Key Activities & Highlights 28 January 2022

Australis Oil & Gas Limited
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.

The Company's acreage within the core of the oil producing TMS provides significant upside potential for ATS with 170 million bbls of 2P+2C reserves and resources including 3.7 million bbls producing reserves providing free cash flow.

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.

Address
Ground Floor, 215 Hay Street
Subiaco, WA 6008
Australia

Suite 3680
3 Allen Center
333 Clay Street
Houston, Texas U.S.A
77002

Contact
Telephone:
+61 8 9220 8700

Facsimile:
+61 8 9220 8799

Email:
contact@australisoil.com

Web:
www.australisoil.com

Australis maintains a controlling interest within one of the last appraised but undeveloped quality unconventional oil plays onshore in the USA.

During the quarter the continued strengthening of the US oil market resulted in an increase in interest for undeveloped Tier 1 shale oil assets.

Overview

- Australis TMS asset has a recoverable estimate of 170 million bbls[1] (net) oil that independent reserve evaluators considered commercial at US$47/bbl. We consider these estimates conservative.
- Production continues to generate positive operating cashflow including all G&A and interest costs.
- Third party drilling activity in TMS has occurred – Reese 11H #1 has been drilled and was awaiting completion activities in Q1 22 – an indicator of growing interest.
- 2nd largest TMS producer (Goodrich) acquired by previous Australis TMS partner, Paloma Partners IV.
- US unconventional market sentiment continues to improve with sustained higher oil prices during the quarter and into early 2022.
- Australis will continue to be patient in its search for the right partner for further field development activities in an improving business environment.

Operations Summary – 4th quarter 2021

- During the quarter Australis generated:
    - Sales volume of 96,200 barrels (WI) (-8% on Q3)
    - Revenue of US$5.9 million (-4% on Q3) including hedge losses on Credit Facility required oil price hedges of US$1.6 million (Q3: loss US$1.5 million)
    - Field Netback of US$2.3 million (+5% on Q3)
    - EBITDA of US$0.5 million (-55% on Q3)

Financial and Corporate

- Continued positive Group operating cashflow after all G&A expenses and interest costs for Q4. Each quarter in 2020 and 2021 produced positive Group operating cashflow after G&A and interest costs.
- Cash balance at quarter end was US$9.3 million and net debt (Macquarie Facility) was US$6.7 million, following a further principal repayment of US$1 million in the quarter.
- Oil price hedge book weighting continues to transition from swaps to cap and collar contracts through 2H 2021, increasing Australis's exposure to higher oil prices.

KEY FINANCIAL INFORMATION

The following table summarises key financial metrics for Q4 2021.

Key Metrics	Unit	Q4 2021	Q3 2021	Qtr on Qtr Change
Core Land Position (Net)	acres	98,000	100,000	(2)%
Net Oil resource (2P + 2C)[1]	MMbbls	170	170	(-)%
Sales Volumes (WI)	bbls	96,200	104,100	(8)%
Average Realised Price[A]	US$/bbl	$77.23	$73.40	5%
Average Achieved Price[B]	US$/bbl	$61.06	$58.92	4%
Sales Revenue (WI)[B]	US$MM	$5.9	$6.1	(4)%
Sales Revenue (Net)[B]	US$MM	$4.5	$4.6	(2)%
Field Netback	US$MM	$2.3	$2.2	5%
Field Netback / bbl (WI)[B]	US$/bbl	$24	$21	14%
Field Netback / bbl (Net)[B]	US$/bbl	$30	$26	15%
EBITDA	US$MM	$0.5	$1.1	(55)%
Cash Balance (Qtr end)	US$MM	$9.3	$9.9	(6)%
Debt Balance (Qtr end)[C]	US$MM	$16.0	$17.0	(6)%

[A] excludes effect of hedge contracts settled
[B] includes the loss from the settlement of hedge contracts of US$1.56 million (Q3 2021: loss of US$1.51 million)
[C] Macquarie Facility debt

TMS PRODUCTION AND OPERATING PERFORMANCE

Production operations during the quarter were routine, with no major weather events nor disruptions to production, other than during December when three wells simultaneously required workovers.

Sales volumes were down 8% compared to Q3 at 96,200 bbls and inventory grew by ~2,500 bbls, which accounted for approximately 1/3 of this sales volume drop.

