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Creating value through exploration, development and production

Annual Report 2018

BYRONENERGY

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Contents

Byron Energy is focused on oil and gas exploration and development in the shallow water of the Gulf of Mexico, and the Transition Zone including the State Waters and adjacent coastline in the USA.

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SM71
April 2016 discovery on production in March 2017

3,600 Bopd
Production
SM71 currently producing approx. 3,600 Bopd and 6.0 Mmcfpd

2P 29.3 Mmboe
Reserves
1P (net) 11.1 Mmboe,
2P (net) 29.3 Mmboe and
3P (net) 41.4 Mmboe

134.5 Mmboe
Prospective Resources
(net) 134.5 Mmboe

SM71 Oil Field
SM71 Oil Field Discovery made possible through use of RTM seismic technology

Key
- SM71
- Exploration Blocks

Chairman's Letter

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During the past year we successfully completed the installation of the SM71 F platform and pipelines, drilled the F2 and F3 wells, both intersecting hydrocarbons as prognosed, and completed all three wells for production, including the F1, the SM71 discovery well.

US$9.5m
Net revenue 2018

29.3 Mmboe (net)
2P Reserves

134.5 Mmboe (net)
Prospective Reserves

Dear Shareholder,

The 2017/18 year was a very active and successful year for the Company, culminating in the commencement of production from our SM71 oil project. Joining the ranks of oil and gas producers in March 2018, was the most significant event in the Company's history, recognised by the sharemarket with the Company's share price increasing from A$0.095 per share, at 30 June 2017, to A$0.335 to close the 2018 financial year with a sharemarket capitalisation of A$243 million.

It was pleasing to see the share price rally strongly and reward all our shareholders, particularly those who supported our capital raising back in September 2017 when we raised A$28.5 million at A$0.07 per share, through a placement and a share purchase plan, to fund drilling and development at SM71.

During the past year we successfully completed the installation of the SM71 F platform and pipelines, drilled the F2 and F3 wells, both intersecting hydrocarbons as prognosed, and completed all three wells for production, including the F1, the SM71 discovery well.

Production from F1 and F2 wells commenced in late March 2018 while F3 commenced production in early April 2018. We had a relatively smooth start-up of production from our SM71 F platform with operational and facility issues in line with the types of issues associated with any new oil production facility.

For the year ended 30 June 2018, Byron's share of oil and gas production from SM71 was 141,611 barrels of oil and 122 mmbtu of gas (net to Byron) generating net revenue, after royalties and transportation costs of US$9.5 million.

Commencement of production at SM71 coincided with a three-year high for oil prices, with the WTI spot oil price finishing the financial year at US$74.13/bbl.

The production income from SM71 allows Byron to pursue further opportunities within our very exciting inventory of internally generated prospects and thereby expose shareholders to a further significant potential increase in value. In that regard, the first exploration well, the Byron operated Weiss-Adler, et. al. No. 1 well, on our Bivouac Peak Prospect Area commenced drilling operations on 25 August 2018. The well is expected to take approximately 75 days to reach total depth.

We continued to leverage our expertise in the Gulf of Mexico. Byron lodged bids on seven lease blocks bid at the Gulf of Mexico, Outer Continental Shelf ('OCS') Lease Sale 250 held in New Orleans, Louisiana on 21 March 2018.

All seven leases we bid on were awarded to Byron in May/June, comprising EI62/63/76/77, VR232/251, and SM70. EI62/63/76/77 (100% Byron) comprise the entire Eugene Island Block 77 Field, located offshore Louisiana, 110 miles southwest of New Orleans, LA in approximately 25 feet of water. This salt dome field has been a prolific oil and gas producer in the past, beginning in 1959 and with total gross cumulative production of 6.5 million barrels of oil and 361 billion cubic feet of gas from 13 pay sands. Bryon previously held the leases over EI63 and 76 but relinquished the leases in January 2018 with the intent of rebidding at Lease Sale 250. Proprietary RTM seismic processing, like that successfully utilised at SM71, was undertaken by Byron over the EI 77 salt dome in 2015 and defined a number of prospective areas.

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Three of the Lease Sale 250 blocks, VR232 (subject to a 50% farm-in from Otto), VR251 (100% Byron), and SM70 (100% Byron), are adjacent to the Byron operated SM71 discovery and substantially increase Byron's footprint in South Marsh Island Block 71 ('the South Marsh Island 73 Field'). Byron evaluated these blocks 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 SM71 in 2016.

Byron also holds 100% working interests in SM57, 59 and 74, acquired in the Gulf of Mexico, OCS Lease Sale 247 held in New Orleans, Louisiana on 22 March 2017.

We have now greatly expanded our footprint in the SM71 area where we now hold working interests in seven leases. By the end of 2018, we will have newly re-processed Reverse Time Migration seismic data and inversion data over all of these leases and expect to drill a well on SM74, in the first half of 2019.

As at 30 June 2018, Byron achieved our SM71 reserves nearly a three-fold increase in SM71 reserves, with SM71 2P remaining reserves, net to Byron, of 6.6 Mmboe at 30 June 2018, up from 2.3 Mmboe at 30 June 2017, a major achievement. Overall our 2P reserves as at 30 June 2018 stood at 29.3 Mmboe, net to Byron, up from 2.3 Mmboe in 2017, an outstanding result.

In addition to our 2P reserves, we have possible reserves of 4.6 million barrels of oil and 45 bcf of gas and prospective resources of 35.8 million barrels of oil and 592.2 bcf of gas, leaving us strongly positioned to grow 2P reserves and subsequent production through further successful drilling.

The increase in Byron's reserves and prospective resources in 2018 is a testament to the skill and experience of the Byron team.

In September 2017, Byron secured the services of key executives, Messrs Smith, Kallenberger and Sack for at least a further three years enabling the Company to access their technical and operational expertise in the Gulf of Mexico and their overall managerial skills. They are a very talented and experienced team of oil and gas professionals, having discovered and brought into production our SM71 oil project and acquired a portfolio of highly prospective exploration leases and thus positioned the Company for significant future growth in our area of focus in the shallow waters of the Gulf of Mexico.

Finally, on behalf of the Board, I would like to thank our shareholders for their continued support and also our dedicated team of executives, staff and contractors for their continued efforts. We look forward to next year with real excitement in anticipation of further success in the Gulf of Mexico.

Doug Battersby
Chairman

Message from the CEO

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Growing our business by leveraging the total control of both the generation and drilling of our prospects has always been in our DNA.

Dear Shareholder,

The Power and Benefits of Operatorship

This year our Company has made the transition from a small oil and gas explorer to a significant producer in the shallow waters of the Gulf of Mexico. Based on the last two months of production, Byron ranks 12th out of a total 119 current oil producers on the shelf of the Gulf of Mexico. Whilst this is an outstanding achievement, this result is based only on 50% of one project and I am confident that this is just the beginning of a long and successful program which will incrementally add significant shareholder value as each of Byron's future projects are brought into production.

Over the last ten years our highly experienced team have methodically collected and interpreted millions of dollars of geological and geophysical data using state of the art data processing technologies to identify thus far, a suite of 31 high quality, low to moderate risk, high impact prospects. These prospects are all contained within one onshore and 13 offshore leases which we now control as the designated operator. These 31 prospects are fully worked up, are drill ready and for the most part, Byron still retains a 100% ownership of each prospect. In order to ensure that all of these projects are drilled before the leases expire, we are about to embark on a very exciting and virtually continuous drilling program over the next two years. These opportunities and the strategic positioning we have achieved has come about due to the hard work and commitment of our extremely talented and versatile small team of professionals.

Perhaps the most underrated part of our strategy is maintaining the ability to operate. Last year I mentioned that the decision to become an operator was not taken lightly. Having been responsible for operations in the GOM before, we knew we were taking on a very serious responsibility which takes a great deal of time, effort and work to manage competently and professionally. The payoff for all of that effort is now about to bear fruit for all involved. Growing our business through the total control of both the generation, drilling and development of our prospects has always been in our DNA.

Being a well-regarded operator in the Gulf has many benefits, whether it be at the upstream or downstream stage of our business. As an explorer in the early phase of our evolution, being the originator of prospects gave us the technical freedom to use the most appropriate technology on a project by project basis to achieve the best interpretation possible and to take full advantage of our team's combined 140 years of Gulf of Mexico experience.

Now that we have moved to the drilling and production phase, operatorship gives us the ability to design our well plans and carefully pick prospect targets and bottom hole locations. This not only optimises our chances of drilling successful wells but also allows us to acquire important information that will help us make better decisions in the future. Additionally, we have the ability to access the leading and most competent contractors active in the Gulf today and leverage our good reputation to secure the best outcomes when negotiating contracts and pricing. Importantly we are also able to maintain control over all our expenditure including the day to day management of facilities and the production of the wells.

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Up to
10 Wells
Expected to be drilled over next three years

10 RTM Prospects
10 out of 30 low to moderate risk RTM prospects

Having said all this, perhaps the most underrated benefit of operating is being able to choose the order in which a company ultimately drills its prospects. We have started out cautiously with a high impact oil project at SM71 which is expected to provide us with good cash flow for years to come. The strong cash flow from the SM71 project has allowed us to keep more equity in SM74 and accelerate the drilling schedule for both SM74 and Bivouac Peak. Over the next three years, in addition to the drilling of Weiss-Adler, et al., #1 (the first Bivouac Peak well) and SM74 D-14 (the first SM74 well), we also plan to drill at least two wells (and possibly up to four wells) at EI62, 63, 76 & 77, at least two more development wells at SM71 (F4 & F5), when production begins to decline, and lastly the initial exploratory wells at SM59/SM57. All these wells fit the risk profile we typically pursue in the Gulf of Mexico and have considerable potential and upside. The combination of these factors, combined with operatorship, will set the company up for substantial future growth.

In order to maximise the risk dollars across multiple projects we have thus far used the promotion of a number of partner companies who pay a disproportionate share of the initial drilling dollars in order to earn an interest in our high quality projects. We carefully tailor the amount of equity we farm out on any given project to match the risk we assess on that particular project. The farm out market in the Gulf of Mexico has been strong and we expect this to be a continued part of our strategy as we move forward. We have also elected not to farm out to a single party but rather prefer to farm out to a number of companies so as to develop strong relationships both in Australia and the US. As our cash flow builds there will be some projects which we will undoubtedly choose not to farm out as risks are considered low relative to the possible rewards.

The exact timing of the drilling of all these projects will depend largely on the cash flow and success of each project as we go along. One of our goals at Byron is to not go back to capital markets to fund our program instead, we prefer to rely on cash flow and the benefit of operatorship to manage and control the pace of our program.

This promises to be an exciting time for the Company and as always, we appreciate our loyal shareholders and their continued support as we make our way through this very substantial program.

Maynard Smith
CEO

Review of Operations

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Introduction

In the 2018 financial year Byron performed strongly and made major strides forward in its strategy to build a substantial oil and gas exploration and production company in the shallow waters of the Gulf of Mexico.

Against a background of strengthening oil prices, the Company became an oil and gas producer at SM71, achieved a material increase in reserves and expanded its portfolio of oil and gas projects in the Gulf of Mexico.

Production summary

For the year ended 30 June 2018 Byron's share of production (net of royalties) was 141,611 barrels of oil and 122,050 mmbtu's of gas.

Production/sales	Quarter ended 30 June 2018	Year ended 30 June 2018	Year ended 30 June 2017
Net production (BYE share 40.625% net of royalty)			
Oil (bbls)	134,160	141,611	–
Gas (mmbtu)	116,950	122,050	–

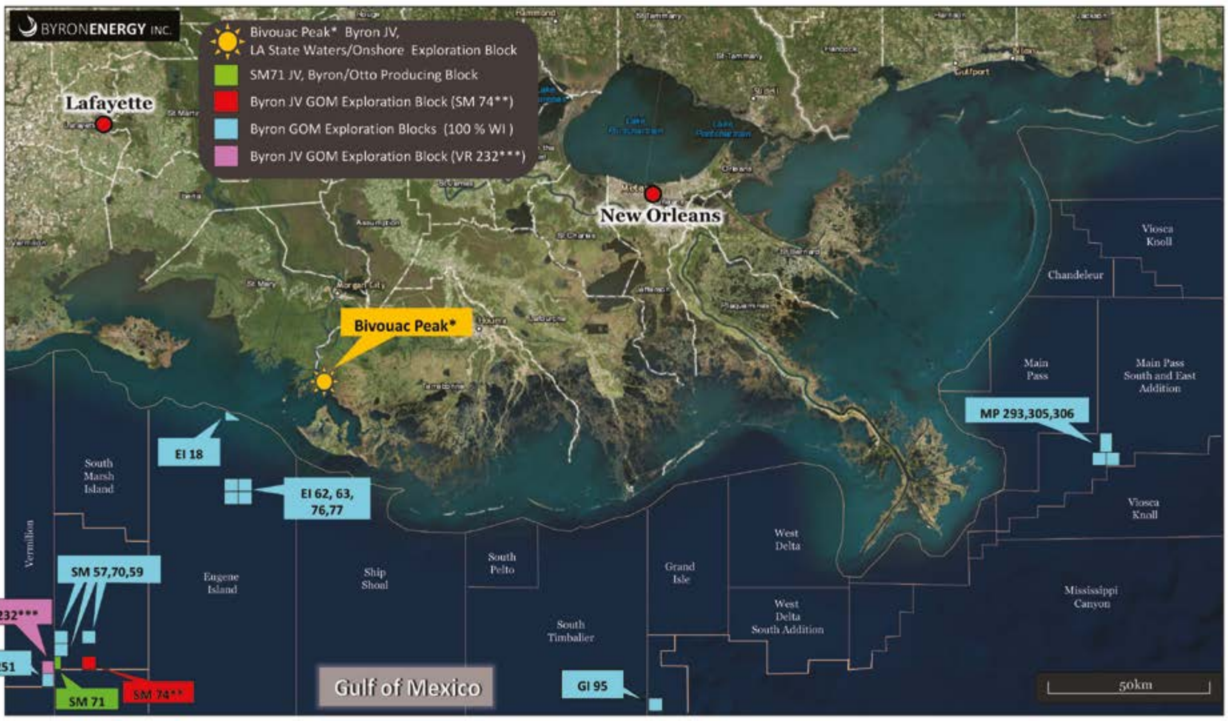
Reserves summary

Compared to the prior year, proved (1P) reserves, net to Byron, increased from 0.7 Mmboe to 11.1 Mmboe while proved and probable reserves (2P) increased from 2.3 Mmboe to 29.3 MMboe.

The increase in 1P, 2P and 3P reserves reflects the Company's successful development activites at SM71 and the acquisition of EI 62/63/76/77 and GI 95 leases.

Against a background of strengthening oil prices, the Company became an oil and gas producer at SM71, achieved a material increase in reserves and expanded its portfolio of oil and gas projects in the Gulf of Mexico.

Byron Energy Gulf of Mexico and Louisiana State Waters Lease Map



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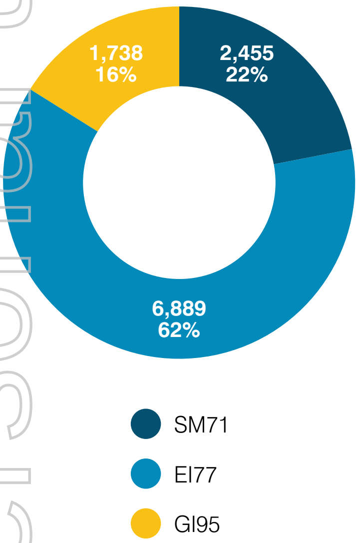
Byron Energy Limited: Reserves and Resources – Gulf of Mexico, Offshore Louisiana, USA

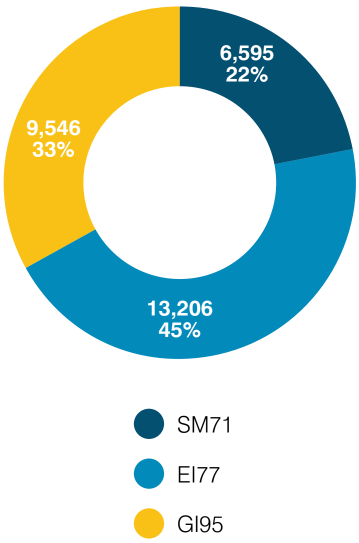
Remaining as at 30 June 2018 (net to Byron)	Oil Mbbl	Gas MMcf	Mboe (6:1)	% change
Reserves (developed and undeveloped)				
Proved (1P)	**3,029**	**48,317**	**11,082**	**1,610%**
Probable reserves	4,938	79,968	18,266	1,027%
Proved and probable (2P)	**7,967**	**128,285**	**29,348**	**1,193%**
Possible reserves	4,573	44,968	12,068	1,918%
Proved, probable and possible (3P)	**12,540**	**173,253**	**41,416**	**1,345%**
Total prospective resources Best Estimate (unrisked)	35,770	592,212	134,473	-0.4%

Byron Net 1P Reserve by Project
Mboe and % of total



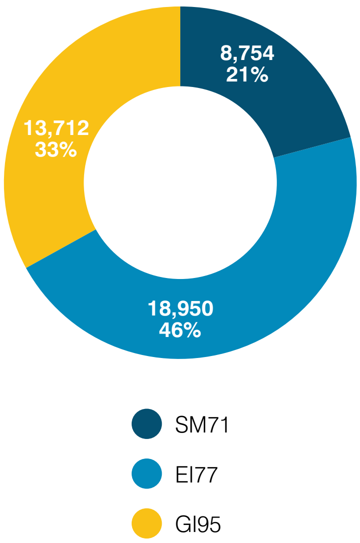
Total 1P Reserve
11,082 Mboe

Byron Net 2P Reserve by Project
Mboe and % of total



Total 2P Reserve
29,348 Mboe

Byron Net 3P Reserve by Project
Mboe and % of total



Total 3P Reserve
41,416 Mboe

Reserves – 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.

Conversion to boe – using a ratio of 6,000 cubic feet of natural gas to one barrel of oil – 6:1 conversion ratio is based on an energy equivalency conversion method and does not represent value equivalency.

Prospective Resource – The estimated quantities of petroleum that may potentially be recovered by the application of a future development project(s) relate to undiscovered accumulations. These estimates have both an associated risk of discovery and a risk of development. Further exploration appraisal and evaluation is required to determine the existence of a significant quantity of potentially moveable hydrocarbon.

The increase in 1P, 2P and 3P reserves reflects the Company's successful development activites at SM71 and the acquisition of EI 62/63/76/77 and GI 95 leases.

Oil and Gas Properties as at 30 June 2018 (Gulf of Mexico, Offshore Louisiana, USA)

Properties	Operator	Interest WI/NRI (%)	Lease Expiry	Lease Area (km^2)
South Marsh Island				
Block 71	Byron	50.00/40.625	Production	12.16
Block 57	Byron	100.00/81.25	June 2022	21.98
Block 59	Byron	100.00/81.25	June 2022	20.23
Block 74*	Byron	100.00/81.25 (70.00/56.875 post earning)	June 2022	20.23
Block 70	Byron	100.00/87.50	June 2023	22.13
Vermillion				
Block 232	Byron	50.00/43.75	June 2023	18.32
Block 251	Byron	100.00/87.50	June 2023	18.17
Eugene Island				
Block 18	Byron	100.00/78.75	April 2020	2.18
Block 62	Byron	100.00/87.50	June 2023	20.23
Block 63	Byron	100.00/87.50	June 2023	20.23
Block 76	Byron	100.00/87.50	June 2023	20.23
Block 77	Byron	100.00/87.50	June 2023	20.23
Grand Isle				
Block 95	Byron	100.00/87.50%	September 2022	18.37
Transition Zone (Coastal Marshlands, Louisiana)				
Bivouac Peak Private Landowner Leases**	Byron	93.00/69.285 currently (43.00/26.33 post earning)	September 2019	9.70
Bivouac Peak State Lease number 21778**	Byron	100/76.00 (43.00/32.68 post earning)	January 2021	0.81
Bivouac Peak State Lease number 21779**		100.00/72.50 (43.00/31.175 post earning)	January 2021	0.53

* Metgasco Limited ('Metagsco') has exercised its option to earn a 30% Working Interest ('WI') and 24.375% Net Revenue Interest ('NRI') in SM74. Metgasco has elected to participate to earn a 30% WI in the SM74 lease and the SM74 D-14 well by paying 40% of the cost of the well to casing point and 40% of the cost of the leasehold acquisition. Metgasco will also reimburse the Company for 30% of certain other acquisition expenses.

** Both Otto Energy Limited ('Otto') and Metgasco have exercised their options to earn a 40% and 10% working interest, respectively, in Byron's Bivouac Peak Landowner Leases and State Leases. If both Otto and Metgasco earn into the Bivouac Peak project, Byron's working interest and net revenue interest will be reduced to 43% and 32.035% respectively. Otto and Metgasco will earn a 40% and 10% working interest respectively by paying a disproportionate share of the costs of the initial test well to reach the earning depth or up to a cap of US$10.0 million (gross cost), whichever occurs first, after which Otto and Metgasco will revert back to paying 40% and 10% of all future costs

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Developed oil and gas properties

South Marsh Island 71

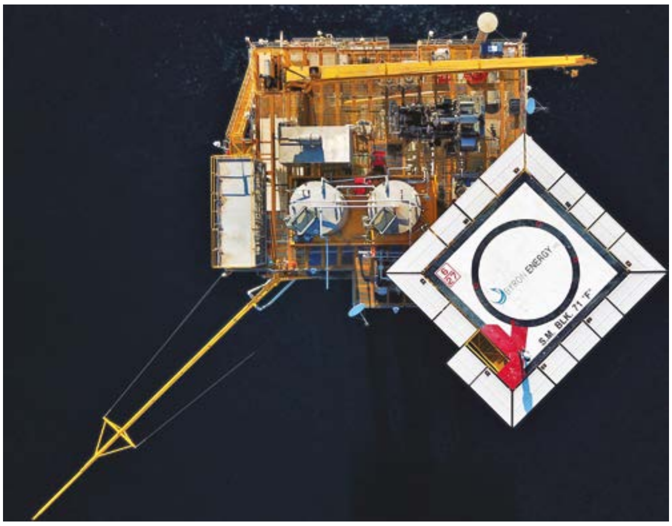
Byron owns the South Marsh Island block 71 ('SM71') a lease in the South Marsh Island Block 73 ('SM73') field. The SM73 field encompasses nine OCS lease blocks (81 square miles) which overlie a large piercement salt dome. The salt dome is responsible for providing the trapping mechanism for production in all portions of the SM73 field. The SM73 field is productive from discrete hydrocarbon-bearing sandstone reservoirs which are primarily trapped in three-way structural closures bound either by salt or stratigraphic thinning, on their updip edge. These reservoirs are Pleistocene to Pliocene age sands ranging in depth from 5,000 ft to 8,800 ft True Vertical Depth ('TVD'). The majority of the field production has come from depths less than 7,500 ft in high-quality sandstone reservoirs.

Byron is the designated operator of SM71 and owns a 50% Working Interest ('WI') and a 40.625% Net Revenue Interest ('NRI') in the block, with Otto Energy Limited group holding an equivalent WI and NRI in the block. Water depth in the area is approximately 137 ft.

The 2017/18 year was active and successful for Byron culminating in first oil production from the Byron operated SM71 oil platform.

South Marsh Island 71 (SM71) Project Summary

Joint Venture Partners	Byron Energy *Otto Energy*
Operator	Byron Energy Inc.
Water depth	40 metres (131 ft)
Previous SM71 production	3.9 mmbo + 10 bcf
Acquired	OCS Sale 222 June 2012
Byron interest	50% WI, 40.625% NRI
Byron #1 (F1) discovery well	April 2016, 132 TVT NFO
F Platform installation completed	November 2017
Byron F2 & F3	F2 November 2017, 205 TVT NFO F3 January 2018, 175 TVT NFO
Initial Production (Three Wells) F1, F2 & F3	F1 & F2 first prod. March 2018 F3 first prod. April 2018
Net 2P Reserves	6,596 Mboe



Review of Operations continued

SM71 Platform and Pipelines

In November 2017, Byron successfully completed the installation of the jacket and decks comprising the SM71 F Platform without safety or operational issues. The Tetra Hedron derrick barge was de-mobilised off location in late November 2017 after successfully placing the jacket and decks over the SM71 F1 well drilled in 2016 and securing the structure with pilings.

Operations to lay the 500 foot 4-inch oil and 7,000 foot 6-inch gas pipelines were also completed during October 2017. Each pipeline was initially laid and buried to within tie-in distance to Byron's SM71 F platform location and their respective sales lines. Final tie-in work at the platform end and sales lines was completed in December 2017 by dive crews soon after the jacket and decks were installed at the platform location in SM71.

SM71 Byron F2 Appraisal Well

The Ensco 68 jack-up rig spudded the Byron operated OCS G-34266 #F-2 well ('F2') on SM71, in early December 2017.

On 27 December 2017 Byron announced that the SM71 F2 appraisal well encountered four discrete hydrocarbon bearing sands, including the B65 and D5, and that the drill pipe became stuck approximately 214 feet below the bottom of the D5 Sand. Byron attempted to free the stuck drill pipe while evaluating various alternatives including the optimisation of the F2 wellbore and 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 an optimal take point in that reservoir. The F2 can also be used to produce the J1 Sand and B55 Sand after cessation of production in B65 Sand in the future.

In early January 2018, 7 5/8 inch casing was run before temporarily suspending the F2 well for a short period while the F3 well is drilled, before completing the F2 for production.

SM71 Byron F3 Development Well

Given the high-quality and thickness of the D5 Sand encountered in the F2 well and the fact that Byron had a one-time option to drill a second well under the Ensco drilling contract, it was decided to drill OCS G-34266 F3 well ('F3') well immediately using the Ensco 68 rig, rather than releasing the rig.

The F3 well was designed to intersect the D5 Sand very near the point that the F2 well intersected the D5 Sand. The F3 well was drilled to provide a second take point in the D5 Sand reservoir in addition to the updip F1 well, which was drilled in 2016. The engineering design of the F3 well allowed for a lower borehole angle of 24 degrees with shorter measured depth than the F2 well which had an angle of 60 degrees.

The F3 well spudded on 9 January 2018 USA Central Daylight Time ('USCDT').

The 2017/18 year was active and successful for Byron culminating in first oil production from the Byron operated SM71 oil platform.

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On 29 January 2018, Byron announced that the F3 well was drilled to a final total depth of 7,717 feet MD. After logging the well with open hole triple combo logging tools on 27 January, operations to run 7 5/8 inch casing to total depth prior to temporary suspension for completion in the D5 Sand commenced. Hydrocarbons in five discrete intervals were measured using both Log While Drilling ('LWD') gamma ray and resistivity tools and wireline Triple Combo porosity tools.

The primary target in the F3 well was the D5 Sand which logged 211 measured depth feet of oil pay (174 feet True Vertical Thickness ('TVT') net oil pay) as determined by open hole logs. While only 70 feet away from the previously drilled SM71 F2 well, the D5 Sand was 45 TVT feet thicker in the F3 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. This means the total oil column proven by the three Byron D5 wells is an astounding 1,160 feet. The F3 well was the second take point in the D5 Sand reservoir at SM71.

Because of the northerly well bore trajectory of the F3 well, only 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.

On 22 February 2018 Byron reported that the F1 well was completed for production.

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 SM71. Byron's 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.

SM71 F1, F2 and F3 Well Completions

(i) F1 Completion

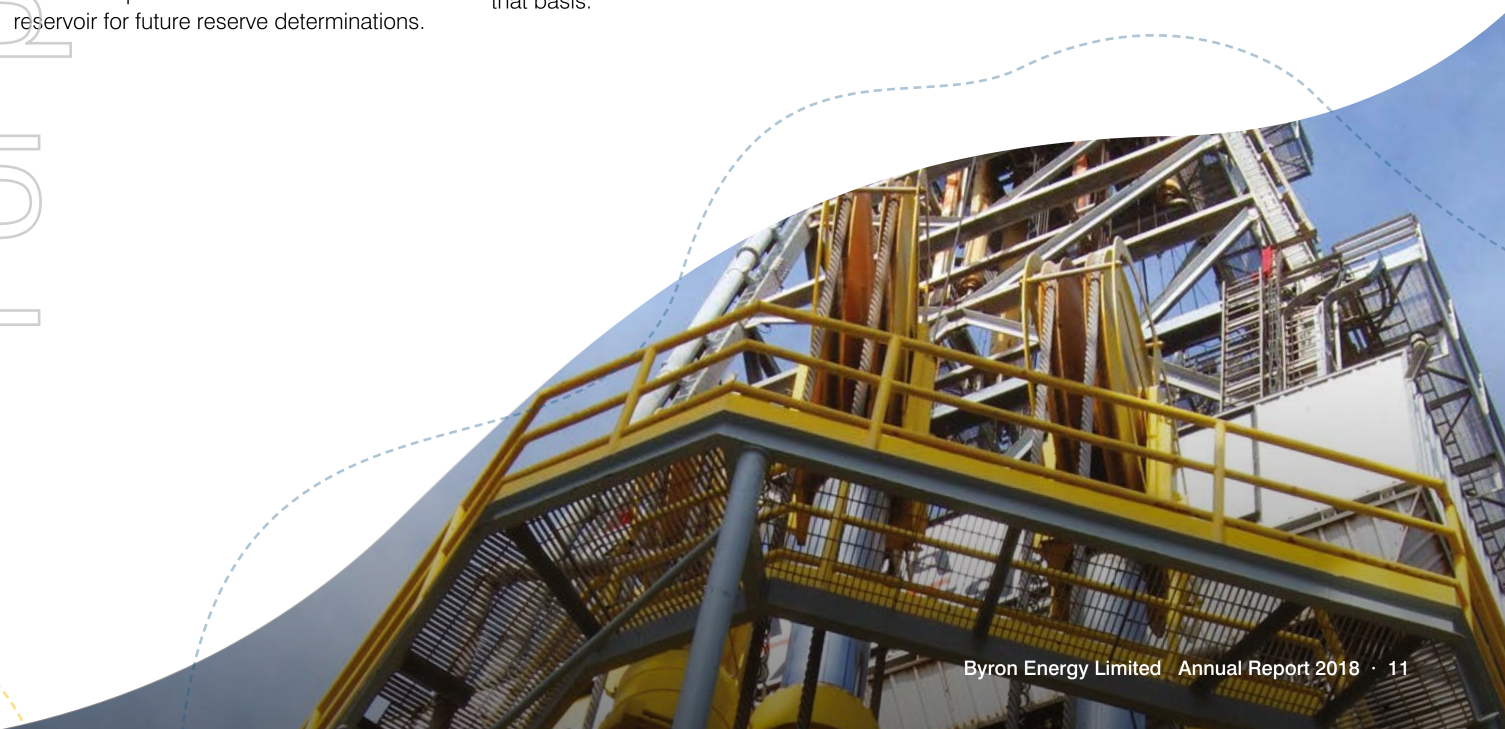
On 5 February 2018 Byron reported that the Ensco 68 drilling rig had been repositioned over the SM71 F1 well and operations to complete the F1 as a producing well in the D5 Sand had begun. This marked the end of drilling operations which began in early December 2017 and the commencement of a three well completion program, commencing with the SM71 F1 well.

