6 February 2019

Reserve and Resource Update
Year end 2018

Australis Oil & Gas
ABN: 34 609 262 937

ASX: ATS

Australis is an upstream oil and gas company seeking to provide shareholders value and growth through the strategic development of its quality onshore oil and gas assets in the United States of America and Portugal.

The Company's acreage within the core of the oil producing TMS provides significant upside potential for ATS with 50 million bbls of 2P reserves including 3.9 million bbls producing reserves providing free cash flow as well as 108 million bbls of 2C contingent resource.

The Company was formed by the founders and key executives of Aurora Oil & Gas Limited, a team with a demonstrated track record of creating and realising shareholder value.

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Australis grows reserve and resource base within the Tuscaloosa Marine Shale

Australis Oil and Gas Limited ("Australis" or "Company") is pleased to provide the market with an update to our reserve and resource position in the Tuscaloosa Marine Shale ("TMS").

The Company holds 110,000 net acres in the TMS Core, which has been independently assessed by Ryder Scott Company with an effective date of 31 December 2018 to generate the following figures[1,2]

- PDP of 3.93 MMbbls with an NPV(10) of US$82.8 million.
- Net oil reserve (after royalties) estimates:
  - 1P – 31.9 MMbbls
  - 2P – 49.7 MMbbls
  - 3P – 89.2 MMbbls
- Net contingent oil resources (after royalties) based on the remaining undeveloped acreage in the TMS core:
  - 1C – 6.9 MMbbls
  - 2C – 107.8 MMbbls
  - 3C – 195.4 MMbbls

Australis believes that consistent with industry experience in onshore North American oil shale assets these remaining contingent resources will convert to reserves when assessed for development. This report only assessed 38% of the total acreage position due to an assumed modest development program within the maximum 5 year development timeframe and it was all allocated a reserve category.

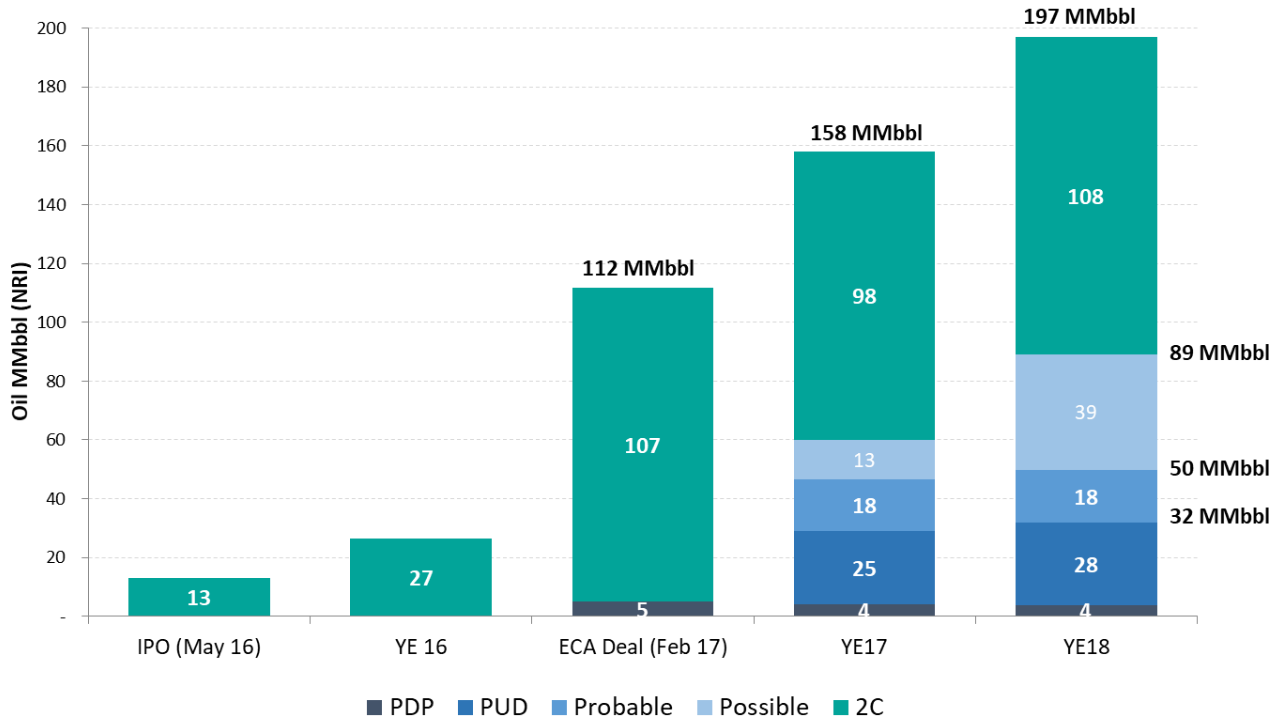
Australis has continued to implement its business strategy of accumulating oil in the ground at accretive leasing prices within the TMS Core. This reserve and resource update by Ryder Scott reflects the impact of this strategy as the resource base continues to significantly grow over time and substantial contingent resources are converted to reserves as the development program progresses.