Overall workover frequency for the quarter was less than projected, further testimony to extended well run life between interventions, a key driver in improved operating costs. Workover costs reduced to $2.91/bbl for the quarter (from $5.28/bbl in Q3 and $4.73/bbl YTD at the end of Q3) although workover operations continued on the three wells into 2022.

Realised and Achieved oil pricing both improved modestly and whilst hedging losses at $1.56 million were similar to the preceding quarter ($1.51 million) a majority of the hedge volume in H1 2022 is on zero cost collar basis and consequently going forward Australis will derive a greater portion of higher oil prices.

There were no safety or environmental incidents reported during the quarter.

FINANCE AND CORPORATE

Cash and Capital

As for the corresponding quarters in 2021 and 2020, Australis generated positive Group operating cashflow, after interest costs and G&A expenses, but before principal debt repayment.

Results for the quarter include:

- EBITDA of US$0.5 million for Q4 and US$2.6 million for the year
- Interest expense of US$0.3 million for Q4 and US$1.2 million for the year
- Debt under our Macquarie Facility reduced by US$1 million to US$16 million
- Cash of US$9.3 million at 31 Dec 2021 (31 Dec 2020: US$4.7 million)
- Net debt of US$6.7 million at 31 Dec 2021 (31 Dec 2020: US$15.3 million)
- Sales Revenue (before the impact of hedges) was
    - US$7.4 million for Q4, 3% lower than Q3 despite reduced sales volume from Q3 (8%)
    - US$28.3 million for 2021, 32% higher than 2020 despite reduced sales volumes (19%)
    - Sales revenue higher per bbl in 2021 due to the average achieved oil price (before hedges) being US$69/bbl (65% higher) than 2020
- Losses from the oil price hedge program:
    - US$1.56 million for the quarter (Q3: US$1.51 million), as achieved oil prices increased by 5% from Q3
    - US$5.4 million for the year (2020: profit US$4.7 million) as the average monthly WTI oil prices increased 72% to $67.91 for 2021

Credit Facility

The outstanding debt under our Macquarie Credit Facility was reduced by US$1 million in the quarter, resulting in a balance at 31 December 2021 of US$16 million. Australis continued to meet all covenant requirements and serviced interest and other facility costs out of operating cash flow during the reporting period. The credit facility maturity remains at November 2023, with minimum quarterly principal repayments of US$1 million.

Oil Price Hedging

During the reporting quarter Australis:

- incurred a hedge loss of US$1.56 million, as the average WTI oil price in each of the months in the quarter, ranging between US$82/bbl and US$71/bbl, exceeded the average monthly hedged WTI price of approx. US$46/bbl. The hedges consisted of a majority of swaps executed at various times from Q3 2019 to Q1 2021.
- The majority of the realised oil price hedging loss resulted from hedges required to be executed under the terms of our Macquarie Credit Facility during the low oil price environment in 2020 to maintain minimum volumes under the terms of the Credit Facility.
- Took advantage of the higher oil futures pricing and executed oil price hedges for an additional 17,000 bbls for the 10 months July 2022 to April 2023 using no-cost collar contracts. These new hedges protect a WTI price of US$55/bbl but retain the benefit of the actual WTI price over the protected price, up to US$88/bbl for Q3 2022 and US$82/bbl for the remaining hedge period.

The table below summarises the protected WTI floor prices and the ceiling prices for all hedged volumes through to September 2024. As the oil price futures improved during the 2H of 2021, an increased weighting to no-cost collars oil price hedges has been implemented.

As at 1 January 22	WTI Swaps		WTI Collars		
Qtr/Year	Volume	Protected Price	Volume	Protected Price (Put)	Ceiling Price (Call)
	000 bbls	US$/bbl	000 bbls	US$/bbl	US$/bbl
Q1/2022	30.7	$51.00	18	$45.83	$69.17
Q2/2022	13.4	$54.78	30	$43.50	$71.38
Q3/2022	19.2	$55.77	21	$43.57	$73.04
Q4/2022	9	$53.09	19.5	$45.00	$74.15
Q1- Q4/2023	22	$55.05	50	$41.65	$66.01
Q1- Q3/2024	14	$53.44	0		

The following table provides an estimate of the effect of these existing hedges at different assumed oil prices over the next three years.