The SM71 F1 well was drilled to a depth of 7,477 feet measured depth in April 2016 and logged a total of 151 feet of TVT net hydrocarbons in four discrete sands. The primary target in the F1 well was the D5 Sand, a prolific oil producing sand in other portions of the SM73 salt dome field. The F1 well logged 91 feet TVT net oil pay in the D5 Sand and Byron committed to construction of a manned tripod production facility on that basis.

On 22 February 2018 Byron reported that the F1 well was completed for production. A 70-foot MD interval of the D5 Sand was perforated on 16 February, 2018 and sand control measures were pumped across the interval on 18 February, 2018. After rigging down the pumping equipment, 2 7/8 inch production tubing was run in the well. All operations were successful and after a short flow back that recovered completion fluids and oil, the F1 well was shut in by closing a surface controlled subsurface safety valve. No production rates were determined during this phase of the F1 completion due to limited oil storage tank capacity on location.

(ii) F2 Completion

After completion of the F1 well, the Ensco 68 drilling rig skidded to position over the SM71 F2 well and completion operations in the B65 Sand began immediately. The B65 Sand in the F2 well was completed with sand control measures similar to the F1 well. These sand control measures are designed to improve the production rate and to minimise reservoir pressure drawdown, resulting in better performance and longevity.



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On 5 March 2018 Byron announced that perforation and sand control operations have concluded on the F2 well. A 72-foot measured depth interval of the B65 Sand was perforated on 26 February 2018 and sand control measures were pumped across the interval on 28 February 2018. After rigging down the pumping equipment, 2 7/8 inch production tubing was run in the well. After the production tubing was landed, a short flow back to recover completion fluids and oil occurred before the F2 well was shut in by closing a surface controlled subsurface safety valve. As per F1 well completion, no production rates were determined during the F2 well completion due to limited oil storage tank capacity on location.

(iii) F3 Completion

The Ensco 68 drilling rig then skidded into position over the SM71 F3 well and completion operations in the D5 Sand began.

A 184-foot interval of the D5 Sand was perforated and hydraulic sand control measures were pumped into the formation. After what appeared to be a normal and successful job, based on all surface pressure readings, the drill pipe became mechanically stuck across the packer, leaving the drill pipe and other completion equipment in the wellbore. Attempts to pull this assembly free were unsuccessful. Because of the fragile nature of this type of equipment, it was considered imprudent to pull extremely hard on the stuck assembly. The Company then mobilised coiled tubing equipment to the location to clean out the drill pipe and then attempt to pull it free with jarring equipment.

On 29 March 2018, the final 290-foot-long portion of the collapsed completion assembly was successfully and completely removed from the SM71 F3 wellbore during fishing operations. Operations then focused on finalising the F3 well for production from the D5 Sand reservoir where over 200 feet of measured depth oil pay (174 feet true vertical depth thickness) was logged during drilling in January 2018.

The Haliburton Stim Star IV returned to SM71 on 31 March 2018 USCDT and a high rate water pack was performed to place sand on the backside of the completion screens. The operation was successful and the well responded positively to the process. In Monday, 2 April 2018 USCDT, 2 7/8 inch production tubing was run and landed into a completion packer inside the wellbore.

The F3 well was opened to flowback equipment on the Ensco 68 rig for an initial clean-up on Tuesday, 3 April 2018 USCDT. No production rates were established from the F3 well at that time, due to limited oil tankage on the rig. Once the flowback was accomplished, the Ensco 68 began the process of de-rigging and jacking down before it was released. The Company then made the final flowline tie-ins to the F3 well and installed instrumentation equipment so that production could commence.

SM71 Production

Production from the Byron operated SM71 F platform began on 23 March 2018 when the SM71 F1 and F2 wells were opened to sales. The SM71 F3 began production on 6 April 2018.

During a four-day pipeline shut in period in April, the Company made several improvements to the oil and gas production system on the platform. Most of these improvements were focused on resizing valves to optimise production levels and minimise downtime on the platform. All three wells were returned to production on 22 April 2018 at a combined gross average rate of 4,650 bopd and 3,200 mcfgpd which is over 90% of the platform's throughput capacity.

Operationally, the ENSCO 68 drilling rig was released on Sunday, 8 April 2018 USCDT and left the location 02.00 hours on 9 April 2018 USCDT when weather conditions allowed transit.

For the year ended 30 June 2018 gross and net production is shown in the table below.

The Company's production for the June 2018 quarter was affected by the shut in of the third-party oil pipeline. Crimson Gulf, LLC, the operator of the oil pipeline that carries SM71 oil to market, undertook maintenance on sections of the oil pipeline commencing on 19 April 2018 which lasted four days. As a result Byron's SM71 wells were offline during that time and resumed production on 22 April 2018 USCDT.

Production/sales	For the year ended 30 June 2018	For the year ended 30 June 2017
Gross production		
Oil (bbls)	348,581	–
Gas (mmbtu)	300,430	–
Byron share of gross production (50% working interest)		
Oil (bbls)	174,291	–
Gas (mmbtu)	150,215	–
Net production (BYE share 40.625% net of royalty)		
Oil (bbls)	141,611	–
Gas (mmtu)	122,050	–

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As announced on 18 May 2018, Byron conducted Flowing Bottom Hole Pressure/ Shutin Bottom Hole Pressure ('FBHP/SBHP') tests on the SM71 F, F2 and F3 wells to further evaluate well performance.

Based on final analysis of the FBHP/SBHP survey data, several general conclusions can be drawn for each reservoir.

D5 Sand (F1 and F3 wells) – The FBHP/ SBHP survey data indicated that the F1 and F3 well intersections of the D5 Sand are entirely consistent with the Company's pre-drill mapping and expectations. The SM71 F1 and F3 wells, were performing to expectations and overall production rates would be largely unaffected by the shut in of the F2 well

B65 Sand (F2 well) – The FBHP/SBHP data from the F2 well indicated that there was no near wellbore damage and the B65 Sand reservoir also had high permeability. However, the F2 well was experiencing reservoir pressure depletion. The FBHP/ SBHP data indicated the B65 Sand had lost over 50% of its initial reservoir pressure and as the pressure dropped, so did daily oil and gas rates. Since the announcement of 18 May, pressure continued to decline, resulting in declining production rates. To date, 32,466 barrels of oil and 60.9 million cubic feet of gas and no barrels of water have been recovered from the B65 Sand in the SM71 F2 well. This data, along with pressure data indicates an estimated trap size of 3 acres, whereas the targeted seismic anomaly size was 175 acres. This provides strong evidence that the B65 Sand intersected by F2 is isolated from the main B65 Sand target area. The F2 well was recently shut in to analyse the pressure build-up of the well and was brought back online on 2 July 2018 USCDT. After flowing for approximately 8 hours, the F2 well ceased production of hydrocarbons and was shut in.

As reported previously, the SM71 F2 has two remaining hydrocarbon zones, the B55 and J1 Sands with 50,000 to 100,000 barrels expected to be recovered from each zone.

As reported previously, the SM71 F2 well has two remaining hydrocarbon bearing zones, the B55 and J1 Sands. The Company will initially perforate the B55 Sand and verify that economic flow rates can be achieved. When the B55 Sand ultimately ceases production, the J1 Sand would be recompleted before the Company will propose redrilling the well to the main B65 Sand area. The initial B55 Sand recompletion work is expected to take place prior to the end of 31 December 2018.

The B65 Sand is one of many focus areas of the recently announced seismic processing project Byron is undertaking with Schlumberger's subsidiary WesternGeco (see SM71 Project Area 3D Seismic Processing Project below) to help determine the placement of future wells.

Exploration and evaluation assets

Lease Sale 249 and Lease Sale 250

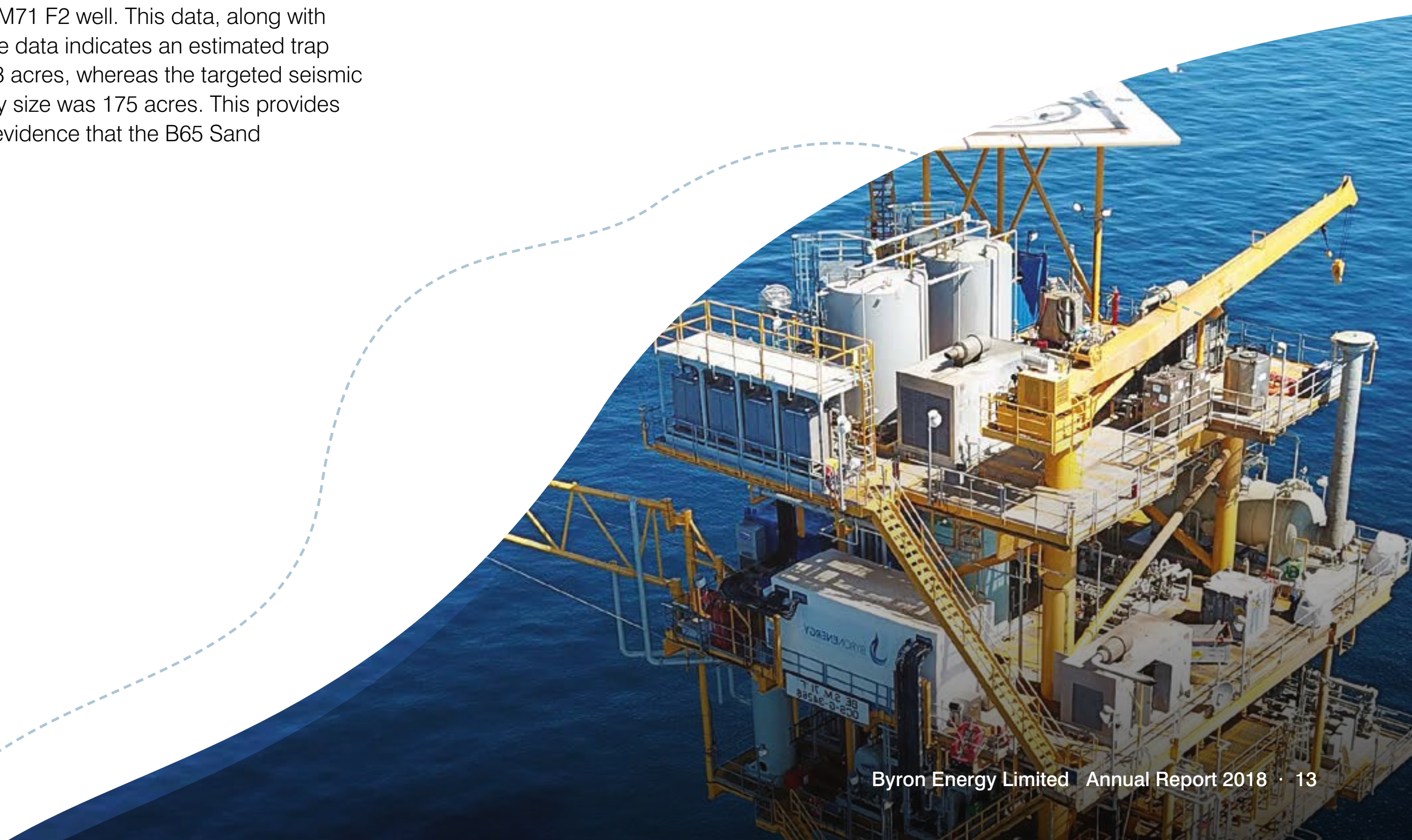
During the year ended 30 June 2018, Byron participated in two Gulf of Mexico, Outer Continental Shelf ('OCS') lease sales conducted by the Bureau of Ocean Energy Management ('BOEM'), the Gulf of Mexico, OCS Lease Sale 249 ('Lease Sale 249') held on 16 August 2017 and the Gulf of Mexico, OCS Lease Sale 250 ('Lease Sale 250') held on 21 March 2018, both held in New Orleans, Louisiana.

Byron was awarded Grand Island 95 the sole block bid by the Company at Lease Sale 249.

Byron also bid on and was subsequently awarded seven blocks at Lease Sale 250, comprising Vermilion blocks 232 & 251, South Marsh Island 70 and Eugene Island blocks 62, 63, 76 and 77. The prospects identified in these seven blocks, in and around salt domes, were generated by interpretation of the Company's high-quality RTM and Inversion processed 3D seismic data.

The BOEM reduced the OCS royalty rate from 18.75% to 12.5% for shallow water blocks starting with Lease Sale 249.

All of the blocks acquired by Byron at Lease Sale 249 and Lease Sale 250 are briefly described below.



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SM71 Project Area

The BOEM awarded Byron three leases comprising South Marsh Island Area Block 57 ('SM57'), South Marsh Island Area Block 59 ('SM59') and South Marsh Island Area South Addition Block 74 ('SM74') at the Central Gulf of Mexico, OCS Lease Sale 247 held on 22 March, 2017 in New Orleans, Louisiana.

The SM57/59/74 blocks increased Byron's footprint near Byron's existing SM71 discovery in the greater SM73 Field. The associated prospects and resulting leases were generated by the interpretation of Byron's high quality Reverse Time Migration ('RTM') and Inversion processed 3D seismic data set.

(a) SM74

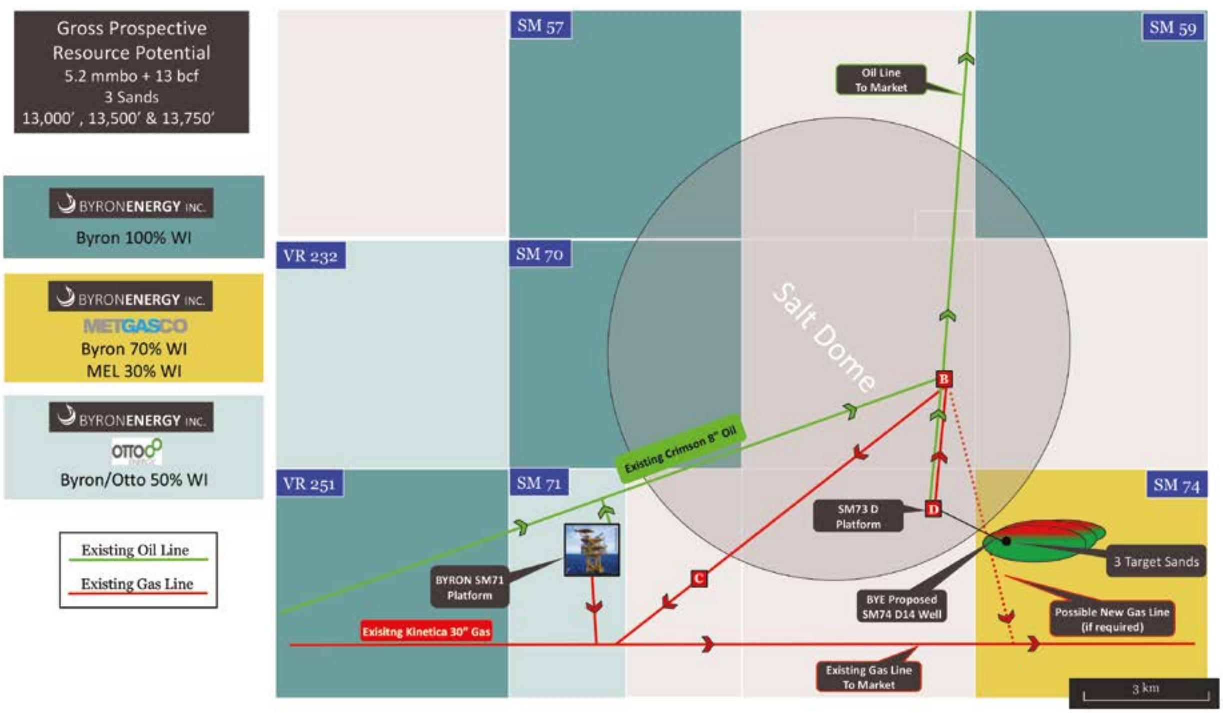
Byron has exchanged signed agreements for 'Platform Use' and 'Production Handling' with the offset operator at SM73 which will allow the company to utilise the 'SM73 D Platform' to drill the first well on SM74 (D-14) and also to process and sell the produced hydrocarbons, assuming a commercial well.

The drilling of the SM74 D-14 well from an existing platform is highly advantageous as both the development cost and cycle time to first production will be significantly reduced if successful.

Based on Byron's recent SM71 development it is estimated as much as US$20 million and 12 to 15 months of cycle time could be saved through the elimination of the construction and installation of a stand-alone production facility on SM74. The reduction of potential development costs lowers the economic threshold and significantly improves the financial return. Byron has further secured an option to drill a second well off the SM73 D platform, should any discovery warrant additional development drilling.

Having regard to its overall funding requirements, Byron has reduced its capital commitment to the SM74 D-14 well to 60% by offering Metgasco Limited ('Metgasco'), a substantial shareholder in Byron, the right to participate for a 30% WI in SM74 under standard industry farm-in terms. Metgasco has formally elected to participate to earn a 30% WI in the SM74 lease and the SM74 D-14 well by paying 40% of the cost of the well to casing point and 40% of the cost of the leasehold acquisition. Metgasco will also reimburse the Company for 30% of certain other acquisition expenses.

SM74 Project Map



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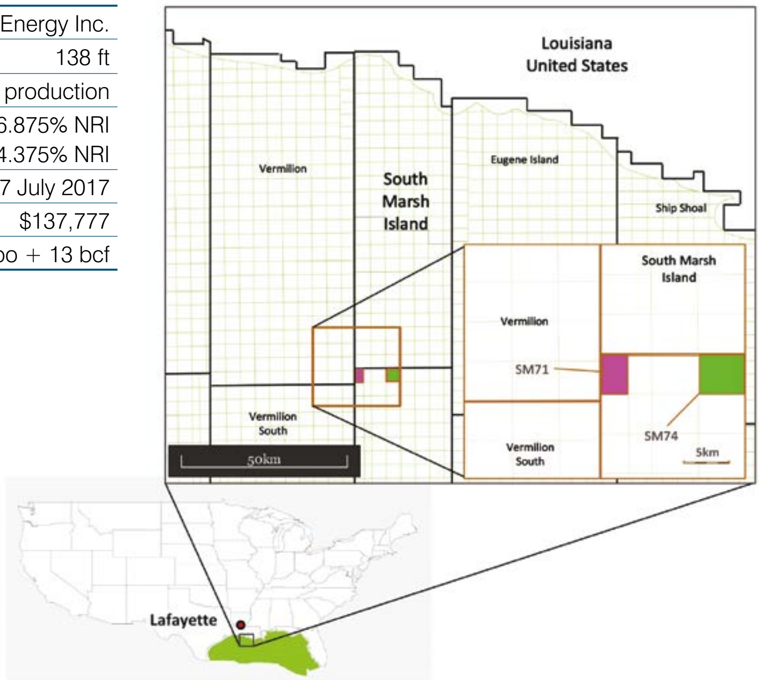
South Marsh Island 74 – Project Summary

Operator	Byron Energy Inc.
Water depth	138 ft
Previous production	No previous production
Byron Energy Inc. interest Metgasco Ltd interest	70% WI, 56.875% NRI 30% WI, 24.375% NRI
Acquired	OCS sale 247 July 2017
Lease bonus (sale 247)	$137,777
Collarini prospective gross resource	5.2 mmbo + 13 bcf



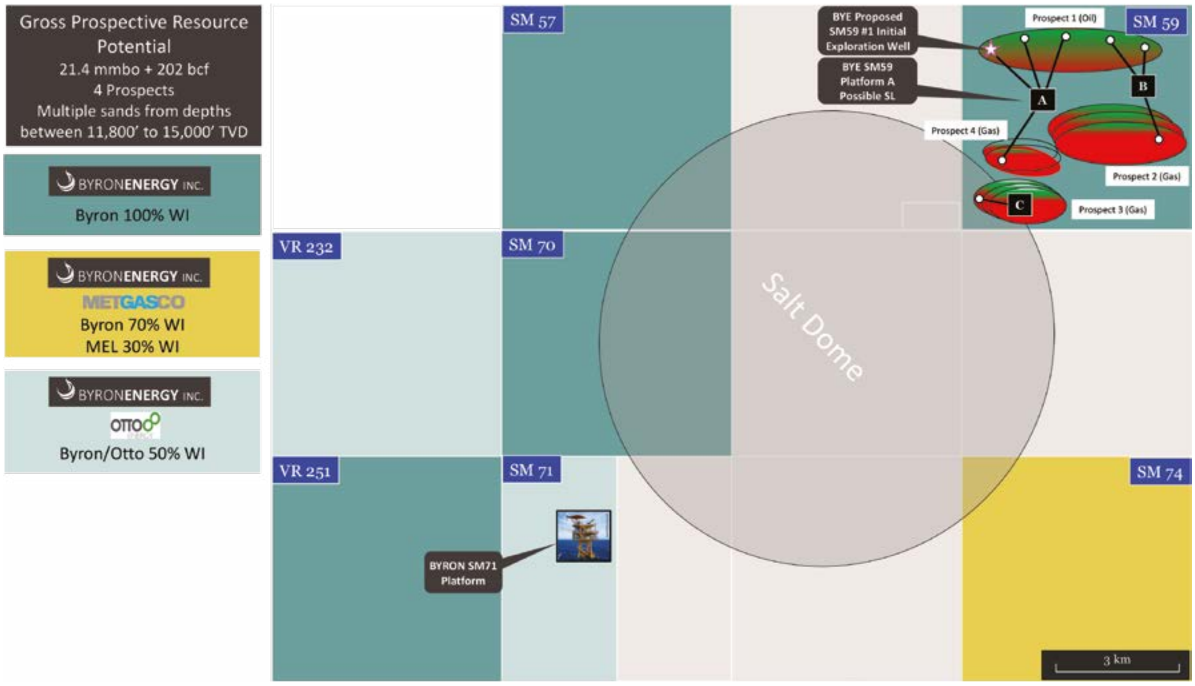
The SM74 D-14 well will be operated by Byron and will be directionally drilled from the 'L' slot on the SM73 D platform to a total depth of 16,464 feet MD (14,741 feet TVD). The SM74 D-14 well will test three stacked seismic amplitude (see illustration 3) supported targets defined by Byron using the same RTM seismic data used to make the Company's nearby SM71 oil discovery in 2016. The three target sands have a combined gross reserve potential of 5.2 million barrels of oil and 13.2 billion cubic feet of gas as reported in the Company's third-party reserve report, prepared by Collarini and Associates, released to the ASX on 19 September 2018.

The estimated cost to drill the SM74 D-14 well is US$11 million, of which US$6.6 million will be borne by Byron and US$4.4 million will be borne by Metgasco. Byron is currently in negotiations for a drilling rig suitable for the well. The necessary permits have been submitted to the BOEM and Byron is awaiting final approval. The well is anticipated to take 40 days to reach total depth. The same rig is expected to remain on location for completion operations which are currently estimated to be US$3.5 million.

If the SM74 D-14 well is successful, produced hydrocarbons will flow from the SM73 D platform to the SM69 B Platform where separation and processing will occur. Oil and gas will then be sold through the same Crimson and Kinetica systems serving the SM71 F Platform, however no SM71 F Platform facilities will be utilised in the SM74 project. A new gas sales pipeline may be required to transport gas from SM69 B to a nearby Kinetica tie-in point. Otherwise, only new separation equipment and additional metering will be required on the SM69 B platform. Total pipeline and facility costs are estimated to be US$4 million and it is estimated that first production could occur six months after drilling and well completion operations are finished.

If the SM74 D-14 well is successful, produced hydrocarbons will flow from the SM73 D platform to the SM69 B Platform where separation and processing will occur.

SM59 Project Map



(b) SM59

SM59 is located on the northeastern flank of the 'SM73 Field' salt dome in 138 feet of water and approximately ten kilometres Northeast of Byron's SM71 discovery. To date, the 'SM73 Field' has produced over 116 Mmbo and 375 BCF of gas.

Byron is targeting four RTM amplitude supported prospects contained within a number of isolated trapping fault block. Target depths of sands contained within these four prospects range from 11,800 feet to 15,000 feet TVD Collarini Associates has assigned an estimated Prospective Resource' of 21.4 mmbo + 202 bcf of gas to SM59. The first well on SM59 will target a large normally pressured oil prospect, which could potentially contain over 19 MMBO. Byron's current projected timeline schedules the initial SM59 #1 test well for May 2020. The cost to drill and complete the SM59 #1 well is currently estimated to be approximately US$ 13.5 million with 'Platform A' facility and pipelines costs currently around US$ 37.0 million. At least eight wells and a further two satellite facilities 'Platform B' and 'Platform C', will be required to fully develop the SM59 project. Byron currently retains a 100% working interest and 81.25% net revenue interest in SM59.

(c) Vermilion blocks 232&251 and SM70

In June 2018 the BOEM awarded Byron Vermilion 232 ('VR232'), Vermilion 251 ('VR251'), and South Marsh Island 70 ('SM70') blocks bid for at Lease Sale 250.

The Company bid $US1.1 million for VR232 as the lease bonus amount. Byron's bid for VR 232 in OCS Lease Sale 247, in March 2017, was rejected and this bid amount represented the value placed on the block by BOEM. As reported in the Company's ASX release dated 20 June 2018, 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 the Byron operated SM71 F platform, but there are currently no plans to drill VR 232 until production levels at the platform allow it to be produced efficiently in the event of success. In addition, the Company has identified two other higher risk/higher reward exploration prospects on VR232 which require further geophysical evaluation before a drilling decision is made.

Pursuant to the Participation Agreement, effective 1 December 2015, between Byron Energy Inc, and Otto Energy (Louisiana) LLC ('Otto'), a wholly owned subsidiary of Otto Energy Limited, Otto has elected to participate in the acquisition of VR 232 for 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%)

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interest share of acquisition costs, which includes the dry hole cost of the initial test well, plus a gross fifty percent (50%) of other past costs paid by Byron. In electing to participate in VR232, each company will own a 50% Working Interest and a 43.75% Net Revenue Interest in the block. Upon election to participate in VR232, Otto has no further rights to participate in any blocks or projects, including SM74, under the December 2015 Participation Agreement.

Byron has identified several higher risk exploratory leads on both VR251 and SM70. These leads will be evaluated once Byron completes its SM71 project seismic reprocessing work in late 2018 (see SM71 Project Area 3D Seismic Processing Project below). Byron placed a bid of US$225,520 for the 5,000 acre VR251 block and a bid of US$273,370 for the 5,468 acre SM70 block.

(c) SM71 Project Area 3D Seismic Processing Project

During the June 2018 quarter Byron executed an agreement with WesternGeco, a Schlumberger subsidiary, to add additional licensed 3D seismic data to its in-house data inventory and to perform new, high effort seismic data processing over the SM71 project area in the Gulf of Mexico.

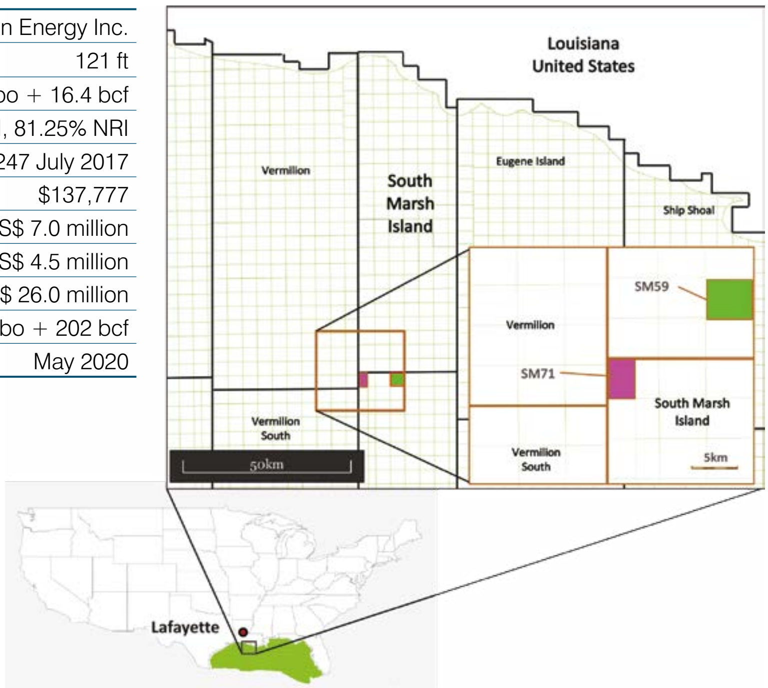
Byron will increase its contiguous 3D seismic data coverage in the SM71 project area to a total of 172 square miles (445 square kilometres) or 22 OCS lease blocks of high-quality 3D seismic. Under the agreement, WesternGeco will also reprocess the data using third generation, high frequency RTM and Kirchhoff PreStack depth migration algorithms to produce broadband, high-quality seismic imaging.

