beyond the small drainage area of the SM 71 F2 well.

72% of the remaining proved and probable reserves are classified as developed or behind pipe with the balance classified as undeveloped.

Possible Reserves

The increase in possible reserves at SM 71 is mainly due to:

a) Potential upside recoveries and drainage areas from the producing D5 reserves
b) The reclassification to possible reserves of a material proportion of the prospective resource previously attributed to the B65 Sand, and
c) the addition of the possible reserves attributed to the B65, J-1 and D5 sands as result of the development drilling in 2017/18.

Material Changes to Prospective Resources

The decrease in prospective resources is due to reclassification of all of the 2017 B65 Sand prospective resource into proved, probable and possible reserves in 2018 following successful discovery, appraisal and development drilling and some production.

SM 71 status

As at 19 September 2018, cumulative gross production was approximately 641,737 barrels of oil and 556 million cubic feet of gas, on a gross basis with no produced formation water. The current field sales rate as of 19 September 2018, was approximately 3,600 bopd and 6.0 mmcfgpd, on a gross basis after shrinkage at the sales meter. Recompletion of the F2 well from the B65 Sand to the B55 Sand is expected to commence during the last week of September 2018.

Likely developments and expected results

Likely developments in the operations of the Group that were not finalised at the date of this report included:

- Drilling results for the Bivouac Peak and Big Tex wells currently drilling;
- Participate in the drilling of another seven wells on the Gulf Coast with Hilcorp; and
- Participate in the drilling of a well in Alaska in early 2019.

Additional comments on expected results of certain operations of the Group are included in the Review of Operations above.

In accordance with its objectives, the Group intends to participate in a number of exploration and appraisal wells and will consider growing its exploration effort by farmin, permit application and/or acquisition within its existing operational focus area of North America with a specific target of the Gulf of Mexico. Further information on likely developments in the operations of the Group and the expected results of operations have not been included in this annual financial report because the Directors believe it would be likely to result in unreasonable prejudice to the Group.

Environmental regulation and performance

So far as the Directors are aware, there have been no breaches of environmental conditions of the Group's exploration or production licences. Procedures are adopted for each exploration program to ensure that environmental conditions of the Group's tenements are met.

Directors' meetings

The number of meetings of Directors (including meetings of committees of Directors) held during the year and the numbers of meetings attended by each Director were as follows:

Director	Board meetings		Audit and risk management committee		Remuneration and nomination committee	
	Number eligible to attend	Number attended	Number eligible to attend	Number attended	Number eligible to attend	Number attended
Mr J Jetter	9	9	-	-	3	3
Mr M Allen	9	9	-	-	-	-
Mr I Macliver	9	9	2	2	3	3
Mr I Boserio	9	9	2	2	-	-
Mr P Senycia	2	2	-	-	-	-

Indemnification and insurance of Directors and officers

During the financial year, the Company paid a premium of $80,713 to insure the Directors and officers of the Company and its controlled entities, and the managers of each of the divisions of the Group.

The liabilities insured are legal costs that may be incurred in defending civil or criminal proceedings that may be brought against the officers in their capacity as officers of entities in the Group, and any other payments arising from liabilities incurred by the officers in connection with such proceedings. This does not include such liabilities that arise from conduct involving a wilful breach of duty by the officers or the improper use by the officers of their position or of information to gain advantage for them or someone else or to cause detriment to the Company. It is not possible to apportion the premium between amounts relating to the insurance against legal costs and those relating to other liabilities.

Proceedings on behalf of company

No person has applied to the Court under section 237 of the Corporations Act 2001 for leave to bring proceedings on behalf of the Company, or to intervene in any proceedings to which the Company is a party, for the purpose of taking responsibility on behalf of the Company for all or part of those proceedings.

No proceedings have been brought or intervened in on behalf of the Company with leave of the Court under section 237 of the Corporations Act 2001.

Rounding of amounts

The Company is of a kind referred to in ASIC Corporations (Rounding in Financial/Directors' Reports) Instrument 2016/191, and in accordance with that instrument, amounts in the consolidated financial statements and Directors' Report have been rounded off to the nearest thousand dollars, unless otherwise indicated.

Non-audit services

The following non-audit services were provided by the entity's auditor, BDO Australia. The Directors are satisfied that the provision of non-audit services is compatible with the general standard of independence for auditors imposed by the Corporations Act 2001. The nature and scope of each type of non-audit service provided means that auditor independence was not compromised.

BDO Australia received or are due to receive the following amounts for the provision of non-audit services:

	2018 US$	2017 US$
Tax compliance services	3,751	28,687
Tax consulting and tax advice	1,056	18,970
	4,807	47,657

Auditor's independence declaration

The auditor's independence declaration is included on page 60 of this report.

Remuneration report (audited)

The Directors of the Company have prepared this remuneration report to outline the overall remuneration strategy, policies and practices which were in place during 2018. This structure includes the share rights and option plans approved by the shareholders at the Company's Annual General Meeting on 16 November 2016. The report has been prepared in accordance with Section 300A of the Corporations Act 2001 and its regulations.

Otto Energy's remuneration policy is designed to ensure that the level and form of compensation achieves certain objectives, including:

a) attraction and retention of employees and management to pursue the Group's strategy and goals;
b) delivery of value-adding outcomes for the Group;
c) fair and reasonable reward for past individual and Group performance; and
d) incentive to deliver future individual and Group performance.

Remuneration consists of base salary, superannuation, short term incentives (STI) and long term incentives (LTI). Remuneration is determined by reference to market conditions and performance. Performance is evaluated at an individual level as well as the performance of the Group as a whole.

The remuneration policies and structure in 2018 were generally the same as for 2017.

Key management personnel disclosed in this report are:

Directors	
Mr John Jetter	Non-Executive Chairman
Mr Matthew Allen	Managing Director and Chief Executive Officer
Mr Ian Macliver	Non-Executive Director
Mr Ian Boserio	Non-Executive Director
Mr Paul Senycia	Executive Director and Vice President Exploration and New Ventures, commenced 4 April 2018
Executives	
Mr David Rich	Chief Financial Officer and Company Secretary, commenced 28 February 2017 and 31 January 2017 respectively
Mr Matthew Worner	Commercial Manager, ceased 1 July 2017
Mr Craig Hasson	Chief Financial Officer, ceased 28 February 2017

Remuneration governance

Role of the Remuneration and Nomination Committee

The Remuneration and Nomination Committee's role is to review and recommend remuneration for key management personnel and review remuneration policies and practices including Company incentive schemes and superannuation arrangements.

The Committee considers independent advice, where circumstances require, on the appropriateness of remuneration to ensure the Group attracts, motivates and retains high quality people. An advisor was not retained for the 2017 calendar year review.

The ASX Listing Rules require that the maximum aggregate amount of remuneration to be allocated among the non-executive Directors be approved by shareholders in a general meeting. In proposing the maximum amount for consideration by shareholders and in determining the allocation, the Remuneration and Nomination Committee takes account of the time demands made on Directors and such factors as fees paid to non-executive Directors in comparable Australian companies.

The Remuneration and Nomination Committee comprises of two non-executive Directors.

Remuneration arrangements for Directors and executives are reviewed by the Remuneration and Nomination Committee and recommended to the Board for approval. The Remuneration and Nomination Committee considers external data and information, where appropriate, and may engage independent advisors where appropriate to establish market benchmarks.

Remuneration arrangements are determined in conjunction with the annual review of the performance of Directors, executives and employees of the Group. Performance of the Directors and the CEO of the Group is evaluated by the Board, assisted by the Remuneration and Nomination Committee. The CEO reviews the performance of executives with the Remuneration and Nomination Committee. These evaluations take into account criteria such as the achievement toward the Group's performance benchmarks and the achievement of individual performance objectives.

Non-executive director remuneration policy

Non-executive Directors of the Group are remunerated by way of fees, statutory superannuation, and LTI's where applicable. Fees are set to reflect current market levels based on the time, responsibilities and commitments associated with the proper discharge of their duties as members of the Board.

The current base fees were reviewed in June 2018. Prior to this there had been no increase in non-executive director fees since 2012. Non-executive Directors' fees are determined within an aggregate non-executive Directors' fee pool limit, which is periodically recommended for approval by shareholders. The maximum currently stands at A$500,000 per annum and was approved by shareholders at the Annual General Meeting in January 2008.

Non-executive Directors received a grant of performance rights on 29 November 2017 following approval by shareholders at the Company's Annual General Meeting. The grant was based on 33% of FAR. The Board believes that the issue constituted reasonable remuneration having considered the peer group comparisons, the recent history of the Company, the experience of each of the Directors and the responsibilities involved in that office.

Directors' fees

The following fees have applied:

	From 1 July 2018	From 1 July 2017 to 30 June 2018	From 1 July 2016 to 30 June 2017
Base fees			
Chair	A$150,000	A$ 125,000	A$ 125,000
Non-executive Directors	A$90,000	A$ 75,000	A$ 75,000
Additional fees			
Audit and Risk Management Committee Chair	A$10,000	A$ 10,000	A$ 10,000

Retirement allowances for non-executive Directors

In line with ASX Corporate Governance Council, non-executive Directors' remuneration does not include retirement allowances. Superannuation contributions required under the Australian superannuation guarantee legislation continue to be made and are deducted from the Directors' overall fee entitlements.

Appointment

The term of appointment is determined in accordance with the Company's Constitution and is subject to the provisions of the Constitution dealing with retirement, re-election and removal of Directors of the Company. The Constitution provides that all Directors of the Company, other than the Managing Director, are subject to re-election by shareholders by rotation every three years during the term of their appointment.

Directors and executive remuneration policy and framework

The remuneration arrangement for Directors and executives of the Group for the year ended 30 June 2018 is summarised below.

The remuneration structure in place for the year ended 30 June 2018 applies to all employees including key management personnel and staff members of the Group. The Group's remuneration structure has three elements:

a) fixed annual remuneration (FAR) or base salary (including superannuation);
b) short term incentive (STI) award which provides a reward for performance in the past year; and
c) long term incentive (LTI) award which provides an incentive to deliver future Company performance.

Executive remuneration mix

In accordance with the Group's objective to ensure that executive remuneration is aligned to Group's performance, a significant portion of the executives' target pay is "at risk".

a) Fixed annual remuneration (FAR) or base salary (including superannuation);

To attract and retain talented, qualified and effective employees, the Group pays competitive base salaries which have been benchmarked to the market in which the Group operates. The Group compiles competitive salary information on companies of comparable size in the oil and gas industry from several sources. Where appropriate, information is obtained from surveys conducted by independent consultants and national and international publications. In the past the Board has engaged independent advisors to review the remuneration levels paid to the Group's key management personnel. An advisor was not retained for the 2017 calendar year review.

FAR is paid in cash and is not at risk other than by termination. Individual FAR is set each year based on job description, competitive salary information sourced by the Group and overall competence in fulfilling the requirements of the particular role.

There is no guaranteed base pay increases included in any executives' contracts.

Superannuation contributions required under the Australian superannuation guarantee legislation continue to be made and are deducted from the executives overall FAR entitlements.

b) Short-term incentives

Executives have the opportunity to earn an annual short-term incentive (STI) if predefined targets are achieved. The CEO and other members of the executive team have an STI opportunity of approximately 20% of FAR. The targets are reviewed annually.

STI awards for the executive team in the 2018 financial year were based on the scorecard measures and weightings as disclosed below. Objectives and measures aligned to the Company's strategic and business objectives were set and monitored by the Board. These included the following general categories:

- Health, safety & environment
- Total shareholder return
- Asset specific
- New business development
- Leadership

The Board and Remuneration and Nomination Committee are responsible for assessing whether the predefined targets are met. The Committee review in February 2018 concluded that no STI would be awarded to the Managing Director and Vice President Exploration and New Ventures and a partial STI of 10% of FAR would be awarded to other staff for the 2017 calendar year. The only KMP to receive a bonus was the Chief Financial Officer who received A$30,000 being 10% of FAR. The primary basis for the Committee's conclusion was that the partial STI provided the newer staff, who had not received any grant of performance rights, was some reward for the successful progress of the SM 71 development (wells had been drilled and production was imminent at the time) and cost and capital management during 2017.

c) Long-term incentives

The Group believes that encouraging its employees to become shareholders is the best way of aligning their interests with those of its shareholders. Long-term incentives are provided to certain employees via the Otto Energy Limited Performance Rights and Employee Share Option Plans which were approved by shareholders at the 2013 Annual General Meeting and again at the 2016 Annual General Meeting.

The Otto Energy Limited Performance Rights and Employee Share Option Plans are designed to provide long-term incentives for employees to deliver long-term shareholder returns. Under the plans, participants are granted performance rights or options which only vest if certain performance conditions are met and the employees are still employed by the Group at the end of the vesting period. Participation in, and administration of, the plan is at the Board's discretion and no individual has a contractual right to participate in the plan or to receive any guaranteed benefits.

The amount of performance rights that will vest depends on the vesting period and/or Otto Energy Limited's total shareholder return ('TSR'), including share price growth, dividends, and capital returns. For the rights on issue during, and at the end of the year, vesting of the rights for directors, the CEO and other members of the executive team were based on TSR performance only. Other employees' rights were based 50% on time and 50% on TSR. The TSR performance required for all rights on issue is 10% per annum, compounding from the date of grant to the measurement date. If the TSR vesting condition is not met on a measurement date, no rights vest and those performance rights continue to exist as unvested performance rights to be retested at the next measurement date or expiry date, whichever is later.

On the measurement date of 1 February 2018 1,600,000 performance rights held by key management personnel vested based on TSR, as the TSR from the grant date of 3 October 2014 to 1 February 2018 was 99.9% (using a grant date share price of A$0.0285 after adjustment for the 2015 dividend and capital return) which is above the required 10% p.a. compounded rate of 37.41%. A total of 3,066,668 rights granted to key management personnel on 23 April 2015 did not vest as the TSR hurdle was not met and hence continue to exist to be tested at the next measurement date.

Once vested, the performance rights are automatically converted into shares. Performance rights are granted under the plan for no consideration.

Generally LTI awards have been based on four maximum LTI organisational benchmarks established as a percentage of individual FARs. These four levels reflect the increased involvements of each level in pursuing and achieving the Company's goals. These benchmarks are set out in the following table.

Organisational level	MD/CEO	Management	Professional and technical	Support staff
LTI Organisational Benchmarks	50%	40%	30%	10%

For the award on 29 November 2017 to key management personnel, a flat rate of 33% of FAR was used to calculate the number of rights awarded.
The total number of performance rights granted is subject to being reduced proportionately so that the total number for performance rights is within:

i) the Board's determined cap on the total number of performance rights which are issued as LTI awards in a given year; and
ii) any discretionary cap on the total number of rights on issue at any given time.

The Board has established an initial guideline that the total number of performance rights to be issued in a single year will be capped at 1.7% of the fully paid issued capital of the Company as at the end of the prior year. In the event that the potential total number of performance rights exceeds the cap then all awardees receive a pro-rated reduced number of performance rights. This cap is at the discretion of the Board and may be altered depending on the prevailing context.

Share trading policy

The trading of shares issued to participants under any of the Company's employee equity plans is subject to, and conditional upon, compliance with the Company's Securities Trading Policy. Executives are prohibited from entering into any hedging arrangements over unvested rights. While the Employee Share Option Plan does not specifically prohibit holders from entering into hedging arrangements over options, the Board would include such restrictions in any offer under the Plan. The Company would consider a breach of this policy as gross misconduct which may lead to disciplinary action and potentially dismissal.

Voting and comments made at the Group's 2017 Annual General Meeting

Otto Energy Limited received more than 98.9% of "yes" votes on its remuneration report for the 2017 financial year. The Company did not received any specific feedback at the Annual General Meeting or throughout the year on its remuneration practices apart from some comments regarding the determination of the 10% TSR vesting hurdle rate versus the number of rights issued (percentage of FAR).

Performance of Otto Energy Limited

The Corporations Act requires disclosure of the Company's remuneration policy to contain a discussion of the Company's earnings and performance and the effect of the Company's performance on shareholder wealth in the reporting period and the four previous financial years. The table below provides a five year financial summary.