Period	Hedged Volume (000 bbls)	Projected Hedge Losses at assumed oil prices (US$ million)		
		US$75/bbl	US$65/bbl	US$55/bbl
2022	161	$1.8	$0.8	$0.5
2023	72	$0.8	$0.2	$0.1
2024	14	$0.3	$0.1	$0.1

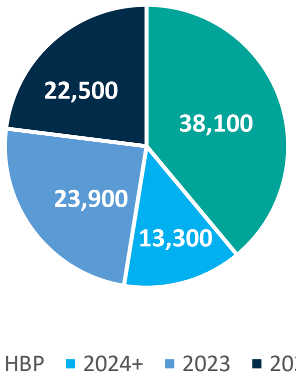
TMS LEASE POSITION

Australis continued its capital disciplined but modest strategic leasing and permitting program in Q4, seeking to protect identified acreage to maintain the Company's control and exposure to the TMS Core area whilst allowing further non-core or lower graded term lease acreage to expire.

Australis closed out the year permitting two units in Mississippi as preliminary planning for drill readiness and will continue a modest leasing and permitting program into 2022. Whilst no additional acres were leased in the quarter, approximately 300 net acres of leases were closed out in January 2022 from this process.

As at 31 December 2021 Australis holds ~98,000 net acres in the TMS Core, of which 38,100 net acres (39%) are HBP.

Figure 1 provides more detail on the expiry profile of the Core acreage position as at 31 December 2021.



Expiration Year – TMS Core Net Acres
Figure 1: Expiration Year - undeveloped net acres

Figure 2 below provides a map of the Australis acreage position.

THIRD PARTY TMS FIELD ACTIVITY

In Q4 2021 State Line Exploration LLC (State Line), a portfolio private operating company for Juniper Capital Advisors (Juniper), drilled and cased the Reese 11H No. 1 well in Amite County, Mississippi. Juniper is a US based energy investment firm with over US$1.2 billion in assets under management and its investments include a controlling stake in Ranger Oil Corporation (NYSE: ROCC, formerly Penn Virginia Corporation).

Subsequent to this reporting period fracture stimulation operations commenced and as a precaution Australis shut in the three adjacent wellbores to monitor for any pressure communication and avoid any potential damage if communication occurred, a total of ~2,000bbls of production was deferred as a result during January. Production from these wells recommenced in late January following the completion of the Reese 11H fracture stimulation.

