Research as a Service

Australis Oil & Gas Limited

Initiation Report

Holding the next big thing

Energy

9 March 2023

Australis Oil & Gas (ASX:ATS) is an oil and gas producer/developer, with a strategic and controlling position in the emerging Tuscaloosa Marine Shale (TMS) oil play, onshore US. The TMS is an Eagle Ford-equivalent but early-stage oil play with recoverable oil potential of around 7bn barrels – this is the next big thing. Australis represents a highly leveraged and attractive exposure to the transformational potential of the TMS oil play. As more developed and mature oil plays exhibit diminishing returns and declining inventories, operators will need to look to new plays for growth and earnings. Importantly, Australis has the management expertise having directors and key staff that built an Eagle Ford business (Aurora Oil & Gas) to A$2.6bn from A$30mn. We expect interest in the TMS play to grow and with some 300 net drilling locations and 117Mb of 2C contingent resources, the company's portfolio holds transformational capacity and a strategic position across an extensive and pervasive oil resource. We initiate coverage of Australis Oil & Gas Limited with a valuation range of $0.12-$0.32/share with a mid-point (base case) of $0.25/share. Our base case represents a >600% premium to the current share price. We expect the share price discount to materially unwind as continuing production data confirms the productivity and economics of the development model and the necessity for investment in next-generation oil plays crystallises in the sector.

Business model

Australis Oil & Gas (ATS) is a development and production company, focused on progressing its strategic position in the emerging Tuscaloosa Marine Shale (TMS) oil play, onshore US. The company holds some 79,600 net acres within the TMS Core which although early-stage, compares favourably with more established and mature provinces like the Bakken, Permian and Eagle Ford. As an emerging play, the operating model is still evolving with type curves and well recoveries yet to be defined, however, the oil-prone nature and relatively low production costs suggest material upside can be delivered through continuing activity and learning curve optimisation. The play is beginning to attract increasing third-party interest and activity, but as with all onshore unconventional plays, growth requires capital and ATS is pursuing a strategic partnership and capital injection to accelerate its growth options. Current production is delivering some US$22mn of revenue (adj.) and generating a positive EBITDA – the building blocks are in place. **Success from this point could see ATS deliver material operational and valuation growth, particularly as the perceived risks unwind.** From here it's about holes in the ground.

De-risking the play to drive earnings and value

In comparative terms, the TMS is an under-drilled and under-developed play, but the data set to date demonstrates production and earnings characteristics on a par with the more developed areas. The development impacts of COVID continue to persist with play activity only beginning to ramp-up after three years of inactivity, but with increasing levels of third-party activity and interest from other developers rising, the next 12-24 months could deliver a major re-rating of the play.

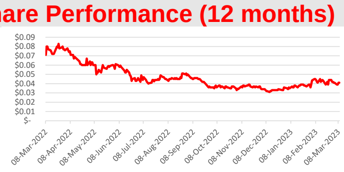
Valuation of $308m or $0.25ps at the mid-point

Whilst valuing pre-development is a subjective exercise, particularly considering financing and timing uncertainties, production data continues to de-risk the economics of the TMS play, increasing confidence in the commercial potential and highlighting the embedded value within the contingent resources. <u>The resource opportunity is massive, based on consistent geology and the next 12 months could deliver further material de-risking outcomes – further type curve definition and financing (partnering) options.</u> We value the reserves and resources against the WTI forward curve adding a premium for the LLS benchmark and overlaying a discretionary RaaS risk to define a low-high NAV range. We set a base-case (mid-point) valuation of $308mn ($0.25ps) to ATS, with an upside case to $397mn ($0.32ps). Against a reference share price of ($0.041ps), this suggests the market is risk-weighting the developed producing reserves alone at around 65% of our ascribed value. <u>Partnering success could unlock material reserves value and deliver valuation upside well in excess of our base case</u>…such is the nature and attraction of oil plays in the US onshore.

Share Details

ASX code	ATS
Share price	$0.041
Market capitalisation	$51M
Shares on issue	1,243M
Net debt at 31-Dec-22	US$4M
Free float	~56.1%

Share Performance (12 months)



Upside Case

- Securing a partner to underpin funding for an expanded drilling programme to drive production and earnings growth
- Oil price upside - the company is a highly leveraged exposure to oil price
- Continuing positive look-through from third-party activity further de-risking the operating model as an analogue to already developed plays

Downside Case

- Finance constrained with risk to lease holdings
- Oil price downside – forward curves point to weaker outcomes versus 2022
- Weaker and slower outcomes from third-party drilling and continuing higher perceived risks to the play

Board of Directors

Ian Lusted	Managing Director/CEO
Jon Stewart	Non-Executive Chairman
Graeme Dowland	Executive Director/CFO
Alan Watson	Non-Executive Director
Stephen Scudamore	Non-Executive Director

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RaaS
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Australis Oil & Gas Limited