	30 June 2014	30 June 2015	30 June 2016	30 June 2017	30 June 2018
Net profit/(loss) after tax (US$'000)	13,295	16,404	(20,086)	(5,247)	(5,194)
Share price at year end (AUD)	0.047*	0.069	0.044	0.025	0.064
Basic earnings/(loss) (US cents per share)	1.16	1.42	(1.70)	(0.44)	(0.37)
Return of capital (AU cents per share)	-	5.64	-	-	-
Total dividends (AU cents per share)	-	0.76	-	-	-

* After deducting the $0.0564 per share return of capital to shareholders on 26 June 2015

Details of remuneration

The following table shows details of the remuneration received by Directors and executives of the Group for the current and previous financial year.

Remuneration and other terms of employment for the Managing Director & Chief Executive Officer and other executives are formalised in service agreements. Each of these service agreements provides for performance related conditions and details relating to remuneration are set out below.

		Fixed remuneration					Variable remuneration		Total
	Year	Salary and fees A$	Annual and long service leave A$	Super-annuation A$	Other benefits (ii) A$	Termination benefits A$	Cash bonus A$	Performance rights (i) A$	A$
Directors									
Mr J Jetter	2018	125,000	-	-	-	-	-	8,238	133,238
	2017	125,000	-	-	-	-	-	-	125,000
Mr M Allen	2018	450,000	8,327	25,000	1,191	-	-	65,450	549,968
	2017	445,000	14,512	30,000	1,429	-	-	73,316	564,257
Mr I Macliver	2018	77,626	-	7,374	-	-	-	5,606	90,606
	2017	77,626	-	7,374	-	-	-	-	85,000
Mr I Boserio	2018	68,493	-	6,507	-	-	-	4,944	79,944
	2017	51,447	-	23,553	-	-	-	-	75,000
Mr P Senycia (iii)	2018	356,000	25,983	25,000	1,011	-	-	59,254	467,248
	2017	346,000	31,820	35,000	1,020	-	-	73,316	487,156
Total Director remuneration	2018	1,077,119	34,310	63,881	2,202	-	-	143,492	1,321,004
	2017	1,045,073	46,332	95,928	2,449	-	-	146,633	849,257
Executives									
Mr D Rich (iv)	2018	304,309	12,288	24,949	1,633	-	30,000	19,777	392,956
	2017	101,887	3,061	9,679	907	-	-	-	115,534
Mr C Hasson (v)	2018	-	-	-	-	-	-	-	-
	2017	185,500	(17,025)	24,231	1,441	132,370	-	(54,298)	272,219
Mr M Worner (vi)	2018	-	(3,424)	2,533	404	(22,525)	-	(42,970)	(65,982)
	2017	320,000	6,710	30,400	1,754	86,115	-	19,822	464,801
Total executive remuneration	2018	304,309	8,864	27,482	2,037	(22,525)	30,000	(23,193)	326,974
	2017	607,387	(7,253)	64,310	4,102	218,485	-	(34,476)	852,556
Total	2018	1,381,428	43,174	91,363	4,239	(22,525)	30,000	120,299	1,647,978
	2017	1,652,460	39,078	160,237	6,551	218,485	-	112,156	2,188,967

(i) Performance rights have been valued using a Hoadley hybrid single share price model. Further details of the Performance Rights Plan is contained in this Remuneration Report on pages 56 to 58 and Note 21.
(ii) Car parking provided by the Company.
(iii) Mr P Senycia was appointed executive director on 24 April 2018.
(iv) Mr D Rich appointed as Chief Financial Officer and Company Secretary on 28 February 2017 and 31 January 2017 respectively.
(v) Mr C Hasson ceased as Chief Financial Officer on 28 February 2017. Share-based payment expense is negative due to reversal on cessation of employment.
(vi) Mr M Worner ceased as Commercial Manager on 1 July 2017. Share-based payment expense and long service leave is negative due to reversal on cessation of employment. Termination benefits in 2018 are negative due to reversal of 30 June 2017 accrual.

The relative proportions of remuneration that are linked to performance and those that are not are as follows:

	Fixed and other		At risk – STI		At risk – LTI [i]	
	2018	2017	2018	2017	2018	2017
Directors						
Mr J Jetter	94%	100%	-	-	6%	-
Mr P Senycia[iv]	87%	85%	-	-	13%	15%
Mr M Allen	88%	87%	-	-	12%	13%
Mr I Macliver	94%	100%	-	-	6%	-
Mr I Boserio	94%	100%	-	-	6%	-
Executives						
Mr D Rich [ii]	87%	100%	8%	-	5%	-
Mr C Hasson [iii]	-	120%	-	-	-	(20%)
Mr M Worner [v]	-	95%	-	-	-	5%

(i) Since long-term incentives are provided exclusively by way of performance rights or options, the percentages disclosed also reflect the value of remuneration consisting of performance rights and options, based on the value of performance rights or options expensed during the year.
(ii) Mr D Rich was appointed as Chief Financial Officer and Company Secretary on 28 February 2017 and 31 January 2017 respectively.
(iii) Mr C Hasson ceased as Chief Financial Officer on 28 February 2017. At risk - LTI is negative due to reversal of share-based payments on cessation of employment.
(iv) Mr P Senycia was appointed executive director on 24 April 2018
(v) Mr M Worner ceased as Commercial Manager on 1 July 2017.

Service agreements

On appointment to the Board, all non-executive Directors enter into a service agreement with the Company in the form of a letter of appointment. The letter summarises the Board policies and terms, including remuneration, relevant to the office of Director.

Remuneration and other terms of employment for the Managing Director and Chief Executive Officer, Chief Financial Officer and other executives (including executive Directors) are also formalised in service agreements. Each of these service agreements provide for the provision of performance related cash bonuses, and participation, when eligible, in the Otto Energy Limited Performance Rights and Employee Share Option Plans. Other major provisions of the agreements relating to remuneration are set out below.

All contracts with executives may be terminated early by either party with notice, per individual agreement, subject to termination payments as detailed below.

Name	Commencement of contract	Base salary including superannuation[i] $A	Termination benefit[ii]
Mr Matthew Allen *Managing Director and Chief Executive Officer*	24 June 2015	$475,000	6 months base salary
Mr Paul Senycia *Executive Director & Vice President Exploration and New Ventures*	1 January 2016	$381,000	3 months base salary
Mr David Rich *Chief Financial Officer and Company Secretary*	9 January 2017	$350,000	3 months base salary

(i) Base salaries quoted are as at 30 June 2018; they are reviewed annually by the Board and the Remuneration and Nomination Committee.
(ii) Termination benefits are payable on early termination by the Company, other than for gross misconduct.

Share-based compensation

Otto Energy Limited has two forms of share based compensation for key management personnel. They are performance rights and options.

Performance rights over equity instruments granted

Performance rights granted to key management personnel were granted as remuneration unless otherwise noted. The rights granted have no exercise price and are exercisable from the date of vesting. Details of vesting periods are set out at Note 21. All rights expire on the earlier of their expiry date or termination of individual's employment. Performance rights granted carry no dividend or voting rights.

The value of rights included in remuneration for the year is calculated in accordance with Australian Accounting Standards. The assessed fair value at grant date of the performance rights is allocated equally over the period from grant date to vesting date and the amount is included in the remuneration tables. Where rights vest fully in the year of grant, the full value of the rights is recognised in remuneration for that year.

The value of performance rights at the grant date is calculated as the fair value of the rights at grant date, using a Hoadley hybrid single share price model, multiplied by the number of rights granted.

No adjustment is made to the value included in remuneration or the financial results where the right ultimately has a lesser or greater value than as at the date of grant. The inputs into the fair value calculation of the rights granted and outstanding as at 30 June 2018 are set out in the following table. As set out below, 11,913,000 performance rights were granted to key management personnel in the year to 30 June 2018 (nil in 2017) (14,187,000 performance rights in total were granted across the Company).

The number of performance rights that will vest depends on the vesting period and/or Otto Energy Limited's Total Shareholder Return ("TSR"), including share price growth, dividends, and capital returns. Once vested, the performance rights are automatically converted to shares. If the vesting condition is not met on a measurement date (no rights vest), the performance rights will not lapse and will continue to exist as unvested performance rights to be retested at the next measurement date or expiry date, whichever is later. Performance rights are granted under the plan for no consideration. All the rights on issue to KMP at 30 June 2018 require a compound TSR of 10% per annum from the grant date to the measurement date in order to vest.

Year ended 30 June 2018 – TSR based performance rights

Measurement date	29 November 2018	29 November 2019	29 November 2020	1 February 2017 (i)	1 February 2018	1 February 2019
Grant date	29 November 2017	29 November 2017	29 November 2017	23 April 2015	23 April 2015	23 April 2015
Expiry date	29 November 2022	29 November 2022	29 November 2022	31 December 2019	31 December 2019	31 December 2019
KMP rights on issue at year end:						
Mr M Allen	1,309,000	1,309,000	1,309,000	766,667	766,667	766,666
Mr J Jetter	344,333	344,333	344,334	-	-	-
Mr I Macliver	234,333	234,333	234,334	-	-	-
Mr I Boserio	206,667	206,667	206,666	-	-	-
Mr D Rich	826,667	826,667	826,666	-	-	-
Mr P Senycia	1,050,000	1,050,000	1,050,000	766,667	766,667	766,666
KMP total rights on issue at year end	3,971,000	3,971,000	3,971,000	1,533,334	1,533,334	1,533,332
Share price at grant date – A$	0.04	0.04	0.04	0.11	0.11	0.11
Expected volatility	20%	20%	20%	47.7%	51.2%	51.2%
Expected dividend yield	Nil	Nil	Nil	Nil	Nil	Nil
Risk free rate	2.09%	2.09%	2.09%	1.95%	1.90%	1.90%
Fair value – A$	0.026	0.020	0.015	0.060	0.070	0.070
Total value – A$	103,246	79,420	59,565	92,000	107,333	107,333

Year ended 30 June 2017 – TSR based performance rights

Measurement date	1 February 2017 (i)	1 February 2018	1 February 2019	1 February 2017 (i)	1 February 2018	1 February 2019	1 February 2018
Grant date	14 August 2015	14 August 2015	14 August 2015	23 April 2015	23 April 2015	23 April 2015	3 October 2014
Expiry date	31 December 2017 (ii)	31 December 2017 (ii)	31 December 2017 (ii)	31 December 2019	31 December 2019	31 December 2019	31 December 2018
Rights on issue at year end:							
Mr M Allen	-	-	-	766,667	766,667	766,666	800,000
Mr P Senycia	-	-	-	766,667	766,667	766,666	800,000
Mr M Worner	466,667	466,667	466,666	-	-	-	-
Total rights on issue at year end	466,667	466,667	466,666	1,533,334	1,533,334	1,533,332	1,600,000
Share price at grant date – A$	0.06	0.06	0.06	0.11	0.11	0.11	0.09
Expected volatility	65.2%	60.4%	57.8%	47.7%	51.2%	51.2%	53.2%
Expected dividend yield	Nil	Nil	Nil	Nil	Nil	Nil	Nil
Risk free rate	1.96%	1.96%	1.96%	1.95%	1.90%	1.90%	2.60%
Fair value – A$	0.04	0.04	0.04	0.06	0.07	0.07	0.06
Total value – A$	18,667	18,667	18,667	92,000	107,333	107,333	96,000

(i) The measurement date was rolled forward to 1 February 2018 for the rights on issue at 30 June 2017 except for those held by Mr M Worner that were tested and lapsed at expiry on 31 December 2017 being six months following cessation of employment.
(ii) Expiry date of rights granted to Mr M Worner amended following his resignation on 1 July 2017.

The expected price volatility is based upon the historic volatility (based on the remaining life of the rights), adjusted for any expected changes to future volatility due to publicly available information.

No cash benefit is received by key management personnel of the Group, until the sale of the resultant shares, which cannot be done unless and until the rights have vested and the shares issued.

The number of performance rights over ordinary shares held, granted to, vested and/or lapsed/expired by Directors and executives of Otto Energy Limited as part of compensation during the year ended 30 June 2018 is set out below.

Key Management Personnel	Balance at start of year	Granted as compensation	Vested and exercised	Lapsed/ expired	Balance at end of year
Directors					
Mr J Jetter	-	1,033,000	-	-	1,033,000
Mr M Allen	3,100,000	3,927,000	(800,000)	-	6,227,000
Mr P Senycia	3,100,000	3,150,000	(800,000)	-	5,450,000
Mr I Macliver	-	703,000	-	-	703,000
Mr I Boserio	-	620,000	-	-	620,000
	6,200,000	9,433,000	(1,600,000)	-	14,033,000
Executives					
Mr D Rich	-	2,480,000	-	-	2,480,000
Mr M Worner	1,400,000	-	-	(1,400,000)	-
	7,600,000	11,913,000	(1,600,000)	(1,400,000)	16,513,000

Options over equity instruments granted

Options granted to the Directors and executives are granted as remuneration unless otherwise noted. Options are issued under the Employee Option Plan. There were no options issued during the financial year.

Shareholding

The number of shares in the Company held during the financial year by key management personnel of the Group, including their personally related parties, is set out below:

Key Management Personnel	Balance at start of year	Granted/ purchased during the year	Received through conversion of performance rights during the year	Sold during the year	Balance at end of year
Directors					
Mr J Jetter	16,589,175	2,857,143	-	-	19,446,318
Mr M Allen	5,243,000	1,000,000	800,000	(143,000)	6,900,000
Mr P Senycia	1,600,000	1,274,287	800,000	(374,129)	3,300,158
Mr I Macliver	4,549,721	857,143	-	-	5,406,864
Mr I Boserio	-	2,073,571	-	-	2,073,571
	27,981,896	8,062,144	1,600,000	(517,129)	37,126,911
Executives					
Mr D Rich	-	795,252	-	-	795,252
	27,981,896	8,857,396	1,600,000	(517,129)	37,922,163

Outstanding balances arising from sales/purchases of goods and services

There are no balances outstanding at the end of the reporting period in relation to transactions with key management personnel and their related parties (2017: nil).

Diversity

Proportion of women employees at 30 June 2018:

	Number	Proportion
Whole organisation*	2/11	18%
Senior executive positions	0/3	0%
Board	0/5	0%

*Includes three non-executive Directors

Performance rights on issue at 30 June 2018

Date granted	Date of expiry	Number
23 April 2015	31 December 2019	4,640,000
29 November 2017	29 November 2022	14,187,000
		18,827,000

No performance right holder has any right under the performance rights to participate in any other share issue of the Company or any other entity. There were no options on issue at 30 June 2018.

No options were granted as remuneration to key management personnel during the year. Details of performance rights and options granted to key management personnel are disclosed on pages 56 to 58.

This report is made in accordance with a resolution of Directors.

I Macliver

Mr I Macliver
Director

21 September 2018

AUDITOR'S INDEPENDENCE DECLARATION
FOR THE YEAR ENDED 30 JUNE 2018

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Australia

DECLARATION OF INDEPENDENCE BY JARRAD PRUE TO THE DIRECTORS OF OTTO ENERGY LIMITED

As lead auditor of Otto Energy Limited for the year ended 30 June 2018, I declare that, to the best of my knowledge and belief, there have been:

1. No contraventions of the auditor independence requirements of the *Corporations Act 2001* in relation to the audit; and
2. No contraventions of any applicable code of professional conduct in relation to the audit.

This declaration is in respect of Otto Energy Limited and the entities it controlled during the period.

Jarrad Prue

Director

BDO Audit (WA) Pty Ltd

Perth, 21 September 2018

CONSOLIDATED STATEMENT OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME

FOR THE YEAR ENDED 30 JUNE 2018

	Note	2018 US$'000	2017 US$'000
Operating Revenue (Net)	2	9,551	-
Cost of sales	3	(1,622)	-
Gross profit		**7,929**	-
Other income	2	213	139
Profit on disposal of property, plant and equipment		2	2
Exploration expenditure	4	(4,827)	(905)
Finance costs	5	(4,436)	(48)
Administration and other expenses	5	(4,072)	(4,374)
Loss before income tax		**(5,191)**	**(5,186)**
Income tax expense	7	(3)	(61)
Loss after income tax for the year		**(5,194)**	**(5,247)**
Other comprehensive income that may be recycled to profit or loss			
Total other comprehensive income		-	-
Total comprehensive loss for the year		**(5,194)**	**(5,247)**
Earnings per share			
Basic loss per share (US cents)	6	(0.37)	(0.44)
Diluted loss per share (US cents)	6	(0.37)	(0.44)

The above consolidated statement of profit or loss and other comprehensive income should be read in conjunction with the accompanying notes.