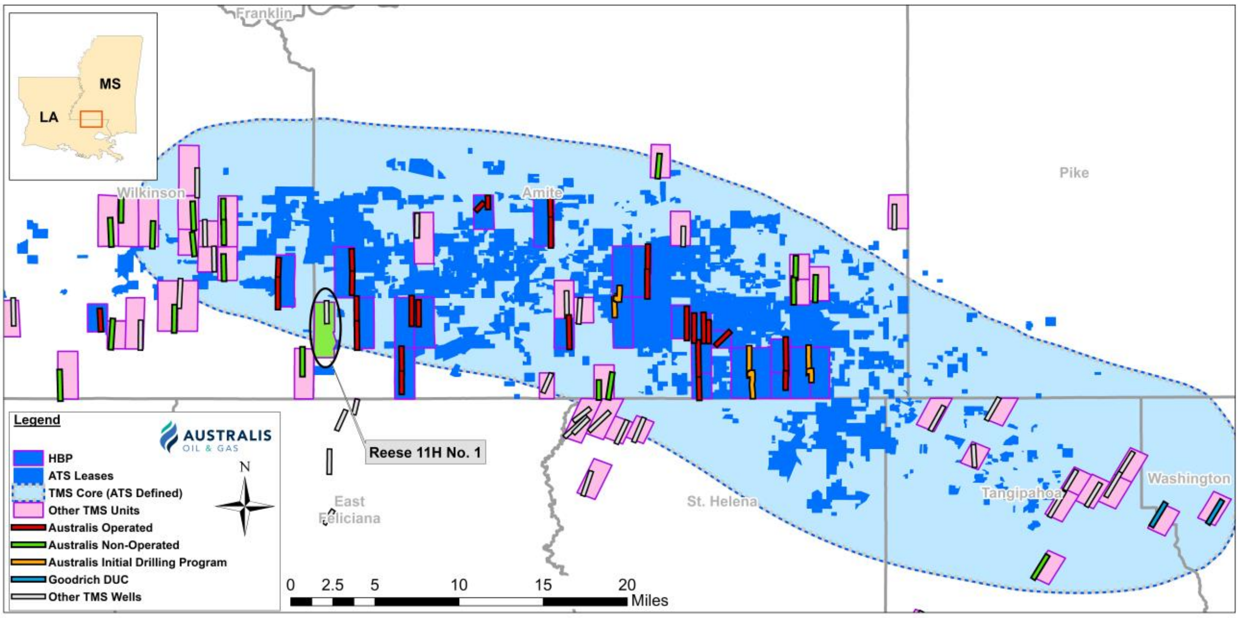


Figure 2: Australis Acreage and Well Locations with State Line Exploration well

On 23 December 2021 Paloma Partners VI Holdings, LLC, an affiliate of Paloma Resources ("Paloma") a portfolio company of EnCap Energy Capital Fund XI L.P. ("EnCap") completed its acquisition of Goodrich Petroleum Corporation ("Goodrich"). Goodrich was an active participant in the TMS prior to 2014 and, following a debt restructuring, the company focused their activities elsewhere within their portfolio. However, they have maintained a material HBP position within the TMS of ~34,000 net acres and 28 operated wells, although some of these interests are outside the Australis designated TMS Core area. Paloma were Australis' original partners in the TMS in 2016/2017 and the Company welcomes another new operator into the TMS.

BUSINESS DEVELOPMENT AND CORPORATE STRATEGY

Australis has remained steadfast in our belief in the quality of the asset and that market conditions are becoming increasingly conducive to finding a partner for ongoing activity in the play.

Australis believes that asset quality for an unconventional oil play is primarily driven by rock productivity and then influenced by several key factors including:

Factor	TMS Advantage
Available third-party infrastructure	Multiple oil and gas pipelines cross the TMS
Proximity to market	Located near refineries, pipelines and gathering centres
Regulatory and operating environment	Mississippi is a very operator-friendly jurisdiction
Quality of produced crude	Produces high quality oil, LLS, which sells at a premium to WTI
Produced water volumes	Produced water volumes, and associated costs, are a fraction of other plays such as the Permian

Many of these elements are largely fixed and/or out of the direct control of an operator.

Thereafter, other than oil price, the fundamental element that drives economics for an unconventional play is the cost base of development. This is heavily influenced by play maturity, as the cost of new wells reduces as more wells are drilled in any given play and designs/execution are optimised with practice. During the earlier stage of evolution, when that optimisation has just started, well costs tend to be higher, but without fail in the US shale industry, trend down over time. Activity levels can also heavily influence costs, with a significant scale of operations offering efficiency savings. Australis therefore believes that the cost of drilling and completing new wells in the TMS will reduce over time.

The TMS produces 95% oil crude and only small quantities of gas and NGLs. When oil productivity is used as the comparison metric, the average oil productivity of the 15 wells drilled by Encana in 2014 and now operated by Australis is comparable to the best areas of the more established plays at that time. This is further evidenced when production data from more recent well performance in 2018/2019 from other plays is used, then the TMS remains competitive, despite the considerable technology advances made and implemented in those established plays in the interim and the optimisation process that has been brought to bear.

The following case history illustrates this point.

In November 2021 Pioneer Natural Resources Company (Pioneer) sold a Delaware basin position to

Continental Resources, Inc. for US$3.25 billion. The majority of that position was originally secured by Pioneer via an acquisition of Parsley Energy (Parsley) in January 2021 who in turn purchased it from Jagged Peak Energy (Jagged Peak) in Q1 2020, just prior to the onset of the COVID 19 pandemic. As part of the material generated by Parsley during their acquisition from Jagged Peak for US$2.3 billion, they selected 35 wells and provided 12 month average cumulative production data for those wells to demonstrate just how productive the rock in this area was. This data set is pertinent for comparison purposes, as the Delaware basin is a similar depth and temperature to the TMS and Australis was drilling in 2018. The Delaware basin is seen as one of the premier unconventional oil plays in the US and the Jagged Peak position was considered high grade acreage within that play.

The table below shows a comparison between those 35 Jagged Peak wells and the 15 TMS wells drilled by Encana in 2014, plus the two full length laterals that Australis drilled in 2018.