Australis Oil & Gas Limited (ASX:ATS) is a junior oil and gas exploration, development and production company operating in the onshore US (Louisiana and Mississippi), focussed exclusively in the emerging Tuscaloosa Marine Shale (TMS) oil play. Australis has leveraged the operating experience of its board and management to acquire a strategically important position within "…one of the last emerging oil shale basins onshore in the USA". Importantly, the company holds its leases in the designated high-grade TMS Core area, having made an initial entry in 2016, it acquired the bulk of its position in 2017 from Encana Corporation (now Ovintiv [ovintiv.com]), which includes a suite of wells in production and cashflow positive. The company has a material reserves and resources base with a large inventory of drilling opportunities providing a substantial operating platform that should deliver material growth and growth options over the forecast period. The TMS is an early-stage play with prospectivity considered to be equivalent to more mature and developed plays like the Bakken. With the mature plays transitioning to 'late-life' outcomes - declining productivity, increasing costs, and lower-grade and thinning drilling inventories, it is likely that under-developed opportunities will attract increasing interest and capital from bigger operators. Herein is where Australis has a significant early-mover advantage. New money is beginning to find its way to the TMS play and activity is rising and more wells deliver a lower-risk development model. Against a background of the transition to a lower carbon energy mix, it was stated at the recent State of the Union address that the US "…will need oil and gas for quite some time". As a comparatively early-stage play, growth options are not without risk both operationally and financially, but continuing activity and production performance can materially unwind the perceived operational risks over the next 12-24 months. The TMS is a growth opportunity in need of capital and the company is actively seeking a partner to accelerate work programmes and build production – there is unlikely to be a more advantageous time for a new partner entry. With production generating a positive EBITDA, the company is adequately financed for its current capital plans and is seeking additional financing options through partnering. There is a material growth opportunity here for ATS to deliver.

Investment Case – There's A Material Oil Play Here For The Taking

The Tuscaloosa Marine Shale play is an early-stage but likely transformational US unconventional oil opportunity where Australis Oil & Gas holds a strategic interest and represents a discounted entry into what could be the next big thing.

Although somewhat limited from a well-density perspective, the production data to hand supports a geological model that shows the prospectivity and deliverability of the TMS can be as good as the best, already developed analogues – Bakken, Permian and Eagle Ford.

Being early-stage comes with low-hanging fruit in that future productivity gains and returns are higher in absolute and relative terms as the play becomes optimised through continuing local and regional activity.

As highly developed plays become increasingly negatively impacted by lower quality inventory, accelerating decline rates, falling returns per dollar of investment, and rising abandonment costs (the hidden cost of the industry), the question will be asked – where do companies go for the next tranche of production and earnings growth?

Diminishing returns in mature analogue areas will support increasing interest from those operators in the highly developed plays – investment capital flows towards the opportunities of greatest returns. As an asset opportunity, ATS holds the pole position…and we highlight the attraction of ATS as a potential M&A option.

There is embedded value residing in the quality of this play and in controlling the 'sweet spot'. At some point, markets and/or corporates will recognise the magnitude of the upside opportunity.

Risk-Adjusted Valuation Range Of $144mn-$397mn

We ascribe a value range for ATS from $0.12-0.32/share **with a mid-point case of $0.25/share,** noting the closing share price of $0.041/share (8-Mar) represents a 67% discount to the low end of the NAV range and in isolation can be considered a risk weighting of ~53% to our assigned value of the 2P reserves (producing and non-producing).

Exhibit 1: The NAV range represents a material premium to the market price

		Risked range (A$m)			
		Low	Mid	High	
Reserves		76	95	119	Correlates reasonably well against the Ryder Scott benchmark
Contingent resources		79	224	289	Contingent resources represent areas ex-production on 1C through 3C basis dependent on the confidence level of the recoverable oil estimate – the closer to producing areas, the higher the confidence level. We have applied a discretionary RaaS risk weighting across the categories in determining the NAV range
		155	**319**	**408**	
Net cash/(debt)			($6)		
Corporate			($5)		
TOTAL		**144**	**308**	**397**	
Shares issued (mn)	1,243	$0.12	$0.25	$0.32	Converted from USD using the spot rate 0.6880 (21-Feb)

Source: RaaS analysis; Risked ranges based on discretionary RaaS probability adjustments

To derive a valuation for ATS we apply a type curve as per **Exhibit 6** applying a risk-weighted outcome across the Proved, Probable and Possible EUR estimate.

We use single well capex estimates and the forward crude oil curve (WTI adjusted) to determine a unit NPV (per barrel) and apply that across the certified reserves to provide a low-mid-high range.

We apply the same methodology across the certified contingent resources to which we overlay a discretionary RaaS risk weighting to account for the embedded uncertainties on conversion to reserves, timing of development, and capital costs. These risk weightings could change as further production data comes to hand over 2023, independent of commodity price changes and should the allocation volumes in each category (1C=3C) change.

Sometimes the only difference between 1C attribution and reserves is timing – how far away from the five-year development window do these volumes sit, which can often be simply a function of capital risk, not geological risk.

The company enterprise value (~$64mn) at the reference share price largely reflects the nominal value of the 1P reserves only. In and of itself this discount on a reserves basis may reflect a more bearish market sentiment to oil prices, anticipation of an equity raise or just reflect the small company discount in a risk-off investing phase.

We would highlight that this discount is not unusual compared to the unit values the market is applying to the sector. However, **de-risking the type curves and material progress on financing (partnering) outcomes should close the 'value gap'** and underpin a resource rating as financed, commercial outcomes become more tangibly demonstrable.

The value proposition lies in being able to unlock additional crude oil upside.

Note our reserves value correlates reasonably well with the estimate provided by Ryder Scott in its end-2022 reserves certification where it ascribes a value of US$82mn [NPV(10)] against the Proven Developed Producing (PDP) reserves only – **refer p.12**.

Our modelled value range is dependent on assumed commodity prices, which is the key sensitivity to the NAV.