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

AS AT 30 JUNE 2018

	Note	2018 US$'000	2017 US$'000
Current assets			
Cash and cash equivalents	8	5,945	12,199
Trade and other receivables	10	4,028	116
Other assets	11	287	384
Total current assets		**10,260**	**12,699**
Non-current assets			
Oil and gas properties	12	27,151	6,272
Property, plant and equipment		82	28
Other assets	10	355	475
Total non-current assets		**27,588**	**6,775**
Total assets		**37,848**	**19,474**
Current liabilities			
Trade and other payables	13	4,763	1,611
Provisions	15	202	317
Convertible note	14	7,542	-
Convertible note derivative	14	3,183	-
Total current liabilities		**15,690**	**1,928**
Non-current liabilities			
Provisions	15	1,128	241
Total non-current liabilities		**1,128**	**241**
Total liabilities		**16,818**	**2,169**
Net assets		**21,030**	**17,305**
Equity			
Contributed equity	16	90,704	81,895
Reserves	17	13,847	13,737
Accumulated losses		(83,521)	(78,327)
Total equity		**21,030**	**17,305**

The above consolidated statement of financial position should be read in conjunction with the accompanying notes.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

FOR THE YEAR ENDED 30 JUNE 2018

	Contributed equity US$'000	Share-based payments reserve US$'000	Foreign currency translation reserve US$'000	Accumulated losses US$'000	Total US$'000
Balance at 1 July 2016	81,895	9,474	4,188	(73,080)	22,477
Loss for the period	-	-	-	(5,247)	(5,247)
Other comprehensive income	-	-	-	-	-
Total comprehensive loss for the year	-	-	-	(5,247)	(5,247)
Transactions with owners in their capacity as owners:					
Equity benefits issued to employees	-	75	-	-	75
Balance at 30 June 2017	81,895	9,549	4,188	(78,327)	17,305
Balance at 1 July 2017	81,895	9,549	4,188	(78,327)	17,305
Loss for the period	-	-	-	(5,194)	(5,194)
Other comprehensive income	-	-	-	-	-
Total comprehensive loss for the year	-	-	-	(5,194)	(5,194)
Transactions with owners in their capacity as owners:					
Issue of shares (net of costs)	8,809	-	-	-	8,809
Equity benefits issued to employees	-	110	-	-	110
Balance at 30 June 2018	90,704	9,659	4,188	(83,521)	21,030

The above consolidated statement of changes in equity should be read in conjunction with the accompanying notes.

CONSOLIDATED STATEMENT OF CASH FLOWS

AS AT 30 JUNE 2018

	Note	2018 US$'000	2017 US$'000
Cash flows from operating activities			
Oil and Gas Sales (net)		6,300	-
Other income		54	24
Payments to suppliers and employees		(4,688)	(4,232)
Payments for exploration and evaluation		(3,949)	(659)
Interest received		159	113
Income tax paid		(2)	(61)
Net cash outflow from operating activities	9	**(2,126)**	**(4,815)**
Cash flows from investing activities			
Payments for property, plant and equipment		(91)	(4)
Proceeds from sale of property, plant and equipment		2	2
Payments for development and evaluation		(20,587)	(2,896)
Bond for development asset		(150)	(175)
Net cash outflow from investing activities		**(20,826)**	**(3,073)**
Cash flows from financing activities			
Proceeds from issue of convertible notes		8,200	-
Transaction costs relating to convertible notes issue		(311)	-
Proceeds from issue of shares		9,166	-
Transaction costs - shares		(356)	(225)
Net cash inflow/(outflow) from financing activities		**16,699**	**(225)**
Net decrease in cash and cash equivalents		(6,253)	(8,113)
Cash and cash equivalents at the beginning of the financial year		12,199	20,309
Effects of exchange rate changes on cash		(1)	3
Cash and cash equivalents at the end of the financial year	8	**5,945**	**12,199**

The above consolidated statement of cash flows should be read in conjunction with the accompanying notes.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEAR ENDED 30 JUNE 2018

ABOUT THIS REPORT

Otto Energy Limited (referred to as 'Otto' or the 'Company') is a for-profit entity limited by shares, incorporated and domiciled in Australia. Its shares are publicly traded on the Australian Securities Exchange. The nature of operations and principal activities of Otto and its subsidiaries (referred to as the 'Group') are described in the Directors' Report.

The consolidated general purpose financial report of the Group was authorised for issue in accordance with a resolution of the Directors on 21 September 2018.

Basis of preparation

The financial report is a general purpose financial report which:

- has been prepared in accordance with the requirements of the *Corporations Act 2001*, Australian Accounting Standards and other authoritative pronouncements of the Australian Accounting Standards Board (AASB) and International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB);
- has been prepared on a historical cost basis, except for certain financial instruments which have been measured at fair value;
- presents reclassified comparative information where required for consistency with the current year's presentation; and
- adopts all new and amended Accounting Standards and Interpretations issued by the AASB that are relevant to the Group and effective for reporting periods beginning on or before 1 July 2017. Refer to note 28 for further details.

Basis of consolidation

The consolidated financial statements comprise the financial statements of the Group. A list of controlled entities (subsidiaries) is contained in note 19.

Subsidiaries are consolidated from the date on which control is obtained by the Group and cease to be consolidated from the date that control ceases. In preparing the consolidated financial statements, all intercompany balances and transactions, income and expenses and profits or losses resulting from intra-group transactions have been eliminated.

Currency

Items included in the financial statements of each of the Group's entities are measured using the currency of the primary economic environment in which the entity operates ('the functional currency'). The consolidated financial statements are presented in United States dollars, which is Otto Energy Limited's functional and presentation currency.

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at year end exchange rates of monetary assets and liabilities denominated in foreign currencies are recognised in profit or loss.

Rounding of amounts

The amounts contained in these financial statements have been rounded to the nearest thousand dollars ($'000) unless otherwise stated, in accordance with ASIC Instrument 2016/191.

ABOUT THIS REPORT (continued)

Other accounting policies

Significant and other accounting policies that summarise the measurement basis used and are relevant to an understanding of the financial statements are provided throughout the notes to the consolidated financial statements.

Going concern

The Group as at 30 June 2018 has recorded a deficiency in working capital amounting to $5.43 million (2017: surplus of $10.771 million), although the Group has commenced production from the SM 71 oil development asset in the Gulf of Mexico and recognised $9.551 million in oil and gas sales net of royalties for the year. Notwithstanding the Group's aforementioned deficiency in working capital, the Group's financial report has been prepared on a going concern basis. The Directors believe the going concern basis to be appropriate due to the following: 1) the future growth strategy underpinned by strong production and cash flow from the SM 71 oil development asset; 2) a successful equity raising approximating A$20 million in August 2018; and 3) the convertible note, which accounts for $10.725 million of the current liabilities, has a conversion price of A$0.055, which is reduced to A$0.05484 post year end as a result of the entitlement offer (refer note 26) and the Company's share price at the date of this report is A$0.068 making conversion, and not redemption, more likely.

Key estimates and judgements

In applying the Group's accounting policies, management has made a number of judgements and applied estimates of future events. Judgements and estimates which are material to the financial report are found in the following notes:

- Note 7 Income tax
- Note 12 Oil and gas properties
- Note 14 Convertible note
- Note 15 Provisions
- Note 21 Share-based payments

FINANCIAL PERFORMANCE

1. Segment information

The Group has identified its operating segments based on the internal management reports that are reviewed and used by the executive management team in assessing performance and in determining the allocation of resources. The operating segments identified by management are based on the geographical locations of the business which are as follows: Gulf of Mexico (USA), Alaska (USA) and Other. Discrete financial information about each of these operating segments is reported to the executive management team on at least a monthly basis.

Operating segments are reported in a manner consistent with the internal reporting provided to the chief operating decision maker. The chief operating decision maker, who is responsible for allocating resources and assessing performance of the operating segments, has been identified as the Board. Management has determined that based on the report reviewed by the Board and used to make strategic decisions Australia is no longer included as a reportable segment and is instead included in 'Other'. The Group had 3 reportable segments during 2018. The prior year comparatives have been restated to reflect the June 2018 reportable segments.

The segment information for the reportable segments for the year ended 30 June 2018 is as follows:

2018	**Gulf of Mexico (USA)**	**Alaska (USA)**	**Other**	**Consolidated**
	US$'000	**US$'000**	**US$'000**	**US$'000**
Operating Revenue	9,551	-	-	9,551
Cost of Production	(1,622)	-	-	(1,622)
Gross Profit	**7,929**	**-**	**-**	**7,929**
Other income	11	-	202	213
Profit on disposal of property, plant and equipment	-	-	2	2
Exploration expenditure	(4,683)	(222)	78	(4,827)
Finance costs	(24)	-	(4,412)	(4,436)
Administration and other expenses	(1,311)	(27)	(2,734)	(4,072)
Profit (Loss) before income tax	**1,922**	**(249)**	**(6,864)**	**(5,191)**
Income tax expense	-	-	(3)	(3)
Profit (Loss) after income tax for the year	**1,922**	**(249)**	**(6,867)**	**(5,194)**
Total non-current assets	27,581	-	7	27,588
Total assets	35,865	-	1,983	37,848
Total liabilities	4,153	7	12,658	16,818

Gross oil revenue of $11.312 million from Gulf of Mexico production was all sold to a single customer. Gross gas revenue of $0.432 million from Gulf of Mexico production was all sold to a different single customer.

1. Segment information (continued)

The segment information for the reportable segments for the year ended 30 June 2017 is as follows:

2017	Gulf of Mexico (USA)	Alaska (USA)	Other	Consolidated
	US$'000	US$'000	US$'000	US$'000
Revenue and other income	-	-	139	139
Profit on disposal of property, plant and equipment	-	-	2	2
Exploration expenditure	(366)	(267)	(272)	(905)
Finance costs	(8)	-	(40)	(48)
Administration and other expenses	(964)	(31)	(3,379)	(4,374)
Loss before income tax	**(1,338)**	**(298)**	**(3,550)**	**(5,186)**
Income tax expense	-	-	(61)	(61)
Loss after income tax for the year	**(1,338)**	**(298)**	**(3,611)**	**(5,247)**
Total non-current assets	6,447	-	328	6,775
Total assets	6,447	7	13,020	19,474
Total liabilities	1,225	10	934	2,169

2. Revenue and other income

	2018	2017
	US$'000	US$'000
Oil Sales	11,312	-
Gas Sales	432	-
Total Sales	11,744	-
Less: Royalties(i)	(2,193)	-
Operating Revenue (Net)	9,551	-
Interest income(ii)	159	113
Other income	54	26
	213	139

(i) Operating Revenue is shown net of royalty payments payable to the (USA) Office of Natural Resources Revenue. Royalty payments are 18.75% of revenue under the terms of the SM 71 lease.

(ii) Interest income is recognised using the effective interest rate method.

3. Cost of sales

	2018	2017
Gathering and Production charges	745	-
Depreciation of capitalised developments	877	-
Total Cost of Sales	1,622	-

Recognition and measurement

Revenue is measured at the fair value of the consideration received or receivable. Revenue is recognised when it can be reliably measured and when it is probable that economic benefits will flow to the Group.

4. Exploration expenditure

	2018 US$'000	2017 US$'000
Exploration expenditure – Gulf of Mexico - Louisiana	4,683	366
Exploration expenditure – Alaska North Slope	222	267
Exploration expenditure – Other	(78)	272
	4,827	905

Recognition and measurement

Costs incurred in the exploration stages of specific areas of interest are expensed against the profit or loss as incurred. All exploration expenditure, including general permit activity, geological and geophysical costs, new venture activity costs and drilling exploration wells, is expensed as incurred. The costs of acquiring interests in new exploration licences is expensed. Once an exploration discovery has been determined, evaluation and development expenditure is capitalised to the Consolidated Statement of Financial Position as oil and gas properties.

5. Other expenses

	2018 US$'000	2017 US$'000
i) Finance costs		
Interest on convertible note – refer Note 14	1,225	-
Accretion of effective interest on convertible note – refer Note 14	347	-
Fair value adjustment on embedded derivative element of convertible note – refer Note 14	2,436	-
Amortisation of borrowing costs	241	40
Success Fee – refer Note 14	163	-
Accretion of decommissioning fund	24	8
Total finance costs	4,436	48
ii) Administration and other expenses		
Employee benefits expense		
Defined contribution superannuation expense	108	178
Share-based payment expense	110	75
Other employee benefits expenses	1,780	2,108
	1,998	2,361
Depreciation expense		
Depreciation expense – furniture and equipment	26	48
	26	48
Other expenses		
Corporate and other costs (net of recharges)	1,508	1,417
Business development	539	498
Foreign currency losses	1	50
	2,048	1,965
Total administration and other expenses	4,072	4,374

5. Other expenses (continued)

iii) Depreciation

Depreciation charges are included above in Note 3 Cost of sales and Note 5(ii) other expenses. Total depreciation for the Consolidated Entity is $0.9 million (2017: $0.05 million)

6. Earnings per share

Basic earnings per share is calculated by dividing the profit or loss attributable to owners of the Company, excluding any costs of servicing equity (other than dividends), by the weighted average number of ordinary shares, adjusted for the bonus element.

Diluted earnings per share adjusts the figures used in the determination of basic earnings per share to take into account the after income tax effect of interest and other financing costs associated with dilutive potential ordinary shares, and the weighted average number of additional ordinary shares that would have been outstanding assuming the conversion of all dilutive potential ordinary shares.

The following table reflects the income and share data used in the basic and diluted EPS calculations:

	2018	2017
Loss attributable to owners of the Company (US$'000)	(5,194)	(5,247)
Weighted average number of ordinary shares on issue for basic and diluted loss per share (number)	1,403,062,899	1,183,556,077
Basic and diluted loss per share (US cents)	(0.37)	(0.44)

Due to the Company reporting a loss for the 2018 and 2017 financial years, the impact of potential shares are not included in calculating diluted EPS because they are anti-dilutive.

7. Income tax

	2018 US$'000	2017 US$'000
The components of tax expense comprise:		
Current tax	3	7
Deferred tax – origination and reversal of temporary differences	-	-
Prior period under provision	-	54
	3	61
Reconciliation of income tax expense to prima facie tax payable:		
Loss before income tax	(5,191)	(5,186)
Prima facie income tax at 27.5%	(1,427)	(1,556)
Difference in overseas tax rates	(3)	2,041
Non-assessable income	-	(1,980)
Tax effect of amounts not deductible in calculating taxable income	479	585
Benefit of deferred tax assets not brought to account	954	917
Prior period under/(over) provision	-	54
Income tax expense	3	61

7. Income tax (continued)

Deferred tax assets	**2018 US$'000**	**2017 US$'000**
Temporary differences		
– provisions and other corporate costs	131	161
– exploration and evaluation costs	-	5,891
	131	6,052
Tax losses - revenue	6,259	903
Tax losses - foreign	6,809	4,708
	13,199	11,663
Offset against deferred tax liabilities recognised	(6,838)	(1,446)
Deferred tax assets not brought to account	(6,361)	(10,217)
Deferred tax assets brought to account	-	-
Deferred tax liabilities		
Temporary differences – Oil and gas properties	6,838	1,446
Offset by deferred tax assets recognised	(6,838)	(1,446)
Deferred tax liabilities brought to account	-	-

Recognition and measurement

The income tax expense for the period is the tax payable on the current period's taxable income based on the applicable income tax rate for each jurisdiction adjusted by changes in deferred tax assets and liabilities attributable to temporary differences and to unused tax losses.

Included in the foreign tax losses of US$6.81 million is tax losses of US$6.20 million that can be offset against future US profits from US Gulf of Mexico operations.

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

Deferred tax assets are recognised for deductible temporary differences and unused tax losses only if it is probable that future taxable amounts will be available to utilise those temporary differences and losses.