	Average 12 month cumulative production (bbls)	Average Lateral Length (ft)	Average Production (bbls/ft)	Average Net Production i.e. post royalties (bbls/ft)
Jagged Peak Average – 35 wells[4]	193,400	8,658	22.3	16.8
2014 ATS TMS wells – 15 wells	153,356	7,254	21.1	16.9
Stewart 30H-1 well	188,754	6,845	27.6	22.1
Taylor 27H – 1 well	136,508	6,555	20.8	16.6

The following points can be made from this table and other information made available by Parsley after the transaction:

- The average net production per foot of the 2014 TMS wells, i.e. what the working interest owners receive, is higher than the selective 35 wells drilled by Jagged Peak in 2018. The more recent Australis wells are similar or better than the Jagged Peak wells.

- Jagged Peak reported well costs which averaged $1,500/horizontal foot in 2018 and by comparison the Stewart 30H-1 well cost $1,519/hz foot and the Taylor 27H-1 well cost $1,632/hz foot, with both wells also having been drilled during 2018.

- Produced water disposal is a major operating cost and increasingly problematic with resultant seismic activity rapidly increasing in the Permian Basin. The Jagged Peak wells produced 6x as much water per bbl of oil as the TMS wells produce on average during the first 12 months. (Aside: low magnitude activity i.e. greater than 1 on the Richter scale has increased in the Delaware basin from 19 events in 2009 to 7,000 events in 2019 and larger events, those greater than 3 on the Richter scale, have increased in the Permian from 9 in 2019 to 176 events in 2021. On 27 December 2021 there was a 4.5 magnitude event in the Midland basin, the largest yet.)

- During 2018, the achieved oil price for Jagged Peak crude was $53.55/bbl, during the same period TMS crude had an achieved price of $59.60/bbl. This differential is a product of oil quality and proximity (i.e. cost to access distribution infrastructure and market produced volumes).

<u>Conclusion</u>

Comparing the high graded 2018 vintage wells in the Delaware basin and 2014 early stage appraisal wells in the TMS shows the same rock productivity, similar well costs, significantly less water production and an 11% premium in realised crude prices. The Parsley US$2.3 billion acquisition of Jagged peak in Q1 2020 involved 78k net acres in the Permian with 38k boe/day production (76%

oil). If it is assumed that the acquisition value was apportioned between developed reserves and undeveloped acreage, at US$30,000/boe production, the undeveloped acreage was valued at US$6,500/acre.

These types of comparisons demonstrate why Australis is confident in the quality of its TMS asset. Whilst the play is at an early stage of development, the underlying economics and reservoir performance are compelling.

To secure a partner for the TMS, Australis requires:

1. Counterparties seeking additional future drilling inventory and prepared to take on an earlier stage play such as the TMS, which is increasingly more likely as the US industry transitions from a period of production maintenance to growth, and
2. Limited alternatives in the established unconventional oil plays as a source of future drilling inventory, which is becoming the reality either due to prohibitive costs, asset maturity or competition preventing the aggregation of a material consolidated new position.

The improved and sustained oil price during H2 2021 and positive outlook is restoring market confidence from the lows of 2020. Improved balance sheets are allowing companies to take a longer term view of their business, which for many means securing additional drilling inventory. The three primary unconventional oil plays that account for over 85% of US oil production are increasingly mature (the Eagle Ford and Bakken) or tightly held following Permian consolidation in 2020 and 2021. This limits opportunities for additional quality inventory from within these traditional targets and forces potential partners to look elsewhere. As demand continues to recover the two key requirements are aligning and the Company remains confident it will secure a partner to help fund development activities in the TMS.

Ends

This ASX announcement was authorised for release by the Australis Disclosure Committee.

Further Information:

Ian Lusted
Managing Director
Australis Oil & Gas
+61 8 9220 8700

Graham Dowland
Finance Director
Australis Oil & Gas
+61 8 9220 8700

ABOUT AUSTRALIS

Australis (ASX: ATS) is an ASX listed 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.

With approximately 98,000 net acres within the production delineated core of the proven oil producing TMS, Australis retains significant upside potential with approximately 380 net future drilling locations, and an independently assessed 170 MMbbls of 2P + 2C recoverable volume including 3.7 MMbbl producing reserves providing net field cash flow[1]. The contingent oil resource is only contingent on a qualifying development program.

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

TMS Assets & Background

Australis holds ~98,000 net acres within the production delineated core of the oil producing Tuscaloosa Marine Shale. The map on page 5 (Figure 2) is a representation of the acreage position that Australis holds within the TMS Core.