For every 5% change in oil price across the forecast curve (**refer Exhibit 11**), the NAV changes by ~8% over the low-high range.

SWOT Outlook – Experienced Hands At The Tiller

SWOT weightings skew materially to the positive – an emerging, material, high-quality oil play in an environment of diminishing returns from more developed plays – that's a powerful combination.

Exhibit 2: SWOT indicates more upside than downside

Strengths	**Comments**
Strategic holdings across material, emerging shale oil plays	Holds a controlling interest in one of the few remaining undeveloped high-quality shale oil plays in the US with independently certified attributable recoverable reserves of ~120Mb (2P + 2C)
High working interests	The company holds a significant proportion of its leases at very high working interests, providing 'financing through partnering' options, particularly as increasing production 'above model' continues to de-risk the economic opportunity
Management has 'been there - done that'…	...and experience counts in both an operating and corporate sense, having built a business (Aurora Oil & Gas Limited) largely from scratch in the Eagle Ford, which listed at a capitalisation of ~A$30mn before being acquired for an enterprise value of A$2.6bn (**refer p.24**)
Strong commercial advantages	TMS crude prices against the LLS (Louisiana Light Sweet) benchmark – at a premium to WTI. Water cuts are lower than more mature onshore plays and less water and gas translates to less cost in unit and absolute terms. The TMS produces >95% oil crude and only small quantities of gas and NGLs
Proximate to infrastructure hubs	Abundant third-party infrastructure across 'core' area …a path to market is not a limiting factor
TMS productivity is comparable to the best areas of established plays	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 (**refer Exhibit 4**)
Favourable and supportive regulatory and operating environment	Mississippi, in particular, has been noted as 'operator-friendly' and we can note recent State of the Union commentary that the US "…will need oil and gas for quite some time"
Weaknesses	**Comments**
Large portfolio requiring continuing lease renewal and replacement	The more capital that is dedicated to lease/portfolio maintenance, the less capital available to deliver production growth with risk to the portfolio in the absence of financing options
Financing and high working interests	Whilst operations are EBITDA positive, like many unconventional plays, it's about getting ahead of the curve and building the production base and that takes capital. Partnering discussions are progressing but the macro environment remains challenging
'TMS productivity is comparable to the best areas of established plays'	**What is a strength can also be a weakness.** Although well productivity is comparable, the comparison set is small and production histories are limited. **Third parties may still consider the play as too early stage for the risks** and that may take a significantly longer production history, over more wells
Few operators - can ATS do the heavy lifting?	New players (private equity) have taken active positions and commenced drilling and testing, however, is the market waiting to see 'big oil' step up as a sign of arm's length validation?
Opportunities	**Comments**
An 'early mover' advantage in an emerging play	Historical, established plays (e.g. Bakken and Eagle Ford) are running out of easy and material growth opportunities – drilling inventories are falling, inventory quality is falling. At some point there will be a transition to the 'next big thing' – the TMS
Benefits from next-gen technology and operational experience…	…as has been evidenced in the more established unconventional plays. The more wells that get drilled, the better the collective operational knowledge (what works and what doesn't). There's significant optimisation upside
A corporate target(?)	If the perceived risks are still too high to justify a risk capital entry, then the alternative is to see if the market re-rates success. If not, it may be more advantageous to take an holistic approach
Threats	**Comments**
The TMS may not be the only Tier 1 play option	Selective comparisons of high-grade Delaware Basin acreage return similar results to the TMS Core on oil productivity and unit drilling costs although realised prices are weaker and water cuts materially higher. Lower margins could be somewhat offset by cheaper entry (leasing and acquisition) costs
There's more to be squeezed out of existing developed areas	This comes down to the law of diminishing returns but operators in the Bakken/Permian/Eagle Ford are pushing out the boundaries of lateral completions, reworking old shut-in wells and simply squeezing more from what they have
Funding	Whilst EBITDA supports a continuing modest programme, accelerated growth needs capital and in the absence of a partner there could be an 'over reliance' on equity. Debt financers are potentially reducing their support for fossil fuel projects although that may not be the case from more traditional US sources, however, debt costs are increasing and would be hedged, potentially limiting leverage to any oil price upside
Oil prices	If there is anything that can confidently be stated about the commodity, it's that currently, volatility is king. The forward curve is pointing to a significant contango…oil 'now' is better than oil later
Is there the chance of new entries to the play ex-ATS?	This is probably a low-risk threat given the company's strategic and almost controlling position in the TMS Core. However, bigger companies can play a waiting game on capital-constrained operators