This will improve the stratigraphic definition within the SM71 project area which is a key to future drilling success. The scope of work is custom-tailored to Byron's imaging objectives adjacent to the SM71 salt dome and is the largest seismic processing project the Company has ever undertaken.

Additional processing work will involve high resolution PreStack inversion processing and reservoir characterisation imaging. This data will be used to further evaluate the producing intervals at SM71 and de-risk other prospects on Byron's acreage within the project area.

South Marsh Island 59 – Project Summary

Operator	Byron Energy Inc.
Water depth	121 ft
Previous production	282 mbo + 16.4 bcf
Byron Energy Inc. Interest	100% WI, 81.25% NRI
Acquired	OCS sale 247 July 2017
Lease bonus (sale 247)	$137,777
Byron SM59 #1 drill costs (dry hole)	US$ 7.0 million
Completion costs	US$ 4.5 million
Pipeline and facility costs	US$ 26.0 million
Collarini prospective resource (gross)	21.4 mmbo + 202 bcf
Current projected SM59 #1 Spud Date	May 2020



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Schlumberger, through WesternGeco, has long been a worldwide leader in seismic data processing and their RTM processed data played a key role in Byron's oil discovery at SM71. The SM71 project contains Byron's cornerstone oil and gas producing asset at SM71. In May 2016, Byron drilled the initial SM71 F1 well which led to the construction and installation of the Company operated SM71 F Platform in November 2017. Beginning in December 2017, Byron drilled two additional wells and subsequently completed the SM71 F1, F2 and F3 wells for production.

Given the success of the SM71 wells, Byron has decided to expand its coverage of both RTM data and inversion processing and take advantage of new processing algorithms offered by WesternGeco for both products.

Additional processing deliverables will include RTM and Kirchhoff based Common Depth Point ('CDP') angle gathers and offset stacks for Amplitude Verses Offset ('AVO') analysis and a new suite of seismic inversion products to aid in reservoir characterisation and understanding.

The processing portion of the project began in June and is expected to take about 6 months to complete. In the interim, Byron has taken delivery of existing data products and has begun evaluating the data. Byron personnel will be closely involved in the processing undertaken by WesternGeco.

Following the Company's success at Lease Sale 250, Byron now holds leasehold rights (as operator) to seven OCS blocks. Six blocks are unleased in the project area and the remaining blocks are held by production. Oil and gas production in the project area has totalled 137 million barrels of oil and 2.2 trillion cubic feet of gas.

Bivouac Peak Prospect Area

The Bivouac Peak Prospect Area is located in the highly productive transitional zone comprising the northernmost shallow waters of the Louisiana State Waters, and onshore coastal Louisiana.

Byron is the operator of the Bivouac Peak Prospect area, through its wholly owned by subsidiary Byron Energy Inc. The Bivouac Peak Prospect Area comprises onshore/marshland leases from:

(a) private landowners over approximately 2,400 contiguous acres (9.7 square kilometres) along the southern Louisiana Gulf Coast inboard of Byron's existing shallow water projects in the Federal OCS leasing areas; and

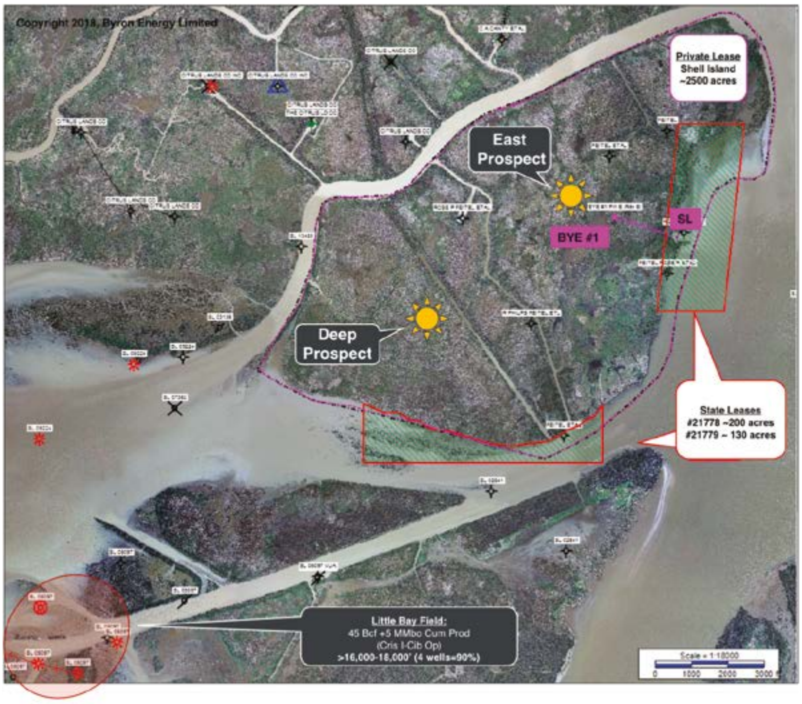
(b) two peripheral, non-core tracts adjoining the Bivouac Peak lease at the Louisiana State lease sale and subsequently awarded State Lease #21778 (~200 acres), with a state royalty rate of 21.5% and an overriding royalty of 2.5%, and State Lease #21779 (~130 acres).

In June 2018 Byron proposed and, Otto, Metgasco, and NOLA Oil and Gas Ventures LLC ('NOLA') have all elected to participate in the Weiss-Adler et. al. No. 1 well to be drilled to a depth of 18,294 ft MD/18,000 ft TVD to test the Bivouac Peak East Prospect.

As part of finalisation of the commitment to drill, the participation interests have been restructured. Byron Energy Inc, a wholly owned subsidiary of the Company, remains as the operator.

Participant	New Working Interest	Previous Working Interest
Byron (operator)	43.00%	40.00%
Otto	40.00%	45.00%
Metgasco	10.00%	10.00%
NOLA	7.00%	5.00%
	100.00%	100.00%

Bivouac Peak Lease Map



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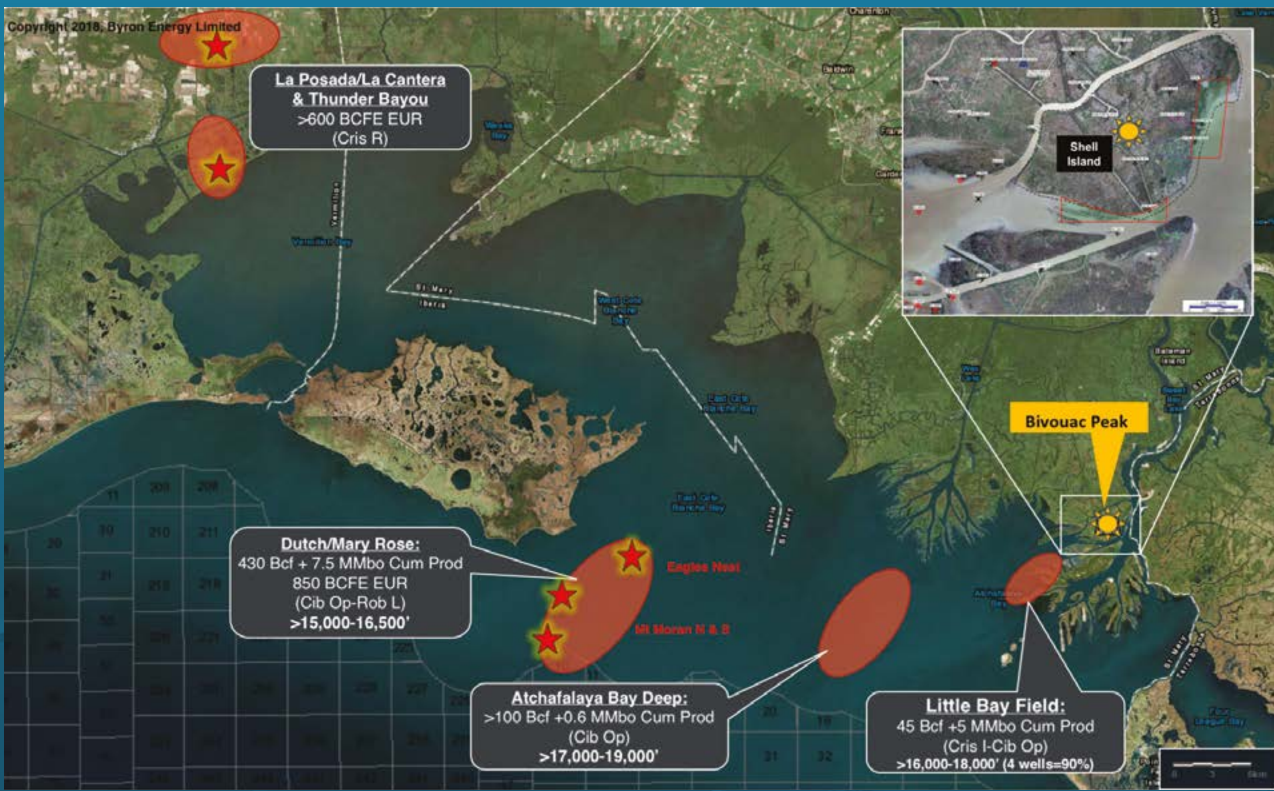
Bivouac Peak Regional Map – LA Transition Zone



The initial test well, the Byron Weiss-Adler, et. al. No. 1 well ('Byron Weiss-Adler #1'), is designed to test the Bivouac Peak East Prospect, targeting a mapped gross prospective resource of 125.6 billion cubic feet ('Bcf') and 11.3 million barrels oil ('Mmbo') (32.2 million barrels oil equivalent ('Mboe'). The Bivouac Peak project area comprises two prospects, the Bivouac Peak East Prospect and the Deep Prospect. As reported in Byron's 2018 annual reserve and prospective resources report, the total gross prospective resources for the two combined prospects at Bivouac Peak are estimated at 16.0 Mmbo and 177.7 Bcf (45.6 Mmboe). After allowing for the earn in by Otto and Metgasco, Byron's share of total Bivouac Peak prospective resource would be 5.1Mmbo and 56.9 Bcf (14.6 Mmboe), net after royalties. Although the prospects are independent, success at the East Prospect would provide positive seismic calibration potentially reducing risk at the Deep Prospect as well.

By electing to participate in the initial test well both Otto and Metgasco have agreed to pay their previously agreed disproportionate share of the first US$10.0 million of drilling costs for drilling of the initial test well to earn into the prospect, and their proportionate share of costs thereafter. Drilling costs for the first well are currently estimated at US$10.8 million. Otto and Metgasco will pay 53.33% and 13.33% respectively of the first $10.0 million of drilling costs (Otto US$5.33 million and Metgasco US$1.33 million). Byron and NOLA will pay 26.33% and 7.00% respectively of the first $10.0 million of costs (Byron US$2.63 million and NOLA US$0.7 million). Drilling costs for the first well are currently estimated at US$10.8 million. Any drilling costs above US$10.0 million in respect of the initial Bivouac Peak test well and all future expenditure on the leases will be in accordance with relevant participating interests (Byron 43%, Otto 40%, Metgasco 10% and NOLA 7%).

The Parker 77B rig commenced drilling operations on 25 August 2018 (USCDT) on the Byron operated Byron Weiss-Adler #1, in the Bivouac Peak Prospect Area. The Byron Weiss-Adler #1 exploration well is being drilled, using the Parker Drilling Company Rig #77-B Deep Drilling 3000 HP Posted Barge Rig, to a depth of 18,294 ft MD, 18,000 ft TVD, to test the Bivouac Peak East Prospect. The well is expected to take approximately 75 days, from spud, to reach total depth.

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EI 62/63/76/77

In June 2018 the BOEM awarded Byron Eugene Island blocks 62, 63, 76 and 77 ('EI 62/63/76/77') blocks bid on at Lease Sale 250. EI 62/63/76/77 were designated as the Eugene Island 77 Field in the 1960's and have produced 362 billion cubic feet of gas and 6.5 million barrels of oil from sands trapped by the Eugene Island 77 salt dome. Initial production from the field began in 1957. There is no production on these blocks currently.

The Company bid $US253,000 for each block for a total of $US1,012,000 for EI 62/63/76/77 as the lease bonus amount. With the recently reduced royalty rates in place for new shelf leases in the Gulf of Mexico, Byron will now receive an 87.5% net revenue interest (previously 81.25%) for its 100% working interest in these four blocks.

The EI 63 and 76 leases were previously held by the Company before being relinquished in January of 2018.

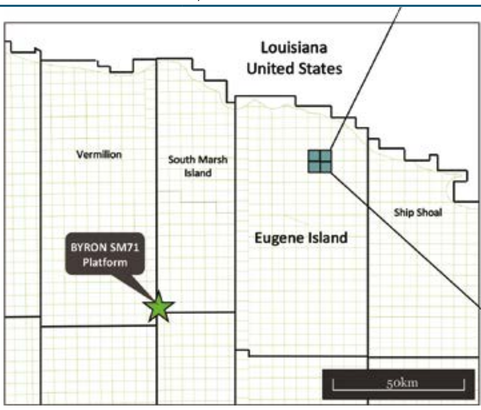
In 2014, Byron undertook proprietary RTM utilising WesternGeco (a Schlumberger group company) over the entire Eugene Island 77 Field. Byron has identified a number of exploration and exploitation opportunities using the RTM seismic data. Many of these prospects are in an updip position to previous oil and gas production and are considered to be low to moderate risk drilling opportunities. RTM data was instrumental in identifying the prospect that led to Byron's recent successful drilling campaign and subsequently establishing production at South Marsh Island 71.

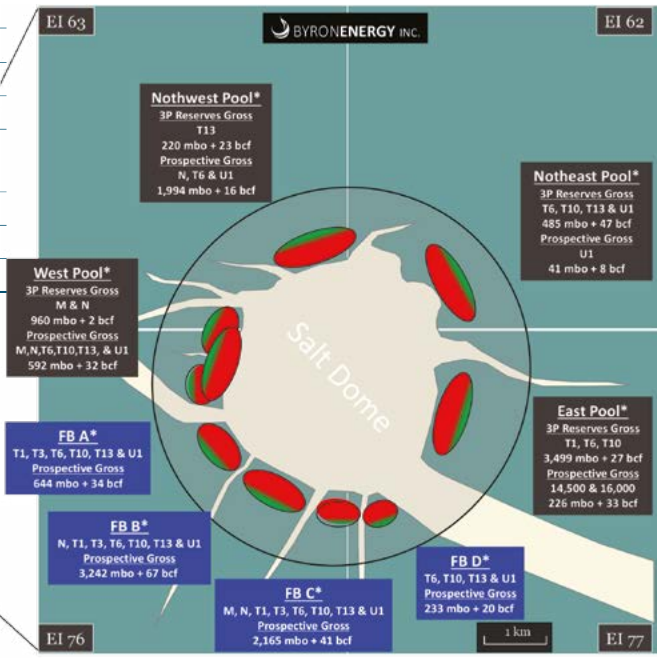
Byron currently regards the EI 62/63/76/77 opportunity as the most significant high impact project in the Company portfolio and we expect to start drilling this project in mid-2019.These leases account for approximately half the increase in our 1P, 2P and 3P reserves for 2018.

Recently completed year-long reservoir engineering analysis and modelling of the entire field this involved analysing 13 producing horizons across 63 wells and integrating this work with the RTM mapping. Eight prospects with up to 13 potential pay horizons were identified. Target depths of sands contained within these eight prospects range from 11,000' to 16,000' TVD with the majority of the objective sands in normally pressured rock. All the prospects are updip to either production or wells that logged downdip wet sands. At this stage there are no plans on farming out any equity in this play. Byron's initial well on EI 62/63/76/77 project will target 3P development reserves of 3.5 mmbo

EI 77 Field Dome

Eugene Island 62,63,76 & 77	
Water Depth	20 ft
Previous Production	6.5 Mmbo + 361 Bcf
Byron Interest	100% WI, 87.50% NRI
Acquired	OCS Lease Sale 250, June 2018
EI 63&76 first leased May 2013	Dropped January 2018
Byron Proprietary RTM acquired	2015
Total 3P Gross Reserves	5,157 mbo + 99 bcf
Total Prospective Gross Resource	9,137 mbo + 251 bcf





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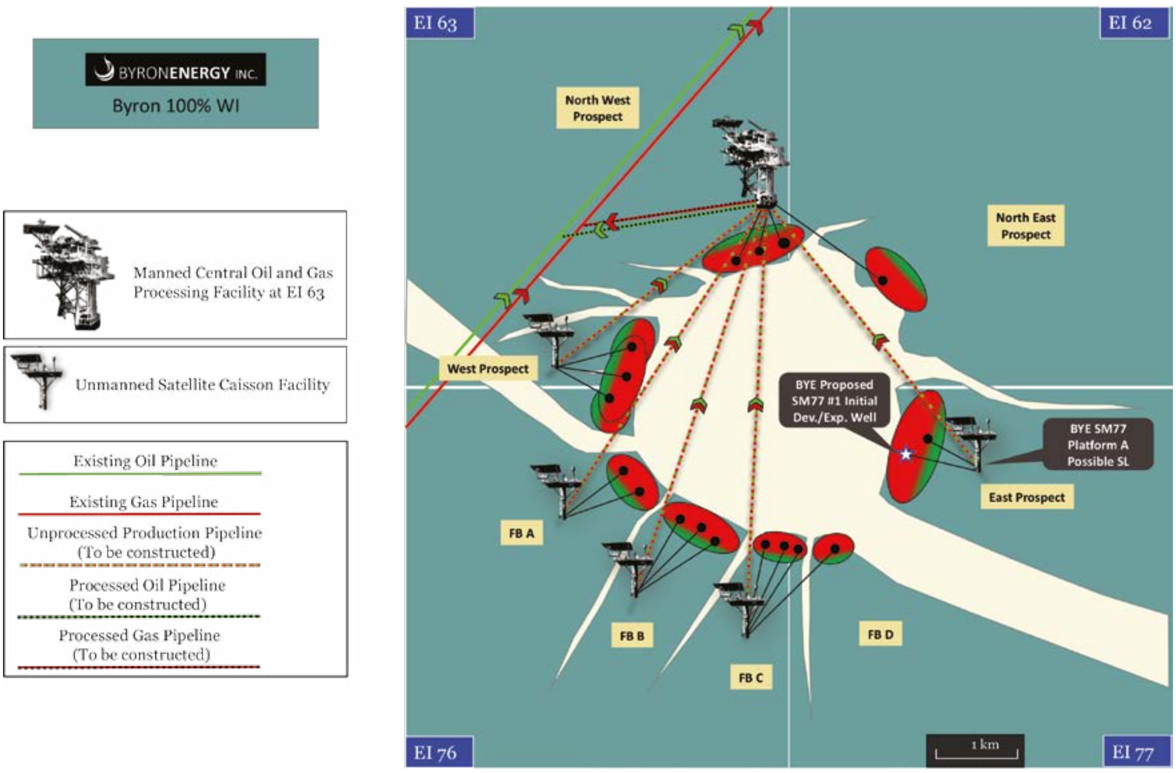
EI 77 Field Project Map



and 27 bcf of gas in the T1, T6 & T10 Sands and prospective resources of 226 mbo and 32.9 bcf of gas in the 14,500 and 16,000 Sands. The high potential of this these blocks was recognised five years ago during which time Byron patiently put this play together.

Grand Isle 95

In an ASX release dated 17 August 2017, Byron reported that it was the apparent high bidder on the Grand Isle Bock 95 ('GI 95') lease at Lease Sale 249 held on 16 August 2017 in New Orleans, Louisiana.

In early September 2017, Byron was advised by the BOEM that its bid for GI 95 has been deemed acceptable by the BOEM and the lease was awarded to Byron.

Byron has a 100% WI and 87.5% NRI, reflecting the recently reduced Federal Government Royalty of 12.5% versus pre- 2017 rate of 18.75%. Water depth in the area is approximately 197 feet.

GI 95 was previously owned by Byron and relinquished in August 2016. The Company took the opportunity to bid for the lease, which contains large gas reserves and resources, at a modest cost and with no work commitments.

GI 95 is a gas prone prospect with economics that will only improve as gas prices firm up and rise over the 5 year term of the lease. With a potentially large gas resources, the block will be very attractive as gas prices improve from their current levels.

Collarini has assigned gross 3P undeveloped reserves of 0.3 Mmbbl and 92.4 Bcf to GI 95. Collarini has also assigned aggregate gross prospective resources of 0.4 Mmbbl and 50.7 Bcf to GI 95.

Eugene Island 18

No exploration activity was undertaken on Eugene Island 18 during the year.

South Marsh Island Block 6 Salt Dome Project

Having earlier obtained permits to plug the two wellbores and remove the caisson on SM6, removal commenced in late August 2017. Otto was responsible for a portion of the plugging liability associated with the SM6 #2 well. Work to remove the wellbores and caisson was successfully completed in mid-September 2017.

Reserves and resources

A summary of the Company's reserves and resources estimate for the Company's projects in the shallow waters in the Gulf of Mexico at 30 June 2018 was released Byron released to the ASX on 19 September 2018 and is summarised below.

The report covers:

(a) SM71, SM57/59/74, EI 62/63/76/77, GI95 and the Bivouac Peak leases based on the independent reserves and resources estimates were prepared by Collarini Associates ('Collarini'), based in Houston, Texas, USA, and

(b) an in-house resources estimate for VR232.

The combined reserves and resources, net to Byron, are as follows:

Byron Energy Limited – Reserves and Resources
Gulf of Mexico, Offshore Louisiana, USA

Remaining as at 30 June 2018 (net to Byron)	Oil Mbbl	Gas MMcf	Mboe (6:1)	% change
Reserves (developed and undeveloped)				
Proved (1P)	**3,029**	**48,317**	**11,082**	**1,610%**
Probable reserves	4,938	79,968	18,266	1,027%
Proved and probable (2P)	**7,967**	**128,285**	**29,348**	**1,193%**
Possible reserves	4,573	44,968	12,068	1,918%
Proved, probable and possible (3P)	**12,540**	**173,253**	**41,416**	**1,345%**
Total Prospective Resources Best Estimate (unrisked)	35,770	592,212	134,473	-0.4%

Reserves – 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

Conversion to boe – Using a ratio of 6,000 cubic feet of natural gas to one barrel of oil – 6:1 conversion ratio is based on an energy equivalency conversion method and does not represent value equivalency

Prospective Resource – The estimated quantities of petroleum that may potentially be recovered by the application of a future development project(s) relate to undiscovered accumulations. These estimates have both an associated risk of discovery and a risk of development. Further exploration appraisal and evaluation is required to determine the existence of a significant quantity of potentially moveable hydrocarbon.

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The following table contains Byron's remaining reserves as at 30 June 2018 split into developed and undeveloped categories by product.

Byron Energy Limited – Remaining Reserves
Net to Byron

	Developed		Undeveloped		Total
June 30 2018	Oil Mbbl	Gas MMcf	Oil Mbbl	Gas MMcf	Boe Mboe (6:1)
SM71					
Proved (1P)	**1,656**	**1,020**	**570**	**352**	**2,455**
Probable Reserves	2,605	1,726	1,064	1,107	4,142
Proved and probable (2P)	**4,261**	**2,746**	**1,634**	**1,459**	**6,597**
Possible reserves	–	–	1,889	1,612	2,158
Proved, probable and possible (3P)	**4,261**	**2,746**	**3,523**	**3,071**	**8,754**
EI 62/63/76/77					
Proved (1P)	**–**	**–**	**785**	**36,624**	**6,889**
Probable reserves	–	–	1,101	31,295	6,317
Proved and probable (2P)	**–**	**–**	**1,886**	**67,919**	**13,206**
Possible reserves	–	–	2,626	18,706	5,744
Proved, probable and possible (3P)	**–**	**–**	**4,512**	**86,625**	**18,950**
GI 95					
Proved (1P)	**–**	**–**	**18**	**10,321**	**1,738**
Probable reserves	–	–	168	45,840	7,808
Proved and probable (2P)	**–**	**–**	**186**	**56,161**	**9,546**
Possible reserves	–	–	58	24,650	4,166
Proved, probable and possible (3P)	**–**	**–**	**244**	**80,811**	**13,713**
Total					
Proved (1P)	**1,656**	**1,020**	**1,373**	**47,297**	**11,082**
Probable reserves	2,605	1,726	2,333	78,242	18,267
Proved and probable (2P)	**4,261**	**2,746**	**3,706**	**125,539**	**29,349**
Possible	–	–	4,573	44,968	12,068
Proved, probable and possible (3P)	**4,261**	**2,746**	**8,279**	**170,507**	**41,417**

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The following table reconciles the movement in Byron's reserves between 30 June 2017 and 30 June 2018.

Byron Energy Limited Reserves (Net to Byron)
Gulf of Mexico, offshore Louisiana, USA

	Oil (Mbbl)				Gas (MMcf)			
Reserves reconciliation	Remaining 30/06/17	Production 2018	Additions and revisions 2018	Remaining 30/06/18	Remaining 30/06/17	Production 2018	Additions and revisions 2018	Remaining 30/06/18
SM71 (developed and undeveloped)								
Proved (1P)	**581**	**-142**	**1,503**	**2,226**	**403**	**-120**	**849**	**1,372**
Probable reserves	1,445	0	2,223	3,669	1,058	0	1,775	2,833
Proved and probable (2P)	**2,026**	**-142**	**3,726**	**5,895**	**1,461**	**-120**	**2,624**	**4,205**
Possible reserves	536	0	1,354	1,890	370	0	1,243	1,612
Proved, probable and possible (3P)	**2,562**	**-142**	**5,080**	**7,785**	**1,831**	**-120**	**3,867**	**5,817**
EI 62/63/76/77 (Undeveloped)								
Proved (1P)	**0**	**0**	**785**	**785**	**0**	**0**	**36,624**	**36,624**
Probable reserves	0	0	1,101	1,101	0	0	31,295	31,295
Proved and probable (2P)	**0**	**0**	**1,886**	**1,886**	**0**	**0**	**67,919**	**67,919**
Possible reserves	0	0	2,626	2,626	0	0	18,706	18,706
Proved, probable and possible (3P)	**0**	**0**	**4,512**	**4,512**	**0**	**0**	**86,625**	**86,625**
GI 95 (Undeveloped)								
Proved (1P)	**0**	**0**	**18**	**18**	**0**	**0**	**10,321**	**10,321**
Probable reserves	0	0	168	168	0	0	45,840	45,840
Proved and probable (2P)	**0**	**0**	**186**	**186**	**0**	**0**	**56,161**	**56,161**
Possible reserves	0	0	58	58	0	0	24,650	24,650
Proved, probable and possible (3P)	**0**	**0**	**244**	**244**	**0**	**0**	**80,811**	**80,811**
Grand total								
Proved (1P)	**581**	**-142**	**2,306**	**3,029**	**403**	**-120**	**47,794**	**48,317**
Probable reserves	1,445	0	3,492	4,938	1,058	0	78,910	79,968
Proved and probable (2P)	***2,026***	***-142***	***5,798***	***7,967***	***1,461***	***-120***	***126,704***	***128,285***
Possible reserves	536	0	4,038	4,573	370	0	44,599	44,968
Proved, probable and possible (3P)	**2,562**	**-142**	**9,836**	**12,540**	**1,831**	**-120**	**171,303**	**173,253**

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Material changes to reserves

Proved and Probable Reserves – Net of Actual Production

The increase in proved and probable reserves is due to:

- SM71
  - the successful SM71 F2 ('F2') appraisal well drilled in December 2017 and the SM71 F3 ('F3') development well drilled in January 2018. Significantly thicker than predicted oil bearing sands were logged in the drilling of the SM71 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 SM71 F2 well resulted in a positive reclassification of a portion of Prospective Resources to the Proved and Probable Reserves categories. Although the SM71 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 SM71 F2 well. Byron expects to side-track the F2 well in the future to intersect and produce those reserves.
- EI 63/63/76/77
  - Inclusion of EI 62/63/76/77 proved and probable reserves by Collarini.
- GI 95
  - Inclusion of GI 95 proved and probable reserves by Collarini.

Byron Energy Limited Prospective Resources (net to Byron)
Gulf of Mexico, offshore Louisiana, USA

Best estimate unrisked 30 June 2018	Oil Mbbl	Gas MMcf	Mboe (6:1)
SM71	387	19,373	3,616
SM74	2,958	7,493	4,207
SM57/59	18,887	239,674	58,833
EI 62/63/76/77	7,995	219,397	44,561
GI 95	334	44,388	7,732
VR 232	74	4,827	879
Bivouac Peak	5,135	57,060	14,645
Total prospective resources (2018)	35,770	592,212	134,473
Total prospective resources (2017)	43,159	551,000	134,992

Possible reserves

The increase in possible reserves at is mainly due to:

- SM71
  - potential upside recoveries and drainage areas from the producing D5 reserves;
  - the reclassification to possible reserves of a material proportion of the prospective resource previously attributed to the B65 Sand, and
  - the addition of the possible reserves attributed to the B65, J-1 and D5 sands as result of the development drilling in 2017/18 financial year.
- EI 62/63/76/77
  - inclusion of EI 62/63/76/77.
- GI 95
  - inclusion of GI 95

The following table shows Byron's prospective resources as at 30 June 2018 compared to 30 June 2017.