The Tuscaloosa Marine Shale is a Cretaceous shallow marine unconventional shale that is present across central Louisiana and southwest Mississippi. The play is the same geological age as the Eagle Ford Shale in South Texas and the Woodbine Shale in East Texas.

The play is relatively deep, high pressured and oil weighted. As experienced in most unconventional plays, early results (2010 – 2014) demonstrated variable production performance and relatively high well costs, driven by operational difficulties encountered whilst drilling and completing the wells. The activity that did take place delineated a core area of the play where production results were consistent and comparable to other, far more developed, unconventional plays such as the Eagle Ford and the Permian. This area is shown in the blue oblong in Figure 2 and represents Australis' interpretation of the TMS Core.

The comparison of the 2014 production results from the core of the TMS (the 15 wells drilled in the Australis TMS core leasehold area in 2014 and which comprise the TMS Type Curve) with the three type curves generated by Ryder Scott for the YE 2020 reserve report is shown in Figure 3 below. To qualify as a reserve Ryder Scott must assess a future location as economic and the YE 2020 reserve report was evaluated assuming a flat oil price of US$47.02/bbl.

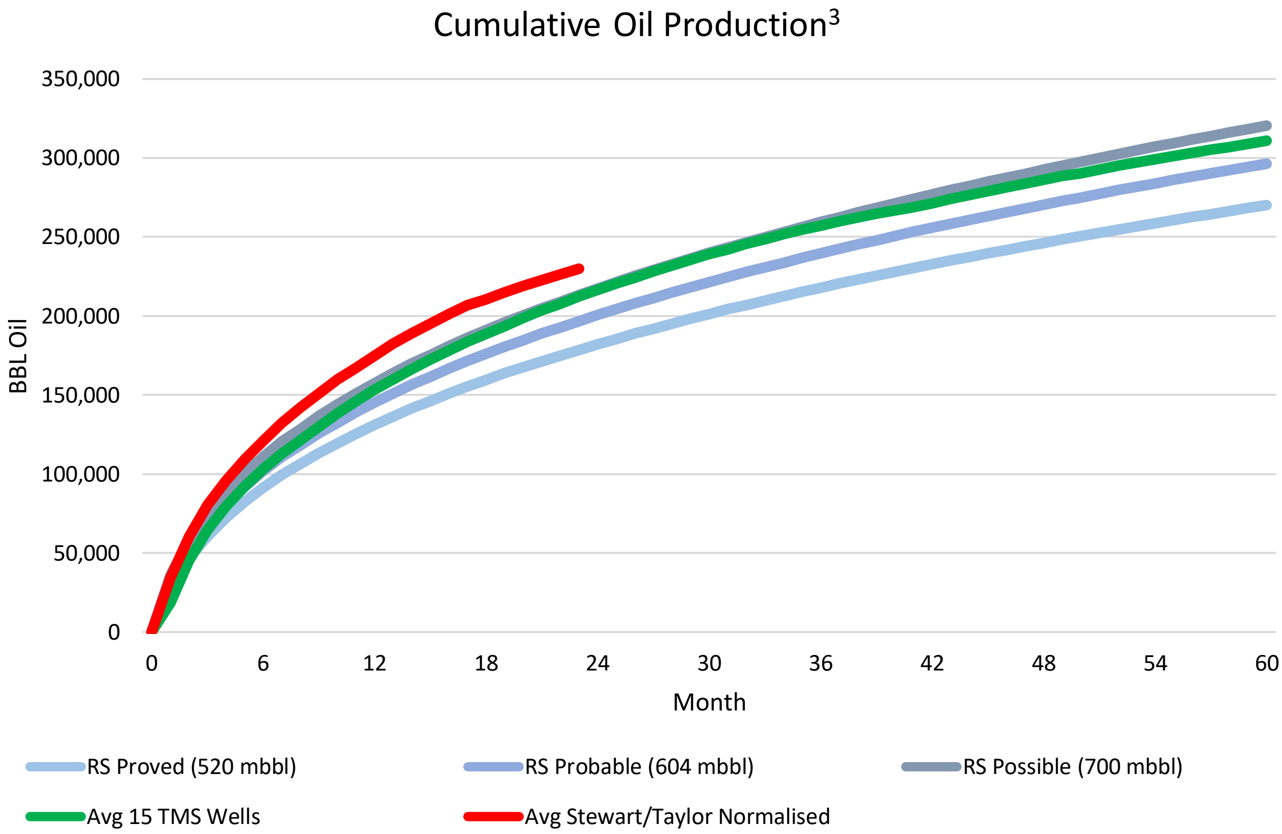


Figure 3: Average oil production of ATS 2014 TMS wells v Ryder Scott Proved, Probable and Possible Type Curves and the performance of full length laterals drilled by Australis in 2018