Resource and Reserve evolution

The chart below represents the chronological evolution in our total reserve and most likely contingent resource base since our IPO, reflecting the progression of our strategy.

The substantial increase in the Possible reserve estimate in 2018 was attributable to an increased acreage position at year end, together with an increase in the assumed number of wells drilled for the 2018 reserves estimate, which converted contingent resources to Possible reserves. With additional development drilling, the Company would expect to see the conversion of the majority of these Possible reserves to Proved and Probable reserves over time.

Figure 1: Evolution of TMS Reserves and Resources (MMbbl) (see notes 1 – 5)



Tuscaloosa Marine Shale Reserve and Resource estimates

Australis holds a substantial net leasehold position of 110,000 acres within the core of the TMS in Mississippi and Louisiana. Operations are presently underway on an initial well program to demonstrate execution costs and well productivity in support of an underlying valuation of Australis's interests.

Australis operates 34 wells and has interests in a further 17 wells operated by others in the play most of which have been on production for at least 4 years. The PDP reserve allocation detailed in this report estimates the remaining recoverable hydrocarbons from these wells, which includes the first two wells from the current ongoing development program. Ryder Scott used a subset of 25 of these wells (excluding the new wells) to generate three production type curves for a Proved, Probable and Possible case.

This reserve report considers a modest development program over the next 5 years which conforms to the maximum evaluation timeframe prescribed by the SPE Petroleum Reporting Management System. The development program builds to a maximum of 4 drilling rigs to drill a total of 184 wells within this period. This program equates to the development of 38% of the overall Australis net acreage position.

Ryder Scott deemed all locations that they evaluated for development to be commercial and they allocated the following reserves and resources to the Australis TMS position.

Reserve Category	Australis Reserves[1,2]		Net Oil YE18 vs YE17
	Gross Oil (Mbbls)	Net Oil (Mbbls)	
Proved Developed Producing (PDP)	6,306	3,927	
Proved Undeveloped (PUD)	40,306	27,936	
Proved (1P)	**46,612**	**31,863**	**10.2%**
Probable Developed Producing	1,309	855	
Probable Undeveloped	25,145	16,998	
Probable Total	26,453	17,854	
Proved + Probable (2P)	**73,065**	**49,717**	**6.7%**
Possible Developed Producing	1,532	1,014	
Possible Undeveloped	67,251	38,457	
Possible Total	68,783	39,471	
Proved + Probable + Possible (3P)	**141,849**	**89,188**	**48.2%**

Contingent Resource Category	Oil (Mbbl)[1,2]	Gas[A] (MMscf)[1,2]	Gas[B] (MMscf)[1,2]	Oil Eq (Mboe)[1,2]	Oil YE18 vs YE17
Low Estimate (1C)	6,945	2,778	13,174	9,604	-21.6%
Best Estimate (2C)	107,809	59,294	27,079	122,205	10%
High Estimate (3C)	195,410	131,901	59,108	227,245	9.9%

Gas[A] is gas associated with the contingent resource oil volume, Gas[B] is gas associated with the proved, probable and possible oil volumes however is considered contingent as there are no immediate plans to capture and develop the gas. If in the future the associated gas is developed then these gas volumes will be included in the appropriate reserve category.

Assumptions

Key assumptions used by Ryder Scott to generate these estimates are as follows:

- Reserves and contingent resources estimates are based on the deterministic estimation method.
- The oil price used for all reserve analysis is a flat realised price of US$69.25/bbl, which is based

on the average Louisiana Light Sweet oil price on the first trading day of each calendar month during 2018 adjusted for transportation costs.