Deferred tax liabilities and assets are not recognised for temporary differences between the carrying amount and tax bases of investments in foreign operations where the Company is able to control the timing of the reversal of the temporary differences and it is probable that the differences will not reverse in the foreseeable future.

Deferred tax assets and liabilities are offset when there is a legally enforceable right to offset current tax assets and liabilities and when the deferred tax balances relate to the same taxation authority. Current tax assets and tax liabilities are offset where the entity has a legally enforceable right to offset and intends either to settle on a net basis, or to realise the asset and settle the liability simultaneously.

7. Income tax (continued)

Current and deferred tax is recognised in profit or loss, except to the extent that it relates to items recognised in other comprehensive income or directly in equity. In this case, the tax is also recognised in other comprehensive income or directly in equity, respectively.

Key estimates and judgements
The Group is subject to income taxes in Australia and jurisdictions where it has foreign operations. Significant judgement is required in determining the worldwide provision for income taxes. There are certain transactions and calculations undertaken during the ordinary course of business for which the ultimate tax determination is uncertain. The Group estimates its tax liabilities based on the Group's understanding of the tax law. Where the final tax outcome of these matters is different from the amounts that were initially recorded, such differences will impact the current and deferred income tax assets and liabilities in the period in which such determination is made.

In addition, the Group recognises deferred tax assets relating to carried forward tax losses to the extent there are sufficient taxable temporary differences (deferred tax liabilities) relating to the same taxation jurisdiction and the same subsidiary against which the unused tax losses can be utilised. However, utilisation of the tax losses depends on the ability of the entity to satisfy certain tests at the time the losses are recouped.

8. Cash and cash equivalents

	2018 US$'000	2017 US$'000
Cash at bank and on hand	5,945	12,199
	5,945	12,199

Recognition and measurement
Cash and cash equivalents includes cash on hand, deposits held at call with financial institutions and other short-term, highly liquid investments with original maturities of three months or less that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value.

Cash at bank earns interest at floating rates based on daily bank deposit rates.

Under the terms of the convertible notes, 50% of net proceeds from SM 71 (after all costs) are only to be used for SM 71 until the total equals the value of the convertible notes and interest outstanding. As at 30 June 2018 the accumulated amount usable only for SM 71 purposes or repayment of amounts in relation to the convertible notes was US$2.7 million of the US$5.9 million cash on hand.

9. Reconciliation of loss after income tax to net cash outflow from operating activities

	2018 US$'000	2017 US$'000
Loss after income tax	(5,194)	(5,247)
Non-cash items:		
Depreciation expense – furniture and equipment	26	48
Share-based payments	110	75
Finance costs – see note 5(i)	4,436	48
Amortisation of deferred costs	877	-
Other non-cash items	(1)	(5)
Change in assets and liabilities:		
Increase in trade and other receivables	(3,165)	(9)
Decrease in other assets	109	30
Increase in trade and other payables	630	271
Increase in provisions	46	(26)
Net cash outflow from operating activities	(2,126)	(4,815)

Changes in financing liabilities arising from cash flow and non-cash flow items

Convertible note		
Balance at the start of the year	-	-
Proceeds from convertible notes	8,200	-
Convertible note transaction costs	(311)	-
Non cash item - interest accretion	(347)	-
Balance at the end of the year	7,542	-

Refer to note 14 for further details on the convertible note.

OPERATING ASSETS AND LIABILITIES

10. Trade and other receivables

	2018 US$'000	2017 US$'000
Trade receivables[i]	3,997	-
Other receivables	831	916
Allowance for doubtful debts [ii]	(800)	(800)
	4,028	116

Recognition and measurement
Other receivables are initially recognised at fair value and subsequently measured at amortised cost less an allowance for uncollectible amounts.

Collectability of trade and other receivables is reviewed on an ongoing basis. Debts that are known to be uncollectible are written off when identified. An allowance for doubtful debts is raised when there is objective evidence that the Group will not be able to collect the debt. Financial difficulties of the debtor, default payments or debts more than 60 days overdue are considered objective evidence of impairment.

(i) Trade receivable relates to June 2018 oil and gas sales (before deduction of royalties).
(ii) Included in other receivables in 2017 and 18 is $0.8 million receivable from Swala Oil and Gas (Tanzania) Plc relating to settlement of the various claims and disputes concerning the Pangani licence. This amount has been fully provided for.

11. Other assets

	2018 US$'000	2017 US$'000
Current		
Prepayments	239	73
Other assets	48	311
	287	384
Non-current		
Convertible note transaction costs [i]	-	300
Bonds[ii]	355	175
	355	475

(i) Represents transaction costs incurred before year end in relation to $8.2 million of secured convertible notes issued subsequent to year end. This amount was offset against the convertible note liability upon issue of the note.
(ii) Development bond for SM 71 (USD325,000) and Security Bond for Houston Office leased premises (USD30,000)

Recognition and measurement
Other financial assets are initially measured at fair value. Transaction costs are included as part of the initial measurement, except for financial assets at fair value through profit or loss. They are subsequently measured at either amortised cost or fair value depending on their classification. Classification is determined based on the purpose of the acquisition and subsequent reclassification to other categories is restricted. The fair values of quoted investments are based on current bid prices. For unlisted investments, the Group establishes fair value by using valuation techniques. These include the use of recent arm's length transactions, reference to other instruments that are substantially the same, discounted cash flow analysis, and option pricing models.

11. Other assets (continued)

Financial assets are derecognised when the rights to receive cash flows from the financial assets have expired or have been transferred and the Group has transferred substantially all the risks and rewards of ownership.

Impairment of financial assets

The Group assesses at the end of each reporting period whether there is any objective evidence that a financial asset or group of financial assets is impaired. Objective evidence includes significant financial difficulty of the issuer or obligor; a breach of contract such as default or delinquency in payments; the lender granting to a borrower concessions due to economic or legal reasons that the lender would not otherwise do; it becomes probable that the borrower will enter bankruptcy or other financial reorganisation; the disappearance of an active market for the financial asset; or observable data indicating that there is a measurable decrease in estimated future cash flows.

The amount of the impairment allowance for financial assets carried at cost is the difference between the asset's carrying amount and the present value of estimated future cash flows, discounted at the current market rate of return for similar financial assets.

12. Oil and gas properties

	2018 US$'000	2017 US$'000
Producing and development assets		
At cost		
Balance at beginning of year	6,272	2,717
Expenditure for the year	21,756	3,555
Amortisation of assets	(877)	-
Balance at end of year	27,151	6,272

All capitalised development and evaluation costs as at 30 June 2018 relate to the SM 71 oil development in the Gulf of Mexico (including provision for decommissioning).

Recognition and measurement

i) Producing and development assets

Producing projects are stated at cost less accumulated amortisation and impairment charges. Development assets include evaluation, construction, installation or completion of production and infrastructure facilities such as platforms and pipelines, development wells, acquired development or producing assets, capitalised borrowing costs and the estimated costs of decommissioning, dismantling and restoration. Evaluation is deemed to be activities undertaken from the beginning of the definitive feasibility study or testing conducted to assess the technical commercial viability of extracting a resource before moving into the development phase.

Once an exploration discovery has been determined, subsequent evaluation and development expenditure is capitalised to the Consolidated Statement of Financial Position as oil and gas properties as it is probable that future economic benefits associated with the item will flow to the Group. Once such costs are capitalised as oil and gas properties, they will be tested for impairment and assessed for impairment indicators for periods thereafter.

The carrying value of oil and gas properties is reviewed annually by directors to ensure it is not in excess of the recoverable amount. This assessment is based on key estimates, the most significant of which are estimated hydrocarbon reserves, future production profiles, commodity prices, operating costs and any future development costs necessary to produce the reserves.

12. Oil and gas properties (continued)

ii) Prepaid drilling and completion costs

Where the Company has a non-operated interest in an oil or gas property, it may periodically be required to make a cash contribution for its share of the Operator's estimated drilling and/or completion costs, in advance of these operations taking place.

Where these contributions relate to a prepayment for exploratory or early stage drilling activity, prior to a decision on the commerciality of a well having been made, the costs are expensed in profit or loss when the cash call is paid. The Operator notifies the Company as to how funds have been expended and any relevant costs are reclassified from exploration expense and capitalised to deferred oil and gas properties.

Where these contributions relate to a prepayment for well completion, these costs are capitalised as prepaid completion costs within oil and gas properties.

iii) Commencement of production

When a well demonstrates commercial feasibility or comes into commercial production, accumulated development and evaluation expenditure for the relevant area of interest is amortised on a units of production basis.

iv) Amortisation and depreciation of producing projects

The Group uses the units of production (UOP) approach when amortising and depreciating field-specific assets. Using this method of amortisation and depreciation requires the Group to compare the actual volume of production to the reserves and then to apply this determined rate of depletion to the carrying value of the depreciable asset.

Capitalised producing project costs relating to commercially producing fields are depreciated/amortised using the UOP basis once commercial quantities are being produced within an area of interest. The reserves used in these calculations are the proved plus probable reserves (2P) and are reviewed at least annually.

Key estimates and judgements

Carrying value of oil and gas assets

Judgement is required to determine when an exploration activity ceases and an evaluation or development activity commences. Evaluation is deemed to be activities undertaken from the beginning of the definitive feasibility study or testing conducted to assess the technical commercial viability of extracting a resource before moving into the development phase. Development assets include evaluation, construction, installation or completion of production and infrastructure facilities such as platforms and pipelines, development wells, acquired development or producing assets, capitalised borrowing costs and the estimated costs of decommissioning, dismantling and restoration.

Circumstances vary for each area of interest and where exploration, evaluation and development activities are conducted within a continual timeframe as part of the same project or drilling campaign with common service providers, a degree of estimation is required in determining the amount of costs capitalised as evaluation and development assets under oil and gas properties.

Assessment of costs associated with non-operated interests is also influenced by notification from the Operator as to how funds have been expended.

12. Oil and gas properties (continued)

Impairment

Assets are tested for impairment in line with the accounting policies disclosed in Note 12(i) whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment loss is recognised for the amount by which the asset's carrying amount exceeds its recoverable amount. The recoverable amount is the higher of an asset's fair value less cost to sell and value in use. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash inflows which are largely independent of the cash inflows from other assets or groups of assets (cash-generating units).

At 30 June 2018, the Group has assessed the SM 71 cash-generating unit and determined that no impairment indicators existed.

Amortisation

Estimation of amortisation of oil and gas assets is based on the updated 2P reserves estimate and estimated future development costs as at 30 June 2018.

Property, plant and equipment

Recognition and measurement

Property, plant and equipment are stated at historical cost less depreciation. Historical cost includes expenditure that is directly attributable to the acquisition of the items.

Depreciation is calculated using the straight-line method to allocate their cost, net of their residual values, over their estimated useful lives. The following estimated useful lives are used in the calculation of depreciation:

Plant and equipment	5 years
Furniture and equipment	3 - 10 years

The assets' residual values and useful lives are reviewed, and adjusted if appropriate, at the end of each reporting period. An asset's carrying amount is written down immediately to its recoverable amount if the asset's carrying amount is greater than its estimated recoverable amount.

Gains and losses on disposals are determined by comparing proceeds with the carrying amount. These are included in profit or loss. When revalued assets are sold, it is Group policy to transfer any amounts included in other reserves in respect of those assets to retained earnings.

13. Trade and other payables

	2018 US$'000	2017 US$'000
Trade payables	2,141	1,611
Success Fee – convertible note see note 14	163	-
Interest payable – convertible note see note 14	1,225	-
Other Accrued expenses	1,234	-
	4,763	1,611

Recognition and measurement

Trade payables are initially recognised at their fair value and subsequently measured at amortised cost. They represent liabilities for goods and services provided to the Group prior to the end of the financial year that are unpaid and arise when the Group becomes obliged to make future payments in respect of the purchase of these goods and services. The amounts are unsecured and generally paid within 30 days of recognition.

14. Convertible Note

Convertible note	2018 US$'000	2017 US$'000
Balance at the beginning of the year	-	-
Convertible note debt host liability – at cost	7,453	-
Add: interest accretion	347	-
Less: Convertible note transaction costs – at cost	(258)	-
Balance at the end of the year	7,542	-

Convertible note derivative		
Balance at the beginning of the year	-	-
Convertible note embedded derivative – at initial fair value through statement of profit or loss	747	-
Convertible note embedded derivative – at 30 June 2018 fair value through statement of profit or loss	2,436	-
Balance at the end of the year	3,183	-

On 2 August 2017 the Company issued $8.2 million secured convertible notes (the 'Notes') to Molton Holdings Limited, a major Otto shareholder ($8.0 million) and Mr John Jetter, Otto's Chairman ($0.2 million). No convertible notes have been converted therefore 8.2 million convertible notes remained on issue as at 30 June 2018.

Principal and Interest

As at 30 June 2018 the principle and interest payable (but not yet due) under the terms of the convertible notes, assuming no conversion, was:

	US$'000
Convertible note principal	8,200
Interest payable – convertible note see below	1,225
	9,425

The key terms of the Notes are as follows:

- Issue amount: 8.2 million convertible notes.
- Face value: US$1 per convertible note.
- Conversion price: A$0.055 per share .
- Interest rate: 14% per annum compounded monthly and paid semi-annually.
- Interest payments: Interest accrues until interest payments commence on the date 60 days after First Oil, at which time any accrued interest will be payable in two equal instalments on the first and second interest payment dates. First Oil is the date on which there has been 30 continuous days of steady state production of hydrocarbons from the SM 71 project into the sales export pipeline.
- Maturity date: 30 June 2019.
- Security: The convertible notes are secured via a share pledge covering the shares in Otto's subsidiaries which hold its Gulf of Mexico interests including the SM 71 project.

14. Convertible Note (continued)

- Conversion: A noteholder may elect to convert convertible notes on: a) any 30 June, 30 September, 31 December and 31 March after the first anniversary of the issue date; b) receipt of a redemption notice; and c) the maturity date, in accordance with the following conversion ratio:

$$\frac{\textit{Number of convertible notes to be converted}}{\textit{Bid exchange rate}} = \textit{Australian dollar equivalent}$$

  where the bid exchange rate means the US Dollar exchange rate published by the Reserve Bank of Australia, and

$$\frac{\textit{Australian dollar equivalent}}{\textit{Conversion price}} = \textit{Number of conversion shares to be issued}$$

- As at 30 June 2018, $8.2million convertible notes at bid exchange rate AUD/USD 0.7391 is equivalent to AUD11,094,574. At the conversion price of A$0.055 per share, the number of conversion shares equated to 201,474,201 shares.
- Redemption: The Company may elect to redeem convertible notes on: a) any 30 June, 30 September, 31 December and 31 March after the first anniversary of the issue date; b) the maturity date; and c) receipt of a takeover offer (including by scheme of arrangement).
- Success fee: Paid 30 days after the maturity date, subject to Cumulative Oil Production (defined as the number of barrels of oil produced from SM 71 as reported to the Bureau of Ocean Energy Management) to the maturity date (inclusive) and calculated as per the table below. If a convertible note is redeemed or converted prior to the maturity date, the success fee payable in respect of the convertible note will be paid pro rata to the number of days the noteholder held it. An accrual for $163k was made in the accounts at 30 June 2018 based on forecast production to maturity.

Cumulative Oil Production (100% field) to 30 June 2019 from SM 71 (bbls)	Less than 1,400,000	Greater than 1,399,999 and less than 1,500,000	Greater than 1,499,999 and less than 1,600,000	Greater than 1,599,999 and less than 1,700,000	Greater than 1,699,999 and less than 1,800,000	Greater than 1,799,999
Total Success Fee amount payable per convertible note (US$)	-	0.025	0.05	0.075	0.10	0.125

- Transferability: A noteholder may transfer the convertible notes subject to notice and other conditions including in relation to transfers to direct competitors of the Company.
- Adjustments: The convertible notes are subject to customary adjustments for alterations to the capital of the Company.
- Default and termination rights: The convertible notes are subject to customary default and termination rights.
- Not quoted: The convertible notes will not be listed on ASX or any other securities exchange.

Key estimates and judgements

For accounting purposes, the Notes have two elements: a debt host liability component and an embedded derivative component. On initial recognition, the fair value of the embedded derivative component is calculated first and the residual value is assigned to the debt host component. No gain or loss is recognised on inception.