The 2014 fall in commodity price generated the opportunity for the two low cost acquisitions by Australis in the TMS and for an ongoing cost-effective and strategic leasing program where longer lease life is targeted together with improved commercial terms. Australis has remained very disciplined and focused only within the production delineated TMS Core.

The appraisal activity by Encana and other participants in the TMS during 2013/2014 also addressed many of the operational challenges that were initially experienced. Costs and performance repeatability were improving, and activity levels were increasing during 2014 until evolution in the play was interrupted by the oil price drop in late 2014. As a direct result, Australis is the only company to have drilled new wells in the play since the beginning of 2015 other than in the last quarter, when State Line Exploration successfully drilled and cased their first well in the play. Consequently, none of the numerous industry improvements that have continued to drive forward the economics of other unconventional plays have yet been applied to the TMS. The production results of the full length laterals drilled by Australis in 2018[3] are also shown above on Figure 3

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

Term	Definition
TMS Core	The Australis designated productive core area of the TMS delineated by production history
WI	Company beneficial interest before royalties
Royalty	Interest in a leasehold area providing the holder with the right to receive a share of production associated with the leasehold area
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 and Tie - in
2D/3D	2 and 3 dimensional seismic surveys
Opex	Operating Expenditure
G&A	General & Administrative 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.
PRB	Probable Reserves
PDP	Proved Developed Producing Reserves
PDNP	Proved Developed Not Producing Reserves
PUD	Proved Undeveloped Reserves
Net Acres	Working Interest before deduction of royalties or burdens
Field Netback	Oil and gas sales net of royalties, production and state taxes, inventory movements, hedging gains or losses and field-based production expenses but excludes depletion and depreciation
EBITDA	Earnings before interest, tax, depreciation, depletion, and amortisation expenses
IP30	The average oil production rate over 30 days of production following clean up
YOY	Year on year
TMS Type Curve	The history matched production performance of 15 wells drilled in the TMS by Encana in 2014. Corresponds to an average treated horizontal length of 7,200ft. Refer to the Appendix of the Australis Corporate Presentation
IDP	Initial drilling program of 6 wells in the TMS by Australis commencing late 2018

Notes

1. All estimates and risk factors taken from Ryder Scott, report prepared as at 31 December 2020 and generated for the Australis concessions to SPE standards. See ASX announcement released on 5 February 2021 titled "Reserves and Resources Update Year End 2020". Australis is not aware of any new information or data that materially affects the information included in the referenced announcement and all the material assumptions and technical parameters underpinning the estimates in the original announcement continue to apply and have not materially changed. Ryder Scott generated their independent reserve and contingent resource estimates using a deterministic method which is based on a qualitative assessment of relative uncertainty using consistent interpretation guidelines. The independent engineers using a deterministic incremental (risk based) approach estimate the quantities at each level of uncertainty discretely and separately.

2. 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.

3. Average production from Stewart 30H-1 and Taylor 27H-1 wells normalized to 7,200 ft completed horizontal length and adjusted for production curtailments during COVID low oil prices Q2 2020.

4. Analysis of data sourced from Parsley Energy Investor Presentation "Acquisition of Jagged Peak Energy" 14 October 2019, Texas Railroad Commission completion reports, ShaleProfile.com and Jagged Peak Energy Q3 2019 report.

Non-IFRS Financial Measures

References are made within this report to certain financial measures that do not have a standardised meaning prescribed by International Financial Reporting Standards (IFRS). Such measures are neither required by, nor calculated in accordance with IFRS, and therefore are considered Non–IFRS financial measures. Field Netback, as defined within the Glossary, is a Non-IFRS financial measure commonly used in the oil and gas industry or financial measures that are relevant to Australis. Non-IFRS financial measures used by the Company may not be comparable with the calculation of similar measures by other companies.

Forward Looking Statements

This document may include forward looking statements. Forward looking statements include, but are not necessarily limited to, statements concerning Australis' planned operation 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.