Source: RaaS analysis

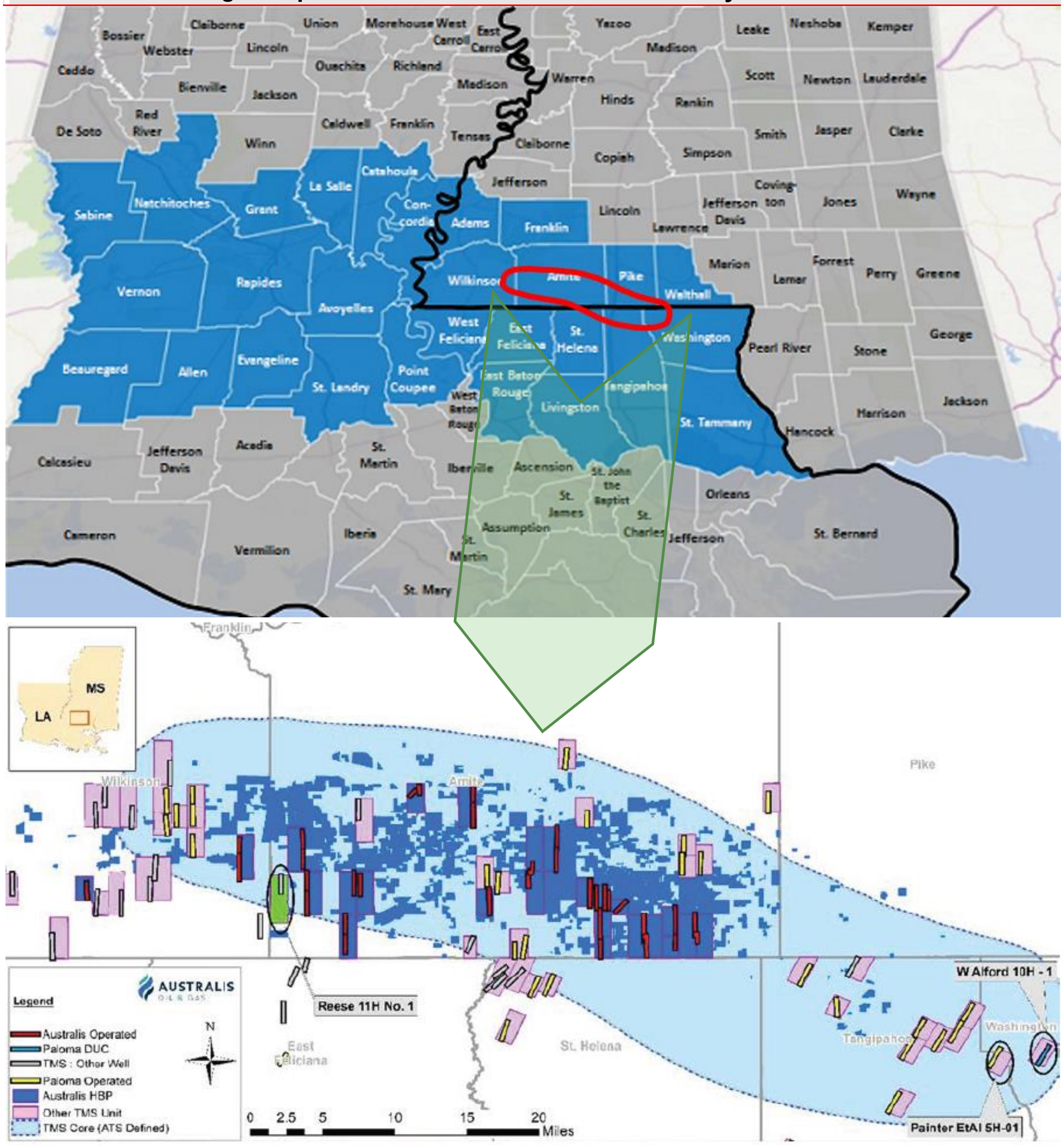
Tenement position – a controlling hand

The Tuscaloosa Marine Shale is a regionally pervasive unit, reported to cover >14mn acres across southern Louisiana and Mississippi, broadly highlighted in blue - **refer Exhibit 3.** We review the petroleum potential and history of the play in broad detail in **Appendix A**. Although the play was first identified around 1950, it has only been subject to significant evaluation through drilling, sporadically over the subsequent 50-60 years. For want of a better term, the 'modern' exploration phase commenced in 2011 supported by a rising oil price, but activity largely ceased around 2016.

Australis was able to secure an initial entry point of some scale through the acquisition of the Encana assets around that time and has over the period to date been actively acquiring additional leases and building a strong and advantageous position, particularly within the TMS Core area contained within the red-bounded area (**refer Exhibit 3)**. Only approximately 450,000 acres (3%) is considered to constitute the TMS Core.

As noted in a number of descriptions of the play, well performance has been highly variable and as described by ATS "…usually binary". The wells designated as high performance have all been drilled within the core area.

Exhibit 3: A leveraged exposure to the core…and that's where you want to be



Source: Company data; HBP = held by production

The company is leveraged to the play exactly where it should, dominantly (and dominating) within the TMS Core area.

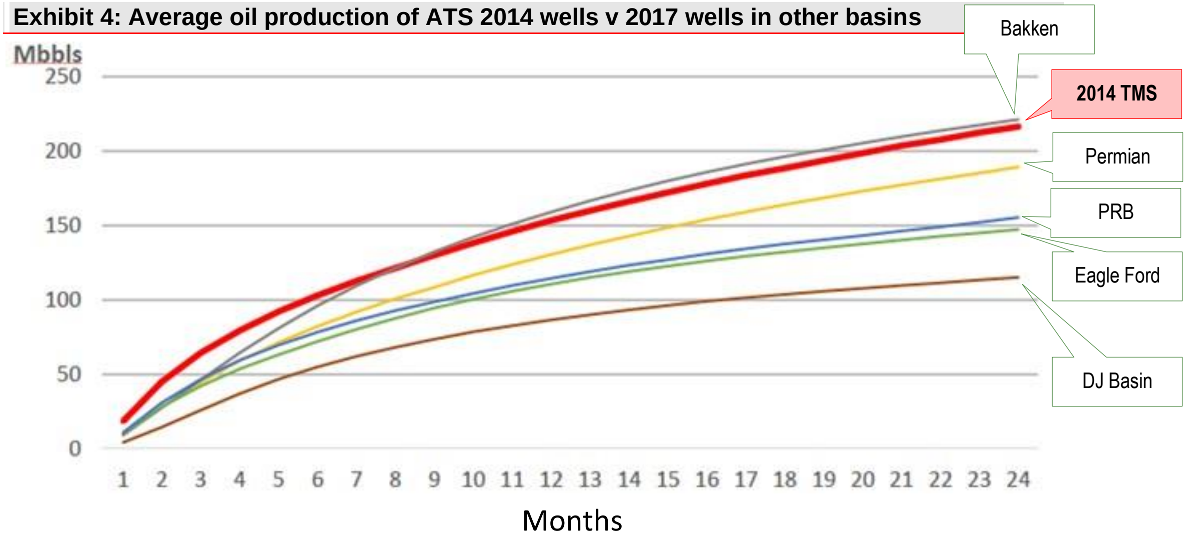
The TMS model.