14. Convertible Note (continued)

The debt host liability component is subsequently carried at amortised cost whereby the initial carrying value of the liability is accreted to the principal amount over the life of the Note. The accretion is recognised as a finance cost together with the interest expense (refer note 5).

The fair value of the embedded derivative is determined each balance date using the Black Scholes model and any changes in fair value are recorded in profit or loss. On the date of issue of the Notes, the fair value of the embedded derivative liability was determined to be $0.747 million using a Black Scholes valuation based on the time to expiry, the Company's current share price of A$0.028, risk free interest rate of 1.8% and assuming 68% volatility. The fair value of the embedded derivative liability at 30 June 2018 was determined to be $3.183 million using a Black Scholes valuation based on the time to expiry, the Company's 30 June 2018 share price of A$0.065 (note this is above the conversion price of A$0.055), risk free interest rate of 2.0% and assuming 65% volatility. The change in fair value of $2.436 million has been recognized as a finance cost (refer note 5).

15. Provisions

	2018 US$'000	2017 US$'000
Current		
Employee benefits	201	197
Tax	1	-
Decommissioning fund (ii)	-	120
	202	317
Non-current		
Employee benefits (i)	6	3
Decommissioning fund (ii)	1,122	238
	1,128	241

(i) The non-current provision for employee benefits includes amounts not expected to be settled within the next 12 months.

(ii) The total present value of the estimated expenditure required to decommission the wells for the permit SM 71. The expenditure is expected to be settled at the end of the field life for the 2P production profile for SM 71.

Recognition and measurement

Employee benefits

A liability is recognised for benefits accruing to employees in respect of wages and salaries, annual leave and long service leave when it is probable that settlement will be required and they are capable of being measured reliably.

Liabilities recognised in respect of employee benefits expected to be settled within 12 months are measured at their nominal values using the remuneration rate expected to apply at the time of settlement.

Liabilities recognised in respect of employee benefits which are not expected to be settled within 12 months are measured as the present value of the estimated future cash outflows to be made by the Group in respect of services provided by employees up to reporting date.

Contributions to superannuation plans are expensed when incurred.

15. Provisions (continued)

Decommissioning fund

Provisions are recognised when the Group has a present obligation (legal or constructive) as a result of past events, it is probable that the Group will be required to settle the obligation and the amount of the provision can be measured reliably.

The amount recognised as a provision is the best estimate of the consideration required to settle the present obligation at the reporting date, taking into account the risks and uncertainties surrounding the obligation. Where a provision is measured using the cash flows estimated to settle the present obligation, its carrying amount is the present value of those cash flows. The unwinding of the discount is expensed as incurred and recognised in the Consolidated Statement of Profit or Loss and Other Comprehensive Income as a finance cost.

Provision is made for the estimated cost of legal and constructive obligations to restore operating locations in the period in which the obligation arises. The estimated costs are capitalised as part of the cost of the related project where recognition occurs upon acquisition of an interest in the operating locations. The carrying amount capitalised is amortised on a unit of production basis during the production phase of the project.

Work scope and cost estimates for restoration are reviewed annually and adjusted to reflect the expected cost of restoration. The Group accounts for changes in cost estimates on a prospective basis.

Key estimates and judgements

Decommissioning costs will be incurred by the Group at the end of the operating life of some of the Group's facilities and properties. The Group assesses its decommissioning provision at each reporting date. The ultimate decommissioning costs are uncertain and cost estimates can vary in response to many factors, including changes to relevant legal requirements, the emergence of new restoration techniques or experience at other production sites. The expected timing, extent and amount of expense can also change. Therefore, significant estimates and assumptions are made in determining the provision for decommissioning. As a result, there could be significant adjustments to the provisions established which would affect future financial results. The provision at reporting date represents management's best estimate of the present value of the future decommissioning costs required.

CAPITAL STRUCTURE, FINANCIAL INSTRUMENTS AND RISK

16. Contributed equity

a) Share capital

	2018 Number	2017 Number	2018 US$'000	2017 US$'000
Balance at beginning of year	1,186,298,324	1,181,908,323	81,895	81,895
Shares issued – placement [i]	236,857,143	-	5,986	-
Shares issued – share purchase plan[ii]	100,000,166	-	2,660	-
Shares issued - directors[iii]	6,142,857	-	163	-
Shares issued on exercise of performance rights[iv]	1,630,000	4,390,001	-	-
Balance at end of year	1,530,928,490	1,186,298,324	90,704	81,895

(i) Share placement (Tranche 1) October 2017 at AUD0.035 per share, converted to USD at the exchange rate on the transaction date of 0.7652. Net of share issue costs.
(ii) Shares issued under Share Purchase Plan November 2017 at AUD0.035 per share, converted to USD at the exchange rate on the transaction date of 0.7599.
(iii) Share placement (Tranche 2) issued to directors following shareholder approval at the AGM in November 2017 at AUD0.035 per share.
(iv) Shares issued on exercise of performance rights February 2018

b) Ordinary shares

Ordinary shares entitle the holder to participate in dividends and the proceeds on winding up of the Company in proportion to the number and amount paid on the shares held. On a show of hands every holder of ordinary shares present at a meeting in person or by proxy, is entitled to one vote, and upon a poll each share is entitled to one vote. The ordinary shares have no par value and the Company does not have a limited amount of authorised capital.

c) Options

Information relating to the Otto Energy Employee Option Plan, including details of options issued, exercised and lapsed during the financial year and options outstanding at the end of the reporting period, is set out in Note 21.

d) Performance rights

Information relating to the Otto Energy Employee Performance Rights Plan, including details of performance rights issued, exercised and lapsed during the financial year and performance rights outstanding at the end of the reporting period, is set out in Note 21.

Recognition and measurement

Ordinary shares are classified as equity.

Incremental costs directly attributable to the issue of new shares or options are shown in equity as a deduction, net of tax, from the proceeds.

17. Reserves

	2018 US$'000	2017 US$'000
Share-based payments reserve	9,659	9,549
Foreign currency translation reserve	4,188	4,188
	13,847	13,737
Share-based payments reserve		
Balance at beginning of year	9,549	9,474
Share-based payment expense	110	75
Balance at end of year	9,659	9,549
Foreign currency translation reserve		
Balance at beginning of year	4,188	4,188
Balance at end of year	4,188	4,188

The share-based payments reserve is used to recognise the value of share-based payments provided to employees (including key management personnel) as part of their remuneration, and share options and performance rights issued as part of consideration for acquisitions. Refer to Note 21 for further details of these plans.

The foreign currency translation reserve is used to record currency differences arising from the translation of the financial statements of foreign operations.

18. Financial instruments

The Group is exposed to market risk, credit risk and liquidity risk. The Group's overall risk management program focuses on the unpredictability of financial markets and seeks to minimise potential adverse effects on the financial performance of the Group. The Group uses different methods to measure different types of risk to which it is exposed.

Otto's Board of Directors ('Board') is responsible for approving Otto's policies on risk oversight and management and ensuring management has developed and implemented effective risk management and internal controls. Risk management is carried out by the senior executives under these policies which have been approved by the Board. Management identifies, evaluates and, if necessary, hedges financial risks within the Group's operating units. The Board then receives reports as required from the Chief Financial Officer in which they review the effectiveness of the processes implemented and appropriateness of policies it sets. At all times during the year, and to the date of this report, the Group had no hedges in place and does not apply any form of hedge accounting.

a) Market risk

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk for the Group comprises three types of risk: currency risk, interest rate risk and commodity price risk.

18. Financial instruments (continued)

a) Market risk (continued)

i) Currency risk

The Group's source currency for the majority of revenue and costs is in US dollars. Given the location of the group's offices and operations there is a small exposure to foreign exchange risk arising from the fluctuations in the US dollar and Australian dollar on cash balances and monetary items at year end.

Currency risk arises where the value of a financial instrument or monetary item fluctuates due to changes in foreign currency. The exposure to currency risk is measured using sensitivity analysis and cash flow forecasting.

The Board has formed the view that it would not be beneficial for the Group to purchase forward contracts or other derivative financial instruments to hedge this currency risk. Factors which the Board considered in arriving at this position included the expense of purchasing such instruments and the inherent difficulties associated with forecasting the timing and quantum of cash inflows and outflows compared to the relatively low volume and value of commercial transactions and monetary items denominated in a currency which is not US dollars.

A hypothetical change of 10% (2017: 10%) in the Australian dollar exchange rate was used to calculate the Group's sensitivity to foreign exchange rates movements, as this is management's estimate of possible rate movements over the coming year taking into account current market conditions and past volatility. At 30 June 2018, management has assessed that the entity's exposure to foreign exchange movements is immaterial and therefore no further analysis is provided.

ii) Interest rate risk

Interest rate risk is the risk that the Group's financial position will fluctuate due to changes in market interest rates. The Group's exposure to the risk of changes in the market interest rates relates to cash and cash equivalents held with financial institutions. The convertible notes facility that the Group has entered into has a fixed interest rate so is not exposed to interest rate risk. Refer note 14.

The financial instruments exposed to movements in variable interest rates are as follows:

	2018 US$'000	2017 US$'000
Cash and cash equivalents	5,945	12,199
	5,945	12,199

The following sensitivity analysis is based on the interest rate risk exposures in existence at the reporting date. The 1.0% sensitivity is based on reasonably possible changes, over a financial year, using an observed range of historical short term deposit rate movements over the last 3 years.

Judgements of reasonably possible movements	**Effect on post tax losses Increase/(decrease)**	
	2018	**2017**
	US$'000	US$'000
Increase 100 basis points	59	122
Decrease 100 basis points	(59)	(122)

18. Financial instruments (continued)

iii) Commodity price risk

Production commenced from the Group's SM 71 oil development in the Gulf of Mexico, USA on 23 March 2018. Prior to that date, as the Group was not generating revenue from oil and gas production it was not directly exposed to commodity price risk. Since 23 March 2018 the Group has generated revenue from its SM 71 production and hence is exposed to oil price fluctuations.

Exposure to oil price risk is measured by monitoring and stress testing the Group's forecast financial position against sustained periods of low oil prices. This analysis is regularly performed on the Group's portfolio and, as required, for discrete projects and acquisitions.

Commodity hedging may be undertaken where the Board of Directors determines that a hedging strategy is appropriate to mitigate potential periods of adverse movements in commodity price. This will be balanced against the desire to expose shareholders to oil price upside and the reliability of production forecast. Commodity hedging may also be undertaken when there is a hedging requirement under a lending facility.

b) Credit risk

Credit risk is the risk that a contracting entity will not complete its obligation under a financial instrument that will result in a financial loss to the Group. Credit risk arises from the financial assets of the Group, which comprise trade and other receivables and deposits with banks and financial institutions.

To manage credit risk from cash and cash equivalents, it is the Group's policy to only deposit with banks maintaining a minimum independent rating of 'AA', 'A+' or 'A-'. Contracts for the sale of production from SM 71, which commenced on 23 March 2018, are with creditworthy customers and counterparties.

Receivables balances are monitored on an ongoing basis with the result that the Group's exposure to bad debts in the ordinary course of business is not significant. At reporting date no receivables were overdue apart from those already provided for.

The maximum exposure to credit risk at reporting date was as follows:

	2018 US$'000	2017 US$'000
Cash and cash equivalents	5,945	12,199
Trade and other receivables	4,028	116
	9,973	12,315

c) Liquidity risk

Liquidity risk is the risk that Group will encounter difficulty in meeting obligations associated with financial liabilities that are settled by delivering cash or another financial asset.

It is the policy of the Board to ensure that the Group is able to meet its financial obligations and maintain the flexibility to pursue attractive investment opportunities through the Group maintaining sufficient working capital and access to further funding when required through debt, equity or other means.

The Group manages liquidity risk by continuously monitoring forecast and actual cash flows with scenario analysis. As at reporting date the Group had sufficient cash reserves to meet its current requirements and no receivables were overdue apart from those already provided for.

18. Financial instruments (continued)

c) Liquidity risk (continued)

The contractual maturity analysis of payables at the reporting date was as follows:

	Carrying Value US$'000	Total US$'000	Less than 1 year US$'000	Between 1-2 years US$'000	Between 2-5 years US$'000
Trade and other payables					
2018	4,763	4,763	4,763	-	-
2017	1,611	1,611	1,611	-	-
Convertible Notes – refer note 14					
2018	7,542	7,542	7,542	-	-
2017	-	-	-	-	-

Capital risk management

The Group manages its capital to ensure that it will be able to continue as a going concern while maximising the potential return to shareholders through the optimisation of the debt and equity balance.

The capital structure of the Group at year end includes convertible notes and equity (2017: 100% equity). Refer to note 14 for details on the convertible note. In determining the funding mix of debt and equity (total borrowings/total equity), consideration is given to the relative impact of the gearing ratio on the ability of the Group to service interest and repayment schedules, credit facility covenants and also to generate adequate free cash available for corporate and oil and gas exploration, development and production activities. The debt to equity ratio is 51% based on the accounting carrying value of the convertible note as at 30 June 2018 (2017: 0%).

The Group may consider raising capital when an opportunity to invest in a business or company was seen as value adding relative to the company's current share price at the time of the investment.

d) Equity price risk

The Group is exposed to equity price risk on its financial liabilities. The liability fluctuates with the Group's underlying share price until either the convertible note is repaid by the Group or the note holders convert. The Group has no policy for mitigating potential adversities associated with its own equity price risk given its dependence on market fluctuations.

In relation to the convertible note derivative, the Group have used an equity price change of 65% (2017: not applicable) upper and lower representing a reasonable possible change based upon the Group's historic share price volatility over the last three years of trading. At reporting date, should the Group's share price be reduced by 65% the value of the derivative would have been affected and the loss decreased by $3.0 million (2017: not applicable). An equal and opposite increase in share price would have increased losses by $5.3 million (2017: not applicable).

18. Financial instruments (continued)

e) Fair values

The following table shows the carrying amounts and fair values of financials liabilities, including their levels in the fair value hierarchy. It does not include fair value information for financial liabilities not measured at fair value if the carrying value is a reasonable approximation of fair value. The different valuation methods are called hierarchies and they are described below:

	Level	Carrying Amount		Fair Value	
		2018 US$'000	2017 US$'000	2018 US$'000	2017 US$'000
Financial liabilities measured at fair value					
Convertible note derivative	Level 2	3,183	-	3,183	-
		3,183	-	3,183	-
Financial liabilities not measured at fair value					
Convertible note liability	Level 2	7,542	-	7,542	-
		7,542	-	7,542	-

Fair value hierarchy

Level 1 – the instrument has quoted prices (unadjusted) in active markets for identical assets or liabilities;

Level 2 – the fair values are measured using inputs (other than quoted prices) that are observable for the asset or liability either directly or indirectly; or

Level 3 – the fair values are measured using inputs for the assets or liability that are not based on observable market data.

Cash and cash equivalents, trade and other receivables, trade creditors, other creditors and accruals have been excluded from the above analysis as their fair values are equal to the carrying values.

The fair value of convertible note derivatives is determined using a Black-Scholes model based on the time to expiry. The key drivers of this value include the Group's own share price and the foreign exchange rate. Sensitivities considering reasonably possible movements in these assumptions are included above at note 18(d).

OTHER DISCLOSURES

19. Subsidiaries

Significant investments in subsidiaries

The consolidated financial statements incorporate the assets, liabilities and results of the following principal subsidiaries:

Subsidiaries of Otto Energy Limited	Country of incorporation	Functional currency	Class of shares	Ownership Interest [i]	
				2018 (%)	2017 (%)
Otto Energy (Tanzania) Pty Limited	Australia	USD	Ordinary	100	100
Otto Energy Investments Limited	Bermuda	USD	Ordinary	100	100
Otto Energy Philippines Inc	Philippines	USD	Ordinary	100	100
Otto Energy (Galoc Investment 1) Aps	Denmark	USD	Ordinary	100	100
Otto Energy (Galoc Investment 2) Aps	Denmark	USD	Ordinary	100	100
GPC Investments SA	Switzerland	USD	Ordinary	100	100
Borealis Petroleum Pty Ltd	Australia	USD	Ordinary	100	100
Borealis Alaska LLC	USA	USD	Ordinary	100	100
Otto Energy (USA) Inc	USA	USD	Ordinary	100	100
Otto Energy (Louisiana) LLC	USA	USD	Ordinary	100	100
Otto Energy (Gulf One) LLC [ii]	USA	USD	Ordinary	100	100
Otto Energy (Gulf Two) LLC [ii]	USA	USD	Ordinary	100	100
Otto Operating LLC[iii]	USA	USD	Ordinary	100	-

[i] The proportion of ownership interest is equal to the proportion of voting power held.
[ii] Otto Energy (Gulf One) LLC and Otto Energy (Gulf Two) LLC were incorporated on 26 April 2017.
[iii] Otto Operating LLC was incorporated on 9th April 2018.