Material changes to prospective resources

The increase in prospective resources, on a barrels of oil equivalent, is mainly due to:

- Inclusion of prospective resources for GI 95 and VR 232.
- Increase in EI 62/63/76/77 prospective resources.
- reclassification of all of the 2017 year end SM71 B65 Sand prospective resource to the proved, probable and possible reserve in the 2018 year following successful appraisal and development drilling.

largely offset by

- reclassification of all of the 2017 year end SM71 B65 Sand prospective resource to the proved, probable and possible reserve in the 2018 year following successful appraisal and development drilling
- Otto and Metgasco exercising their option to earn an interest in Bivouac Peak, thus reducing Byron's NRI (assuming earnin completed); and
- Metgasco exercising its option to earn an interest in SM74, thus reducing Byron's NRI (assuming earnin completed).

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Notes to reserves and resources statement

Reserves and resources governance

Byron's reserves estimates are compiled annually. Byron engages Collarini and Associates, a qualified external petroleum engineering consultant, to conduct an independent assessment of the Company's reserves. Collarini and Associates is and 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 (for SM71, SM57/59/74, EI 62/63/76/77, GI 95 and Bivouac Peak)

The information in this report that relates to oil and gas reserves and resources 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.

Competent Persons Statement (for VR 232)

The information in this report that relates to oil and gas prospective resources was compiled by Mr Prent H. Kallenberger (BSc. Geology, MSc. Geophysics,), an Executive Director of Byron Energy Limited. 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 release are based on, and fairly represents, information and supporting documentation prepared by, or under the supervision of, Mr Kallenberger. Mr Kallenberger 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 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. The 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 a future development project(s) relate to undiscovered accumulations. These estimates have both an associated risk of discovery and a risk of development. Further exploration appraisal and evaluation is required to determine the existence of a significant quantity of potentially moveable hydrocarbons.

Forward-looking statements

This document may contain forward-looking information. Forward-looking information is generally identifiable by the terminology used, such as 'expect', 'believe', 'estimate', 'should', 'anticipate' and 'potential' or other similar wording. Forward-looking information in this document includes, but is not limited to, references to: well drilling programs and drilling plans, estimates of potentially recoverable resources, and information on future production and project start-ups. By their very nature, the forward-looking statements contained in this document require Byron and its management to make assumptions that may not materialise or that may not be accurate. Although Byron believes its expectations reflected in these statements are reasonable, such statements involve risks and uncertainties, and no assurance can be given that actual results will be consistent with these forward-looking statements.

Pricing assumptions

Oil prices used in this report represent consensus base prices (Citi Research June 8 2018, Bloomberg Street Consensus), starting on January 1, 2019, of $US63.00 per barrel, with a final price of $US62.75 per barrel on January 1, 2021, and held constant thereafter. Gas prices used in this report represent a Henry Hub base, starting on January 1, 2019, of $US3.00 per MMBtu, rising to a final price of $US3.15 per MMBtu on January 1 2021, and held constant thereafter. These prices were adjusted to account for transportation cost, basis difference, and oil gravity resulting in lower realised prices.

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 6:1 BOE conversion ratio for gas to oil; 6:1 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 and 5.26.8).

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

(ix) For prospective resources, the estimated quantities of petroleum that may potentially be recovered by the application of a future development project(s) relate to undiscovered accumulations. These estimates have both an associated risk of discovery and a risk of development. Further exploration appraisal and evaluation is required to determine the existence of a significant quantity of potentially moveable hydrocarbons (LR 5.28.2).

(x) All of Byron's reserve, contingent resources and prospective resources are located in the shallow waters of the Gulf of Mexico, offshore Louisiana; furthermore, all of Byron's reserves are undeveloped as at 30 June 2018 (LR 5.39.1).

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Financial Report

For year ended 30 June 2018

Directors' Report

Your directors submit herewith their report together with the Financial Report of Byron Energy Limited ('the consolidated entity' or 'Group'), being Byron Energy Limited ('Byron' or the 'Company') and its subsidiaries, for the financial year ended 30 June 2018.

Directors

The names and details of the Company's directors in office during the financial year and until the date of this report are as follows:

Douglas G Battersby

Maynard V Smith

Prent H Kallenberger

Charles J Sands

Paul A Young

William R Sack

All directors have held office for the whole year unless otherwise stated.

Names, qualifications, experience and special responsibilities

Douglas G Battersby

Non-Executive Chairman

Appointed 18 March 2013

Doug is a petroleum geologist with over 40 years' technical and managerial experience in the Australian and international oil and gas industry.

Doug co-founded two ASX listed companies (Eastern Star Gas Limited, which was taken over by Santos Limited in November 2011, and SAPEX Limited, which was taken over by Linc Energy Limited in October 2008), and two private oil and gas exploration/development companies, Darcy Energy Limited, which was sold to I B Daiwa Corporation in 2005, and Byron Energy (Australia) Pty Ltd where he was Executive Chairman until May 2013 when Byron Energy (Australia) Pty Ltd merged with Trojan Equity Limited to create Byron Energy Limited. Between 1990 and 1999 Doug was Technical Director at Petsec Energy Limited, an ASX listed operator in the shallow waters of the Gulf of Mexico with production reaching 100 MMcf per day of gas and 9,000 barrels of oil per day in 1997.

Doug holds a Master of Science degree in Petroleum Geology and Geochemistry from Melbourne University.

Other current directorships of listed companies

None.

Former directorships of listed companies in last three years

None.

Maynard V Smith

Executive Director and Chief Executive Officer

Appointed 18 March 2013

Maynard is a geophysicist with over 30 years' technical and managerial experience in the oil and gas industry with a particular focus on the Gulf of Mexico.

Maynard co-founded Darcy Energy Limited, sold to I B Daiwa Corporation in 2005, and Byron Energy (Australia) Pty Ltd where he has been Chief Executive until May 2013 when Byron Energy (Australia) Pty Ltd merged with Trojan Equity Limited to create Byron Energy Limited. Prior to that, Maynard was Chief Operating Officer with Petsec Energy Limited (1989-2000). In the late 1970s and early 1980s Maynard held senior exploration positions with Tenneco Oil Company, based in Bakersfield, California.

Maynard holds a Bachelor of Science degree in Geophysics from California State University at San Diego.

Other current directorships of listed companies

None.

Former directorships of listed companies in last three years

None.

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Prent H Kallenberger

Executive Director and Chief Operating Officer

Appointed 18 March 2013

Prent is a geoscientist with over 30 years' experience in the oil and gas industry with extensive exploration and development experience in the Gulf of Mexico, having generated prospects which have led to the drilling of over 125 wells in the Gulf of Mexico and California. He was Vice President of Exploration with Byron Energy (Australia) Pty Ltd until May 2013 when Byron Energy (Australia) Pty Ltd merged with Trojan Equity Limited to create Byron Energy Limited.

Between 2000 and 2006, Prent was Vice President of Exploration with Petsec Energy Inc, where he was responsible for a team of seven people and generated projects leading to the drilling of 10 successful wells in 12 attempts in the shallow waters of the Gulf of Mexico. These wells produced 32 Bcf and 1.5 MMBbls of oil. Between 1992 and 1998 Prent was Geophysical Manager with Petsec Energy Inc, a wholly owned subsidiary of Petsec Energy Limited. He holds a Bachelor of Science degree in Geology from Boise State University and Master of Science degree in Geophysics from Colorado School of Mines.

Other current directorships of listed companies

None.

Former directorships of listed companies in last three years

None.

Charles J Sands

Non-Executive Director

Appointed 18 March 2013

Charles was a Non-Executive director of Byron Energy (Australia) Pty Ltd until May 2013 when Byron Energy (Australia) Pty Ltd merged with Trojan Equity Limited to create Byron Energy Limited. Charles was also a Director of Darcy Energy Limited.

Charles has over 30 years' of broad based business and management experience in the USA and is President of A. Santini Storage Company of New Jersey Inc, enabling him to advise on the general business operating environment and practices in the USA. He holds a Bachelor of Science degree from Monmouth University.

Charles is currently a member of the Audit and Risk Management Committee.

Other current directorships of listed companies

None.

Former directorships of listed companies in last three years

None.

Paul A Young

Non-Executive Director

Appointed 18 March 2013

Paul is a Managing Director of Henslow Corporate and country head for Oaklins, a global mid-market corporate advisory firm. He has been in merchant banking for more than 30 years. He has extensive experience in the provision of corporate advice to a wide range of Australian and international listed and unlisted companies including restructurings, capital raisings, initial public offerings and mergers and acquisitions.

Paul is an Honours Graduate in Economics (University of Cambridge) and has an Advanced Diploma in Corporate Finance. He is a Fellow of the Institute of Chartered Accountants in England and Wales and a Fellow of the Australian Institute of Company Directors.

Paul is currently Chairman of the Audit and Risk Management Committee.

Other current directorships of listed companies

- Ambition Group Limited
- Opus Group Limited

Former directorships of listed companies in last three years

None.

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William R Sack

Executive Director

Appointed 3 October 2014

Bill is an explorationist with 28 years' experience in the Gulf of Mexico region in both technical and Executive roles. He was appointed to the Board of Directors on 3 October 2014.

Bill's qualifications comprise BSc. Earth Sci./Physics, MSc. Geology and an MBA. He was co-founder/Managing Partner of Aurora Exploration, LLC ('Aurora') a private entity focused on generating and drilling Gulf of Mexico exploration opportunities that has drilled more than 80 wells with a success rate in excess of 80%, and under his leadership has created substantial growth and monetised investments via multiple corporate level asset sales.

Other current directorships of listed companies

None.

Former directorships of listed companies in last three years

None.

Summary of shares and options on issue

At 30 June 2018, the Company had 684,987,034 ordinary shares and 51,800,000 options on issue. Details of the options are as follows:

Issuing entity	Number of shares under option	Class of shares	Exercise price	Expiry date
Byron Energy Limited	9,500,000	Ordinary	A$0.25	31 December 2019
Byron Energy Limited	10,000,000	Ordinary	A$0.25	21 July 2019
Byron Energy Limited	1,950,000	Ordinary	A$0.25	30 September 2018
Byron Energy Limited	28,350,000	Ordinary	A$0.12	31 December 2021
Byron Energy Limited	2,000,000	Ordinary	A$0.16	31 December 2021

During the financial year, 407,539,872 ordinary fully paid shares were issued at A$0.07 per share to existing and new shareholders and to the directors and/or their associates, as approved by shareholders, raising a total of US$22,337,260 (A$28,527,791) before equity raising costs.

Also during the financial year, the Company issued 30,350,000 share options to executive directors, staff and consultants of which 28,350,000 are exercisable at A$0.12 per security and 2,000,000 at A$0.16 per security any time before 31 December 2021.

The Company did not receive any applications or consideration for the conversion of options during the year and 1,700,000 share options with an exercise price of A$0.65 expired on 30 September 2017. No share options were exercised subsequent to 30 June 2018, through to the date of this report.

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Shareholdings of directors and other key management personnel

The interests of each director and other key management personnel, directly and indirectly, in the shares and options of Byron Energy Limited at the date of this report are as follows:

Director/ key management personnel	Ordinary shares	Options over ordinary shares	Exercise price	Option expiry date
D G Battersby	48,123,203	–	–	–
M V Smith	32,313,583	2,500,000	A$0.25	31 December 2019
M V Smith	–	6,300,000	A$0.12	31 December 2021
P H Kallenberger	1,732,223	2,500,000	A$0.25	31 December 2019
P H Kallenberger	–	6,300,000	A$0.12	31 December 2021
C J Sands	19,765,997	–	–	–
P A Young	18,655,931	–	–	–
W R Sack	1,900,000	1,700,000	A$0.25	30 September 2018
W R Sack	–	2,500,000	A$0.25	31 December 2019
W R Sack	–	6,300,000	A$0.12	31 December 2021
N Filipovic	584,788	1,000,000	A$0.25	31 December 2019
N Filipovic	–	3,780,000	A$0.12	31 December 2021

During the financial year, 22,680,000 share options were granted to Directors or key management personnel of the Company after shareholder approval:

Director/key management personnel	Number of options granted	Issuing entity	Number of ordinary shares under option
M V Smith	6,300,000	Byron Energy Limited	6,300,000
P H Kallenberger	6,300,000	Byron Energy Limited	6,300,000
W R Sack	6,300,000	Byron Energy Limited	6,300,000
N Filipovic	3,780,000	Byron Energy Limited	3,780,000

No shares were issued or granted to directors or key management personnel.

Company Secretary

Nick Filipovic

Appointed 18 March 2013.

Nick is a qualified accountant with over 35 years' experience in the financial services and natural resources industries, including oil and gas, where he has held a range of senior financial and commercial management positions. He was the Chief Financial Officer and Company Secretary of Byron Energy (Australia) Pty Ltd until May 2013 when Byron Energy (Australia) Pty Ltd merged with Trojan Equity Limited to create Byron Energy Limited.

Principal activities

The principal activities of the consolidated entity during the financial year were oil and gas exploration, development and production in the shallow waters and the transition zone (offshore Louisiana) in the Gulf of Mexico ('GOM'), USA.

Consolidated results

The profit for the consolidated entity after income tax was US$1,298,968 (2017: US$5,357,583 loss).

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Review of operations

Financial Review

The Group recorded a net profit of US$1,298,968 for the year ended 30 June 2018, compared to a net loss of US$5,357,583 for the year ended 30 June 2017, primarily due to the commencement of oil and gas production from the Byron operated South Marsh Island ('SM71') lease in late March 2018.

For the year ended 30 June 2018 Byron's share of net revenue, after transport costs and royalties, was US$9,544,507 while cost of sales were US$1,807,414.

At 30 June 2018, the consolidated entity had total assets of US$40,236,652 (2017: US$13,919,656) and total liabilities of US$11,730,029 (2017: US$9,592,243) resulting in net assets of US$28,506,623 (2017: US$4,327,413), an increase of US$24,179,210 mainly due to the development expenditure incurred on SM71 financed by equity issued during the year.

At 30 June 2018, the consolidated entity held cash and cash equivalents of US$2,256,958 (2017: US$3,395,501) of which US$1,959,529 (2017: US$3,221,110) were denominated in United States dollars and US$297,429 (2017: US$174,391) were denominated in Australian dollars. The consolidated entity has an A$5,000,000 (2017: A$8,000,000) secured convertible note to Metgasco Limited ('Metgasco') and loans from Directors of US$1,384,332 (2017: $nil).

Corporate review

Placements and SPP

On 14 August 2017, Byron announced an A$26.5 million Placement ('Placement') conditional on shareholder approval. The Placement was approved by shareholders at an Extraordinary General Meeting ('EGM') of Byron's shareholders, held on 18 September 2017 and the shares were allotted on 27 September 2017. The Placement consisted of 378,970,262 fully paid new ordinary shares issued at A$0.07 per share raising approximately A$26.5 million (before issue costs).

The Company also announced on 14 August 2017, a Share Purchase Plan ('SPP') to raise approximately A$2.0 million on the same terms as the Placement. The SPP was fully subscribed and 28,569,610 fully paid shares were issued on 28 September 2017.

Issue of new share options

On 18 August 2017, Byron announced, subject to shareholder approval, the issue of 28.35 million unlisted options to executive directors, staff and contractors of the Company, exercisable at an exercise price of A$0.12 per security on or after issue at any time on or before 31 December 2021. Shareholders approved the issue of these share options at an EGM held on 18 September 2017 and the options were allotted on 28 September 2017.

On 20 December 2017, Byron announced the allotment of 2.0 million unlisted options to a newly appointed executive of the Company, exercisable at A$0.16 per security on or after issue at any time on or before 31 December 2021.

Issued capital

As at 30 June 2018, Byron's issued capital comprised:

Securities	Total issued	Quoted	Unquoted
Shares (ASX:BYE)	684,987,034	684,987,034	Nil
Options	51,800,000	Nil	51,800,000
Convertible notes	5,000,000	Nil	5,000,000

Convertible notes outstanding

Balance at 30 June 2017	Total redeemed during year ended 30 June 2018	Balance 30 June 2018
8,000,000 @ A$1	3,000,000 @ A$1	5,000,000 @ A$1

8,000,000 @ A$1.00 secured convertible notes (unquoted) were issued to Metgasco Limited in January 2017. The convertible notes are convertible at the election of the note holder (i) between 20 July 2018 and 21 July 2019; or (ii) on the occurrence of a change of control, at a price which is a 10% discount to the 30 day VWAP. The convertible notes are repayable in A$1.0 million quarterly instalments over two years commencing in October 2017.

Developed oil and gas properties – SM71

Byron owns SM71, a lease in the South Marsh Island Block 73 ('SM73') field. The SM73 field encompasses nine Outer Continental Shelf ('OCS') lease blocks (81 square miles) which overlie a large piercement salt dome. The salt dome is responsible for providing the trapping mechanism for production in all portions of the SM73 field. The SM73 field is productive from discrete hydrocarbon-bearing sandstone reservoirs which are primarily trapped in three-way structural closures bound either by salt or stratigraphic thinning, on their updip edge. These reservoirs are Pleistocene to Pliocene age sands ranging in depth from 5,000 feet to 8,800 feet True Vertical Depth ('TVD'). The majority of the field production has come from depths of less than 7,500 feet in high-quality sandstone reservoirs.

Byron is the designated operator of SM71 and owns a 50% Working Interest ('WI') and a 40.625% Net Revenue Interest ('NRI') in the block, with Otto Energy Limited group holding an equivalent WI and NRI in the block. Water depth in the area is approximately 137 feet.

The 2017/18 year was active and successful for Byron culminating in successful oil and gas production from the Byron operated SM71 platform, commencing in late March 2018.

SM71 Platform and Pipelines

In November 2017, Byron successfully completed the installation of the jacket and decks comprising the SM71 F Platform.

Operations to lay the 500 feet 4 inch oil and 7,000 feet 6 inch gas pipelines were also completed during October 2017. Each pipeline was initially laid and buried to within tie-in distance to Byron's SM71 F platform location and their respective sales lines. Final tie-in work at the platform end and sales lines was completed in December 2017.

SM71 Byron F2 Appraisal Well

The Ensco 68 jack-up rig spudded the Byron operated OCS G-34266 #F-2 well ('F2') on SM71 in early December 2017.

The SM71 F2 appraisal well encountered four discrete hydrocarbon bearing sands, including the B65 and D5 sands.

In early January 2018, 7 5/8 inch casing was run before temporarily suspending the F2 well for a short period while the F3 well was drilled, before completing the F2 well for production.

SM71 Byron F3 Development Well

Given the high-quality and thickness of the D5 Sand encountered in the F2 well, Byron exercised its right to drill a second well under the then existing Ensco drilling contract, it was decided to drill OCS G-34266 F-3 well ('F3'), rather than release the rig.

The F3 well was designed to intersect the D5 Sand very near the point that the F2 well intersected the D5 Sand. The F3 well was drilled to provide a second take point in the D5 Sand reservoir in addition to the up dip F1 well, which was drilled in 2016. The F3 well spudded on 9 January 2018 USA Central Daylight Time ('USCDT').

On 29 January 2018, Byron announced that the F3 well was drilled to a final total depth of 7,717 feet Measured Depth ('MD'). After logging the well with open hole triple combo logging tools on 27 January 2018, operations to run 7 5/8 inch casing to total depth prior to temporary suspension for completion in the D5 Sand commenced. Hydrocarbons in five discrete intervals were measured using both Log While Drilling ('LWD') gamma ray and resistivity tools and wireline Triple Combo porosity tools.

The primary target in the F3 well was the D5 Sand which logged 211 measured depth feet of oil pay (174 feet Total Vertical Thickness ('TVT') net oil pay) as determined by open hole logs. While only 70 feet away from the previously drilled SM71 F2 well, the D5 Sand was 45 TVT feet thicker in the F3 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, only 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 sand which is productive in other parts of the dome but, to date, not productive at SM71.

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SM71 F1, F2 and F3 Well Completions

During the March 2018 quarter Byron completed the F1, F2 and F3 wells for production.

The SM71 OCS G-34266 #F-1 well ('F1') well was drilled to a depth of 7,477 feet measured depth in April of 2016 and logged a total of 151 feet of TVT net hydrocarbons in four discrete sands. The primary target in the F1 well was the D5 Sand, a prolific oil producing sand in other portions of the SM73 salt dome field. The F1 well logged 91 feet TVT net oil pay in the D5 Sand and Byron committed to construction of a manned tripod production facility on that basis.

A 70-foot measured depth interval of the D5 Sand in the F1 well was perforated on 16 February 2018 and sand control measures were pumped across the interval on 18 February 2018. After rigging down the pumping equipment, 2 7/8 inch production tubing was run in the well.

After completion of the F1 well, the Ensco 68 drilling rig skidded to position over the SM71 F2 well and the B65 Sand was completed with sand control measures similar to the F1 well. These sand control measures are designed to improve the production rate and to minimise reservoir pressure drawdown, resulting in better performance and longevity.

After completion of the F2 well the Ensco 68 drilling skidded into position over the SM71 F3 well and completion operations in the D5 Sand began. A 184-foot interval of the D5 Sand was perforated and hydraulic sand control measures were pumped into the formation.

On 29 March 2018, the final 290-foot-long portion of the collapsed completion assembly was successfully and completely removed from the SM71 F3 wellbore during fishing operations The F3 well was then completed for production from the D5 Sand reservoir where over 200 feet of MD oil pay (174 feet true vertical depth thickness) was logged during drilling in January 2018.

SM71 Production

Production from the Byron operated SM71 F platform began on 23 March 2018 when the SM71 F1 and F2 wells were opened to sales. The SM71 F3 began production on 6 April 2018.

For the year ended 30 June 2018, production from SM71 is shown in the table below.

Production/sales	For the year ended 30 June 2018	For the year ended 30 June 2017
Gross production		
Oil (bbls)	**348,581**	Nil
Gas (mmbtu)	**300,430**	Nil
Byron share of Gross Production (50% working interest)		
Oil (bbls)	**174,291**	Nil
Gas (mmbtu)	**150,215**	Nil
Net production (BYE share 40.625% net of royalty)		
Oil (bbls)	**141,611**	Nil
Gas (mmbtu)	**122,050**	Nil

The Company's production for the June 2018 quarter was affected by the shut in of the third-party oil pipeline. Crimson Gulf, LLC, the operator of the oil pipeline that carries SM71 oil to market, undertook maintenance on sections of the oil pipeline commencing on 19 April 2018 which lasted four days. As a result Byron's SM71 wells were offline during that time and resumed production on 22 April 2018 USCDT.

In May 2018, Byron conducted Flowing Bottom Hole Pressure/Shutin Bottom Hole Pressure ('FBHP/SBHP') tests on the SM71 F1, F2 and F3 wells to further evaluate well performance. Based on final analysis of the FBHP/SBHP survey data, the following conclusions were drawn for each reservoir.

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The FBHP/SBHP survey data indicated that the F1 and F3 well intersections of the D5 Sand are entirely consistent with the Company's pre-drill mapping and expectations. The SM71 F1 and F3 wells, are performing to expectations and overall production rates will be largely unaffected by the shut in of the F2 well.

The B65 Sand (F2 well) production data, along with pressure data indicates an estimated trap size of three acres, whereas the targeted seismic anomaly size was 175 acres. This provides strong evidence that the B65 Sand intersected by F2 is isolated from the main B65 Sand target area. The F2 well was recently shut in to analyse the pressure build-up of the well and was brought back online on 2 July 2018 USCDT. After flowing for approximately eight hours, the F2 well ceased production of hydrocarbons and was shut in.

As reported previously, the SM71 F2 well has two remaining hydrocarbon bearing zones, the B55 and J1 Sands. The Company will initially perforate the B55 Sand and verify that economic flow rates can be achieved. When the B55 Sand ultimately ceases production, the J1 Sand would be recompleted before the Company will propose redrilling the well to the main B65 Sand area. Due to equipment availability, the initial B55 Sand recompletion work is expected to take place prior to the end of 31 December 2018.

The B65 Sand is one of many focus areas of the recently announced seismic processing project Byron is undertaking with Schlumberger's subsidiary WesternGeco (as discussed below under SM71 Project Area 3D Seismic Processing Project) to help determine the placement of future wells.

Exploration and evaluation assets

Lease Sale 249 and Lease Sale 250

During the year ended 30 June 2018, Byron participated in two Gulf of Mexico, Outer Continental Shelf ('OCS') lease sales conducted by the Bureau of Ocean Energy Management ('BOEM'), the Gulf of Mexico, OCS Lease Sale 249 ('Lease Sale 249') held on 16 August 2017 and the Gulf of Mexico, OCS Lease Sale 250 ('Lease Sale 250') held on 21 March 2018, both held in New Orleans, Louisiana.

Byron was awarded Grand Island 95 ('GI 95'), the sole block bid by the Company at Lease Sale 249.

Byron also bid on and was subsequently awarded seven blocks at Lease Sale 250, comprising Vermilion blocks 232 and 251, South Marsh Island 70 and Eugene Island blocks 62, 63, 76 and 77. The prospects identified in these seven blocks, in and around salt domes, were generated by interpretation of the Company's high-quality RTM and Inversion processed 3D seismic data.

The BOEM reduced the OCS royalty rate from 18.75% to 12.5% for shallow water blocks starting with Lease Sale 249.

The seven blocks acquired at Lease Sale 250 are briefly described below.

SM71 Project Area

South Marsh Island blocks 57, 59 and 74

The BOEM awarded Byron three leases comprising South Marsh Island Area Block 57 ('SM57'), South Marsh Island Area Block 59 ('SM59') and South Marsh Island Area South Addition Block 74 ('SM74') at the Central Gulf of Mexico, OCS Lease Sale 247 held on 22 March 2017 in New Orleans, Louisiana.

The SM57/59/74 blocks increased Byron's footprint near Byron's existing SM71 oil project in the greater SM73 Field. The associated prospects and resulting leases were generated by the interpretation of Byron's high-quality Reverse Time Migration ('RTM') and Inversion processed 3D seismic data set.

Planning and technical work was advanced during the March and June 2018 quarters, focused on the SM74 Block.

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Vermilion blocks 232, 251 and SM70

In June 2018 the BOEM awarded Byron Vermilion 232 ('VR232'), Vermilion 251 ('VR251'), and South Marsh Island 70 ('SM70') blocks bid for at Lease Sale 250.

The VR232 prospect could be tested from the Byron operated SM71 F platform, but there are currently no plans to drill VR232 until production levels at the platform allow it to be produced efficiently in the event of success. In addition, the Company has identified two other higher risk/higher reward exploration prospects on VR232 which require further geophysical evaluation before a drilling decision is made.

Pursuant to the Participation Agreement, effective 1 December 2015, between Byron Energy Inc, and Otto Energy (Louisiana) LLC ('Otto'), a wholly owned subsidiary of Otto Energy Limited, Otto elected to participate in the acquisition of VR232 for a 50% WI. Under that agreement, Otto must pay an amount equal to a gross 133% of Otto's 50% interest share of acquisition costs, which includes the dry hole cost of the initial test well, plus a gross 50% of other past costs paid by Byron. In electing to participate in VR232, each company will own a 50% WI and a 43.75% NRI in the block. Upon election to participate in VR232, Otto has no further rights to participate in any blocks or projects, including SM74, under the December 2015 Participation Agreement.

Byron has identified several higher risk exploratory leads on both VR251 and SM70. These leads will be evaluated once Byron completes its SM71 project area seismic reprocessing work in late 2018 (see SM71 Project Area 3D Seismic Processing Project below).

SM71 Project Area 3D Seismic Processing Project

During the June 2018 quarter, Byron executed an agreement with WesternGeco, a Schlumberger subsidiary, to add additional licensed 3D seismic data to its in-house data inventory and to perform new, high effort seismic data processing over the SM71 project area in the Gulf of Mexico. Byron will increase its contiguous 3D seismic data coverage in the SM71 project area to a total of 172 square miles (445 square kilometres) or 22 OCS lease blocks of high-quality 3D seismic.

Given the success of its SM71 wells, Byron decided to expand its coverage of both RTM data and inversion processing and take advantage of new processing algorithms offered by WesternGeco for both products.

Additional processing deliverables will include RTM and Kirchhoff based Common Depth Point ('CDP') angle gathers and offset stacks for Amplitude Verses Offset ('AVO') analysis and a new suite of seismic inversion products to aid in reservoir characterisation and understanding.

The processing portion of the project began in June 2018 and is expected to take about six months to complete.

Bivouac Peak Prospect Area

The Bivouac Peak Prospect Area is located in the highly productive transitional zone comprising the northernmost shallow waters of the Louisiana State Waters, and onshore coastal Louisiana.

Byron is the operator of the Bivouac Peak Prospect area, through its wholly owned subsidiary Byron Energy Inc. The Bivouac Peak Prospect Area comprises onshore/marshland leases from:

(a) private landowners over approximately 2,400 contiguous acres (9.7 square kilometres); and

(b) two peripheral, non-core tracts adjoining the Bivouac Peak private landowners lease leased from the Louisiana State.

In June 2018 Byron proposed and Otto Energy Limited ('Otto'), Metgasco Limited ('Metgasco'), and NOLA Oil and Gas Ventures LLC ('NOLA') have all elected to participate in the Weiss-Adler et. al. No. 1 well to be drilled to a depth of 18,294 ft MD/18,000 ft TVD to test the Bivouac Peak East Prospect.

As part of finalisation of the commitment to drill, the participation interests have been restructured. Byron Energy Inc, a wholly owned subsidiary of the Company, remains as the operator with a 43% working interest. The balance of the working interest is held by Otto 40%, Metgasco 10%, and NOLA 7%.