Establishing the development model/type curve is the key. It proffers a state of predictability, lowers geological and economic risk, and transforms plays into a more annuity-style opportunities.

We highlight that there have only been <100 wells drilled in the TMS compared to literally tens of thousands attributable to the other plays as designated, and simply on the knowledge and experience curve, there is currently a higher level of intrinsic risk to the TMS play.

Notwithstanding the early-stage nature of the TMS in comparative terms, production and performance data compares favourably to the more intensively developed analogue areas:

Exhibit 4: Average oil production of ATS 2014 wells v 2017 wells in other basins



Source: Company data

Data reported in a Journal of Petroleum Technology article (2020):

"Production data from the oldest horizontal wells in the three largest oil plays in the US (Permian, Bakken, Eagle Ford) *show that annual decline rates remain relatively high for a long period of time. This challenges assumptions held about production after 5 years and directly affects reserve and ultimate recovery estimates".*

"Tight-oil production in the US set new records in 2019" but that came with a red flag in that *"…more than two-thirds of crude production from shale plays flowed from wells drilled in the previous two years".*

https://jpt.spe.org/life-after-5-how-tight-oil-wells-grow-old

The high-level implication is that with persistently higher decline rates, the economics of wells may be being overstated in the large and developed oil plays and that mature area growth is perhaps only going to become more difficult and expensive as the Tier-1 inventory is drilled out and the quality of the remaining inventory progressively reduces. More investment has to be made in lower-ranked drilling options to achieve the same results – mature area developments can be considered as 'having to run faster just to stand-still'.

The long-term production profile for the TMS is yet to be defined with certainty and TMS wells may exhibit similar behaviour towards the tail end of well life. However, the data to date indicates the **five-year decline and production rates of most TMS laterals completed since 2014 are at least as good if not better than their Permian, Bakken, or Eagle Ford** counterparts.

When the alternative in mature areas is falling-grade drilling inventory and higher capital growth the investment case for the TMS as an investment and early-stage operational alternative becomes materially stronger.

What should also be considered as part of the diminishing returns equations is the burgeoning abandonment liabilities associated with lower productivity wells.

Capital will flow to the areas of greatest returns.

We highlight the highly encouraging drilling outcomes with State Line Exploration (Reese-11H #1 well) and Paloma Natural Gas Partners (Painter-5H and West Alford-10H wells*) as new entrants to the TMS play bringing fresh capital and ideas.

ATS holds a 10% interest in these wells; Make a partial contribution towards sunk drilling costs and will be responsible for 10% of the ongoing costs of leasing and stimulation operations in the two units.

ATS has provided commentary on these wells in its quarterly reports.

The Reece-11H #1 well is the first new well drilled in the TMS since 2019 and is located in correlatable distance to several TMS laterals drilled by Encana. The well was completed with a lateral length in excess of 6,000 feet (~1,830m) and fracked using modern slickwater methods and which has been reported as the first time this method had been deployed in this play but having been successful in other basins. From that perspective the performance of this well should provide a critical look-through for future well development styles.

Early production results were highly encouraging, with a reported IP24 (hours) of 1,801bpd and a sustained average flow rate of ~500bpd, without artificial lift, during May 2022, which under natural (unassisted flow) is an encouraging result.

Data on the wells in the TMS is published by the Mississippi State O&G Board (MSOGB) on a regular basis with the latest available data Dec-2022.

www.ogb.state.ms.us

Exhibit 5: Early production data from Reese-11H – an important look-through result for ATS

							Aggregate		
			Oil		Gas	Water	Oil	Gas	
		days	b	bpd	mcf	b	kb	mmcf	
Feb	2022	25	8,813	353	8,250	36,668	8.8	8.3	High initial water likely represents returns of frack fluids
Mar	2022	25	13,799	552	10,230	19,539	22.6	18.5	
Apr	2022	30	4,176	139	9,900	3,776	26.8	28.4	
May	2022	30	14,975	499	9,900	11,573	41.8	38.3	
Jun	2022	30	6,370	212	9,900	2,603	48.1	48.2	
Jul	2022	30	9,586	320	10,230	7,624	57.7	58.4	
Aug	2022	31	4,316	139	10,571	2,848	62.0	69.0	Pump difficulties
Sep	2022	6	32	5	2,046	40	62.1	71.0	Changing from ESP to rod pump
Oct	2022	25	9,933	397	8,525	2,620	72.0	79.5	
Nov	2022	30	6,391	213	9,903	3,930	78.4	89.5	
Dec	2022	31	5,324	172	10,233	3,751	83.7	99.7	High oil cuts
		293							

Source: www.ogb.state.ms.us

State Line had subsequently installed an electrical submersible pump (ESP), which has not been used on a TMS well previously, but did report operational difficulties and has replaced the ESP with conventional long-stroke rod pump on the well.