20. Interest in joint operations

a) Joint operations

The Group's share of the assets, liabilities, revenues and expenses of joint arrangement operations have been incorporated into the financial statements in the appropriate items of the Consolidated Statement of Profit or Loss and Other Comprehensive Income and Consolidated Statement of Financial Position.

The Group's interest in joint arrangement assets is detailed below. Oil and Gas exploration and production is the principal activity performed across these assets.

Asset	Country	2018 Group interest	2017 Group interest
South Marsh Island 71	USA	50%	50%
South Marsh Island 70 [iii]	USA	-	50%
Bivouac Peak [i]	USA	45%	45%
VR 232 [iv]	USA	50%	-
Onshore Alaska North Slope – Western Blocks [v]	USA	22.5%	8 – 10.8%
Onshore Alaska North Slope – Central Blocks	USA	8 – 10.8%	8 – 10.8%
Service Contract 55 [ii]	Philippines	-	68.18%

20. Interest in joint operations (continued)

(i) At 30 June 2017 and 2018 Otto had the right to earn a 45% working interest in the Bivouac Peak lease by drilling 1 exploration well. On 9 July 2018 Otto elected to participate in the initial exploration well at a 40% working interest.
(ii) As at 30 June 2017, an agreement had been signed to transfer the permit to existing joint venture partners but this had not yet been approved by the DOE. The interest transfer was approved by the DOE effective 26 March 2018.
(iii) SM 70 expired on 31 July 2017.
(iv) Otto has the right to participate for a 50% working interest in VR 232.
(v) A binding terms sheet was executed on 25 June 2018 taking Otto's working interest to 22.5%. Definitive agreements were executed on 30 July 2018.

b) Commitments through joint operations

The aggregate of the Group's commitments through jointly controlled assets is as follows:

	2018 US$'000	2017 US$'000
Exploration expenditure commitments – not later than 1 year	750	2,600
Capital expenditure commitments – not later than 1 year	-	2,956
	750	5,556

Operating lease arrangements
Operating lease arrangements relate to the lease of a compressor on the SM 71 F platform. The term is for a minimum 36 months with a 30 day notice period option to discontinue the arrangement beyond the 3 year period. These obligations are not provided for in the financial statements and the Group doesn't have a purchase option.

	2018 US$'000	2017 US$'000
(a) Payments recognised as an expense		
Net minimum lease payments recognised as an expense	25,665	-
(b) Minimum net future lease payments		
Not longer than 1 year	54,206	-
Between 1 and 5 years	64,860	-
	119,066	-

21. Share-based payments

a) Employee share option plan

The establishment of the Employee Share Option Plan was approved by shareholders at the 2013 Annual General Meeting and again at the 2016 Annual General Meeting. The Employee Share Option Plan is designed to provide long term incentives for employees and key management personnel (KMP) to deliver long term shareholder returns. Under the plan, participants are granted options at the Board's discretion and no individual has a contractual right to participate in the plan or to receive any guaranteed benefits. Options granted under the plan carry no dividend or voting rights.

The exercise price of options is based on the weighted average price at which the Company's shares are traded on the Australian Securities Exchange (ASX) during the week up to and including the date of the grant. An option may only be exercised after that option has vested and any other conditions imposed by the Board on exercise are satisfied. Options are granted under the plan for no consideration.

21. Share-based payments (continued)

Set out below are summaries of share options granted under the Employee Share Option Plan and on issue during the year ended 30 June 2017. There were no options on issue during the 2018 financial year.

The Company did not grant any options during the 2018 or 2017 financial years. During the year ended 30 June 2018, nil (2017: 8,000,000) options expired.

		Exercise price	Balance at start of the year	Granted during the year	Exercised during the year	Expired/ forfeited during the year	Balance at end of the year	Vested and exercisable at end of the year
Grant date	**Expiry date**	**A$**	**Number**	**Number**	**Number**	**Number**	**Number**	**Number**
2017								
2 Dec 2013	2 Dec 2016	0.0549	8,000,000	-	-	(8,000,000)	-	-
Weighted average exercise price – A$			0.055					

b) Performance rights

The Performance Rights Plan was approved by shareholders at the 2013 Annual General Meeting and again at the 2016 Annual General Meeting. The Performance Rights Plan is designed to provide long term incentives for senior managers and employees to deliver long term shareholder returns. Participation in the plan is at the Board's discretion and no individual has a contractual right to participate in the plan or to receive any guaranteed benefits.

The amount of performance rights that will vest depends on vesting period and/or Otto Energy Limited's TSR, including share price growth, dividends, and capital returns. Once vested, the performance rights are automatically converted to shares. If the vesting condition is not met on a measurement date (no rights vest), the performance rights will not lapse and will continue to exist as unvested performance rights to be retested at the next measurement date or expiry date, whichever is later. Performance rights are granted under the plan for no consideration.

Rights granted under the plan carry no dividend or voting rights.

21. Share-based payments (continued)

Set out below are summaries of rights granted under the Performance Rights Plan:

2018		**Fair value on date of issue**	**Balance at start of the year**	**Rights issued during the year**	**Exercised/ vested**	**Lapsed/ expired**	**Balance at end of the year**
Grant date	**Expiry date**	**A$**	**Number**	**Number**	**Number**	**Number**	**Number**
3 Oct 2014	31 Dec 2018	0.05	10,000	-	(10,000)	-	-
3 Oct 2014	31 Dec 2018	0.06	1,610,000	-	(1,610,000)	-	-
23 Apr 2015	31 Dec 2019	0.06	1,543,334	-	-	-	1,543,334
23 Apr 2015	31 Dec 2019	0.07	3,096,666	-	-	-	3,096,666
23 Apr 2015	31 Dec 2019	0.08	10,000	-	(10,000)	-	-
14 Aug 2015	31 Dec 2017 (i)	0.04	1,400,000	-	-	(1,400,000)	-
29 Nov 2017	29 Nov 2022	0.05	-	4,729,000	-	-	4,729,000
29 Nov 2017	29 Nov 2022	0.04	-	4,729,000	-	-	4,729,000
29 Nov 2017	29 Nov 2022	0.04	-	4,729,000	-	-	4,729,000
Total			7,670,000	14,187,000	(1,630,000)	(1,400,000)	18,827,000
Weighted average exercise price – A$			0.06	0.05	0.06	0.04	0.05

(i)

2017		**Fair value on date of issue**	**Balance at start of the year**	**Rights issued during the year**	**Exercised/ vested**	**Lapsed/ expired**	**Balance at end of the year**
Grant date	**Expiry date**	**A$**	**Number**	**Number**	**Number**	**Number**	**Number**
3 Oct 2014	31 Dec 2018	0.05	4,500,000	-	(4,286,667)	(203,333)	10,000
3 Oct 2014	31 Dec 2018	0.06	2,299,998	-	(43,333)	(646,665)	1,610,000
23 Apr 2015	31 Dec 2019	0.06	2,079,170	-	-	(535,836)	1,543,334
23 Apr 2015	31 Dec 2019	0.07	4,237,497	-	-	(1,140,831)	3,096,666
23 Apr 2015	31 Dec 2019	0.08	79,167	-	-	(69,167)	10,000
23 Apr 2015	31 Dec 2019	0.09	79,166	-	(60,001)	(19,165)	-
14 Aug 2015	31 Dec 2017 (i)	0.04	1,400,000	-	-	-	1,400,000
Total			14,674,998	-	(4,390,001)	(2,614,997)	7,670,000
Weighted average exercise price – A$			0.06	-	0.05	0.06	0.06

(ii) Expiry date of rights granted to M.Worner amended per the plan rules following cessation of his employment on 1 July 2017.

21. Share-based payments (continued)

Set out below is the share based payment expense:	2018 US$'000	2017 US$'000
Performance rights issued in financial year 2015	24	75
Performance rights issues in financial year 2018	86	-
Total	110	75

The fair value of the performance rights granted under the Plan is estimated at the date of grant using Hoadley hybrid ESOS – single share price target valuation model. The following table lists inputs to the models used for grants made during the year ended 30 June 2018.

Total Return on Shareholders ('TSR') based performance rights

2018

	Tranche 1	Tranche 2	Tranche 3
Measurement date	29 Nov 2018	29 Nov 2019	29 Nov 2020
Grant date	29 Nov 2017	29 Nov 2017	29 Nov 2017
Expiry date	29 Nov 2022	29 Nov 2022	29 Nov 2022
Share price at grant date – A$	0.04	0.04	0.04
Expected volatility	20%	20%	20%
Expected dividend yield	Nil	Nil	Nil
Risk free rate	2.09%	2.09%	2.09%
Fair value – A$	0.03	0.02	0.02

The expected price volatility of 20% was based on the 30 day volume weighted average price (VWAP) which is the applicable volatility measure for the rights given vesting is determined by a 30 day VWAP. Note this differs from the volatility used for the Convertible Note valuation which does not rely on a 30 day VWAP.

The Company did not grant any performance rights during the 2017 financial year.

The weighted average remaining contractual life of performance rights outstanding at 30 June 2018 was 3.7 years (2017: 1.9 years).

The expected price volatility is based on the historic volatility (based on the remaining life of the rights), adjusted for any expected changes to future volatility due to publicly available information.

For the year ended 30 June 2018, the Group recognised share-based payments expense of $109,556 in the Consolidated Statement of Profit or Loss and Other Comprehensive Income (2017: $75,351).

Recognition and measurement

The Group has provided benefits to its employees and key management personnel in the form of share-based payments, whereby services were rendered partly or wholly in exchange for shares or rights over shares. The Board has also approved the grant of options or performance rights as incentives to attract employees and to maintain their long-term commitment to the Company. These benefits were awarded at the discretion of the Board, or following approval by shareholders (equity-settled transactions).

21. Share-based payments (continued)

The costs of these equity-settled transactions are measured by reference to the fair value of the equity instruments at the date on which they are granted. The fair value of performance rights granted is determined using a Hoadley hybrid single share price model. The fair value of options granted is determined by using a Black-Scholes option pricing technique.

The costs of these equity-settled transactions is recognised, together with a corresponding increase in equity, over the period in which the performance and/or service conditions are fulfilled (the vesting period), ending on the date on which the relevant employees become fully entitled to the equity instrument (vesting date).

At each subsequent reporting date until vesting, the cumulative charge to the Consolidated Statement of Profit or Loss and Other Comprehensive Income is the product of (i) the fair value at grant date of the award; (ii) the current best estimate of the number of equity instruments that will vest, taking into account such factors as the likelihood of employee turnover during the vesting period and the likelihood of any non-market performance conditions being met and (iii) the expired portion of the vesting period.

The charge to the Consolidated Statement of Profit or Loss and Other Comprehensive Income for the period is the cumulative amount as calculated above less the amounts already charged in previous periods. There is a corresponding credit to equity.

Until an equity instrument has vested, any amounts recorded are contingent and will be adjusted if more or fewer equity instruments vest than were originally anticipated to do so. Any equity instrument subject to a market condition is considered to vest irrespective of whether or not that market condition is fulfilled, provided that all other conditions are satisfied.

If the terms of an equity-settled award are modified, as a minimum, an expense is recognised as if the terms had not been modified. An additional expense is recognised for any modification that increases the total fair value of the share-based payment arrangement, or is otherwise beneficial to the recipient of the award, as measured at the date of modification.

If an equity-settled transaction is cancelled (other than a grant cancelled by forfeiture when the vesting conditions are not satisfied), it is treated as if it had vested on the date of cancellation, and any expense not yet recognised for the award is recognised immediately. However, if a new equity instrument is substituted for the cancelled award and designated as a replacement award on the date that it is granted, the cancelled and new equity instrument are treated as if they were a modification of the original award, as described in the preceding paragraph.

Key estimates and judgements
The Group measures the cost of equity-settled transactions with employees by reference to the fair value of the equity instruments at the date at which they are granted. The fair value is determined by using either a Hoadley hybrid single share price model or the Black-Scholes model taking into account the terms and conditions upon which the instruments were granted. The accounting estimates and assumptions relating to equity-settled share-based payments would have no impact on the carrying amounts of assets and liabilities within the next annual reporting period but may impact profit or loss and equity.

22. Related parties

	2018 US$	2017 US$
Key management personnel compensation		
Short-term employee benefits	1,125,219	1,277,350
Post-employment benefits	70,914	120,903
Other benefits	3,264	4,914
Termination benefits[i]	(17,553)	167,893
Share-based payments	95,100	91,861
Total USD	1,276,944	1,662,921
Total AUD equivalent	1,647,979	2,188,967

(i) Reversal of over-accrual of annual leave entitlement on termination at 30 June 2017

Detailed remuneration disclosures are provided in the remuneration report on pages 49 to 59.

Transactions with key management personnel

On 15th April 2018 the Company modified the sub-lease agreement with Pathfinder Energy Pty Ltd, a company of which Mr Ian Boserio is a Director. The sub-lease is on a month to month basis and is in relation to office premises at 32 Delhi Street, West Perth. A fee of A$1,000 per month is payable. There were no amounts outstanding at balance date.

On 2 August 2017 the Company issued $8.2 million secured convertible notes to Molton Holdings Limited, a major Otto shareholder ($8.0 million) and Mr John Jetter, Otto's Chairman ($0.2 million). No convertible notes have been converted therefore 8.2 million convertible notes remained on issue as at 30 June 2018. The note issue was approved by shareholders at a general meeting on 25 July 2017. Refer to note 14 for information on the convertible notes.

23. Auditor's remuneration

During the year the following fees were paid or payable for services provided by the auditor of the parent entity, its related practices and non-related audit firms:

	2018 US$	2017 US$
BDO Australia		
Audit and review of financial statements	34,419	36,941
Tax compliance services	3,751	28,687
Tax consulting and tax advice	1,056	18,970
Total remuneration of BDO Australia	**39,226**	**84,598**
Network firms of BDO Australia		
Audit and review of financial statements	7,681	35,580
Tax compliance services	14,001	18,000
International tax consulting	12,265	4,211
Total remuneration of network firms of BDO Australia	**33,947**	**57,791**
Non-BDO		
Audit and review of financial statements	6,021	6,556
Tax compliance services	1,764	4,950
Total remuneration of non-BDO audit firms	**7,785**	**11,506**
Total auditors' remuneration	**80,958**	**153,895**

It is the Group's policy to employ BDO on assignments additional to their statutory audit duties where BDO's expertise and experience with the Group are important. These assignments are principally tax advice where BDO is awarded assignments on a competitive basis. It is the Group's policy to seek competitive tenders for all major consulting projects.

24. Contingent liabilities

Convertible note success fee

There is a success fee payable in respect of the convertible note based on cumulative SM 71 oil production to 30 June 2019 (refer Note 14). Production at SM 71 commenced in March 2018. The maximum amount of success fee payable is $1,025,000. As at 30 June 2018 US$163,000 has been accrued.

25. Commitments

a) Exploration expenditure commitments

Exploration expenditure contracted for at the reporting date but not recognised as liabilities are as follows:

	2018 US$'000	2017 US$'000
Not later than 1 year	750	2,600
	750	2,600

b) Capital expenditure commitments

Capital expenditure committed to at reporting date but not recognised as liabilities are as follows:

	2018 US$'000	2017 US$'000
Not later than 1 year	-	2,956
	-	2,956

c) Lease commitments

The Group has entered into non-cancellable operating leases for corporate offices, a photocopier and a compressor (in JV with Byron Energy Ltd for the SM 71 Development). The leases have varying terms, including escalation and renewal rights.