The initial test well is designed to test the Bivouac Peak East Prospect. The Bivouac Peak Prospect area comprises two prospects, the Bivouac Peak East Prospect and the Deep Prospect. Although the prospects are independent, success at the East Prospect would provide positive seismic calibration potentially reducing risk at the Deep Prospect as well.

By electing to participate in the initial test well both Otto and Metgasco have agreed to pay their previously agreed disproportionate share of the first US$10.0 million of drilling costs for drilling of the initial test well to earn into the prospect, and their proportionate WI share of costs thereafter.

Drilling operation on the Weiss-Adler et. al. No. 1 well began in the second half of August 2018.

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Eugene Island blocks 62, 63, 76 and 77

In June 2018 the BOEM awarded Byron, Eugene Island blocks 62, 63, 76 and 77 ('EI 62, 63, 76 and 77') blocks, bid on at Lease Sale 250.

With the recently reduced royalty rates in place for new GOM shelf leases, Byron will now receive an 87.5% NRI (previously 81.25%) for its 100% WI in blocks EI 62, 63, 76 and 77.

The Eugene Island 63 and 76 leases were previously held by the Company before being relinquished in January 2018.

EI 62, 63, 76 and 77 were designated as the Eugene Island 77 Field in the 1960s and have produced 362 billion cubic feet of gas and 6.5 million barrels of oil from sands trapped by the Eugene Island 77 salt dome. Initial production from the field began in 1957. There is no production on these blocks currently.

In 2014, Byron undertook proprietary RTM seismic utilising WesternGeco (a Schlumberger group company) over the entire Eugene Island 77 Field. Byron has identified a number of exploration and exploitation opportunities using the RTM seismic data. Many of these prospects are in an updip position to previous oil and gas production and are considered to be low to moderate risk drilling opportunities.

Grand Isle 95

In September 2017, Byron was advised by the BOEM that its bid for GI 95, at Lease Sale 249 was deemed acceptable by the BOEM and the lease was awarded to Byron.

With revised Federal Government royalty rates in place for new leases in the Gulf of Mexico shelf blocks, Byron has a 100% WI and an 87.50% NRI in GI 95.

GI 95, previously held by Byron before being relinquished in August of 2016, is located in US Federal waters, approximately 100 miles (161 kilometres) southeast of New Orleans, Louisiana, at a water depth of approximately 201 feet (61 metres).

The Company took the opportunity to bid again for the lease, which contains large gas reserves and resources, at a modest cost with no work commitments.

No exploration activity was undertaken on the GI 95 gas project during the reporting period..

Eugene Island 18

No exploration activity was undertaken on EI 18 during the year.

South Marsh Island Block 6 Salt Dome Project

As announced on 26 August 2016, in light of Byron's significant success at SM71 and prevailing low oil and gas prices, Byron decided to focus its resources on development of SM71 and relinquished the SM6 lease.

Having earlier obtained permits to plug the two wellbores and remove the caisson on SM6, removal commenced in late August 2017. Otto was responsible for a portion of the plugging liability associated with the SM6 #2 well. Byron was responsible for all other abandonment liabilities on SM6. Work to remove the wellbores and caisson was successfully completed in mid-September 2017.

Properties

As at 30 June 2018, Byron's portfolio of oil and gas properties, all in the shallow waters of the Gulf of Mexico, and coastal marshlands of Louisiana, USA comprised:

Properties	Operator	Interest WI/NRI (%)	Lease expiry date	Lease area (km²)
South Marsh Island				
Block 71	Byron	50.00/40.625	Production	12.16
Block 57	Byron	100.00/81.25	June 2022	21.98
Block 59	Byron	100.00/81.25	June 2022	20.23
Block 74*	Byron	100.00/81.25	June 2022	20.23
Block 70	Byron	100.00/87.50	June 2023	22.13
Vermillion				
Block 232	Byron	50.00/43.75	June 2023	18.32
Block 251	Byron	100.00/87.50	June 2023	18.17
Eugene Island				
Block 18	Byron	100.00/78.75	April 2020	2.18
Block 62	Byron	100.00/87.50	June 2023	20.23
Block 63	Byron	100.00/87.50	June 2023	20.23
Block 76	Byron	100.00/87.50	June 2023	20.23
Block 77	Byron	100.00/87.50	June 2023	20.23
Grand Isle				
Block 95	Byron	100.00/87.50	September 2022	18.37
Transition Zone (Coastal Marshlands, Louisiana)				
Bivouac Peak Private Landowner Leases**	Byron	93.00/69.285	September 2019	9.70
Bivouac Peak State Lease number 21778**	Byron	100.00/76.00	January 2021	0.81
Bivouac Peak State Lease number 21779**	Byron	100.00/72.50	January 2021	0.53

* Metgasco Limited ('Metgasco') has exercised its option to earn a 30% Working Interest ('WI') and 24.375% Net Revenue Interest ('NRI') in SM74. Metgasco has elected to participate to earn a 30% WI in the SM74 lease and the SM74 D-14 well by paying 40% of the cost of the well to casing point and 40% of the cost of the leasehold acquisition. Metgasco will also reimburse the Company for 30% of certain other acquisition expenses

** Both Otto Energy Limited ('Otto') and Metgasco Limited ('Metgasco') have exercised their options to earn a 40% and 10% working interest, respectively, in Byron's Bivouac Peak Landowner Leases and State Leases. If both Otto and Metgasco earn into the Bivouac Peak project, Byron's working interest and net revenue interest will be reduced to 43% and 32.035% respectively. Otto and Metgasco will earn a 40% and 10% working interest respectively by paying a disproportionate share of the costs of the initial test well to reach the earning depth or up to a cap of US$10.0 million (gross cost), whichever occurs first, after which Otto and Metgasco will revert back to paying 40% and 10% of all future costs.

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Review of strategy, principal risks and uncertainties facing the company

Strategy

Since inception Byron has focused on the shallow waters and transition zone (offshore Louisiana) of the OCS in the GOM. The Directors believe that the shallow waters and transition zone (offshore Louisiana) of the GOM offer significant advantages to Byron, as the GOM:

- is a prolific producer of oil and gas;
- has significant proved and unproved reserves of low cost oil and gas as well as significant potential for further hydrocarbon discoveries;
- has extensive, established and accessible oil and gas exploration, development and production infrastructure;
- offers a short development cycle and rapid payback;
- has modern 3D seismic coverage, suitable for improved imaging, over fields and prospects, available for purchase from third-party providers; advanced seismic processing techniques have allowed the industry to better distinguish hydrocarbon traps and identify previously unknown prospects;
- has a well-established and stable administration with one landowner for the shallow waters, BOEM; and
- the GOM shallow waters have regular lease sales conducted by BOEM with 5,000 acre blocks available, generally to the highest bidder, to lease for five years at US$7 per acre per annum.

Byron is well positioned to exploit the competitive advantages of the GOM as the Company has:

- an experienced team of oil and gas exploration, development and production personnel with a successful track record in the GOM, with significant experience utilising advanced seismic image processing techniques, including reverse time migration, in Byron's area of focus;
- a producing and cash generating asset, SM71;
- an inventory of relatively low risk, ready to drill prospects, including several prospects with significant oil potential; and
- the capacity to grow its asset portfolio in the shallow waters and transition zone of the GOM.

Byron's strategy in the GOM comprises three key elements:

- to identify highly prospective oil and gas plays, aided by leading edge seismic technology such as RTM, which is particularly effective in the shallow waters of the GOM;
- to secure the leases, usually on a 100% or majority working interest basis primarily through the annual Federal Government lease sale process in the GOM; and
- Byron will either drill-test the play as operator holding a 100% working interest or seek to farm out up to 50% of its WI to a non-operator or another operator with a proven track record of drilling and producing wells in the GOM, retaining a 40 to 50% WI in the block.

Principal risks and uncertainties

The key areas of risk, uncertainty and material issues facing the Company in executing its strategy and delivering on its targets are described below.

Risks relating to the company's industry, business and financial condition

There are a number of risks which may impact on the operating and financial performance of the Company and therefore, on the value of its shares. Some of these risks can be mitigated by the Company's systems and internal controls, but many are outside of the control of the Company and the Board. There can be no guarantee that the Company will achieve its stated objectives or that any forward-looking statements will eventuate.

In addition to risks and uncertainties in the ordinary course of business that are common to all businesses, important factors that are specific to the Company and the oil and gas industry could materially impact the Company's future performance and results of operations. Below is a list of known material risk factors that should be reviewed when considering buying or selling Byron's shares. These are not all the risks the Company faces and other factors currently considered immaterial or unknown may impact future operations.

Oil and natural gas price risk

The Company's revenues, profitability and future growth depend significantly on crude oil and natural gas prices. Oil and natural gas prices are volatile and low prices could have a material adverse impact on cash flow and on Byron's business. Among the factors that can cause these fluctuations are: (i) changes in global supply and demand for oil and natural gas, (ii) the ability of the members of the Organisation of Petroleum Exporting Countries to agree to and maintain oil price and production controls, (iii) the price and volume of imports into the USA of foreign oil and natural gas, (iv) political and economic conditions, including embargoes, in oil-producing countries or affecting other oil-producing activity (vi) the level of global oil and gas exploration and production activity, (vii) weather conditions, (viii) technological advances affecting energy consumption, (ix) USA domestic and foreign governmental regulations and taxes, (xi) proximity and capacity of oil and gas pipelines and other transportation facilities, (x) the price and availability of competitors' supplies of oil and gas in captive market areas, (xi) the introduction, price and availability of alternative forms of fuel to replace or compete with oil and natural gas, (xii) import and export regulations for LNG and/or refined products derived from oil and gas production from the USA, (xii) speculation in the price of commodities in the commodity futures market, (xiii) the availability of drilling rigs and completion equipment; and the overall economic environment.

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Financing risk

Byron's business plan, which includes participation in seismic data purchases, lease acquisitions and the drilling of exploration and development prospects, has required and is expected to continue to require capital expenditures. Byron may require additional financing to fund its planned growth. This additional financing may be in the form of equity, debt or a combination thereof. Byron may also obtain capital by farming out part of its working interest in one or more of its oil and gas properties. Byron's ability to raise additional capital will depend on the results of its operations and the status of various capital and industry markets at the time it seeks such capital. Accordingly, additional financing may not be available on acceptable terms, if at all. In the event additional capital resources are unavailable, Byron may be required to curtail its exploration and development activities. It is difficult to quantify the amount of financing Byron may need to fund its planned growth in the longer term. The amount of funding Byron may need in the future depends on various factors, including but not limited to: (i) the Company's financial condition, and (ii) the success or otherwise of its exploration and development programme. Further, the availability of such funding may depend on various factors, including but not limited to, the liquidity of the Company's shares at the time the Company seeks to raise funds and the prevailing and forecast market price of oil and natural gas. If Byron raises additional funds through the issue of equity securities, this may dilute the holdings of existing shareholders. If Byron obtains additional capital by farming out part of its working interest in one or more of its oil and gas properties, the Company's share of reserves, future production and therefore oil and/or and gas revenues, if any, from those properties will be reduced.

Third-party pipelines and operators risk

Byron may from time to time, depend on third-party platforms and pipelines that provide processing and delivery options from its facilities. As these platforms and pipelines are not owned or operated by Byron, their continued operation is not within Byron's control. Revenues in the future may be adversely affected if Byron's ability to process and transport oil or natural gas through those platforms and pipelines is impaired. If any of these platform operators ceases to operate their processing equipment, Byron may be required to shut in the associated wells, construct additional facilities or assume additional liability to re-establish production.

Oil and gas reserves estimation risk

There are numerous uncertainties in estimating crude oil and natural gas reserves and their value, including many factors that are beyond the control of the Company. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities of reserves. In order to prepare these estimates, Byron's independent third-party petroleum engineers must project production rates and timing of development expenditures as well as analyse available geological, geophysical, production and engineering data, and the extent, quality and reliability of this data can vary. The process also requires economic assumptions relating to matters such as natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and pre-tax net present value of reserves. In addition, estimates of proved reserves may be adjusted to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond the Company's control and may prove to be incorrect over time. As a result, estimates may require substantial upward or downward revisions if subsequent drilling, testing and production reveal different results. Furthermore, some of the producing wells included in the Company's reserve report have produced for a relatively short period of time. Accordingly, some of the Company's reserve estimates are not based on a multi-year production decline curve and are calculated using a reservoir simulation model together with volumetric analysis. Any downward adjustment could indicate lower future production and thus adversely affect the Company's financial condition, future prospects and market value.

Oil and gas reserves depletion risk

Byron's future oil and natural gas production depends on its success in finding or acquiring new reserves. If Byron fails to replace reserves, its level of production and cash flows will be adversely impacted. Production from oil and natural gas properties decline as reserves are depleted, with the rate of decline depending on reservoir characteristics. Byron's total proved reserves will decline as reserves are produced unless it can conduct other successful exploration and development activities or acquire properties containing proved reserves, or both.

Further, all of Byron's proved reserves are proved developed producing or behind pipe. Accordingly, Byron does not have significant opportunities to increase production from its existing proved reserves. Byron's ability to make the necessary capital investment to maintain or expand its asset base of oil and natural gas reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. Byron may not be successful in exploring for, developing or acquiring additional reserves. If Byron is not successful, its future production and revenues will be adversely affected.

Oil and gas drilling risk

Drilling for crude oil, natural gas and natural gas liquids are high risk activities with many uncertainties that could adversely affect the Company's business, financial condition or results of operations.

The drilling and operating activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for crude oil, natural gas and natural gas liquids can be unprofitable, not only from dry holes, but from productive wells that do not produce sufficient revenues to return a profit. In addition, Byron's drilling and producing operations may be curtailed, delayed or cancelled as a result of other factors, including, unusual or unexpected geological formations and miscalculations; pressures; fires; explosions and blowouts; pipe or cement failures; environmental hazards; such as natural gas leaks; oil spills; pipeline and tank ruptures; encountering naturally occurring radioactive materials and unauthorised discharges of toxic gases, brine, well stimulation and completion fluids, or other pollutants into the surface and subsurface environment; loss of drilling fluid circulation; title problems; facility or equipment malfunctions; unexpected operational events; shortages of skilled personnel; shortages or delivery delays of equipment and services; compliance with environmental and other regulatory requirements; natural disasters; and adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life; severe damage to or destruction of property, natural resources and equipment, pollution, environmental contamination, clean-up responsibilities, loss of wells, repairs to resume operations; and regulatory fines or penalties.

Operating risk

The oil and natural gas business, including production activities, involves a variety of operating risks, including: blowouts, fires and explosions; surface cratering; uncontrollable flows of underground natural gas, oil or formation water; natural disasters; pipe and cement failures; casing collapses; stuck drilling and service tools; reservoir compaction; abnormal pressure formation; environmental hazards such as natural gas leaks, oil spills, pipeline and tank ruptures or unauthorised discharges of brine, toxic gases or well fluids; capacity constraints, equipment malfunctions and other problems at third-party operated platforms, pipelines and gas processing plants over which Byron has no control; repeated shut ins of Byron's well bores could significantly damage the Company's well bores; required workovers of existing wells that may not be successful.

If any of the above events occur, Byron could incur substantial losses as a result of injury or loss of life; reservoir damage; severe damage to and destruction of property or equipment; pollution and other environmental and natural resources damage; restoration, decommissioning or clean-up responsibilities; regulatory investigations and penalties; suspension of our operations or repairs necessary to resume operations.

Offshore operations are subject to a variety of operating risks peculiar to the marine environment, such as capsizing and collisions. In addition, offshore operations, and in some instances operations along the Gulf Coast, are subject to damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, the Company could incur substantial liabilities that could reduce the funds available for exploration, development or leasehold acquisitions, or result in loss of properties.

If Byron was to experience any of these problems, it could affect well bores, platforms, gathering systems and processing facilities, any one of which could adversely affect its ability to conduct operations. In accordance with customary industry practices, Byron maintains insurance against some, but not all, of these risks. Losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The Company may not be able to maintain adequate insurance in the future at rates we consider reasonable, and particular types of coverage may not be available. An event that is not fully covered by insurance could have a material adverse effect on the Company's financial position and results of operations.

Execution risk (drilling and operating programs)

Shortages or increases in the cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect Byron's operations which could have a material adverse effect on its business, financial condition and results. Where Byron is the operator it assumes additional responsibilities and risks. As the designated operator, Byron, under the BOEM regulations, will be required to post bonds for exploration and development activities as well as for production activities and future decommissioning obligations. There is the risk that the Company may not be able to obtain sufficient bonding and may have to collateralise obligations with cash. If the Company was unable to provide such bonds, it would not be able to proceed with its operating plans. In addition, as the designated operator Byron will have to demonstrate the required oil spill financial responsibility ('OSFR') under the Oil Pollution Act of 1990. The OSFR is based on worst case oil-spill discharge volume. Byron expects to demonstrate OSFR requirement through the purchase of OSFR insurance coverage, a method of demonstrating OSFR acceptable to the BOEM. If the Company was unable to demonstrate OSFR as required by the BOEM, it would not be able to proceed with its operating plans.

Geographic concentration risk

The geographic concentration of Byron's properties in the shallow waters and transition zone (offshore Louisiana) in the GOM means that some or all of the properties could be affected by the same event should the Gulf of Mexico experience severe weather, delays or decreases in production, changes in the status of pipelines, delays in the availability of transport and changes in the regulatory environment.

Because all of the Company's properties could experience the same condition at the same time, these conditions could have a relatively greater impact on results of operations than they might have on other operators who have properties over a wider geographic area.

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Climate change risk

Climate change continues to attract considerable public, governmental and scientific attention. As a result, numerous proposals have been made and could continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of greenhouse gases. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on the Company's business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. Offshore operations are particularly at risk from severe climatic events. If any such effects were to occur, they could have an adverse effect on the Company's financial condition and results of operations.

Competition risk

Competition in the oil and natural gas industry is intense which may make it more difficult for Byron to acquire further properties, market oil and gas and secure trained personnel. There is also competition for capital available for investment, particularly since alternative forms of energy have become more prominent. Most competitors possess and employ financial, technical and personnel resources substantially greater than those available to Byron. As a result increased costs of capital could have an adverse effect on Byron's business.

Regulatory risk

Byron's oil and gas operations in the Gulf of Mexico, USA are subject to regulation at the US Federal, State and local level and some of the laws, rules and regulations that govern operations carry substantial penalties for non-compliance. Rules and regulations affecting the oil and gas industry are under constant review for amendment or expansion. In addition to possible increased costs, the imposition of increased regulatory-based procedures may result in delays in being able to initiate or complete drilling programs.

Environmental risk

The natural gas and oil business involves a variety of operating risks, including but not limited to (i) blowouts, fires and explosions, (ii) surface cratering, (iii) uncontrollable flows of underground natural gas, oil or formation water and natural disasters. If any of the above events occur, Byron could incur losses as a result of injury or loss of life, reservoir damage, damage to and destruction of property or equipment, pollution and other environmental damage, clean-up responsibilities and regulatory investigations and penalties.

The operation of our future oil and gas properties will be subject to numerous federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties and the imposition of injunctive relief. Accidental releases or spills may occur in the course of the operations of our properties, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons.

Among the environmental laws and regulations that could have a material impact on the oil and natural gas exploration and production industry and the Company's business are the following: Waste Discharges, Air Emissions and Climate Change, Oil Pollution Act, National Environmental Policy Act, Worker Safety, Safe Drinking Water Act, Offshore Drilling, Hazardous Substances and Wastes and Protected and Endangered Species.

Key management risk

To a large extent, the Company depends on the services of its senior management. The loss of the services of any of the senior management team, could have a negative impact on the Company's operations. Byron does not maintain or plan to obtain for the benefit of the Company any insurance against the loss of any of these individuals.

Oil and gas transport and processing risk

All of Byron's oil and natural gas is transported through gathering systems, pipelines and processing plants. Transportation capacity on gathering system pipelines and platforms is occasionally limited and at times unavailable due to repairs or improvements being made to these facilities or due to capacity being utilised by other natural gas or oil shippers that may have priority transportation\ agreements. If the gathering systems, processing plants, platforms or Byron's transportation capacity is materially restricted or is unavailable in the future, the Company's ability to market its oil and/or natural gas could be impaired and cash flow from the affected properties could be reduced, which could have a material adverse effect on its financial condition and results of operations. Further, repeated shut ins of Byron's wells could result in damage to its well bores that would impair its ability to produce from these wells and could result in additional wells being required to produce existing reserves.

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Exchange rate risk

The functional currency of Byron is Australian dollars and the functional currency of its United States-based subsidiaries is United States dollars. Byron has historically presented its financial statements in United States dollars, as the United States dollar is viewed as the best measure of performance for Byron because oil and gas, the dominant sources of revenue, are priced in United States dollars and its oil and gas operations are located in the United States with costs incurred in United States dollars.

As all Byron's operating assets are in the United States, the Company's presentation currency, the currency in which it reports its financial results, will be United States dollars. Accordingly, an Australian dollar investment in the Company is exposed to fluctuations between the Australian dollar and the United States dollar exchange rate. In particular, as most of the Company's capital and operating expenses will be in United States dollars any appreciation/depreciation in the Australian dollar against the United States dollar will effectively decrease/increase the quantum of those costs for shareholders. In addition the Company's revenue is derived from United States dollar oil and gas sales. Any appreciation/depreciation of the Australian dollar against the United States dollar will effectively reduce/increase the value of that revenue for shareholders.

Adverse exchange rate variations between the Australian dollar and the United States dollar may impact upon cash balances held in Australian dollars. Since most of Byron's operations are conducted in United States dollars, Byron generally maintains a substantial portion of its cash balances in United States dollar accounts. From time to time the Company may have substantial cash deposits in Australian dollar accounts. Until these funds are converted into United States dollars, the United States dollar value of the deposits will change as the exchange rate between the two currencies fluctuates.

The Company does not currently have in place any foreign exchange hedging arrangements. However, foreign exchange hedging strategies will be reviewed by the Company from time to time, implementation of any strategy will depend, inter alia, upon the foreign exchange hedging options available to the Company from time to time, the cash cost of entering into hedging transactions and the Company's capacity to pay for such costs.

Other risks

There are a number of other risks which may impact on the operating and financial performance of the Company, including but not limited to:

Seismic risk

3D seismic data and visualisation techniques only assist geoscientists and geologists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know if hydrocarbons are present or producible economically.

Lease termination risk

The failure to timely effect all lease related payments could cause the leases to be terminated by the BOEM.

Profitability and impairment write-downs risk

Byron may incur non-cash impairment charges in the future, which could have a material adverse effect on its results of operations for the periods in which such charges are taken.

Working interest partners' risk

If partners are not able to fund their share of costs, it could result in the delay or cancellation of future projects, resulting in a reduction of Byron's reserves and production, which could have a materially adverse effect on its financial condition and results of operations.

Bonding risk

As an operator, Byron is required to post surety bonds of US$200,000 per lease for exploration and US$500,000 per lease for developmental activities as part of its general bonding requirements, as well as the posting of additional supplemental bonds to cover, among other things, decommissioning obligations. A failure by an operator to post required supplemental bonding or other financial assurances required by the BOEM could result in the BOEM assessing monetary penalties or requiring any operations on an operator's federal lease to be suspended or cancelled or otherwise subject an operator to monetary penalties. Any one or more such actions imposed on us could materially adversely affect Byron's financial condition and results of operations.

Asset retirement obligations ('AROS') risk

Byron is required to record a liability for the present value of AROs to plug and abandon inactive, non-producing wells, to remove inactive or damaged platforms, facilities and equipment and to restore land and seabed when production finishes. Estimating future costs is uncertain because most obligations are many years in the future, regulatory requirements will change and technologies are evolving which may make it more expensive to meet these obligations.

Insurance risk

In accordance with industry practice Byron maintains insurance against some, but not all, of the operating risks to which its business is exposed. Byron will not be insured against all potential risks and liabilities. Future insurance coverage for the oil and gas industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that are economically acceptable.

Cyber-security risk

The oil and gas industry is increasingly dependent on digital technologies to conduct certain exploration, development, production, processing and distribution activities. The industry faces various security threats, including cyber-security threats. Cyber-security attacks in particular are increasing. Although to date Byron has not experienced any material losses related to cyber-security attacks, it may suffer such losses in the future. If any of these events were to materialise, they could lead to losses of intellectual property and other sensitive information essential to the Company's business and could have a material adverse effect on its business prospects, reputation and financial position.

Share market investment risk

The Company's shares are quoted on the ASX, where their price may rise or fall. The shares carry no guarantee in respect of profitability, dividends or return of capital, or the price at which they may trade on the ASX. The value of the shares will be subject to the market and hence a range of factors outside of the control of the Company and the Directors and officers of the Company. Returns from an investment in the shares may also depend on general share market conditions, as well as the performance of the Company

Historically, the stock market has experienced significant price and volume fluctuations. Stock market volatility and volatility in commodity prices has had a significant impact on the market price of securities issued by many companies, including companies in the oil and gas industry. The changes frequently appear to occur without regard to the operating performance of the affected companies. Hence, the price of the Company's shares could fluctuate based upon factors that have little or nothing to do with Byron, and these fluctuations could materially reduce its share price.

The Company's board of directors presently intends to retain all of our earnings for the expansion of the business; therefore, there are no plans to pay regular dividends. Any payment of future dividends will be at the discretion of the board of directors and will depend on, among other things, earnings, financial condition, capital requirements, level of indebtedness, and other considerations that the board of directors deems relevant.

Future sales or the availability for sale of substantial amounts of the Company's shares in the public market could adversely affect the prevailing market price of Byron's shares and could impair its ability to raise capital through future issues of equity securities.

Significant events after the balance date

There has been no matter or circumstance since 30 June 2018 which has significantly affected or may significantly affect the operations of the consolidated entity, the results of those operations or the state of affairs of the consolidated entity in subsequent financial years other than those described below:

(i) On 9 July 2018, Byron announced to the ASX that, Otto Energy Limited, Metgasco Limited and NOLA Oil and Gas Ventures LLC have all elected to participate in the Byron operated Weiss-Adler et. al. No. 1 well to be drilled to a depth of 18,294 ft MD/18,000 ft TVD to test the Bivouac Peak East Prospect;

(ii) On 19 July 2018, Byron announced to the ASX that it was finalising documentation to allow the SM74 prospect to be drilled from the adjacent existing SM73 D platform and that it has farmed out a 30% working interest on standard industry terms;

(iii) On 6 August 2018, Byron announced to the ASX the SM71 reserves and prospective resources, as at 30 June 2018, as independently assessed by Collarini Associates;

(iv) On 16 August 2018, Byron announced to the ASX that it was the high bidder on Main Pass 293, 305 and 306 leases at the Gulf of Mexico OCS Lease Sale 251, held on 15 August 2018; and

(v) On 19 September 2018, the Company released its annual reserves and resources report as of 30 June 2018.

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Future developments

It is expected that the consolidated entity will continue its oil and gas exploration, development and production activities in the shallow and transition zone waters of the Gulf of Mexico, USA.

Further information regarding likely developments are not included in this report. As the Company is listed on the Australian Securities Exchange ('ASX'), it is subject to the continuous disclosure requirements of the ASX Listing Rules which require immediate disclosure to the market of information that is likely to have a material effect on the price or value of Byron Energy Limited's securities.

Dividends

No dividends in respect of the current financial year have been paid, declared or recommended for payment (2017: nil).

Environmental regulation

The consolidated entity's operations are not regulated by any significant environmental regulation under a law of the Commonwealth or of any State or Territory of Australia. The consolidated entity's oil and gas exploration activities are subject to significant environmental regulation under United States of America Federal and State legislation.

The Directors are not aware of any breach of environmental compliance requirements relating to the consolidated entity's activities during the year.

Non-audit services

Deloitte Touche Tohmatsu did not provide non-audit services to the Company during the financial year.

Auditor independence declaration

A copy of the auditor's independence declaration under s.307C of the *Corporation Act 2001* in relation to the audit of the full year is included in this report.

Indemnification and insurance of officers and auditors

During the financial year the Company paid an insurance premium in respect of Directors' and officers' liability for the current directors and officers including the company secretary. Under the terms of the policy the premium amount, coverage and other terms of the policy have been agreed to be confidential and not to be disclosed.

The Company has not otherwise, during or since the financial year, except to the extent permitted by law, indemnified or agreed to indemnify an officer or auditor of the Company or of any related body corporate against a liability incurred as such an officer or auditor.

Significant changes in the state of affairs

During the financial year, there were no significant changes in the state of affairs of the consolidated entity, other than those set out in the Review of Operations.

Directors' meetings

The charter for the Audit and Risk Management Committee was adopted on 12 July 2007 and most recently amended on 25 June 2014. The current members of the committee consist of Paul Young (Chairman) and Charles Sands.

During the year there was four Board meetings and four Audit and Risk Management Committee meetings held. The numbers of meetings attended by each Director were as follows:

	Board of directors		Audit and risk management committee	
Directors	**Entitled to attend**	**Attended**	**Entitled to attend**	**Attended**
Douglas G Battersby	4	4	–	–
Maynard V Smith	4	4	–	–
Prent H Kallenberger	4	4	–	–
Charles J Sands	4	2	4	4
Paul A Young	4	3	4	4
William R Sack	4	3	–	–

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Remuneration Report – Audited

This Remuneration Report, which forms part of the Directors' Report, sets out information about the remuneration of the Group's Directors and other key management personnel for the financial year ended 30 June 2018. The prescribed details for each person covered by this report are detailed below.