Although this well is a producer, it can be considered as providing some 'research' data with respect to frack design and pumping that can support the evolution of the development model – sometimes it's as important to know what not to do.

Given the still early-stage of the well as a producer modelling future production profiles and ultimate recoveries remains an exercise with significant uncertainty.

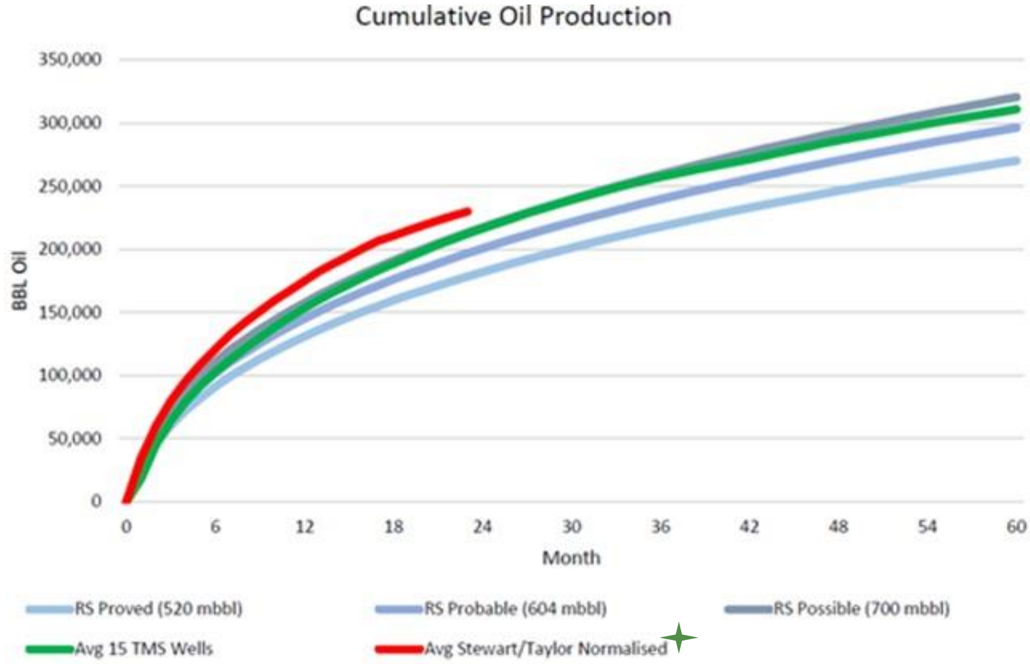
Paloma Natural Gas Partners successfully completed two drilled and previously uncompleted (DUC) wells - Painter 5H and West Alford-10H - again using modern slickwater frack designs.

As noted in the most recent ATS quarterly update (Dec-2022) *"…Painter 5H, which has been on production for 6 months, has produced similar oil volumes to the Australis proved type curve"*, whilst *"…West Alford 10H, has under-performed, but this appears to be a product of reservoir quality* (this well is located just within the extreme south-east edge of the Australis TMS Core area and high in the target zone) *and not the frac design".*

The slickwater design was/is expected to deliver *"…a more complex fracture network"* and *"…generate improved medium-term productivity".* This is an important wait-and-see point.

Importantly, the State Line and Paloma wells represent new money, new ideas and more wells, and that is an excellent outcome in support of the investment case.

Exhibit 6: Comparison across TMS wells (2014) and Ryder Scott recovery assumptions



Source: Company data; 'Stewart/Taylor' curve is based on wells drilled in 2018-2019;
Results are normalised for 7,200 feet (~2,200m) horizontal completions over 60 months

An important comparison in setting benchmarks for future type curves is shown in **Exhibit 6** using the Encana wells drilled in 2014 (**green**) and more recent wells (**Stewart/Taylor**) that have been in production over the last seven-eight years against the Ryder-Scott (RS) model of 60-month aggregate production.

Herein we will refer to the Encana wells as the **TMS** wells as per the chart legend. Encana, the dominant TMS player in 2014, eventually sold its holdings to Australis.

We note how closely the TMS wells match the RS Possible (3P) curve which is modelled with an EUR of 700kb and how much better the **Stewart/Taylor** productivity curve is. Perhaps at this point we can suggest the RS type curves could potentially represent a 'base case'.

The Stewart-30H and Taylor-27H-1 wells were drilled by Encana as part of a four-well campaign conducted over 2018-2019. As of end-Dec 2022 data from the Mississippi State O&G Board:

Stewart-30H had produced:

- **312,200b and 118,100mcf (94% crude oil)** in 49 months

Taylor-27H-1 had produced:

- **211,714b and 104,489mcf (92% crude oil)** in 43 months.

TMS Core wells typically have a very low gas-to-oil ratio with an oil cut >92%.

It is worth reiterating that whilst individual wells can provide variable results the play is cum '…the technical and financial productivity gains' evidenced in equivalent unconventional plays, as more wells gets drilled and the benefits of economies of scale become entrenched.