Commitments for minimum lease payments in relation to non-cancellable operating leases are payable as follows:

	2018 US$'000	2017 US$'000
Not later than 1 year	170	268
Later than 1 year but not later than 5 years	389	-
	559	268

Recognition and measurement

Leases in which a significant portion of the risks and rewards of ownership are not transferred to the Group as lessee are classified as operating leases. Payments made under operating leases (net of any incentives received from the lessor) are charged to profit or loss on a straight-line basis over the period of the lease.

Commitments are disclosed net of the amount of GST recoverable from, or payable to, the tax authority.

Lease rentals due on the Group's exploration leases can be cancelled and the leases relinquished. Therefore the lease rentals are not non-cancellable and hence are not included in the above.

26. Events after the reporting period

No matters or circumstances have arisen since 30 June 2018 that have significantly affected, or may significantly affect the Group's operations, the results of those operations, or the Group's state of affairs in future financial years apart from those listed below:

Appointment of US technical team

The Company has completed the establishment of its Houston office and appointment of a US-based technical team. Managing Director Matthew Allen has relocated to Houston to lead the team. In addition, Otto is pleased to announce the following technical appointments in Houston:

Will Armstrong – Vice President, Exploration and New Ventures

Philip Trajanovich – Senior Commercial Manager

Mark Sunwall – Senior Exploration Consultant

Kevin Small – Senior Exploration Consultant

The exploration team will be led by Will Armstrong, who has more than 30 years of experience across the Gulf of Mexico. Will's exploration work has seen the drilling of 162 prospects across his career at a commercial success rate in excess of 66%.

The exploration team have been engaged as consultants inside the Otto business since early 2018. This has involved the screening of a number of prospects and investment opportunities including the Hilcorp Gulf Coast package. As a result of this consulting work, and past experience, the exploration team are very familiar with the Company's current portfolio, screening criteria and focus area for potential prospects.

In addition, Otto has opened its office located at Two Allen Center in Houston Downtown. Refer to the ASX release of 16 July 2018 for further details.

Alaska Western Blocks

On 30 July 2018 Otto advised that, via its wholly owned subsidiary Borealis Alaska LLC, it had executed definitive agreements with Great Bear Petroleum Operating LLC, along with the Consortium Partners, 88 Energy Limited (Captivate Energy Alaska, Inc) and Red Emperor Resources NL, to acquire the majority of Great Bear's working interest in exchange for drilling a commitment well on the Western Blocks prior to 30 May 2019. Refer to the operational update above and Otto's ASX release of 25 June 2018 for the details of the agreement and Western Blocks opportunity.

On 29 August 2018 the Company announced that the operator Captivate Energy Alaska, Inc, (a 100% owned subsidiary of 88 Energy Limited) had executed a rig contract for the drilling of the Winx Prospect, located on the Western Blocks, North Slope of Alaska.

The Winx Prospect is a 3D seismic defined oil prospect in the successful Nanushuk play fairway with a gross mean unrisked prospective resource of 400MMbbls (75MMbbls net to Otto) and a geological chance of success in the range of 25-30%.

Hilcorp eight well farmin

On 31 July 2018 Otto advised that it had entered into a joint venture with Hilcorp Energy which will see it earn a 37.5% working interest in an eight well portfolio of prospects in the Onshore/Near Shore USA Gulf Coast (Gulf of Mexico). The wells will be drilled by Hilcorp, a highly experienced, privately-owned operator based in Houston, over the next 15 months

26. Events after the reporting period (continued)

Details of the Agreement

Under a Joint Exploration and Development Agreement (JEDA) with Hilcorp Energy Otto has committed to an eight well drilling program with an estimated cost of US$75 million (100%).

Otto will earn a 37.5% working interest by paying 50.0% of the costs of drilling and either setting casing or plugging and abandoning the well plus lease acquisition costs at each of the eight prospects. The estimated cost of the commitment to Otto is US$37.5 million. US$4 million was paid immediately to cover initial land and other costs.

Well Cap - Otto has the option to discontinue participation in each prospect well if actual costs exceed the approved expenditure budget by 20%. If Otto elects to not continue, it will forfeit rights to that prospect. If Otto proceeds, costs from then on will be at working interest percentages.

Program Cap - Once Otto has incurred a total amount relating to the initial eight wells of US$42.5m, it will have the option to elect (but not the obligation) to participate in the remaining undrilled prospects in the initial eight well program at working interest percentages. If Otto elects to not participate in any undrilled prospects, it will forfeit rights in those prospects.

Minimum Commitment – Should Otto not participate in one or more of the eight wells, it shall be liable for liquidated damages in the sum of US$1 million per prospect.

Additional Upside

Should either the Tarpon or Mustang prospects be successful then Otto has ground floor rights (ie pays only its working interest) to participate in the nearby Damsel and Corsair/Hellcat opportunities. These wells are in addition to the eight wells.

Under the JEDA Otto has a right of first offer to a subsequent Gulf Coast program, if Hilcorp elect to offer such a program to third parties.

About Hilcorp Energy

Founded in 1989, Hilcorp is one of the largest privately held oil and natural gas companies in North America. Hilcorp specializes in reinvigorating legacy oil and gas fields across North America; including in the US Gulf Coast, Alaska and the Rockies and currently produces approximately 325,000 boepd. To put this into context, Australia's largest oil and gas company, Woodside, produces ~230,000 boepd.

Hilcorp has nearly 2,000 employees and has been consistently recognized for its strong culture, values and ethics both within the firm and in the communities in which it operates.

Otto is very pleased to be partnering with a Gulf Coast operator with proven capability to take exploration prospects into production.

Impact on Strategy

Otto has a clear strategy to grow production in the Gulf of Mexico to 5,000 boepd by the end of 2020. More specifically Otto's target area for new opportunities lies within the Pliocene, Miocene and Oligocene reservoir systems of the US Gulf of Mexico shelf and Gulf Coast where capital costs are manageable for Otto and the availability of infrastructure means the time from discovery to production is short. Otto is deploying its experienced technical team to find attractive, low risk drill opportunities in this area to provide high-margin oil and gas production growth.

This growth strategy is underpinned by the strong production and cashflow from Otto's 50% owned SM 71 oil field in the Gulf of Mexico shelf.

26. Events after the reporting period (continued)

The Hilcorp eight well portfolio is a significant step toward the 5,000 boepd and puts Otto into partnership a large and well-respected operator in the region. In addition it offers further potential through follow-up drilling and a right of offer on further Hilcorp Gulf Coast farmouts.

Details of the Drilling Program

Information regarding the eight wells is set out in the table below. Note that on 30 August 2018 Otto announced that the Big Tex well commenced drilling. Further details are set out later in this subsequent events note.

Prospect Name	Planned Spud Date	Target Depth (TVD), ft	Rig Type	Working Interest (WI)	Net Revenue Interest (NRI)	Stratigraphic Interval	County/ Parish	Location
Big Tex	Sep-18	13,500	Barge	37.50%	29.51%	Tex	Plaquemines	Louisiana
Lightning	Oct-18	14,500	Land	37.50%	28.50%	Frio Tex Miss	Matagorda	Texas
Don Julio 2	Dec-18	11,500	Land	37.50%	28.50%	Oligocene	Chambers	Texas
Mustang	Jan-19	17,500	Land	37.50%	30.00%	Oligocene	Chambers	Texas
Beluga	May-19	13,000	Barge	37.50%	28.50%	Oligocene	Galveston Bay	Texas
Oil Lake	Jul-19	14,500	Land	37.50%	29.06%	Frio	Cameron	Louisiana
Tarpon	Jul-19	14,000	Barge	37.50%	29.06%	Oligocene	Galveston Bay	Texas
Mallard	Nov-19	11,000	Barge	37.50%	29.63%	Mid Miocene	Assumption	Louisiana

Prospective Resources

The range of prospective resources for each prospect is set out below.

Prospect Name	Working Interest	Net Revenue Interest	Probability of Success	Prospective Resources MMboe							
				100%				Otto Net Revenue Interest			
				P90	P50	Mean	P10	P90	P50	Mean	P10
Big Tex	37.50%	29.51%	54%	0.5	3.3	6.8	16.9	0.1	1.0	2.0	5.0
Lightning	37.50%	28.50%	45%	0.9	3.2	4.4	10.1	0.3	0.9	1.3	2.9
Don Julio 2	37.50%	28.50%	44%	0.7	2.5	4.0	9.6	0.2	0.7	1.1	2.7
Mustang	37.50%	30.00%	56%	2.9	6.7	8.5	16.8	0.8	1.9	2.6	4.8
Beluga	37.50%	28.50%	45%	0.8	2.9	4.7	11.2	0.2	0.9	1.3	3.4
Oil Lake	37.50%	29.06%	45%	1.2	3.3	4.4	9.3	0.3	1.0	1.3	2.7
Tarpon	37.50%	29.06%	34%	7.7	24.0	35.6	81.0	2.2	7.0	10.3	23.5
Mallard	37.50%	29.63%	64%	0.2	0.9	3.3	4.5	0.1	0.3	1.0	1.3

26. Events after the reporting period (continued)

Equity raising

On 31 July 2018 the Company announced it was undertaking a capital raising of approximately A$20 million via an institutional Placement and a fully-underwritten, accelerated non-renounceable Entitlement Offer to fund its US$37.5 million share of the drilling program. Refer above and to the ASX release of 31 July 2018 for details on the Gulf Coast Package of eight wells with Hilcorp.

The offer price of A$0.059 represented a:

- 7.8% discount to the last close of A$0.064 on Monday 30 July 2018;
- 9.5% discount to the 30 day VWAP; and
- 6.5% discount to TERP.

Placement

The Placement raised a total of A$10m through the issue of approximately 169.5 million shares at A$0.059 per share.

Institutional Entitlement Offer

The Institutional Entitlement Offer raised a total of A$3m through the issue of approximately 51.6 million shares at A$0.059 per share

The Institutional Entitlement Offer shortfall was strongly oversubscribed by institutional shareholders. Shares issued under the placement and Institutional Entitlement Offer were allotted on Friday 10 August 2018.

Retail Entitlement Offer

The retail component of the Entitlement Offer (Retail Entitlement Offer) provided eligible retail shareholders in Otto the opportunity to acquire 1 new share for every 9 shares held at the record date of 7.00pm (AEST) on 2 August 2018.

A$5.5 million (78%) of Entitlements were taken up leaving a Shortfall of A$1.5 million. A further A$6.0 million in subscriptions were received for Additional New Shares which was A$4.5 million in excess of the Shortfall of A$1.5 million, hence the A$4.5 million was refunded. The scale back was determined based on the pro-rata of the Additional New Shares applied for to the shareholder's entitlement as at the Record Date. Accordingly, given the Retail Entitlement Offer was oversubscribed, there was no allocation to underwriters.

A total of A$7 million was raised from the Retail Entitlement Offer through the issue of 118.5 million shares at A$0.059 per share.

New shares issued under the Retail Entitlement Offer were allotted on 29 August 2018.

As a result of the entitlement offer, the conversion price for the convertible notes reduced from A$0.055 to A$0.05484.

Bivouac Peak

On 9 July 2018 Otto announced that it had elected to participate in the initial test well, Weiss-Adler et. al. No. 1 ("Weiss-Adler#1"), on the Bivouac Peak East prospect.

The estimated cost for the 18,294 ft MD/18,000 ft TVD well is US$10.8 million (100% dry hole cost). Otto will earn a 40% working interest by paying 53.33% of the costs of the well to reach the earning depth or up to a cap of US$5.33 million, whichever occurs first, after which Otto will revert back to paying 40% of all future costs.

26. Events after the reporting period (continued)

The Bivouac Peak project area comprises two prospects, the East Prospect and the Deep Prospect. The total mapped gross 8/8ths prospective resources for the two combined prospects at Bivouac Peak are estimated at 16.0 million barrels of oil ("Mmbo") and 177.7 billion cubic feet of gas ("Bcf "), or 45.6 million barrels oil equivalent ("Mmboe")1 .

The Weiss-Adler #1 well is designed to test the Bivouac Peak East Prospect, targeting the regionally productive Miocene Cib Op section, with a mapped gross 8/8ths prospective resource of 11.3 MMbbls and 125.6 Bcf, or a combined 32.2MMboe. Although the East and the Deep prospects are independent, success at the East Prospect would provide positive seismic calibration, potentially reducing risk at the Deep Prospect as well.

On 27 August 2018 Otto announced that the Weiss-Adler #1 exploration well had commenced. The Parker Drilling Company Rig #77-B Deep Drilling 3000 HP Posted Barge Rig will drill to a depth of 18,294 ft Measured Depth ("MD")/18,000 ft True Vertical Depth ("TVD"). The well is expected to take approximately 75 days to reach total depth.

In case of success, completion and development costs to first production are currently estimated in the range of US$9.0-11.0 million (gross). Should the well be productive, it is currently estimated that this well would commence production within 8-10 months following drilling of the initial test well.

Big Tex spud

On 30 August 2018 Otto announced that the initial exploration well, SL 192 PP 031, on the Big Tex prospect had commenced drilling from a bargemounted rig.

The well will be drilled to 13,175 ft MD/12,700 ft TVD and is expected to take 55 days to reach total depth. Otto will earn a 37.5% working interest by paying 50% of the costs of drilling and either setting casing or plugging and abandoning the well, after which point Otto will pay 37.5% of all future costs. The well is expected to cost the Company US$4.23 million (50% paying interest). The exploration well on the Big Tex prospect is targeting the Tex W 16 Sand and Tex W 18 Sand that are Middle Miocene in age. This is a prolific section, having produced from the east in Hilcorp's East Bay Field, and from the west from the massive West Delta 30 Field, which has produced 562 MMBO and 934 BCF to date.

The success case development concept will be a flowline tieback to an existing platform. The prospect has been assessed as having a probability of success of 54%.

Nearly threefold reserve increase at SM 71

On 6 Aug 2018 Otto provided an update on the Company's reserves and resources position for its 50% owned South Marsh Island Block 71 ("SM 71") oil producing project, in the shallow waters of the Gulf of Mexico as independently assessed by Collarini Associates ("Collarini").

26. Events after the reporting period (continued)

The SM 71 reserves and resources as at 30 June 2018 are as follows:

SM 71	Gross (100%)			Otto Net (40.625%)		
	Oil (Mbbl)	Gas (MMscf)	MBoe	Oil (Mbbl)	Gas (MMscf)	MBoe
Proved Producing	3,466	2,130	3,821	1,408	865	1,552
Proved Behind Pipe	609	380	672	248	155	274
Proved Undeveloped	1,404	868	1,549	570	352	629
Proven (1P)	**5,479**	**3,378**	**6,042**	**2,226**	**1,372**	**2,455**
Probable	9,030	6,974	10,192	3,668	2,833	4,140
Proven Plus Probable (2P)	**14,509**	**10,352**	**16,234**	**5,894**	**4,205**	**6,595**
Possible	4,651	3,970	5,313	1,890	1,613	2,159
Proven Plus Probable Plus Possible (3P)	**19,160**	**14,322**	**21,547**	**7,784**	**5,818**	**8,754**
Total Prospective Resource (best estimate, unrisked)	954	47,687	8,902	387	19,373	3,616

The Collarini report is effective as of 30 June 2018 and is the first independent reserve report for the SM 71 project since production began in March 2018. All reserves quoted below are remaining reserves, excluding production of approximately 349,000 barrels of oil and 240 MMcf of gas (gross) through 30 June 2018.

Collarini has estimated an increase in 2P reserves of 4.3 MMboe net to Otto (excluding production to 30 June 2018) a near tripling of the 2017 2P reserves estimate.

The significant increase in all key reserve categories is directly due to the success of the appraisal and development drilling program in 2017/18. Both the thicker than expected net oil zones and exceptional well performance to date from the D5 producing sands in both the F1 and F3 wells are contributing factors to the positive additions and revisions to the Company's reserves. Further details on the material changes to reserves is set out below.

Proved and Probable Reserves - Net of Actual Production

The increase in proved and probable reserves is due to the successful SM 71 F2 ("F2") appraisal well drilled in December 2017 and the SM 71 F3 ("F3") development well drilled in January 2018. Significantly thicker than predicted oil bearing sands were logged in the drilling of the SM 71 F2 and F3 wells in the D5 Sand which has resulted in reserve additions and upgrades. Additionally, flow rates from the F1 and F3 wells have continued to exceed pre-start-up predictions resulting in positive revisions to expected recoveries.