Details of directors and other key management personnel

Directors and other key management personnel of the Company during and since the end of the financial year are as follows

Directors

Douglas G Battersby

Maynard V Smith

Prent H Kallenberger

Charles J Sands

Paul A Young

William R Sack

Key management personnel

Nick Filipovic – Chief Financial Officer and Company Secretary

The Remuneration Report is set out below under the following main headings:

A. Principles and agreements; and

B. Remuneration of Directors and other key management personnel

A. Principles and agreements

Remuneration levels are set to attract and retain appropriately qualified and experienced directors and executives. The Board is responsible for remuneration policies and practices. The Board may seek independent advice on remuneration policies and practices, including compensation packages and terms of employment.

The directors' and key management personnel remuneration levels are not directly dependent upon the Company or consolidated entity's performance or any other performance conditions.

Directors' remuneration is inclusive of committee fees.

Additional information

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 US$	30 June 2015 US$	30 June 2016 US$	30 June 2017 US$	30 June 2018 US$
Revenue (net of royalties)	–	–	–	–	**9,544,507**
Net profit (loss) before tax	(7,305,087)	(4,238,855)	(30,944,243)	(5,357,583)	**1,298,968**
Net profit (loss) after tax	(7,305,087)	(4,238,855)	(30,944,243)	(5,357,583)	**1,298,968**
Share price at start of year	A$0.405	A$0.70	A$0.23	A$0.15	**A$0.095**
Share price at end of year	A$0.70	A$0.23	A$0.15	A$0.095	**A$0.355**
Basic earnings per share	(US$0.057)	(US$0.029)	(US$0.147)	(US$0.02)	**US$0.0022**
Diluted earnings per share	(US$0.057)	(US$0.029)	(US$0.147)	(US$0.02)	**US$0.0022**

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(i) Non-executive directors

The ASX Listing Rules provide that the aggregate remuneration of Non-Executive Directors shall be determined from time to time by a general meeting of shareholders. The latest determination was at the Extraordinary General Meeting held on 22 April 2013 when shareholders approved an aggregate remuneration of A$300,000 per annum.

The amount of aggregate remuneration sought to be approved by shareholders and the fee structure is reviewed annually.

The Chairman, Douglas Battersby, is paid an annual non-executive director's fee of A$80,000, paid pro-rata on a quarterly basis, as well as costs relating to performance of duties as a Director.

Non-executive directors, Charles Sands and Paul Young, are paid an annual Non-Executive Director's fee of A$40,000 each, paid pro-rata on a quarterly basis, as well as costs relating to performance of duties as a Director.

There are no termination or retirement benefits for Non-Executive Directors (other than statutory superannuation where applicable).

(II) Executive directors and key management personnel

Remuneration levels of executive directors and key management personnel are set to attract and retain appropriately qualified and experienced Directors and Executives. This involves assessing the appropriateness of the nature and amount of remuneration on a periodic basis by reference to market conditions, length of service and particular experience of the individual concerned.

Remuneration packages may include a mix of fixed and variable remuneration, short and long-term performance-based incentives. The remuneration packages are reviewed annually by the Board as required.

Remuneration and other terms of employment of the Chief Executive Officer (Maynard Smith), Executive Director and Chief Operating Officer (Prent Kallenberger), Executive Director (William Sack) and the CFO/Company Secretary (Nick Filipovic) are detailed below.

Fixed remuneration for executive directors and key management personnel

Maynard Smith

The Company entered into a service agreement with Maynard Smith via a company of which Mr Smith is a Director. Mr Smith's contract is for a period of two years at an annual rate of A$240,000 plus reasonable and justifiable business expenses commencing on 24 May 2013 with an automatic extension for a further one year unless the parties elect to terminate the contract at the end of two years. The contract is further terminable by either party 'for cause' immediately on notice and otherwise 'without cause' on 120 days' notice As announced to the ASX on 30 May 2016, Mr Smith agreed to extend his contract with the Company for a further six months until 24 November 2016. Effective 1 April 2015, Mr Smith's service agreement fee was reduced by one-third to A$160,000 per annum plus reasonable and justifiable business expenses. Since 24 November 2016, Mr Smith has continued in his role as CEO on a service fee of A$160,000 per annum plus reasonable and justifiable business expenses. On 15 September 2017, the Company announced that Mr Smith had entered into a new service agreement, for three years commencing on 15 September 2017. Under the new service agreement Mr Smith's service fee will continue at the current rate of A$160,000 per annum in fixed service fees and will be reviewed after production at SM71 commences. In addition, Mr Smith will be eligible to participate in the Company's short and long-term incentive scheme as determined by the Board from time to time.

On 26 June 2018 the Company announced that the annual service fee payable in respect of Mr Smith's services has been increased from A$160,0000 to A$550,000 (excluding GST) per annum, effective 1 July 2018. All other terms and conditions of the service agreement remain unchanged.

Prent Kallenberger

The Company entered into an employment agreement with Prent Kallenberger. Mr Kallenberger's contract is for a period of two years, at annual rate of US$350,000 plus medical insurance and reasonable and justifiable business expenses commencing on 24 May 2013 with an automatic extension for a further one year unless the parties elect to terminate the contract at the end of two years. The contract is further terminable by the Company 'for cause' immediately on notice and otherwise 'without cause' on 90 days' notice. As announced to the ASX on 30 May 2016, Mr Kallenberger agreed to extend his contract with the Company for a further six months until 24 November 2016. Effective 1 April 2015, Mr Kallenberger's service agreement remuneration was reduced by one-third to US$234,000 per annum plus medical insurance and reasonable and justifiable business expenses. Since 24 November 2016 Mr Kallenberger has continued in his role with remuneration at a rate of US$234,000 per annum plus medical insurance and reasonable and justifiable business expenses. On 15 September 2017, the Company announced that Mr Kallenberger had entered into a new service agreement, for three years commencing on 15 September 2017. Under the new service agreement, Mr Kallenberger's remuneration will be reinstated to its former level of US$350,000 per annum in fixed remuneration plus medical insurance. In addition, Mr Kallenberger will be eligible to participate in the Company's short and long-term incentive scheme as determined by the Board from time to time.

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William Sack

The Company entered into an employment agreement with William Sack. Mr Sack's contract is for a period of two years, at annual rate of US$350,000 plus medical insurance and reasonable and justifiable business expenses commencing on 3 October 2014 with an automatic extension for a further one year unless the parties elect to terminate the contract at the end of two years. The contract is further terminable by the Company 'for cause' immediately on notice and otherwise 'without cause' on 90 days' notice. Effective 1 April 2015, Mr Sack's service agreement remuneration was reduced by one-third to US$234,000 per annum plus medical insurance and reasonable and justifiable business expenses. On 15 September 2017, the Company announced that Mr Sack had entered into a new service agreement for three years commencing on 15 September 2017. Under the new service agreement, Mr Sack's remuneration will be reinstated to its former level of US$350,000 per annum in fixed remuneration plus medical insurance. In addition, Mr Sack will be eligible to participate in the Company's short and long-term incentive scheme as determined by the Board from time to time.

Nick Filipovic

The Company has entered into a formal letter agreement with Nick Filipovic. Under Mr Filipovic's letter of engagement, he is entitled to a gross salary of A$300,000 per annum plus superannuation at the statutory rate. Byron may terminate Mr Filipovic's employment at any time by giving 90 days' notice or in case of serious misconduct employment may be terminated without notice. Should Mr Filipovic resign from Byron he will need to give 90 days' notice. Effective 1 April 2015, Mr Filipovic's remuneration was reduced by one-third and to A$200,000 per annum, plus superannuation at the statutory rate. Commencing on 1 October 2017, Mr Filipovic's remuneration under his letter of engagement was reinstated to its former level of A$300,000 per annum plus superannuation at statutory rate.

B. Remuneration of directors and key management personnel

Options

The Executive Directors were granted 6,300,000 share options each, following shareholder approval at the EGM held on 18 September 2018, in consideration for entering into new three-year service agreements and in recognition of a successful discovery at SM71, new lease acquisitions and completion of a successful fund raising. The exercise price of the share options of A$0.12 cents was a premium of 71% over the share price at the time of the announcement of the option issue. The Board considers the number of share options granted to the Executive Directors is commensurate with their value to the Company and the potential for them to increase shareholder value. In addition, 3,780,000 share options were granted to the CFO and Company Secretary, in recognition of his contribution to the Company, which the Board considers to be commensurate with his value to the Company and the potential for him to increase shareholder value. No options were exercised during the financial year. There are no Employee Share Option plans in place.

At the end of the financial year, the following share-based payment arrangements were in existence:

Grantee	Number	Grant date	Vesting date	Expiry date	Exercise price	Fair value at grant date
M Smith	2,500,000	24 Nov 2016	24 Nov 2016	31 Dec 2019	A$0.25	A$0.0489
M Smith	6,300,000	18 Sept 2017	18 Sept 2017	31 Dec 2021	A$0.12	A$0.0555
P Kallenberger	2,500,000	24 Nov 2016	24 Nov 2016	31 Dec 2019	A$0.25	A$0.0489
P Kallenberger	6,300,000	18 Sept 2017	18 Sept 2017	31 Dec 2021	A$0.12	A$0.0555
W Sack	2,500,000	24 Nov 2016	24 Nov 2016	31 Dec 2019	A$0.25	A$0.0489
W Sack	1,700,000	15 Feb 2016	15 Feb 2016	30 Sept 2018	A$0.25	A$0.0959
W Sack	6,300,000	18 Sept 2017	18 Sept 2017	31 Dec 2021	A$0.12	A$0.0555
N Filipovic	1,000,000	24 Nov 2016	24 Nov 2016	31 Dec 2019	A$0.25	A$0.0489
N Filipovic	3,780,000	18 Sept 2017	18 Sept 2017	31 Dec 2021	A$0.12	A$0.0555

These options are transferrable and not quoted. They may be exercised at any time after vesting date.

The following table summarises the value of remuneration options granted during the year. Other than the value of options granted in the table below, there were no other Directors and other key management personnel options granted or exercised during the year.

Grantees	Value of options granted in US$*
Mr M V Smith	270,921
Mr P H Kallenberger	270,921
Mr W R Sack	270,921
Mr N Filipovic	162,552

* The value of the options granted to a Director as part of their remuneration is calculated as at the grant date in accordance with AASB 2 using a binomial pricing model.

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Other transactions with key management personnel of the group

During the year, the Company entered into unsecured loan agreements, bearing interest at 10% per annum, with three of the Company's Directors, for a total drawdown of US$1,000,000 and A$520,000. The loans were outstanding on 30 June 2018 and due for repayment in October 2018. The individual Directors' transactions and balances for these loans were:

- Veruse Pty Ltd, a company controlled by Mr Douglas Battersby, provided an unsecured loan of A$520,000 to the Company; and interest charges of A$7,693 have been accrued as at 30 June 2018;
- Geogeny Pty Ltd, a company controlled by Mr Maynard Smith, provided an unsecured loan of US$500,000 to the Company; and interest charges of US$9,178 have been accrued as at 30 June 2018; and
- Charles Sands, provided an unsecured loan of US$500,000 to the Company; and interest charges of US$8,384 (net of withholding taxes) have been accrued as at 30 June 2018.

		Short-term employee benefits			Post employment benefits	Share-based payments	
	Salaries and fees US$	Short term cash incentive US$	Other benefits US$	Service agreements US$	Super-annuation US$	100% vested share options US$	Total US$
2018							
Directors							
D G Battersby	–	–	–	62,024	–	–	62,024
M V Smith	–	–	–	124,048	–	270,921	394,969
P H Kallenberger	321,000	–	27,786	–	–	270,921	619,707
C J Sands	31,012	–	–	–	–	–	31,012
P A Young	31,012	–	–	–	2,946	–	33,958
W R Sack	321,000	–	24,400	–	–	270,921	616,321
Key management personnel							
N Filipovic	213,208	–	–	–	20,255	162,552	396,015
	917,232	–	52,186	186,072	23,201	975,315	2,154,006

		Short-term employee benefits			Post employment benefits	Share-based payments	
	Salaries and fees US$	Short term cash incentive US$	Other benefits US$	Service agreements US$	Super-annuation US$	100% vested share options US$	Total US$
2017							
Directors							
D G Battersby	–	–	–	60,360	–	–	**60,360**
M V Smith	–	–	–	120,720	–	92,218	**212,938**
P H Kallenberger	243,667	–	26,805	–	–	92,218	**362,690**
C J Sands	30,180	–	–	–	–	–	**30,180**
P A Young	30,180	–	–	–	2,867	–	**33,047**
W R Sack	243,667	–	19,000	–	–	92,218	**354,885**
Key management personnel							
N Filipovic	150,900	–	–	–	14,336	36,887	**202,123**
	698,594	**–**	**45,805**	**181,080**	**17,203**	**313,541**	**1,256,223**

Bonuses

No bonuses were granted during the financial year ended 30 June 2018 (2017: nil).

Additional information – key management personnel equity and share option holdings

The interests of each director and other key management personnel (directly and indirectly), in the shares and options of Byron Energy Limited are as follows:

Ordinary Shares

Director/key management personnel	Balance on 1 July 2017 number	Granted as compensation number	Received on exercise of options number	Placement of shares* number	Balance on 30 June 2018 number
D G Battersby	30,123,203	–	–	18,000,000	**48,123,203**
M V Smith	18,027,868	–	–	14,285,715	**32,313,583**
P H Kallenberger	1,732,223	–	–	–	**1,732,223**
C J Sands	11,865,997	–	–	7,900,000	**19,765,997**
P A Young	9,926,617	–	–	8,729,014	**18,655,631**
W R Sack	700,000	–	–	1,200,000	**1,900,000**
N Filipovic	584,788	–	–	–	**584,788**

* Subscriptions for new shares via a placement.

During the financial year, no shares were granted to directors or other key management personnel of the Company.

Share options over ordinary shares

Director/key management personnel	Balance on 1 July 2017 number	Granted as compensation number	Exercise of options number	Expired number	Balance on 30 June 2018 number
M V Smith	2,500,000	6,300,000	–	–	**8,800,000**
P H Kallenberger	2,500,000	6,300,000	–	–	**8,800,000**
W R Sack	5,900,000	6,300,000	–	(1,700,000)	**10,500,000**
N Filipovic	1,000,000	3,780,000	–	–	**4,780,000**

During the financial year, Messers Smith, Kallenberger and Sack were each granted 6,300,000 share options and the Nick Filipovic was granted 3,780,000 share options. All share options granted were approved at a Company EGM.

End of Remuneration Report.

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This Directors' Report is signed in accordance with a resolution of directors made pursuant to s.298(2) of the *Corporations Act 2001*.

On behalf of the directors.

D G Battersby
Chairman

25 September 2018

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Auditor's Independence Declaration

Deloitte.

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25 September 2018

The Board of Directors
Byron Energy Limited
Level 4, 480 Collins Street
MELBOURNE VIC 3000

Dear Board Members

Byron Energy Limited

In accordance with section 307C of the *Corporations Act 2001*, I am pleased to provide the following declaration of independence to the directors of Byron Energy Limited.

As lead audit partner for the audit of the financial statements of Byron Energy Limited for the financial year ended 30 June 2018, I declare that to the best of my knowledge and belief, there have been no contraventions of:

(i) the auditor independence requirements of the *Corporations Act 2001* in relation to the audit; and
(ii) any applicable code of professional conduct in relation to the audit.

Yours sincerely

Deloitte Touche Tohmatsu

DELOITTE TOUCHE TOHMATSU

Craig Bryan
Partner

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Member of Deloitte Touche Tohmatsu Limited

Consolidated Statement of Profit or Loss and Other Comprehensive Income

For the Financial Year Ended 30 June 2018

	Note	Consolidated 2018 US$	2017 US$
Continuing operations			
Revenues from sale of oil and gas		**11,743,399**	–
Royalty expense		**(2,198,892)**	–
Cost of sales	2	**(1,807,414)**	–
Gross profit		**7,737,093**	–
Recoupment of operator overheads		**251,084**	
Corporate and administration costs		**(1,671,486)**	(1,503,082)
Impairment expense		**(1,746,863)**	(1,241,717)
Share-based payments		**(1,441,662)**	(754,493)
Depreciation/amortisation of property, plant and equipment		**(20,710)**	(15,957)
Other expenses		**(751,881)**	(1,220,724)
Earnings before interest and tax (EBIT)	2	**2,355,575**	(4,735,973)
Financial income	3	**15,425**	12,398
Financial expense	3	**(1,072,032)**	(634,008)
Profit before tax		**1,298,968**	(5,357,583)
Income tax expense	4	**–**	–
Profit for the year from continuing operations		**1,298,968**	(5,357,583)
Other comprehensive income, net of income tax			
Items that may subsequently be reclassified to profit and loss			
Exchange differences on translating the parent entity group		**135,435**	(144,321)
Total comprehensive profit for the year		**1,434,403**	(5,501,904)
Earnings per share			
Basic (cents per share)	5	**0.22**	(2.0)
Diluted (cents per share)	5	**0.22**	(2.0)

The accompanying notes form part of these financial statements.

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Consolidated Statement of Financial Position

At 30 June 2018

	Note	Consolidated 2018 US$	2017 US$
Assets			
Current assets			
Cash and cash equivalents	18(b)	**2,256,958**	3,395,501
Trade and other receivables	6	**6,208,427**	1,026,142
Other	7	**855,215**	665,930
Total current assets		**9,320,600**	5,087,573
Non-current assets			
Other	7	**732,062**	475,289
Exploration and evaluation assets	8(a)	**3,937,828**	2,421,473
Oil and gas properties	8(b)	**26,174,962**	5,896,622
Property, plant and equipment	9	**39,118**	36,921
Other intangible assets	10	**32,082**	1,778
Total non-current assets		**30,916,052**	8,832,083
Total assets		**40,236,652**	13,919,656
Liabilities			
Current liabilities			
Trade and other payables	11	**4,956,559**	2,329,884
Provisions	12	**131,112**	828,601
Borrowings	13	**4,750,992**	2,307,600
Total current liabilities		**9,838,663**	5,466,085
Non-current liabilities			
Provisions	12	**1,184,180**	127,758
Borrowings	13	**707,186**	3,998,400
Total non-current liabilities		**1,891,366**	4,126,158
Total liabilities		**11,730,029**	9,592,243
Net assets		**28,506,623**	4,327,413
Equity			
Issued capital	14	**99,296,931**	77,993,786
Foreign currency translation reserve	15	**(152,653)**	(288,088)
Share option reserve	15	**4,694,257**	3,252,595
Accumulated losses		**(75,331,912)**	(76,630,880)
Total equity		**28,506,623**	4,327,413

The accompanying notes form part of these financial statements.

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Consolidated Statement of Changes in Equity

For the Financial Year Ended 30 June 2018

Consolidated entity	Ordinary share capital US$	Share option reserve US$	Foreign currency translation reserve US$	Accumulated losses US$	Total US$
Balance at 1 July 2016	**74,040,848**	**2,498,102**	**(143,767)**	**(71,273,297)**	**5,121,886**
Loss for the year	–	–	–	(5,357,583)	(5,357,583)
Exchange differences arising on translation of the parent entity	–	–	(144,321)	–	(144,321)
Total comprehensive loss for the year	–	–	(144,321)	(5,357,583)	(5,501,904)
The issue of 36,916,167 shares under a placement at A$0.13 per share	3,628,601	–	–	–	3,628,601
The issue of 5,474,617 shares under a placement at A$0.13 per share	527,228	–	–	–	527,228
Recognition of share-based payments	–	754,493	–	–	754,493
Equity raising costs	(202,891)	–	–	–	(202,891)
Balance at 30 June 2017	**77,993,786**	**3,252,595**	**(288,088)**	**(76,630,880)**	**4,327,413**
Balance at 1 July 2017	**77,993,786**	**3,252,595**	**(288,088)**	**(76,630,880)**	**4,327,413**
Profit for the year	**–**	**–**	**–**	**1,298,968**	**1,298,968**
Exchange differences arising on translation of the parent entity	**–**	**–**	**135,435**	**–**	**135,435**
Total comprehensive profit for the year	**–**	**–**	**135,435**	**1,298,968**	**1,434,403**
The issue of 378,970,262 shares under a placement at A$0.07 per share	**20,771,360**	**–**	**–**	**–**	**20,771,360**
The issue of 28,569,610 shares under a SPP at A$0.07 per share	**1,565,900**	**–**	**–**	**–**	**1,565,900**
Recognition of share-based payments	**–**	**1,441,662**	**–**	**–**	**1,441,662**
Equity raising costs	**(1,034,115)**	**–**	**–**	**–**	**(1,034,115)**
Balance at 30 June 2018	**99,296,931**	**4,694,257**	**(152,653)**	**(75,331,912)**	**28,506,623**

The accompanying notes form part of these financial statements.

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Consolidated Statement of Cash Flows

For the Financial Year Ended 30 June 2018

	Note	Consolidated 2018 US$	Consolidated 2017 US$
Cash flows from operating activities			
Receipts from customers		7,746,143	–
Payments to suppliers and employees		(4,326,903)	(2,777,225)
Interest paid		(803,503)	(327,630)
Interest received		8,717	2,213
Net cash flows from (used in) operating activities	18(a)	2,624,454	(3,102,642)
Cash flows from investing activities			
Payments for development of oil and gas properties		(20,769,583)	–
Payments for exploration and evaluation assets		(3,278,167)	(4,353,697)
Payments for property, plant and equipment		(53,599)	–
Net cash flows used in investing activities		(24,101,349)	(4,353,697)
Cash flows from financing activities			
Proceeds from issues of ordinary shares		22,337,260	4,155,828
Payment of equity raising costs		(1,034,115)	(202,891)
Redemption of convertible notes		(2,342,900)	–
Proceeds from borrowings		1,390,676	6,010,400
Net cash flows from financing activities		20,350,921	9,963,337
Net increase (decrease) in cash and cash equivalents held		(1,125,974)	2,506,998
Cash and cash equivalents at the beginning of the year		3,395,501	883,398
Effect of exchange rate changes on the balance of cash held in foreign currencies		(12,569)	5,105
Cash and cash equivalents at the end of the year	18(b)	2,256,958	3,395,501

The accompanying notes form part of these financial statements.

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For the Financial Year Ended 30 June 2018

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1. Summary of significant accounting policies

Statement of compliance

These financial statements are general purpose financial statements which have been prepared in accordance with the *Corporations Act 2001*, Accounting Standards and Interpretations, and comply with other requirements of the law.

The financial statements comprise of the consolidated financial statements of the Group. For the purposes of preparing the consolidated financial statements, the Company is a for-profit entity.

Accounting Standards include Australian Accounting Standards. Compliance with Australian Accounting Standards ensures that the financial statements and notes of the Company and Group comply with International Financial Reporting Standards ('IFRS').

The financial statements were authorised for issue by the Directors on 25 September 2018.

The following significant policies have been adopted in the preparation and presentation of the financial statements:

Basis of preparation

The Financial Report has been prepared on the basis of historical cost. Historical cost is based on the fair values of the consideration given in exchange for goods and services. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, regardless of whether that price is directly observable or estimated using another valuation technique. All amounts are presented in United States of America dollars, unless otherwise noted.

Critical accounting judgements and key sources of estimation uncertainty

The preparation of the consolidated financial statements requires management to make judgements, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expense. Actual results may differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognised in the period in which the estimate is revised and in any future periods effected.

In particular, information about significant areas of estimation uncertainty and critical judgements in applying accounting policies that have the most significant effect on the amount recognised in the financial statements are described in Notes 1 (c) Oil and gas properties (amortisation based upon estimates of proved and probable reserves), 1 (d) Impairment and 1 (n) Provisions (site restoration).

Adoption of new and revised accounting standards

The Group has adopted all of the new and revised Standards and Interpretations issued by the Australian Accounting Standards Board (the 'AASB') that are relevant to their operations and effective for the current year.

New and revised standards and amendments thereof and Interpretations effective for the current year that are relevant to the Group include:

Standard/interpretation

AASB 1048 'Interpretation of Standards'

AASB 2016-2 'Disclosure Initiative: Amendments to AASB 107'

AASB 2016-1 'Recognition of Deferred Tax Assets for Unrealised Losses'

AASB 2017-2 'Further Annual Improvements 2014-2016'

AASB 15 'Revenue from Contracts with Customers, AASB 2014-5 Amendments to Australian Accounting Standards arising from AASB 15, AASB 2015-8 Effective date of AASB 15, AASB 2016-3 Clarifications to AASB 15'

The adoption of all new and revised Standards and Interpretations has not resulted in any changes to the Group's accounting policies and has no effect on the amounts reported for the current year.

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Standards and interpretations in issue not yet adopted

At the date of authorisation of the financial statements, the Standards and Interpretations relevant to the Group that were in issue but not yet effective are listed below.

The consolidated entity does not expect a material impact on its consolidated financial statements resulting from the application of the following standards.

Standard/interpretation	Effective for annual reporting periods beginning on or after	Expected to be initially applied in the financial year ending
AASB 9 'Financial Instruments' 2014	1 January 2018	30 June 2019
AASB 2016-5 Classification and Measurement of Share-based Payment Transactions	1 January 2018	30 June 2019
AASB 2018-1 Amendments to Australian Accounting Standards – Annual Improvements 2015–2017 Cycle	1 January 2019	30 June 2019
AASB 16 'Leases'	1 January 2019	30 June 2020

Standards and interpretations issued not yet effective – IASB and IFRIC interpretations

At the date of authorisation of the financial statements, the following IASB Standards and IFRIC Interpretations (for which Australian equivalent Standards and Interpretations have not yet been issued) were in issue but not yet effective:

Standard/interpretation	Effective for annual reporting periods beginning on or after	Expected to be initially applied in the financial year ending
Amendments to References to the Conceptual Framework in IFRS Standards	1 January 2020	30 June 2021

The following significant accounting policies have been adopted in the preparation and presentation of the Financial Report:

(a) Basis of consolidation

Subsidiaries

The consolidated financial statements incorporate the financial statements of the Company and entities controlled by the Company (referred to as 'the consolidated entity' or 'the Group' in these financial statements). Control is achieved where the Company:

- has power over the investee;
- is exposed, or has rights, to variable returns from its involvement with the investee; and
- has the ability to use its power to affect its returns.

The Company reassesses whether or not it controls an investee if facts and circumstances indicate that there are changes to one or more of the three elements of control listed above.

The results of subsidiaries acquired or disposed of during the year are included in the consolidated income statement from the effective date of acquisition or up to the effective date of disposal, as appropriate. Where necessary, adjustments are made to the financial statements of subsidiaries to bring their accounting policies into line with those used by other members of the consolidated entity.

Joint operating arrangements

Joint operating arrangements are those legal entities over whose activities the consolidated entity has joint control, established by contractual agreement. The interest of the consolidated entity in unincorporated joint operating arrangements are brought to account by recognising in its financial statements, its respective share of the assets it controls, the liabilities and the expenses it incurs and its share of income that it earns from the sale of goods or services by the joint operating arrangements.

Transactions eliminated on consolidation

All intra-group transactions, balances, income and expenses are eliminated in full on consolidation.

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1. Summary of significant accounting policies continued

(b) Exploration and evaluation expenditure

Exploration and evaluation costs, including the costs of acquiring leases, are intangible assets capitalised as exploration and evaluation assets on an area of interest basis. Costs incurred before the consolidated entity has obtained the legal rights to explore an area are recognised in the income statement.

Exploration and evaluation assets are only recognised if the rights of the area of interest are current and either:

(i) the expenditures are expected to be recouped through successful development and exploitation of the area of interest; or alternatively, by its sale; or

(ii) activities in the area of interest have not, at the reporting date, reached a stage which permits a reasonable assessment of the existence or otherwise of economically recoverable reserves, and active and significant operations in, or in relation to, the area of interest are continuing.

Exploration and evaluation assets are initially measured at cost and include acquisition of rights to explore, lease rental payments, seismic and other expenditure to provide legal tenure of the area of interest.

When an area of interest is abandoned or the Directors decide that it is not commercial, any capitalised costs in respect of that area are written off in the financial period the decision is made.

Exploration and evaluation assets are assessed for impairment if:

(i) sufficient data exists to determine technical feasibility and commercial viability, and

(ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purposes of impairment testing, exploration and evaluation assets are allocated to cash-generating units to which the exploration activity relates. The cash-generating unit shall not be larger than the area of interest.

Once the technical feasibility and commercial viability of the extraction of oil and gas reserves relating to a prospect are demonstrable and development is proceeding, exploration and evaluation assets attributable to that prospect are first tested for impairment and then reclassified assets to oil and gas assets.

All other exploration and evaluation costs are expensed as incurred.

(c) Oil and gas properties

The cost of oil and gas producing assets include acquisition and capitalised development costs that are directly attributable to the accessing and production of the proved and probable oil and gas reserves.

In addition, costs include:

(i) the initial estimate at the time of installation or acquisition and during the period of use, when relevant of the costs of dismantling and removing the items and restoring the site on which they are located, and

(ii) changes in the measurement of existing liabilities recognised for these costs resulting from changes in the timing or outflow of resources required to settle the obligation or from changes in the discount rate.

Amortisation

When an oil and gas asset commences commercial production, all acquisition and/or costs carried forward will be amortised on a units of production of basis over the remaining proved and probable recoverable reserves ('2P'). The remaining 2P reserves are measured by external independent petroleum engineers.

Changes in factors that affect amortisation calculations do not give rise to prior financial period adjustments and are dealt with on a prospective basis.

(d) Impairment

The carrying amounts of the Company's and the consolidated entity's non-financial assets, except exploration and evaluation expenditure, are reviewed each balance date or when there is an indication of an impairment loss, to determine whether they are in excess of their recoverable amount. An impairment loss is recognised whenever the carrying amount of an asset or its cash-generating unit exceeds its recoverable amount.