- Operating costs are based on actuals incurred between Aug – Nov 2018, which management believe conservatively reflect likely costs going forward.
- The existing PDP estimates are based on production from 34 operated and 17 non-operated wells (33.4 net wells). They have a combined NPV(10) of $82.8 million (pre tax).
- Proposed future well locations are allocated a reserve category based on proximity to existing wells and production.
- The 5 year development plan assumes an single rig operating ongoing, 2 rigs from October 2019, 3 rigs in July 2020 and then running 4 rigs from July 2021, drilling a total of 184 gross well locations and all were deemed commercial. The development plan assumed 8 wells per standard development unit and approximately 250 acre spacing. This represents approximately 38% of the Australis core undeveloped acreage.
- Anticipated D, C & T well costs range from US$10.7 to US$12.1 million depending on well length with an incremental average cost of US$337k per well for shared infrastructure assuming 8 wells in a unit and 4 to 6 wells on each surface pad.
- The development plan assumes a 31 day period to drill new wells.
- Type curves are based on historical production data from a sample of 25 wells. A proved, probable and possible type curve was generated by Ryder Scott and used for future wells
- Well treatable horizontal lengths assumed for new locations ranged from 6,900 ft to 10,154ft horizontally, depending on unit size. Type curves were normalised to horizontal length.
- The Stewart 30H-1 was allocated a PDP type curve that was normalised for the horizontal length of the well for this report as it had only been on production for a day at the effective date. Since that date Australis has reported an IP30 that is significantly above the IP30 of the allocated PDP type curve.
- The Bergold 29H-2 was allocated a PDP type curve based on the initial production in January, which is believed to be from a single fracture stage.
- Average royalty payable on future well locations allocated a reserve in this report was 19.7%.
- Contingent resources are only estimated for areas not included in the reserve analysis. The 1C contingent resources are limited to any unit offsetting existing TMS wells that were not considered for reserves. The 2C and 3C considered all of the undeveloped acreage within the core area, but used different estimates of in-place and recovery efficiencies.
- No gas sales are assumed as all gas is consumed on the lease, therefore neither gas nor gas liquids have been included in the reserves estimates.

PDP reconciliation

The following table provides a reconciliation of net PDP reserves between 31 December 2017 and 31 December 2018

Description	Net Oil (Mbbl)
PDP + PDNP Reserve (31/12/17)[3]	4,093
Net Production (31/12/17 – 31/12/18)	(407)
New wells	383
Technical Adjustment	(142)
PDP Reserve (31/12/18)[1,2]	3,927

Contributors to the technical adjustment shown in the above table.

- Operating costs influence economic cut off (i.e. the date in which it is no longer economic to produce oil from a well, generally many years after first production) which in turn varies the attributable reserves at the end of well life but has a negligible impact on discounted NPV values. The operating cost used for future wells is based on actual costs incurred during the period of August to November 2018, which are higher than the operating costs assumed for the YE2017 Report, leading to a reduction of reserves at the end of the life of certain wells. This period captured some of the improvements in LOE, downtime and workover frequency that resulted from changes implemented by Australis to completion design and operating practices. However, reductions in operating costs per barrel have continued since this period but those improvements are not reflected in the assumed numbers within the 31 December 2018 Reserves Report.
- The economic cut off is also influenced by the higher oil price assumptions used in this reserve report compared with the YE 2017 Report.
- Revisions in production forecast based on 2018 production.

Contingent Resource reconciliation

The following table summarises the change in contingent resource estimated on 31 December 2018 and 31 December 2017.

Description	Contingent Resource 31 Dec 2017[3] (MMbbl)	Contingent Resource 31 Dec 2018[1,2] (MMbbl)
Low Contingent Resource (1C)	8.9	6.9
Most Likely Contingent Resource (2C)	98.0	107.8
High Contingent Resource (3C)	177.8	195.4

The following key factors contributed to the changes in contingent resource.

- Between the two dates Australis increased its net acreage position in the TMS core from 95,000 net acres to 110,000 net acres.
- There was an increase in the number of wells drilled for the reserves estimate in 2018 compared to the report in 2017. This led to a significant increase in the Possible reserve estimate (190%) as contingent resources converted to reserves.

Portugal

On 25 January 2017 Australis provided an updated Contingent and Prospective Resource estimate to the market completed by NSAI[6]. Whilst Australis has carried out a number of technical workscopes in the intervening period, the Company is not aware of any information that would influence these estimates and therefore they were not updated at year end. For ease of reference the Aljubarrota gas discovery Contingent Resource estimates are shown below:

	Low Estimate 1C (Bcf)	Best Estimate 2C (Bcf)	High Estimate 3C (Bcf)
Net Contingent Resource[7]	217.4	458.5	817.7

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GLOSSARY

Unit	Measure	Unit	Measure
B	Prefix – Billions	bbl	Barrel of oil
MM	Prefix – Millions	boe	Barrel of Oil equivalent (1bbl = 6 mscf)
M	Prefix – Thousands	scf	Standard cubic foot of gas
/d	Suffix – per day	Bcf	Billion cubic feet of gas