Drilling of the B65 Sand in the SM 71 F2 well resulted in a positive reclassification of a portion of Prospective Resources to the Proved and Probable Reserves categories. Although the SM 71 F2 well has experienced premature pressure depletion, suggesting the well is in an isolated compartment, the reservoir is mapped well beyond the small drainage area of the SM 71 F2 well.

72% of the remaining proved and probable reserves are classified as developed or behind pipe with the balance classified as undeveloped.

26. Events after the reporting period (continued)

Possible Reserves

The increase in possible reserves at SM 71 is mainly due to:

a) Potential upside recoveries and drainage areas from the producing D5 reserves
b) The reclassification to possible reserves of a material proportion of the prospective resource previously attributed to the B65 Sand, and
c) the addition of the possible reserves attributed to the B65, J-1 and D5 sands as result of the development drilling in 2017/18.

Material Changes to Prospective Resources

The decrease in prospective resources is due to reclassification of all of the 2017 B65 Sand prospective resource into proved, probable and possible reserves in 2018 following successful discovery, appraisal and development drilling and some production.

SM 71 status

As at 19 September 2018, cumulative gross production was approximately 641,737 barrels of oil and 556 million cubic feet of gas, on a gross basis with no produced formation water. The current field sales rate as of 19 September 2018, was approximately 3,600 bopd and 6.0 mmcfgpd, on a gross basis after shrinkage at the sales meter. Recompletion of the F2 well from the B65 Sand to the B55 Sand is expected to commence during the last week of September 2018.

27. Parent entity disclosures

As at, and throughout the financial year ended 30 June 2018, the parent company of the Group was Otto Energy Limited.

	Parent entity	
	2018 US$'000	2017 US$'000
Summarised statement of profit or loss and other comprehensive income		
Loss for the year after tax	(5,486)	(3,419)
Total comprehensive loss for the year	(5,486)	(3,419)
Summarised statement of financial position		
Current assets	1,936	12,519
Non-current assets	51,185	25,367
Total assets	53,121	37,886
Current liabilities	12,471	672
Non-current liabilities	6	3
Total liabilities	12,477	675
Net assets	40,644	37,211
Total equity of the parent entity comprises:		
Share capital	90,704	81,895
Share based payments reserves	9,658	9,549
Foreign currency translation reserve	118	118
Accumulated losses	(59,836)	(54,351)
Total equity	40,644	37,211

27. Parent entity disclosures (continued)

Guarantees entered into by the parent in relation to the debts of its subsidiaries

Parent company guarantees are extended on a case by case basis. Otto Energy Limited has provided a number of performance guarantees for subsidiaries under the terms of joint operations operating agreements, participation agreements and agreements with Governments pertaining to oil & gas exploration.

Otto Energy Limited has a guarantee in place to Byron Energy Inc, for the performance of Otto Energy (Louisiana) LLC's obligations in relation to SM 71 and Bivouac Peak.

Contingent liabilities

The parent entity had no contingent liabilities as at 30 June 2018 and 30 June 2017 beyond those listed in Note 24

Commitments

The parent entity had no capital commitments as at 30 June 2018 and 30 June 2017. The parent entity has an operating lease on office premises on a month to month basis.

	2018 US$'000	2017 US$'000
Not later than 1 year	3	268
Later than 1 year but not later than 5 years	-	-
	3	268

Significant accounting policies

The accounting policies of the parent entity are consistent with those of the Group, except for the following: Investments in subsidiaries are accounted for at cost, less any impairment in the parent entity.

28. New accounting standards and interpretations

New, revised or amended Accounting Standards and Interpretations adopted by the Group
A number of new or amended standards became applicable for the current reporting period. The adoption of these Accounting standards however, did not have any significant impact on the financial performance or position of the Group. Any new, revised and amending Accounting Standards or Interpretations that are not yet mandatory have not been early adopted.

Standards issued but not yet effective
A number of new standards, amendment of standards and interpretations have recently been issued but are not yet effective and have not been adopted by the Group as at the financial reporting date.

The Group has reviewed these standards and interpretations, and with the exception of the items listed below for which the final impact is yet to be determined, none of the new or amended standards will significantly affect the Group's accounting policies, financial position or performance.

28. New accounting standards and interpretations (continued)

Reference and title	Summary	Application date of standard *	Application date for Group *
AASB 9 *Financial Instruments*	AASB 9 (December 2014) is a new Principal standard which replaces AASB 139. This new Principal version supersedes AASB 9 issued in December 2009 (as amended) and AASB 9 (issued in December 2010) and includes a model for classification and measurement, a single, forward-looking 'expected loss' impairment model and a substantially-reformed approach to hedge accounting. Based on an initial impact assessment, the new standard is not expected to significantly impact the financial statements.	1 January 2018	1 July 2018

Standards issued but not yet effective (continued)

Reference and title	Summary	Application date of standard *	Application date for Group *
AASB 15 *Revenue from Contracts with Customers*	AASB 15 provides a single, principles-based five-step model to be applied to all contracts with customers. Guidance is provided on topics such as the point at which revenue is recognised, accounting for variable consideration, costs of fulfilling and obtaining a contract and various related matters. New disclosures regarding revenue are also introduced. Based on an initial impact assessment, the new standard is not expected to significantly impact revenue recognition.	1 January 2018	1 July 2018
AASB 16 *Leases*	This Standard introduces a single lessee accounting model and requires a lessee to recognise assets and liabilities for all leases with a term of more than 12 months, unless the underlying asset is of low value. A lessee is required to recognise a right-of-use asset representing its right to use the underlying leased asset and a lease liability representing its obligation to make lease payments. Management are still in the process of assessing the potential impact the new standard may have on the financial statements.	1 January 2019	1 July 2019

* Designates the beginning of the applicable annual reporting period

DIRECTORS' DECLARATION

FOR THE YEAR ENDED 30 JUNE 2018

In accordance with a resolution of the Directors of Otto Energy Limited, I state that:

1. In the opinion of the Directors:
    a. the financial statements, notes and the additional disclosures included in the audited 2017 Remuneration Report, comply with Australian Accounting Standards (including Australian Accounting Interpretations) and the *Corporations Act 2001*;
    b. the financial statements and notes give a true and fair view of the financial position of the Group as at 30 June 2018 and of its performance for the year ended on that date;
    c. the financial statements and notes comply with International Financial Reporting Standards as disclosed in the 'Basis of Preparation' section within the notes to the 2018 Financial Report; and
    d. there are reasonable grounds to believe that the Company will be able to pay its debts as and when they become due and payable.
2. This declaration has been made after receiving the declarations required to be made to the Directors in accordance with section 295A of the *Corporations Act 2001* for the year ended 30 June 2018.

On behalf of the Board

I Macliver

Mr I Macliver
Director
21 September 2018

INDEPENDENT AUDITOR'S REPORT

FOR THE YEAR ENDED 30 JUNE 2018

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INDEPENDENT AUDITOR'S REPORT

To the members of Otto Energy Limited

Report on the Audit of the Financial Report

Opinion

We have audited the financial report of Otto Energy Limited (the Company) and its subsidiaries (the Group), which comprises the consolidated statement of financial position as at 30 June 2018, the consolidated statement of profit or loss and other comprehensive income, the consolidated statement of changes in equity and the consolidated statement of cash flows for the year then ended, and notes to the financial report, including a summary of significant accounting policies and the directors' declaration.

In our opinion the accompanying financial report of the Group, is in accordance with the *Corporations Act 2001*, including:

(i) Giving a true and fair view of the Group's financial position as at 30 June 2018 and of its financial performance for the year ended on that date; and

(ii) Complying with Australian Accounting Standards and the *Corporations Regulations 2001*.

Basis for opinion

We conducted our audit in accordance with Australian Auditing Standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the Financial Report* section of our report. We are independent of the Group in accordance with the *Corporations Act 2001* and the ethical requirements of the Accounting Professional and Ethical Standards Board's APES 110 *Code of Ethics for Professional Accountants* (the Code) that are relevant to our audit of the financial report in Australia. We have also fulfilled our other ethical responsibilities in accordance with the Code.

We confirm that the independence declaration required by the *Corporations Act 2001*, which has been given to the directors of the Company, would be in the same terms if given to the directors as at the time of this auditor's report.

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

Key audit matters

Key audit matters are those matters that, in our professional judgement, were of most significance in our audit of the financial report of the current period. These matters were addressed in the context of our audit of the financial report as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

BDO

Carrying Value of Oil and Gas Properties

Key audit matter	***How the matter was addressed in our audit***
The Group's carrying value of oil and gas properties as disclosed in note 12 is a key audit matter as the assessment of carrying value requires management to exercise judgement in identifying indicators of impairment for the purposes of determining whether the assets need to be tested for impairment.	We evaluated management's assessment of impairment indicators at 30 June 2018 in accordance with AASB 136: *Impairment of Assets*. Our work included but was not limited to the following procedures: • Obtaining and reviewing available reserve report data from the management's external expert to determine whether they indicate a significant change that would impact the value of the asset. This included assessing the competency and objectivity of management's expert; • Benchmarking and analysing management's oil and gas price assumptions against external market data, to determine whether they indicate a significant change that would impact the value of the asset; • Reviewing the Director's minutes and ASX announcements for evidence of consistency of information with management's assessment of the carrying value; • Considering whether there were any other facts and circumstances that existed to indicate impairment testing was required; and • Assessing the adequacy of the related disclosures in note 12 to the financial report.

Valuation of convertible notes derivatives

Key audit matter	*How the matter was addressed in our audit*
During the year Otto Energy Limited issued convertible notes to fund the Group's operations. The valuation of embedded derivatives associated with the US Dollar denominated convertible notes on issue is considered to be a key audit matter due to the following: • Judgements required by management in the selection of a suitable valuation methodology; • The inputs used and valuation method applied; and • The complexity of the accounting policy adopted by management. Refer to note 14 of the financial report for a description of the accounting policy and significant estimates and judgements applied to these transactions.	Our work included but was not limited to the following procedures: • Reviewing the relevant convertible note agreements; • Enquiring with management to understand the convertible note transactions; • Assessing whether management's assessment of the classification of the instrument was in accordance with the accounting standards; • Reviewing management's calculation carried out in respect of the valuation for debt and derivative components of instruments; • Assessing the appropriateness of the volatility and share price assumptions used in the Group's calculation of the derivative components of the instruments; and • Assessing the appropriateness of the disclosures included in note 14 to the financial statements.

Other information

The directors are responsible for the other information. The other information comprises the information in the Group's annual report for the year ended 30 June 2018, but does not include the financial report and the auditor's report thereon.

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

In connection with our audit of the financial report, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial report or our knowledge obtained in the audit or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of the directors for the Financial Report

The directors of the Company are responsible for the preparation of the financial report that gives a true and fair view in accordance with Australian Accounting Standards and the *Corporations Act 2001* and for such internal control as the directors determine is necessary to enable the preparation of the financial report that gives a true and fair view and is free from material misstatement, whether due to fraud or error.

In preparing the financial report, the directors are responsible for assessing the ability of the group to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the directors either intend to liquidate the Group or to cease operations, or has no realistic alternative but to do so.

Auditor's responsibilities for the audit of the Financial Report

Our objectives are to obtain reasonable assurance about whether the financial report as a whole is free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with the Australian Auditing Standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of this financial report.

A further description of our responsibilities for the audit of the financial report is located at the Auditing and Assurance Standards Board website (http://www.auasb.gov.au/Home.aspx) at: http://www.auasb.gov.au/auditors_responsibilities/ar1.pdf
This description forms part of our auditor's report.

Report on the Remuneration Report

Opinion on the Remuneration Report

We have audited the Remuneration Report included in pages 49 to 59 of the directors' report for the year ended 30 June 2018.

In our opinion, the Remuneration Report of Otto Energy Limited, for the year ended 30 June 2018, complies with section 300A of the *Corporations Act 2001*.

Responsibilities

The directors of the Company are responsible for the preparation and presentation of the Remuneration Report in accordance with section 300A of the *Corporations Act 2001*. Our responsibility is to express an opinion on the Remuneration Report, based on our audit conducted in accordance with Australian Auditing Standards.

BDO Audit (WA) Pty Ltd

BDO
J Prue

Jarrad Prue
Director

Perth, 21 September 2018

ADDITIONAL ASX INFORMATION
AS AT 7 SEPTEMBER 2018

Distribution of shareholdings

Range	Number of holders	Number of shares
1 – 1,000	124	25,684
1,001 – 5,000	242	769,622
5,001 – 10,000	529	4,386,755
10,001 – 100,000	2,622	108,840,328
100,001 and over	1,463	1,756,503,223
Total	4,980	1,870,525,612

Shareholders by location (31 August 2018)

	Number of holders	Number of shares
Australian holders	4,732	1,486,978,475
Overseas holders	257	383,547,137
	4,989	1,870,525,612

Unmarketable parcels

There were 535 shareholders holding less than a marketable parcel of shares.

Twenty largest shareholders

	Name	Ordinary shares	
		Number of shares	%
1	Molton Holdings Limited	305,859,697	16.35%
2	Perennial Value Management	118,673,345	6.34%
3	Citicorp Nominees Pty Limited	99,646,230	5.33%
4	J P Morgan Nominees Australia Limited	95,636,100	5.11%
5	HSBC Custody Nominees (Australia) Limited	52,266,506	2.79%
6	AMP Life Limited	33,583,462	1.80%
7	Safari Capital Pty Ltd	28,657,138	1.53%
8	National Nominees Limited	25,765,970	1.38%
9	BNP Paribas Nominees Pty Ltd <DB A/C>	24,392,331	1.30%
10	John Jetter (Consolidated Relevant Interest)	21,607,020	1.16%
11	BNP Paribas Noms Pty Ltd <DRP>	21,497,521	1.15%
12	Nero Resource Fund Pty Ltd	18,949,153	1.01%
13	BNP Paribas Nominees Pty Ltd <IB AU NOMS RETAILCLIENT DRP>	17,007,110	0.91%
14	DBS Vickers Securities (Singapore) Pte Ltd	14,020,833	0.75%
15	Mr Austin Sydney Evan Miller	12,203,389	0.65%
16	Ecapital Nominees Pty Ltd	12,000,000	0.64%
17	CS Fourth Nominees Pty Ltd	11,931,228	0.64%
18	Sphinx Holdings Ltd	9,126,587	0.49%
19	Debuscey Pty Ltd	8,501,292	0.45%
20	Mr Andrew McCrea Coulter & Mrs Sally Anne Travis	8,128,572	0.43%
		939,453,484	**50.22%**

Substantial shareholders

Name	Ordinary shares	
	Number of shares	%
Molton Holdings Limited	305,859,697	16.35
Perennial Value Management (IOOF)	118,673,345	6.77

Unquoted securities

The unlisted securities of the Company as at 7 September 2018 are 18,827,000 performance rights and 8,200,000 convertible notes. Neither the performance rights, nor the convertible notes, carry a right to vote at a general meeting of shareholders.

Performance Rights

Grant date	Expiry date	Exercise price	Number of performance rights	Number of holders
23 April 2015	31 December 2019	A$0.00	4,640,000	3
29 November 2017	29 November 2022	A$0.00	14,187,000	7
			18,827,000	

Convertible notes

As at 7 September 2018 there were 8,200,000 convertible notes on issue. Refer to the Appendix 3B released to ASX on 2 August 2017 for information on the terms. Refer also to Note 14 of the financial statements. Subsequent to year end, the conversion price of the notes reduced from A $0.055 to A$0.05484 as a result of the entitlement offer (ASX release of 31 July 2018).

Voting rights

Ordinary shares
In accordance with the Company's Constitution, on a show of hands every shareholder present in person or by proxy, attorney or representative of a shareholder has one vote and on a poll every shareholder present in person or by proxy, attorney or representative of a shareholder has in respect of fully paid shares, one vote for every share held.

Options
There were no options on issue as at the date of this Financial Report.

Performance rights
There are no voting rights attached to the performance rights.

Corporate Governance

The Company's Corporate Governance Statement for the 2018 financial year can be accessed at www.ottoenergy.com

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