Calculation of the recoverable amount

The recoverable amount of an asset is the greater of its fair value less cost to sell and value in use. In assessing the value in use, the estimated future cash flows are discounted to their present value using a post-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which the estimates of future cash flows have not been adjusted. If the recoverable amount of an asset (or cash-generating unit) is estimated to be less than its carrying amount, the carrying amount of the asset (cash-generating unit) is reduced to its recoverable amount. An impairment loss is recognised immediately in profit or loss. Refer to Note 8 for further details.

Reversals of impairment

Impairment losses are reversed when there has been a change in the estimates used to determine recoverable amounts.

An impairment loss is reversed only to the extent that the asset's carrying value does not exceed the carrying amount that would have been determined, net of depreciation or amortisation, if no impairment loss had been recognised.

(e) Leased assets

Leases are classified as finance leases whenever the terms of the lease transfer substantially all the risks and benefits of ownership to the lessee. All other leases are classified as operating leases. Operating lease payments are recognised as an expense on a straight-line basis over the lease term.

(f) Foreign currency

Functional and presentation currency

Items included in the financial statements of each of the consolidated entity's subsidiaries are measured using the currency of the primary economic environment in which the subsidiaries operate ('the functional currency'). The functional currency of the Company is Australian dollars (A$) and the functional currency of the Company's overseas subsidiaries is United States dollars (US$).

The financial statements are presented in United States dollars. The consolidated entity believes the US dollar is the best measure of performance for the Group because oil and gas, the consolidated entity's dominant sources of revenue are priced in US$ and the consolidated entity's main operations are based in the USA with costs incurred in US$.

Prior to consolidation, the results and financial position of each entity within the consolidated entity are translated from the functional currency into the consolidated entity's presentation currency as follows:

- asset and liabilities of the non US$ denominated balance sheet are translated at the closing rate at the date of that balance sheet;
- income and expenses for the non US$ denominated income statement is translated at average exchange rates (unless this is not a reasonable approximation of the cumulative effect of the rates prevailing on the transaction dates, in which case the income and expenses are translated at the dates of the transactions);
- components of equity are translated at the historical rates; and
- all resulting exchange differences are recognised as a separate component of equity.

Foreign currency transactions and balances

Foreign currency transactions are translated into the functional currency at the exchange rates prevailing at the date of the transaction. Monetary asset and liabilities denominated in foreign currencies at the balance sheet date are translated to the respective functional currency at the foreign exchange rate at that date. 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 are recognised in the statement of comprehensive income.

Non-monetary asset and liabilities that are measured in terms of historical cost in a foreign currency are translated using the exchange rate at the date of the transaction.

Foreign exchange gains and losses arising from a monetary item receivable from or payable to a foreign operation, the settlement of which is neither nor likely in the foreseeable future, are considered to form part of the net investment in a foreign operation are recognised directly in equity in the foreign currency translation reserve.

Interest bearing loans and borrowings repayable in fixed currency denominations

Interest bearing loans and borrowings are initially measured at fair value, net of transaction costs. As some of the loans from shareholders are legally repayable in non-functional or non United States currency denominations, any unrealised foreign currency exchange gains and losses emanating from the recognition of the amounts required to settle these future obligations are recognised in the profit and loss.

(g) Cash and cash equivalents

Cash comprises cash on hand and deposits held at call with financial institutions. Cash equivalents are short-term, highly liquid investments that are readily convertible to known amounts of cash, which are subject to an insignificant risk of changes in value.

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1. Summary of significant accounting policies continued

(h) Share based payments

Equity settled share based payments with Directors, employees and others providing similar services are measured at the fair value of the equity instrument at the grant date. Fair value is measured by use of an appropriate model. A share based payment expense is recognised in profit and loss with a corresponding increase in equity at grant date where the share-based payment arrangements vest immediately.

(i) Revenue recognition

Revenue is measured at the fair value of the consideration received or receivable.

Sale of oil and gas revenue

Revenue associated with the sale of crude oil, natural gas, condensate and natural gas liquids ('NGLs') owned by the Company is recognised when title is transferred from the Company to its customers under short-term contracts (less than 12 months). Revenue is measured at the fair value of the consideration received or receivable. Revenue from the sale of crude oil, natural gas, condensate and NGLs is recognised when all of the following conditions have been satisfied:

- Byron has transferred the significant risks and rewards of ownership of the goods to the buyer;
- Byron retains no continuing managerial involvement to the degree usually associated with ownership or effective control over the goods sold;
- the amount of revenue can be measured reliably;
- it is probable that the economic benefits associated with the transaction will flow to Byron; and
- the costs incurred or to be incurred in respect of the transaction can be measured reliably.

The Company recognises oil, natural gas and NGL revenues based on its share of the quantities of production, solely owned or under joint ownership, sold to purchasers under short term contracts at market prices.

Interest revenue

Interest revenue is accrued on a time basis, by reference to the principal outstanding and at the effective interest rate applicable, which is the rate that exactly discounts estimated future cash receipts through the expected life of the financial asset to that asset's net carrying amount.

(j) Income tax

Income tax expense comprises current and deferred tax. Income tax expense is recognised in the profit or loss except to the extent that it relates to items recognised directly in equity, in which case it is recognised in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantially enacted at the balance sheet date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognised using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognised for the following temporary differences: the initial recognition of goodwill, the initial recognition of assets or liabilities in a transaction that is not a business combination and that affect neither accounting nor taxable profit/loss, and differences relating to investments in subsidiaries to the extent that they will not reverse in the foreseeable future. Deferred tax is measured at the tax rates that are expected to be applied to the temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the balance sheet date.

A deferred tax asset is recognised only to the extent that it is probable that future taxable profits will be available against which the asset can be utilised. Deferred tax assets are reviewed at each balance sheet date and are reduced to the extent that it is no longer probable that the related tax benefit will be realised.

(k) Financial assets

Investments are initially measured at fair value, net of transaction costs. Subsequent to initial recognition, investments in subsidiaries are measured at cost in the Company's financial statements.

Receivables

Receivables that have fixed or determinable payments that are not quoted in an active market are classified as 'loans and receivables'. Loans and receivables are measured at amortised cost using the effective interest method less impairment.

Impairment of financial assets

Financial assets, other than those at fair value through profit or loss, are assessed for indicators of impairment at the end of each reporting period. Financial assets are impaired where there is objective evidence that as a result of one or more events that occurred after the initial recognition of the financial asset the estimated future cash flows of the investment have been impacted.

(l) 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 consolidated entity in respect of services provided by employees up to reporting date.

Defined contribution plans

Contributions to defined contribution superannuation plans are expensed when employees have rendered service entitling them to the contributions.

(m) Property, plant and equipment (including software)

Buildings held for use in the production or supply of goods or services, or for administrative purposes, are carried in the statement of financial position at cost, less any subsequent accumulated depreciation and subsequent accumulated impairment losses.

Plant and equipment are stated at cost less accumulated depreciation and impairment. Construction in progress is stated at cost. Cost includes expenditure that is directly attributable to the acquisition or construction of the item. In the event that settlement of all or part of the purchase consideration is deferred, cost is determined by discounting the amounts payable in the future to their present value as at the date of acquisition.

Depreciation is provided on property, plant and equipment, including freehold buildings but excluding land. Depreciation is calculated on a straight-line basis so as to write off the net cost or other revalued amount of each asset over its expected useful life to its estimated residual value. The estimated useful lives, residual values and depreciation method are reviewed at the end of each annual reporting period, with the effect of any changes recognised on a prospective basis.

The gain or loss arising on disposal or retirement of an item of property, plant and equipment is determined as the difference between the sales proceeds and the carrying amount of the asset and is recognised in profit or loss.

The following useful lives are used in the calculation of depreciation:

Buildings	40 years
Plant and equipment	4 to 10 years
Intangible assets – software	3 years

(n) Provisions

Provisions are recognised when the consolidated entity has a present obligation (legal or constructive) as a result of a past event, it is probable that the consolidated entity will be required to settle the obligation, and a reliable estimate can be made of the amount of the obligation.

The amount recognised as a provision is the best estimate of the consideration required to settle the present obligation at 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.

When some or all of the economic benefits required to settle a provision are expected to be recovered from a third-party, the receivable is recognised as an asset if it is virtually certain that reimbursement will be received and the amount of the receivable can be measured reliably.

Site restoration and rehabilitation of oil and gas properties

Provisions made for environmental rehabilitation are recognised where there is a present obligation as a result of exploration, development or production activities having been undertaken and it is probable that an outflow of economic benefits will be required to settle the obligation, and the amount of the provision can be measured reliably. The estimated future obligations include the cost of removing the facilities, abandoning the well(s) and restoring the affected areas. The provision for future restoration is the best estimate of the present value of the expenditure required to settle the obligation at the reporting date, based on current legal requirements and technology. Future restoration costs are reviewed annually; and any changes are reflected in the present value of the restoration provision at the end of the reporting period. The amount of the provision for future restoration costs relating to exploration and producing activities is capitalised as a cost of these activities. The provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects the time value of money. The unwinding of discounting on the provision is recognised as a finance cost rather than being capitalised into the cost of the related asset.

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1. Summary of significant accounting policies continued

(o) Financial liabilities

Financial liabilities

Financial liabilities, including borrowings and trade and other payables, are initially measured at fair value, net of transaction costs. Other financial liabilities are subsequently measured at amortised cost using the effective interest method, with interest expense recognised on an effective yield basis.

The effective interest method is a method of calculating the amortised cost of a financial liability and of allocating interest expense over the relevant period. The effective interest rate is the rate that exactly discounts estimated future cash payments through the expected life of the financial liability, or (where appropriate) a shorter period, to the net carrying amount on initial recognition.

Borrowing, finance and interest costs

Borrowing, finance and interest costs comprise interest payable on borrowings calculated using the effective interest rate method, loans transactions costs, lease finance charges, amortisation of discounts or premiums related to the borrowings and the unwinding of discounts on the rehabilitation provisions.

Derecognition of financial liabilities

The Group derecognises financial liabilities when, and only when, the Group's obligations are discharged, cancelled or they expire. The difference between the carrying amount of the financial liability derecognised and the consideration paid and payable is recognised in profit or loss.

(p) Issued capital

Issued and paid up capital is recognised at the fair value of the consideration received by the Company.

Transaction costs on the issue of equity instruments

Transaction costs arising on the issue of equity instruments are recognised directly in equity as a reduction of the proceeds of the equity instrument to which the costs relate. Transaction costs are costs that are incurred directly in connection with the issue of those equity instruments and which would not have been incurred had those instruments not been issued.

(q) Reserves

Foreign currency translation reserve

Foreign currency exchange differences relating to the translation of Australian dollars, being the functional currency of the parent entity group into the presentational currency of US dollars for the consolidated entity are brought to account by entries made directly to the foreign currency translation reserve.

Share option reserve

The share option reserve arises on the grant of share options to Directors, staff, consultants and other service providers to the Group. Amounts are transferred out of the reserve and into issued capital when the options are exercised. Further information about share-based payments is made in Note 1(h).

(r) Goods and services tax

Revenues, expenses and assets are recognised net of the amount of goods and services tax ('GST'), except:

(i) where the amount of GST incurred is not recoverable from the taxation authority, it is recognised as part of the cost of acquisition of an asset or as part of an item of expense; or

(ii) for receivables and payables which are recognised inclusive of GST.

The net amount of GST recoverable from, or payable to, the taxation authority is included as part of receivables or payables.

Cash flows are included in the cash flow statement on a gross basis. The GST component of cash flows arising from investing and financing activities which is recoverable from, or payable to, the taxation authority is classified as operating cash flows.

2. Profit for the year

	Consolidated 2018 US$	Consolidated 2017 US$
Profit for the year has been arrived at after charging the following items of expense		
Cost of sales		
Lease operating costs	943,506	–
Amortisation of oil and gas properties	863,908	–
	1,807,414	–
Professional and consulting costs	505,616	882,010
Insurance	74,572	58,918
Office lease rental expense	139,217	138,869
Employee benefits expense		
Other employee benefits	1,175,479	824,639
Share-based payments (share options issued to executives, staff and consultants)	981,096	324,607
Defined contribution superannuation expense	29,026	22,005
	2,185,601	1,171,251

3. Financial income and expenses

	2018 US$	2017 US$
Financial income		
Interest income	8,717	2,213
Foreign exchange gain on A$ denominated loans	6,708	10,185
	15,425	12,398
Financial expense		
Interest expense	1,046,926	608,494
Unwinding of discount on rehabilitation of oil and gas properties	–	5,990
Interest expense paid or accrued on loans from related parties	25,106	19,524
	1,072,032	634,008

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4. Income tax

	Consolidated 2018 US$	2017 US$
Income tax recognised in profit and loss	**–**	–
The income tax expense/(benefit) for the year can be reconciled to the accounting profit/(loss) as follows:		
Profit/(loss) before tax from continuing operations	**1,298,968**	(5,357,583)
Income tax expense/(benefit) calculated at 27.5% (2017: 30.0%)	**357,216**	(1,607,275)
Effect of expenses that are not deductible in determining taxable profit	**472,398**	241,038
Effect of different tax rates of subsidiaries operating in other jurisdictions	**53,558**	(304,845)
Effect of unused tax losses and tax offsets not recognised as deferred tax assets	**(883,172)**	1,671,082
Income tax expense/(benefit) on continuing operations	**–**	–
Deferred tax assets not recognised		
Deferred tax assets not recognised comprises temporary differences and tax losses attributable to:		
Australian tax losses	**2,570,669**	2,409,883
USA tax losses	**27,948,337**	22,946,390
Temporary differences	**(6,113,146)**	(294,296)
Total deferred tax assets not recognised	**24,405,860**	25,061,977

The potential deferred tax asset will only be recognised if:

(i) the consolidated entity derives future assessable income of a nature and amount sufficient to enable the benefits to be realised, in the jurisdiction in which the losses were incurred;

(ii) the consolidated entity continues to comply with conditions for tax deductibility imposed by law; and

(iii) no changes in tax legislation adversely affect the ability of the consolidated entity to realise the tax benefits.

Byron Energy Limited and its 100% owned Australian subsidiary, Byron Energy (Australia) Pty Ltd formed a tax consolidated group effective from 1 July 2013.

5. Earnings per share

The following reflects the profit/(loss) and share data used in calculating basic and diluted earnings per share:

	2018 US$	2017 US$
Net profit/(loss) for the year	**1,298,968**	(5,357,583)
Basic profit/(loss) per share	**0.0022**	(0.02)
Diluted profit/(loss) per share	**0.0022**	(0.02)
Weighted average number of ordinary shares	**585,536,025**	269,675,754
Shares deemed to be issued for no consideration in respect of share options	**10,657,622**	–
Weighted average number of ordinary shares used in the calculation of diluted earnings per share	**596,193,647**	269,675,754
Anti-dilutive options on issue not used in the dilutive earnings per share calculation	**21,450,000**	23,150,000

Options outstanding

There is partial dilution of shares due to some options issued or outstanding as the potential ordinary shares are anti-dilutive in accordance with AASB 133, paragraph 41 and are therefore not included in the calculation of diluted earnings per share.

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6. Trade and other receivables

	Consolidated 2018 US$	2017 US$
Oil and gas sales receivables	**3,997,256**	–
Joint operating arrangements and other receivables	**2,196,263**	1,013,528
GST receivable	**14,908**	12,614
	6,208,427	1,026,142

Sales and other debtors are non-interest bearing and are settled within 30 days.

7. Other assets

Current		
Prepayments	**848,770**	102,160
Security deposits	**6,445**	563,770
	855,215	665,930
Non-current		
Prepayments	**–**	289
Security deposits	**732,062**	475,000
	732,062	475,289

8 (a). Exploration and evaluation assets

Costs carried forward in respect of areas in the exploration and/or evaluation phase at cost:	**3,937,828**	2,421,473
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**2,421,473**	4,834,429
Additions at cost	**3,263,218**	1,129,019
Amounts transferred to oil and gas properties	**–**	(2,300,258)
Impairment expense	**(1,746,863)**	(1,241,717)
Carrying amount at the end of the financial year	**3,937,828**	2,421,473

Ultimate recovery of deferred exploration and evaluation costs is dependent upon success in exploration and evaluation or the full or partial sale (including farm-out) of the exploration interests.

The impairment charge covers three leases, one was relinquished in the prior year of which residual restoration costs were incurred in the current year and two other leases were relinquished.

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8 (b). Oil and gas properties

	Consolidated 2018 US$	Consolidated 2017 US$
Costs carried forward in respect of areas in the oil and gas properties at cost:	**26,174,962**	5,896,622
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	**5,896,622**	–
Additions at cost	**20,846,775**	3,300,504
Additions for site restoration	**295,473**	295,860
Amounts transferred from exploration and evaluation assets	**–**	2,300,258
Amortisation of oil and gas properties included in cost of sales	**(863,908)**	–
Carrying amount at the end of the financial year	**26,174,962**	5,896,622

Recoverable amount

The estimated recoverable amount of all cash-generating units in the development or production phase is determined by discounting the estimated future cash flows to their present value using a post-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the assets. The consolidated entity utilises future cash flows as estimated by independent petroleum engineers for this assessment. The key assumptions used include: (i) estimated future production based on proved and probable reserves (2P reserves), (ii) hydrocarbon prices that the consolidated entity estimates to be reasonable, taking into account historical prices, current prices, and prices used in making its exploration and development decisions, and (iii) future operating and development costs as estimated by the Company and reviewed for reasonableness by the independent petroleum engineers.

The estimated recoverable amount of Byron's oil and gas properties is sensitive to a change in estimated recoverable reserves, oil and gas prices, discount rates and cost estimates.

9. Property, plant and equipment

	2018 US$	2017 US$
Buildings at cost	**10,797**	11,237
Accumulated depreciation	**(3,254)**	(3,106)
	7,543	8,131
Reconciliation of movements:		
Carry amount at the beginning of the financial year	**8,131**	8,121
Depreciation for year	**(283)**	(275)
Foreign currency translation movements	**(305)**	285
Carrying amount at the end of the financial year	**7,543**	8,131
Plant and equipment at cost	**117,208**	105,625
Accumulated depreciation	**(85,633)**	(76,835)
	31,575	28,790
Reconciliation of movements:		
Carry amount at the beginning of the financial year	**28,790**	39,060
Additions at cost	**12,600**	–
Depreciation for year	**(9,730)**	(10,517)
Foreign currency translation movements	**(85)**	247
Carrying amount at the end of the financial year	**31,575**	28,790
Total property, plant and equipment	**39,118**	36,921

10. Other intangible assets

	Consolidated 2018 US$	2017 US$
Capitalised software costs at cost	**102,594**	62,112
Accumulated amortisation	**(70,512)**	(60,334)
	32,082	1,778
Reconciliation of movements:		
Carry amount at the beginning of the financial year	**1,778**	6,940
Additions at cost	**41,000**	–
Amortisation for year	**(10,696)**	(5,162)
Carrying amount at the end of the financial year	**32,082**	1,778

11. Trade and other payables

	2018 US$	2017 US$
Current		
Trade payables	**3,131,736**	2,011,622
Oil and gas royalties payable	**747,833**	–
Accrued interest payable on loans from related parties	**23,248**	–
Insurance premium financing (interest bearing)	**1,029,289**	276,038
Other payables	**24,453**	42,224
	4,956,559	2,329,884

Terms and conditions relating to the above financial instruments:

(i) Trade creditors are non-interest bearing and are usually settled on 30-day terms.

(ii) Some of the other payables are non-interest bearing and have an average term of 30 days.

(iii) The insurance premium financing bears an average 4.39% fixed interest rate, please see Note 27(c).

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12. Provisions

	Consolidated 2018 US$	Consolidated 2017 US$
Current		
Accumulated employee entitlements	131,112	87,741
Site restoration SM6	–	740,860
	131,112	828,601
Non-current		
Accumulated employee entitlements	61,716	41,897
Site restoration SM71	1,122,464	85,861
	1,184,180	127,758
Site restoration provisions		
Reconciliation of movements:		
Carrying amount at the beginning of the financial year	826,721	524,871
Site restoration work undertaken on SM6	(740,860)	–
Unwinding of discount SM6	–	5,990
Additions to SM71 site restoration	1,036,603	295,860
Carrying amount at the end of the financial year	1,122,464	826,721

Provisions are recognised for the Group's restoration obligations at SM71. The estimation of future costs associated with the abandonment and restoration requires the use of estimated costs in future periods that, in some cases, will not be incurred until a number of years into the future. Such cost estimates could be subject to revisions in subsequent years due to regulatory requirements, technological advances and other factors that are difficult to predict. Likewise the appropriate future discount rates used in the calculation are subject to change according to the risks inherent in the liability. The measurement and recognition criteria relating to restoration obligations is described in Note 1 (n).

13. Borrowings

	Consolidated 2018 US$	Consolidated 2017 US$
Current unsecured*		
Loans from related parties	**1,384,332**	–
Current secured**		
Convertible note – debt liability	**2,956,400**	2,307,600
Convertible note – derivative liability	**410,260**	–
Total current borrowings	**4,750,992**	2,307,600
Non-current secured**		
Convertible note – debt liability	**707,186**	3,578,944
Convertible note – derivative liability	**–**	419,456
Total non-current borrowings	**707,186**	3,998,400

* During the June 2018 quarter, three of the Company directors made unsecured short-term advances to the Company at an interest of 10% per annum. The advances and accrued interest are scheduled for repayment in October 2018. For more details, please refer to the related party transactions note.

** On 22 July 2016, Byron and Metgasco Limited (ASX:MEL) entered into a three-year agreement to issue up to A$8 million in convertible notes ('convertible note'), repayable over the course of the agreement. The key financing terms of the agreement are listed below:

i. Security: the convertible note is secured by a General Deed of Security and Priority (over Byron's assets), a Negative Pledge from Byron and a registered interest over Byron's share of SM70/71 leases;

ii. Interest only for the first 12 months from establishment on drawn funds then amortising in eight equal instalments over balance of term;

iii. Facility Fee: 2.5% of Face Value (A$200,000), payable on first drawdown under the facility;

iv. Line Fee: 2%, payable quarterly in advance, for the first six months of the facility on the Face Value and then, thereafter, on the drawn (outstanding) balance under the convertible note;

v. Coupon: on drawn funds at 12% pa, payable quarterly in arrears;

vi. Conversion: convertible at Metgasco's election after 18 months from initial drawdown with one week's notice at a 10% discount to the then prevailing 30-day volume weighted average price ('VWAP') of Byron;

vii. Repayment: repayable early by Byron with one month's notice (a) at any time after 90 days from initial drawdown until expiry of 18 months from initial drawdown at 115% of principal outstanding (along with any accrued interest and line fee), and (b) at any time after 18 months from initial drawdown at 105% of principal outstanding (along with any accrued interest and line fee).

On 20 January 2017, Metgasco subscribed for the full 8.0 million @ A$1.00 convertible notes (unquoted). The convertible notes are repayable over the remainder of the term of the agreement (that is, by 21 July 2019).

The net proceeds received from the issue of the convertible notes have been split between the financial liability element and an embedded derivative component, representing the residual attributable to the option to convert the financial liability into equity of the Company. The liability component is measured at amortised cost. The net debt liability is amortised by the effective interest rate of 20.90% over the term of the notes and the derivative liability is expensed over the life of the convertible notes.

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14. Issued capital

	Consolidated 2018 US$	Consolidated 2017 US$
(a) Issued and paid up capital	**99,296,931**	77,993,786

Changes to the then Corporations Law abolished the authorised capital and par value concept in relation to share capital from 1 July 1998. Therefore, the Company does not have a limited amount of authorised capital and issued shares do not have a par value.

	2018 Number	2018 US$	2017 Number	2017 US$
(b) Movement				
Fully paid ordinary shares				
Balance at beginning of the financial year	**277,447,162**	**77,993,786**	235,056,378	74,040,848
Shares issued				
The issue of 378,970,262 shares under a placement at A$0.07 per share	**378,970,262**	**20,771,360**		
The issue of 28,569,610 shares under a SPP at A$0.07 per share	**28,569,610**	**1,565,900**		
The issue of 36,916,167 shares under a placement at A$0.13 per share			36,916,167	3,628,601
The issue of 5,474,617 shares under a placement at A$0.13 per share			5,474,617	527,228
Equity raising costs	**–**	**(1,034,115)**	–	(202,891)
Balance at end of financial year	**684,987,034**	**99,296,931**	277,447,162	77,993,786

(c) Terms and conditions of contributed equity

Ordinary shares

Ordinary shares have the right to receive dividends as declared and, in the event of winding up of the Company, to participate in the proceeds from the sale of all surplus assets in proportion to the number of and amounts paid up on shares held. Ordinary shares entitle their holder to one vote, either in person or by proxy, at a meeting of the Company.

The issued capital of the Company comprises 684,987,034 ordinary shares (2017: 277,447,162). All of the shares are quoted on the ASX.

(d) Share options

Options over ordinary shares

At the end of the financial year, there were 51,800,000 (2017: 23,150,000) unissued ordinary shares in respect of which the following options were outstanding:

Expiry date	Number	Securities	Exercise price
31 December 2019	9,500,000	Unlisted options	A$0.25
21 July 2019	10,000,000	Unlisted options	A$0.25
30 September 2018	1,950,000	Unlisted options	A$0.25
31 December 2021	28,350,000	Unlisted options	A$0.12
31 December 2021	2,000,000	Unlisted options	A$0.16
Total	**51,800,000**		

During the financial year, 28,350,000 share options were issued with an exercise amount of A$0.12 and a further 2,000,000 share options with an exercise price of A$0.16 cents were issued; all options issued in the 2018 year will expire on 31 December 2021. No share options were converted into ordinary fully paid shares during the year and 1,700,000 share options with an exercise price of A$0.65 expired on 30 September 2017.

15. Reserves

	Consolidated	
	2018 US$	**2017 US$**
Foreign currency translation reserve		
Balance at beginning of financial year	**(288,088)**	(143,767)
Currency translation movements for the year	**135,435**	(144,321)
Balance at end of financial year	**(152,653)**	(288,088)

The reserve arises out of the translation of A$, being the functional currency of the parent entity group into the consolidated entity presentation currency of US$.

Share option reserve		
Balance at beginning of financial year	**3,252,595**	2,498,102
28,350,000 options issued to directors, staff and consultants as approved by shareholders and 2,000,000 options issued to a staff member	**1,441,662**	–
10,000,000 options issued to Metgasco Limited as approved by shareholders	**–**	404,066
9,500,000 options issued to directors, staff and consultants as approved by shareholders	**–**	350,427
Balance at end of financial year	**4,694,257**	3,252,595

The reserve arises on the grant of share options to directors, key management personnel, consultants and other third parties as equity-based payments.

16. Franking credits

There are no franking credits available for distribution (2017: nil).

17. Expenditure commitments

The Group has expenditure commitments at the end of the financial year for non-cancellable operating lease office rental payments. These obligations are not provided for in the financial statements.

(a) Commitments for office lease rental payments

Not longer than 1 year	**108,930**	104,338
Between 1 and 5 years	**22,377**	109,647
	131,307	213,985

(b) Exploration lease expenditure commitments

The Group has no exploration lease commitments at the end of the financial year as the leasing arrangements of the Gulf of Mexico blocks do not require firm work program commitments.

(c) Seismic expenditure commitments

The Group has a financial commitment as at balance date for seismic expenditure over the greater SM71 project area.

Commitments for seismic expenditure		
Not longer than 1 year	**595,000**	–

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18. Cash flow reconciliation

	Consolidated 2018 US$	2017 US$
(a) Reconciliation of profit/(loss) from ordinary activities after tax to net cash flows from operations		
Profit/(loss) for the year	1,298,968	(5,357,583)
Non-cash flows in operating result:		
Amortisation oil and gas properties	863,908	–
Depreciation and amortisation of property, plant and equipment	20,710	15,957
Impairment expense	1,746,863	1,241,717
Equity settled share-based payments	1,441,662	754,493
Net foreign exchange (gain)/loss on A$ loans	(6,708)	(10,185)
Unwinding of discount on rehabilitation of oil and gas properties	–	5,990
Reversal of equity raising charges	–	19,571
Foreign exchange differences arising on translation of the parent entity group	253,519	160,594
	5,618,922	(3,169,446)
Movements in working capital		
(Increase)/decrease in assets:		
Trade and other receivables	(4,000,043)	(4,220)
Other assets	(340,046)	152,436
Increase/(decrease) in liabilities:		
Trade and other payables	1,277,358	(90,902)
Provisions	68,263	9,490
Net cash from/(used in) operating activities	2,624,454	(3,102,642)
(b) Reconciliation of cash		
Cash and cash equivalents comprise:		
Cash and bank balances	2,256,958	3,395,501

(c) Financing facility

The Group had no finance facilities at balance date.

(d) Non-cash financing and investing activities

There were no non-cash financing or investing activities during the financial year.

19. Controlled entities

The following entities are controlled by Byron Energy Limited and they have been consolidated into the financial statements for the consolidated entity:

Name	Country of domicile	Class of share	Percentage beneficially owned
Byron Energy (Australia) Pty Ltd	Australia	Ordinary	100%
Byron Energy Inc	USA	Ordinary	100%
Byron Energy LLC	USA	Ordinary	100%

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20. Foreign currency translation

The exchange rate utilised in the translation of the parent entity group Australia dollar figures to United States of America dollars is as follows:

	2018	2017
Spot rate at 30 June	**0.7391**	0.7692
Average rate for year	**0.7753**	0.7545

21. Contingent liabilities

The directors are of the opinion, that the recognition of a provision is not required in respect of the following matters, as it is not probable that a future sacrifice of economic benefits will be required or the amount is not capable of reliable measurement.