Unit	Measure
Gross or WI	Company beneficial interest before royalties or burdens
Net or NRI	Company beneficial interest after royalties or burdens
C	Contingent Resources (1C/2C/3C equivalent to low/most likely/high)
NPV(10)	Net Present Value (@ discount rate)
EUR	Estimated Ultimate Recovery of a well
WTI	West Texas Intermediate oil benchmark price
LLS	Louisiana Light Sweet oil benchmark price
D, C & T	Drill, Complete, Tie – in and artificial lift
2D/3D	2 and 3 dimensional seismic surveys
Opex	Operating Expenditure
HBP	Held by production – within a formed unit a producing well meets all lease obligations within that unit. Primary term remains valid whilst well is on production.
LOE	Lease Operating Expense

Notes

1. All estimates have been taken from the independent Ryder Scott report, effective 31 December 2018. The report was prepared in accordance with the definitions and disclosure guidelines contained in the Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), American Association of Petroleum Geologists (AAPG), and Society of Petroleum Evaluation Engineers (SPEE) Petroleum Resources Management (SPE-PRMS) as revised in June 2018. Ryder Scott generated their independent reserve and contingent resource estimates using a deterministic method.
2. Previous Australis reserve and resource estimates were prepared using the 2007 SPE-PRMS definitions and guidelines. The 2018 SPE-PRMS updated and clarified the 2007 guidelines. A key clarification in this update was:
   a. "Projects associated with Undeveloped Reserves should initiate development within 5 years from the initial classification date". Practically this requires that Australis develop any reserve it was given credit for on 31 December 2017, within 4 years of the effective date of this report.
3. Contingent Resources and Reserves estimated with an effective date 31 December 2017 are taken from the independent Ryder Scott report dated 26 January 2018 and announced on 30 January 2018 and titled 'Reserve and Resource Update Year End 2017'.
4. Contingent Resources estimated with an effective date 1 May 2016 are taken from Section 8 (Technical Experts Reports) of the Company's prospectus dated 29 June 2016 and is available on the company website.
5. Contingent Resources estimated with an effective date 31 December 2016 are taken from the independent Ryder Scott report dated 23 January 2017 and announced on 25 January 2017 and titled '2016 Year End Resource Update'.
6. All estimates have been taken from the independent Netherland, Sewell & Associates report, effective 31 December 2016 and announced on 25 January 2017 titled '2016 Year End Resource Update'. The report was prepared in accordance with the definitions and disclosure guidelines contained in the Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), American Association of Petroleum Geologists (AAPG), and Society of Petroleum Evaluation Engineers (SPEE) Petroleum Resources Management (SPE-PRMS). The Company is not aware of any new information or data that materially affects the information included in the referenced market announcement and that all material assumptions and technical parameters underpinning the estimates in the referenced market announcement continue to apply and have not materially changed.
7. Australis holds a 100% working interest in the Batalha and Pombal Concessions, however this interest is subject to a 3% working interest option granted to a contractor and the Net estimates provided by NSAI are prepared with the assumption that this option has been exercised. The Net estimates provided by NSAI also make an allowance for royalties payable to the Portuguese government. The actual royalties payable by Australis are detailed in Article 51 of Decree Law nr 109/94 of the 26th April,1994 and Article 19.2 of each concession contract. For oil there is a staged royalty of between 0 and 9% based on produced volumes and for gas there is a similar staged royalty of between 3 and 8% again based on produced volumes. As there is not a development plan and an associated production profile for either the contingent or prospective resource estimates, the royalty rate has been assumed to be 8 and 9% respectively.
8. The deterministic method is based on qualitative assessment of relative uncertainty using consistent interpretation guidelines. The independent engineers using a deterministic incremental (risk-based) approach estimates the quantities at each level of uncertainty discretely and separately.

Competent Persons Statement

The reserves and contingent resource estimates provided in this announcement pertaining to the Tuscaloosa Marine Shale is based on, and fairly represents, information and supporting documentation, prepared by, or under the supervision of, Raymond Yee, P.E., who is an employee of Ryder Scott Company, L.P. an independent professional petroleum engineering firm. Mr Yee is a Professional Engineer in the State of Texas (Registration No. 81182). The reserve and resource information pertaining to the Tuscaloosa Marine Shale in this announcement has been issued with the prior written consent of Mr Yee in the form and context in which it appears.

Forward Looking Statements

This document may include forward looking statements. Forward looking statements include, but are not necessarily limited to, statements concerning Australis' planned development program and other statements that are not historic facts. When used in this document, the words such as "could", "plan", "estimate", "expect", "intend", "may", "potential", "should" and similar expressions are forward looking statements. Although Australis 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.