Whilst oil prices are the critical sensitivity, the other fundamental element that supports the economics of unconventional plays is the capital (new and sustaining) and operating cost base of development. This is a direct function of play maturity - the cost of new wells reduces as more wells are drilled and completions become optimised in design and practice.

In early-stage plays well costs tend to be higher, but historically as evidenced by analogue development areas, these costs trend down over time. Naturally, activity levels also heavily influence costs, with a significant scale up of operations delivering efficiency savings – this is not specific to onshore, unconventional plays and applies to portfolio drilling of any kind. However, given the high-density drilling that is the norm for these developments the capital gains can be material in absolute terms.

As advised by the company specifically highlighting the TMS, the play *"…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".***

Building resources and reserves

As at 31-Dec-2022, Australis held 79,600 net acres within the TMS Core area of which 38,700 net acres (49%) are HBP. The reserves and resources estimates are provided by Ryder Scott Company L.P. ("Ryder") and based on a well portfolio of:

- 31 operated wells and 17 non-operated wells considered as producing; and
- Two operated PDNP wells.

Since 2021, Australis has used a more conservative approach in determining its reserves and resources volumes, considering only existing production as reserves and categorising any estimated recoverable oil and gas potential as a contingent resource in the absence of funded development programmes.

No reserve estimates have been attributed to undeveloped acreage.

Exhibit 7: The investment opportunity lies in the contingent resources…there's multiples of upside here

	Reserves	New	Old	
		2022 (kb)	**2021 (kb)**	
PDP	Proven Developed Producing	2,475	*2,954*	
PDNP	Proved Developed Non-Producing	29	*29*	
1P	**TOTAL Proved Developed**	**2,504**	***2,983***	A 16% reduction largely attributable to full-year production of (282kb) and a 'technical adjustment' of (261kb)
	Probable Developed Producing	631	*690*	
	Probable Developed Non-Producing	-	*1*	
	TOTAL Probable Developed	**631**	***691***	
2P	**TOTAL Proved + Probable Developed**	**3,135**	***3,674***	
	Possible Developed Producing	812	*866*	
	Possible Developed Non-Producing	-	*1*	
	TOTAL Possible Developed	**812**	***867***	
3P	**TOTAL Proved + Probable + Possible Developed**	**3,947**	***4,541***	R/P ratios range from nine-14 years against 2022 production outcomes

	Resources	New			Old	
		Oil (kb)	**Gas (mmcf)**	**kboe**	**kboe**	
1C		21,070	9,430	22,642	*25,161*	
2C		117,058	65,730	128,013	*162,904*	Over 300 net drilling location, implies an EUR of ~390kb per well
3C		211,981	144,984	236,145	*300,575*	

Source: Company data – these are volumes net of royalties

The contingent resource estimate is based on 72,080 undeveloped net acres which equates to ~300 net drilling locations based on a 240-acre spacing and a development model of a 7,200 foot (~2,200m) completed lateral section.

Adjusting for nominal royalty barrels (uplift of 1.2x) and averaging across the remaining drilling locations suggests a working EUR estimate of ~500kb/well, but we note guidance from the company that the 'C' case is a more subjective, probabilistic estimate and likely understates the 'de-risked' production outcome – and this makes intrinsic sense with the actual development model still to optimised in terms of well productivity.

The certification is based on an LLS oil price of US$95.80/b and has an assessed NPV(10) for the PDP reserves of US$82.06mn. This is a simplistic and perhaps optimistic view of the oil price outlook, but in our opinion provides a reasonable basis for our valuation correlation.

We note the WTI forward curve as of 22-Feb, for the remainder of 2023 at an average of US$78.42/b as reference point versus the previous price assumption, suggests that all things being equal (assuming reserves replacement and a US$2.50/b LLS premium), the NPV(10) would reduce to ~US$70mn.

We highlight this only to caution against the NPV(10) estimates as applied to US reserves certifications as a definitive valuation and suggest it should only be used as a very broad indicator for comparison to market pricing (Refer RaaS valuation – **Exhibit 1**).

		End 2022	End 2021	End 2020
Oil Price Benchmark	US$/b	95.80	67.27	47.02
Net Acres		~79,600	~98,000	~108,000
Operating Well Count		31	33	38
PDP Wells		31.33	31.31	
PDNP Wells		1.93	2.08	

In the ATS context, resource bookings need to be considered in conjunction with the company's lease (net acreage) position.

Reserves/resources as booked are a direct function of the lease tenure position…

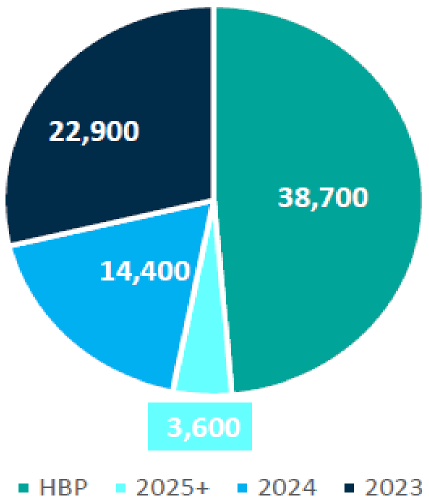
…particularly in the US onshore. Although for the majority of Australian-focussed operations, the reserves = net aces X barrels/acre equation only really applies in a selected and limited number of cases.

In the US onshore unconventional plays, the net acres equation can provide a better than working estimate, particularly in areas like the Bakken, Eagle Ford and Permian, where production history is long and well density is high.