(a) Byron Energy Limited has guaranteed the performance of Byron Energy Inc, a wholly owned subsidiary, under the Participation Agreement dated 1 December 2015 between Byron Energy Inc and Otto Energy (Louisiana) LLC.

(b) BOEM Supplemental Bonds – As the operator of producing block SM71, Byron is required to post supplemental bonds to cover, among other things, decommissioning obligations of the SM71 lease. To date, BOEM has not yet made demands for financial assurances covering the Company's decommissioning obligations in relation to the SM71 F platform and pipelines.

22. Share based payments

Movements in share based payments options

The aggregate share based payments paid as remuneration for the financial year are set out below:

	Consolidated	
	2018 US$	2017 US$
Details of share based payments		
Fair value of options granted to directors, staff and consultants	**1,441,662**	350,427
Expense arising from share based payments paid as remuneration	**1,441,662**	350,427

No share options were exercised during the financial year. There are no Employee Share Option plans in place.

	2018 Number	2018 Exercise price	2017 Number	2017 Exercise price
Balance at beginning of year	**13,150,000**		6,250,000	
Granted during the year	**28,350,000**	**A$0.12c**	9,500,000	A$0.25c
Granted during the year	**2,000,000**	**A$0.16c**		
Expired during the year	**(1,700,000)**		(2,600,000)	
Exercised during the year	**–**		–	
Balance at end of year	**41,800,000**		13,150,000	
Exercisable at end of year	**1,950,000**	**A$0.25c**	1,950,000	A$0.25c
Exercisable at end of year	**9,500,000**	**A$0.25c**	9,500,000	A$0.25c
Exercisable at end of year	**28,350,000**	**A$0.12c**		
Exercisable at end of year	**2,000,000**	**A$0.16c**		

Weighted average remaining contractual life

The 1,950,000 share options of A$0.25 have an expiry of 92 days (2017: 457 days) remaining and the 9,500,000 share options of A$0.25 have 549 days (2017: 914 days) remaining. Both tranches of the 28,350,000 and 2,000,000 share options have an expiry of 1,280 days remaining.

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22. Share based payments continued

Director and key management personnel equity share options

Share-based payment options held at the end of the reporting year were as follows:

Grantee	Number	Grant date	Vesting date	Expiry date	Exercise price	Fair value at grant date
M Smith	2,500,000	24 Nov 2016	24 Nov 2016	31 Dec 2019	A$0.25	A$0.0489
M Smith	6,300,000	18 Sept 2017	18 Sept 2017	31 Dec 2021	A$0.12	A$0.0555
P Kallenberger	2,500,000	24 Nov 2016	24 Nov 2016	31 Dec 2019	A$0.25	A$0.0489
P Kallenberger	6,300,000	18 Sept 2017	18 Sept 2017	31 Dec 2021	A$0.12	A$0.0555
W Sack	2,500,000	24 Nov 2016	24 Nov 2016	31 Dec 2019	A$0.25	A$0.0489
W Sack	1,700,000	15 Feb 2016	15 Feb 2016	30 Sept 2018	A$0.25	A$0.0959
W Sack	6,300,000	18 Sept 2017	18 Sept 2017	31 Dec 2021	A$0.12	A$0.0555
N Filipovic	1,000,000	24 Nov 2016	24 Nov 2016	31 Dec 2019	A$0.25	A$0.0489
N Filipovic	3,780,000	18 Sept 2017	18 Sept 2017	31 Dec 2021	A$0.12	A$0.0555

Calculation of the fair value of equity share options issued

The total fair value of all share options granted and issued during the financial year was US$1,441,662. Options were priced using the Binominal Option Pricing model and calculated by an independent external consultant entity.

Inputs into the model	28,350,000 Share options granted to directors, staff and consultants on 18 September 2017	2,000,000 Share options were issued to a staff member on 20 December 2017
Closing share price prior to valuation	A$0.09	A$0.195
Exercise price	A$0.12	A$0.16
Expected volatility	90.3%	101.8%
Option life	4.3 years	4.0 years
Risk-free interest rate	2.30%	2.26%

23. Employee benefits and superannuation commitments

The consolidated entity contributes in accordance with the Australian Government superannuation guarantee legislation.

24. Auditors' remuneration

Amounts received or due and receivable by Deloitte Touche Tohmatsu:

	Consolidated	
	2018 US$	2017 US$
Audit or review of the financial statements of the Group	**51,271**	39,831
	51,271	39,831

The auditors did not receive any other benefits.

25. Key management personnel compensation

Total aggregate remuneration of directors and key management personnel.

	Short-term employee benefits				Post-employment benefits	Share-based payments	
	Salaries and fees US$	Short-term cash incentive US$	Other benefits US$	Service agreements US$	Super-annuation US$	Share options US$	Total US$
Year 2018	**917,232**	**–**	**52,186**	**186,072**	**23,201**	**975,315**	**2,154,006**
Year 2017	698,594	–	45,805	181,080	17,203	313,541	1,256,223

More detailed information on remuneration and retirement benefits of directors is disclosed in the Remuneration Report.

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26. Related party transactions

The following related party transactions were entered into during the financial year ended 30 June 2018:

(a) Following approval by shareholders at an Extraordinary General Meeting ('EGM') held on 18 September 2017, the following fully paid ordinary shares in the Company were issued for cash at an issue price of A$0.07 per share:

- 18,000,000 fully paid ordinary shares in the Company issued to Mr Douglas Battersby a director of the Company, and/or his associates;
- 14,285,715 fully paid ordinary shares in the Company issued to Mr Maynard Smith a director of the Company, and/or his associates;
- 8,729,014 fully paid ordinary shares in the Company issued to Mr Paul Young a director of the Company, and/or his associates;
- 7,900,000 fully paid ordinary shares in the Company issued to Mr Charles Sands a director of the Company, and/or his associates; and
- 1,200,000 fully paid ordinary shares in the Company issued to Mr William (Bill) Sack, a director of the Company, and/or his associates.

(b) Following approval by shareholders at EGM held on 18 September 2017, the following directors and key management personnel were issued with share options in Byron Energy Limited, exercisable at an exercise price of A$0.12 per share on or after issue at any time on or before 31 December 2021:

- Mr Maynard Smith a director of the Company, and/or his associates, were issued with 6,300,00 share options;
- Mr Prent Kallenberger a director of the Company, and/or his associates were issued with 6,300,00 share options;
- Mr William (Bill) Sack a director of the Company, and/or his associates were issued with 6,300,00 share options; and
- Mr Nick Filipovic the Company Secretary and CFO, and/or his associates were issued with 3,780,000 share options.

(c) Corporate advisory services at normal commercial rates totalling A$338,915 were provided by Henslow Corporate, of which Paul Young is an executive director and shareholder. There was no outstanding amounts payable at 30 June 2018.

(d) During the year, the Company entered into unsecured loan agreements, bearing interest at 10% per annum, with three of the Company's directors, for a total drawdown of US$1,000,000 and A$520,000. The loans were outstanding on 30 June 2018 and due for repayment in October 2018. The individual directors' transactions and balances for these loans were:

- Veruse Pty Ltd, a company controlled by Mr Douglas Battersby, provided an unsecured loan of A$520,000 to the Company; and interest charges of A$7,693 have been accrued as at 30 June 2018;
- Geogeny Pty Ltd, a company controlled by Mr Maynard Smith, provided an unsecured loan of US$500,000 to the Company; and interest charges of US$9,178 have been accrued as at 30 June 2018; and.
- Charles Sands, provided an unsecured loan of US$500,000 to the Company; and interest charges of US$8,384 (net of withholding taxes) have been accrued as at 30 June 2018.

27. Financial instruments

The consolidated entity's financial instruments consist mainly of cash and cash equivalents, trade and other receivables, security deposits, trade and other payables and secured borrowings. The main risks the consolidated entity is exposed to through its financial instruments are interest rate risk, foreign currency risk, liquidity risk and credit risk.

This note presents information about the consolidated entity's exposure to each of the above risks and processes for measuring and managing the risks and the management of capital.

	Consolidated	
Categories of financial instruments	**2018 US$**	**2017 US$**
Financial assets at fair value		
Cash and cash equivalents	**2,256,958**	3,395,501
Trade and other receivables	**6,208,427**	1,026,142
Bonds and security deposits	**738,507**	1,038,770
	9,203,892	5,460,413
Financial liabilities at fair value		
Trade and other payables	**3,927,270**	2,053,846
Insurance premium financing	**1,029,289**	276,038
Loans from related parties	**1,384,332**	–
Convertible note liabilities	**3,663,586**	5,886,544
	10,004,477	8,216,428

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27. Financial instruments continued

(a) Capital risk management

The Group manages its capital to ensure that entities in the Group will be able to continue as a going concern while maximising the return to shareholders. The Group's capital structure consists of: (i) equity comprising issued capital, reserves and accumulated losses and (ii) as required, unsecured borrowings from related parties and shareholders.

During the 2018 financial year, no dividends were paid (2017: nil).

Neither the Company nor any of its subsidiaries are subject to externally imposed capital requirements.

(b) Credit risk exposure

Credit risk refers to the risk that a counterparty will default on its contractual obligations resulting in financial loss to the Group. The Group has adopted a policy of only dealing with creditworthy counterparties as a means of mitigating the risk of financial loss from defaults.

The Group has a material credit exposure to the party that purchases its oil production from the SM71 lease. There are no risk mitigation strategies in place, however the purchasing company is a large global energy corporation, so the risk of financial default is considered low. Apart from this credit risk exposure, the Group does not have any significant credit risk exposure to any single counterparty or any group of counterparties having similar characteristics. The credit risk on liquid funds is limited as the counterparties are banks with high credit ratings assigned by international credit rating agencies.

The carrying amount of financial assets recorded in the financial statements, net of any allowances for losses, represent the Group's maximum exposure to credit risk

(c) Liquidity risk management

The Group manages liquidity risk by maintaining adequate cash reserves and if required, standby credit facilities to meet commitments when they fall due. Management continuously monitors cash forecasts to manage liquidity risk.

Liquidity, credit and interest risk tables

The following table details the Group's remaining contractual maturity for its non-derivate financial assets.

Consolidated financial assets	Weighted average effective interest rate %	Less than 1 month US$	1 to 3 months US$	3 months to 12 months US$	1 to 5 years US$
2018					
Non-interest bearing	**–**	**6,193,520**	**14,908**	**6,445**	**732,061**
Variable interest rate instruments	**0.14%**	**2,256,958**	**–**	**–**	**–**
2017					
Non-interest bearing	–	1,026,142	–	556,708	482,062
Variable interest rate instruments	0.13%	3,395,501	–	–	–

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The table below details the Group's remaining contractual maturities for its non-derivative financial liabilities. The following are future contractual cash payments of financial liabilities, including estimated interest payments

Consolidated financial liabilities	Weighted average effective interest rate %	Less than 1 month US$	1 to 3 months US$	3 months to 12 months US$	1 to 5 years US$
2018					
Non-interest bearing	**–**	**3,904,022**	**–**	**23,248**	**–**
Fixed interest rate instruments	**4.39%**	**154,160**	**308,321**	**566,808**	**–**
Related party liabilities	**10.00%**	**–**	**–**	**1,384,332**	**–**
Convertible note liabilities	**20.90%**	**739,100**	**–**	**2,217,300**	**707,186**
2017					
Non-interest bearing	–	2,053,846	–	–	–
Fixed interest rate instruments	3.42%	69,009	138,020	69,009	–
Convertible note liabilities	20.90%	–	–	2,872,962	4,465,206

(d) Fair values

The directors consider that the carrying amounts of financial assets and financial liabilities recorded at cost less any accumulated impairments in the financial statements approximates their fair values.

The fair values of financial assets and financial liabilities are determined as follows:

(i) holdings in unlisted shares are measured at cost less any impairments. The directors consider that no other measure could be used reliably; and

(ii) other financial assets and financial liabilities are determined in accordance with generally accepted pricing models.

(e) Interest rate risk management

The Group's exposure to the risk of changes in market interest rates relates primarily to the Group's cash and cash equivalents with a floating interest rate. The Group is not currently engaged in any hedging or derivative transactions to manage interest rate risk. This risk is managed through the use of cash flow forecasts supplemented by sensitivity analysis.

As at 30 June 2018, the Group had no loans outstanding with a variable interest rate; the convertible notes, insurance premium funding and related party loans, all have applicable fixed interest rates.

Interest rate sensitivity analysis

A sensitivity analysis have been determined based on the exposure to interest rates at reporting date with the stipulated change taking place at the beginning of the financial year and held constant throughout the reporting period.

At reporting date, if interest rates had been 50 basis points higher or lower and all other variables were held constant, the Group's net profit would increase by US$14,131 (2017: US$10,697) for an increase of 50 basis points, conversely a decrease of 50 basis points would result in a decrease of US$14,131 (2017: US$10,697) to the net profit. This is mainly due to the Group's exposure to variable interest rates on cash and cash equivalents.

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27. Financial instruments continued

(f) Foreign currency risk management

The Group incurs costs in USA dollars and Australian dollars.

The Group holds the majority of liquid funds in USA dollars.

Fluctuations in the Australian dollar/USA dollar exchange rate can impact the performance of the consolidated entity. The consolidated entity is not currently engaged in any hedging or derivative transactions to manage foreign currency risk. As cash inflows and cash outflows are predominately denominated in USA dollars, with the exception of Australian dollar denominated equity funding, surplus funds are primarily held in USA dollars.

The carrying amounts of the Group's foreign currency denominated monetary assets and monetary liabilities at the end of the reporting period are as follows.

	Monetary assets		Monetary liabilities	
Consolidated	**2018 $**	**2017 $**	**2018 $**	**2017 $**
USA currency denominated	**8,885,111**	5,266,700	**5,842,432**	2,242,397
Australian currency denominated	**431,311**	251,836	**5,631,234**	7,766,551

The following table details the Group's sensitivity to a 10% increase and decrease in the US$ against the A$.

A positive number below indicates an increase in profit or equity where the US dollar strengthens 10% against the relevant currency. For a 10% weakening of the US dollar against the relevant currency, there would be a comparable negative impact on the profit or equity. The impact is mainly due to the Australian group of holding companies incurring and settling expenses and outgoings in Australian dollars.

	Australian dollar impact on profit/loss	
Consolidated	**2018 US$**	**2017 US$**
Profit or equity	**92,138**	378,063

28. Segment information

Management has determined based on the reports reviewed by the Executive management group (the chief operating decision makers) and used to make strategic decisions, that the Group operates within one business segment of oil and gas exploration, development and production; and one geographical segment, the shallow waters of the Gulf of Mexico, United States of America.

The geographical locations of the Group's non-current assets are United States of America US$30,905,960 (2017: US$8,818,499) and Australia US$10,092 (2017: US$13,584).

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29. Parent entity information

Financial position	2018 US$	2017 US$
Assets		
Current assets	311,361	184,512
Non-current assets	94,521,359	77,872,923
Total assets	94,832,720	78,057,435
Liabilities		
Current liabilities	4,814,420	2,358,754
Non-current liabilities	707,185	3,998,400
Total liabilities	5,521,605	6,357,154
Net assets	89,311,115	71,700,281
Equity		
Issued capital	98,633,188	77,330,043
Accumulated losses	(7,373,036)	(4,389,221)
Reserves	(1,949,037)	(1,240,541)
Total equity	89,311,115	71,700,281
Financial performance		
Loss for the year	(2,983,815)	(1,827,804)
Other comprehensive income	(2,150,158)	821,508
Total comprehensive loss for the financial year	(5,133,973)	(1,006,296)

Expenditure commitments

The parent entity has no expenditure commitments at the end of the 2018 financial year (2017: nil).

Guarantees

There were no guarantees entered into during the year by the parent entity in relation to the debts of its subsidiaries.

Contingent liabilities

The parent entity had no contingent liabilities at 30 June 2018 (2017: nil).

30. Operating lease arrangements

Operating lease arrangements relate to the lease of a compressor on the SM71 F platform. The term is for a minimum 36 months with a 30-day notice period option to discontinue the arrangement beyond the three-year period. These obligations are not provided for in the financial statements and the Group doesn't have a purchase option.

	2018 US$	2017 US$
(a) Payments recognised as an expense		
Net Byron 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	–

Notes to the Financial Statements continued

For the Financial Year Ended 30 June 2018

31. Interests in joint operations

As at 30 June 2018, Byron Energy Inc, a wholly owned subsidiary of the Company was a party, to the following joint operations:

- SM71 Offshore Operating Agreement with Otto Energy (Louisiana) LLC covering all of Block 71, South Marsh Island Area, to explore, develop, produce and operate the lease. Byron Energy Inc is the designated operator of SM71 and owns a 50% Working Interest ('WI') and a 40.625% Net Revenue Interest ('NRI') in the block, with Otto Energy (Louisiana) LLC holding an equivalent WI and NRI in the block.
- Both Otto Energy (Gulf One) LLC and Metgasco Limited have exercised their options to earn a 40% and 10% WI, respectively, in Byron's Bivouac Peak project. If both parties earn into the Bivouac Peak project, Byron's WI and NRI will be reduced to 43% (from 93.00%) and 32.035% (from 69.285%) respectively. Byron is the operator.
- In June 2018 Byron announced that Otto Energy Limited exercised its right to acquire a 50% WI in Vermillion 232. Byron will retain a WI of 50.00% and NRI of 43.75% NRI. Byron is the operator.

Subsequent to 30 June 2018, Metagsco Limited exercised its option to earn a 30% WI and 24.375% NRI in South Marsh Island, Block 74 ('SM74').

If Metgasco Limited earns into SM74, Byron's WI and NRI will be reduced to 70% (from 100.00%) and 56.875% (from 81.25%) respectively. Byron is the operator.

32. Subsequent events

Subsequent to the end of the financial year the following has occurred:

- On 9 July 2018, Byron announced to the ASX that, Otto Energy Limited, Metgasco Limited and NOLA Oil and Gas Ventures LLC have all elected to participate in the Byron operated Weiss-Adler et. al. No. 1 well to be drilled to a depth of 18,294 ft MD/18,000 ft TVD to test the Bivouac Peak East Prospect;
- On 19 July 2018, Byron announced to the ASX that it was finalising documentation to allow the SM74 prospect to be drilled from the adjacent existing SM73 D platform and that it has farmed out a 30% working interest on standard industry terms;
- On 6 August 2018, Byron announced to the ASX the SM71 reserves and prospective resources, as at 30 June 2018, as independently assessed by Collarini Associates;
- On 16 August 2018, Byron announced to the ASX that it was the high bidder on Main Pass 293, 305 and 306 leases at the Gulf of Mexico OCS Lease Sale 251, held on 15 August 2018; and
- On 19 September 2018, the Company released its annual reserves and resources report as of 30 June 2018.

Except for the above, there have not been any other matters or circumstances occurring subsequent to the end of the financial year that have significantly affected, or may significantly affect the operations of the Group, the results of those operations, or the state of affairs of the Company in future financial period.

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Directors' Declaration

The directors of Byron Energy Limited declare that in the opinion of the directors:

(a) there are reasonable grounds to believe that the Company will be able to pay its debts as and when they become due and payable;

(b) the attached financial statements are in compliance with International Financial Reporting Standards as stated in Note 1 to the financial statements;

(c) the attached financial statements and notes thereto are in accordance with the *Corporations Act 2001*, including compliance with Accounting Standards and giving a true and fair view of the financial position and performance of the consolidated entity; and

(d) the Directors have been given the declarations required by section 295A of the *Corporations Act 2001*.

Signed in accordance with a resolution of the directors of Byron Energy Limited made pursuant to section 295(5) of the *Corporations Act 2001*.

On behalf of the directors.

D G Battersby
Chairman

25 September 2018

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Independent Auditor's Report
to the Members of Byron Energy Limited

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Independent Auditor's Report to the members of Byron Energy Limited

Report on the Audit of the Financial Report

Opinion

We have audited the consolidated financial report of Byron 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 statements, 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 then ended; 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 auditor independence requirements of 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 on 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.

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Key Audit Matters	How the scope of our audit responded to the Key Audit Matters

Accounting for the Metgasco convertible note
 	
In July 2016, management entered into a funding agreement with Metgasco Limited by the issue of a convertible note of $A8 million to provide Byron Energy Limited with funding for the SM 71 project as disclosed in Note 13 of the financial statements.
 	
The accounting for the convertible note requires significant judgement to determine the appropriate accounting treatment, measurement and classification of all the elements of the agreement including:
• The measurement of the debt component of the note; and
• The measurement of the derivative liability embedded in the note.
 	
The measurement of these components are subject to certain assumptions including:
• The timing of funding drawdown under the note;
• The discount rate used to present value the future payments under the terms of the note; and
• The timing of conversion (if at all).
	In conjunction with our valuation experts, our procedures included, but were not limited to:
	• Obtaining an understanding of the key elements of the convertible note;
	• Assessing management's process to recognise and measure all liabilities arising from the contract;
	• Evaluating management's methodology and their documented basis for key assumptions used in their valuation model;
	• Challenging the key assumptions used in the valuation model as follows:
	    ○ estimating draw down funds and probabilities around the expected conversion dates; and
	    ○ assessing the appropriateness and accuracy of the inputs used to measure the embedded derivative.
	
	Assessing the appropriateness of the disclosures in Note 13 to the financial statements.

Amortisation of Oil and Gas properties During the year then ended 30 June 2018 there was $USD 0.9 million amortisation as disclosed in Note 8(b) of the financial report. When an oil and gas asset commences commercial production, all acquisition and/or costs carried forward will be amortised on a units of production of basis over the remaining proved and probable recoverable reserves. The remaining reserves are measured by external independent petroleum engineers. The measurement of this amortisation is subject to certain assumptions including: • The level of future proved and probable recoverable reserves; and • The future capital expenditure required to access the reserves.	Our audit procedures included, but were not limited to: • Assessing management's external expert report used to estimate the level of proven and probable oil and gas reserves and future development capital expenditure; • Assessing the competence and objectivity of management's expert to support assumptions used; • Testing the metered production usage in the current year per independent third party reporting; and • Testing on a sample basis the mathematical accuracy of the amortisation recognised. We also assessed the appropriateness of the disclosures in Note 8 to the financial statements.

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Other Information

The directors are responsible for other information disclosed. The other information comprises the information included in the Group's annual report for the year ended 30 June 2018, but does not include the financial report and our 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 Group's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the directors either intend to liquidate the Group or to cease operations, or have 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.

As part of an audit in accordance with the Australian Auditing Standards, we exercise professional judgement and maintain professional scepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial report, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Group's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by the directors.

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

- Evaluate the overall presentation, structure and content of the financial report, including the disclosures, and whether the financial report represents the underlying transactions and events in a manner that achieves fair presentation.

- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Group to express an opinion on the financial report. We are responsible for the direction, supervision and performance of the Group audit. We remain solely responsible for our audit opinion.

We communicate with the directors regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide the directors with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

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

Report on the Remuneration Report

Opinion on the Remuneration Report

We have audited the Remuneration Report included in pages 46 to 50 of the Directors' Report for the year ended 30 June 2018.

In our opinion, the Remuneration Report of Byron 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.

Deloitte Touche Tohmatsu

DELOITTE TOUCHE TOHMATSU

Craig Bryan
Partner
Chartered Accountants
Melbourne, 25 September 2018

ASX Additional Information

Additional information required by the Australian Securities Exchange Ltd. Listing Rules and not disclosed elsewhere in this report is as follows. The information is current as at 25 September 2018.

Distribution of equity securities

As at 25 September 2018 the Company had a total of 688,753,513 ordinary shares on issue and 51,800,000 options on issue comprising:

Quoted ordinary shares

688,753,513 fully paid ordinary shares are held by 2,380 shareholders. All issued ordinary shares carry one vote per share without restriction. Every member at a meeting of shareholders shall have one vote and upon a poll each share shall have one vote.

Unquoted options on issue

51,800,000 options are held by 24 option holders. 1,950,000 options are exercisable on or before 30 September 2018 at an exercise price of $A0.25 cents each, 10,000,000 options are exercisable on or before 21 July 2019 at an exercise price of A$0.25 cents each, 9,500,000 options are exercisable on or before 31 December 2019 at an exercise price of A$0.25 cents each, 28,350,000 options are exercisable on or before 31 December 2021 at an exercise price of A$0.12 cents each and 2,000,000 options are exercisable on or before 31 December 2021 at an exercise price of A$0.16 cents each. There are no voting rights attached to these options.

Escrowed securities

As at 25 September 2018 there are no escrowed securities.

The number of shareholders, by size of holding and the total number of quoted shares on issue, are:

Size of holding	Number of holders	Number of shares
1 – 1,000	119	38,672
1,001 – 5,000	615	1,690,911
5,001 – 10,000	322	2,623,886
10,001 – 100,000	769	30,869,517
100,001 and over	555	653,530,527
Total holders	**2,380**	**688,753,513**

The number of security investors holding less than a marketable parcel of securities is 74 with a combined total of 4,966 securities.

The number of option holders, by size of holding and the total number of unquoted options on issue, are:

Size of holding	Number of holders	Options exercisable at A$0.25 Exp 30/09/2018	Number of holders	Options exercisable at A$0.25 Exp 21/07/2019
1 – 1,000	0	0		
1,001 – 5,000	0	0		
5,001 – 10,000	0	0		
10,001 – 100,000	0	0		
100,001 and over	2	1,950,000	1	10,000,000
Total	**2**	**1,950,000**	**1**	**10,000,000**

Size of holding	Number of holders	Options exercisable at $A0.25 Exp 31/12/2019	Number of holders	Options exercisable at $A0.12 Exp 31/12/2021	Number of holders	Options exercisable at $A0.16 Exp 31/12/2021
1 – 1,000	0	0				
1,001 – 5,000	0	0				
5,001 – 10,000	0	0				
10,001 – 100,000	2	200,000				
100,001 and over	7	9,300,000	11	28,350,000	1	2,000,000
Total	**9**	**9,500,000**	**11**	**28,350,000**	**1**	**2,000,000**

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Substantial shareholders

Set out below are the names of the substantial holders and the number of equity securities held by those substantial holders (including those equity securities held by their associates).

Name of holder		Number of ordinary shares held	Percentage of issued capital
1.	Douglas Battersby (and associates)	48,123,203	6.99%
2.	Metgasco Limited	41,663,479	6.05%

20 Largest shareholders

Quoted ordinary shares		Number	Percentage
1.	METGASCO LIMITED	41,663,479	6.049%
2.	VERUSE PTY LIMITED	36,460,405	5.294%
3.	EQUITAS NOMINEES PTY LIMITED <PB-600387 A/C>	18,659,538	2.709%
4.	MR MATTHEW DOMINELLO	18,563,693	2.695%
5.	FITZROY RIVER CORPORATION LIMITED	18,131,868	2.633%
6.	MR CHARLES SANDS	16,569,569	2.406%
7.	WALLEROO PTY LTD	15,348,408	2.228%
8.	CAMERON RICHARD PTY LTD <LPS PL NO 5 EXEC B/PLAN A/C>	13,938,461	2.024%
9.	BARRIJAG PTY LTD <HADLEY SUPER FUND A/C	13,809,524	2.005%
10.	MR JOHN SANDS A SANTINI	13,199,153	1.916%
11.	DISCOVERY INVESTMENTS PTY LTD	13,000,000	1.887%
12.	LINWIERIK SUPER PTY LTD <LINTON SUPER FUND A/C>	12,500,000	1.815%
13.	CLAPSY PTY LTD <BARON SUPER FUND A/C>	11,492,784	1.669%
14.	MERRILL LYNCH (AUSTRALIA) NOMINEES PTY LIMITED	11,108,700	1.613%
15.	AGRICO PTY LTD <PALM SUPER FUND A/C	11,083,385	1.609%
16.	GEOGENY PTY LIMITED	10,714,045	1.556%
17.	MR DOUGLAS GEOFFREY BATTERSBY & MS ALISON ROSEMARY BATTERSBY & MR EWAN BATTERSBY <VERUSE EMPLOYEES S/FUND A/C>	8,631,798	1.253%
18.	DESBETT PTY LTD <FITZGERALD FAMILY A/C>	7,175,554	1.042%
19.	BARRIJAG PTY LTD <HADLEY FAMILY A/C>	7,142,858	1.037%
20.	MR JONATHAN MERVIS	7,000,000	1.016%
Total quoted shares held by top 20 shareholders		306,193,222	44.456%
Quoted shares held by other Shareholders		382,560,291	55.544%
Total quoted shares		**688,753,513**	**100.00%**

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Corporate Directory

Directors

Doug Battersby	(Non-Executive Chairman)
Maynard Smith	(Executive Director and CEO)
Prent Kallenberger	(Executive Director)
William Sack	(Executive Director)
Charles Sands	(Non-Executive)
Paul Young	(Non-Executive)

Chief Executive Officer

Maynard Smith

Chief Financial Officer and Company Secretary

Nick Filipovic

Registered and principal australian office

Level 4
480 Collins Street
MELBOURNE VIC 3000

Principal office (USA)

Suite 604
201 Rue Iberville
LAFAYETTE LA 70508

Legal adviser

Piper Alderman
Level 23
Governor Macquarie Tower
1 Farrer Place
Sydney NSW 2000

Auditors

Deloitte Touche Tohmatsu
550 Bourke Street
Melbourne VIC 3000

Website

byronenergy.com.au

Home stock exchange

ASX Limited
20 Bridge Street
SYDNEY NSW 2000
ASX Code: BYE

Share registry

Boardroom Pty Limited
Grosvenor Place, Level 12, 225 George Street
Sydney NSW 2000
Tel: 1300 737 760
Fax: 1300 653 459

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