In these highly developed and 'grid' drilled plays, the geological character and hydrocarbon potential can be estimated/calculated with a significantly high level of mathematical confidence – to a degree this is no different than drilling conventional structural prospects, where success in the core of the structure can be extrapolated to the closure (with appropriate risk factors).

For ATS, the net acreage under tenure is critically important in this context and directly impacts the resources estimates – more net acres can be extrapolated to more net drilling locations and likely higher attributable contingent resources.

Exhibit 8: In a rising interest rate world, the facilities look fairly priced



As per the most recent quarterly update:

- ATS has 38,700 net acres held by production (HBP)
- The company has some 22,900 net acres expiring in 2023
- Approximately 2,050 net acres were leased during the quarter with commitments on a further ~ 430 net acres of targeted leases.

Source: Company data

Managing lease positions is not simple when compared to an Australian tenement/permit situation and can be considered somewhat more complex in broad terms – such is the nature of the US oil and gas industry.

By extrapolation to the reserves notes, the 22,900 net acres expiring in 2023 represents ~94 potential future drilling locations at risk should the company not re-lease, exercise extensions or hold by production.

Given the current capital constraints and as highlighted through the recent quarterly updates, ATS intends to *"…employ a modest, discretionary leasing program out of free cashflow, targeting key leases within the focus area that also maintains a level of control."*

The company plan is to target strategic leases allowing ATS to maintain a controlling position within much of the TMS Core, holding a base (high-graded) position as the platform to grow the lease holdings as and when further capital becomes available.

It is worthwhile highlighting that the company is similarly positioned in terms of acreage held and expiry profile as originally acquired from Encana in 2017.

The company remains well set within the TMS Core, retaining, we suggest, the most advantageous and leveraged position to the play.

RaaS Research as a Service

Financials

The operational and financial data over the past two years (eight quarters) demonstrate ATS in a refining and maintenance mode working through lease retention and modest capital programmes.

The company has managed to maintain production and mitigate decline on a stable production base of 47 wells (31 operated, 18 non-operated) with no new wells added through the review period, whilst maintaining a positive (albeit small) EBITDA.

It should be noted that ATS has managed to remain EBITDA positive despite the hedging structure restricting the company's capacity to fully benefit from the recent peak in crude oil prices, although the hedges currently in place look to be in the money given the bearish nature of the current forward curves (**refer Exhibits 11 and 12).**

Exhibit 9: Quarterly data

		Q1 21	Q2 21	Q3 21	Q4 21	Q1 22	Q2 22	Q3 22	Q4 22
Operations									
TMS core land	Acres	106,400	103,000	100,000	98,000	94,300	83,500	81,900	79,600
Net oil resource (2P + 2C)	Mb	170	170	170	170	153	153	153	153
Sales volumes	kb	99.8	109.6	104.1	96.2	91.6	82.9	89.6	83.3
Ave realised price	US$/b	59.78	65.95	73.40	77.23	96.00	110.00	95.00	85.00
Ave price (after hedging)	US$/b			58.92	61.06	77.00	88.00	83.00	80.00
Financials	**US$mn**								
Sales revenue									
After hedges and royalties		4.0	4.4	4.6	4.5	5.3	5.6	5.7	5.3
Field netback		1.9	2.0	2.2	2.3	3.0	2.9	3.5	2.8
Field netback	*US$/b*	*19*	*19*	*21*	*24*	*32*	*34*	*39*	*33*
Field netback (after hedging)	*US$/b*	*24*	*23*	*26*	*30*	*40*	*43*	*48*	*42*
EBITDA	US$mn	0.6	0.5	1.1	0.5	2.2	1.0	1.8	1.1
Cash balance	US$mn	10.9	10.2	9.9	9.3	8.8	8.7	8.3	7.8
Total debt	US$mn	19.0	18.0	17.0	16.0	15.0	14.0	13.0	12.0
Hedging gains/(losses)		(0.9)	(1.4)	(1.5)	(1.6)	(1.8)	(1.8)	(1.1)	(0.5)
EBITDA						2.2	1.0	1.8	1.1
Margin %						*31.4*	*13.7*	*24.3*	*16.7*
Margin after royalties %						*41.5*	*17.9*	*31.6*	*20.8*
Interest expense					(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
Capex							(1.1)	(1.9)	(0.7)
Debt repayment		(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)	(1.0)

Source: Company data

Australis has held a senior, secured, non-revolving facility with Macquarie Bank Limited since June 2018, which has a maturity date of November 2025 and is subject to an interest rate of SOFR plus 6.0% per annum.

The facility is secured over the group US assets, so is effectively a reserves-based lending tranche, subject to *"…industry standard financial covenants* including *minimum liquidity, financial ratios and PDP reserves ratios. In addition, there is a financial debt to PDP value ratio".*

The company is not in breach of any financial covenants.

Exhibit 10: A hedge book in the money

Hedging	2023	2024	2025	Forecasts	2023	2024	2025
Volumes	43.0	24.0	12.0	Sales	286	258	231
Swap price	$69	$62	$65	Forecast oil price	81.82	76.92	72.66
Volume	50.0	38.0	17.0	Average received price (after hedge impacts)	79.48	79.71	73.84
Collar price (lower)	$43	$57	$50				
Collar price (upper)	$68	$83	$80				

Source: Company data; Prices in US$/b, volumes/sales in kb

Under the T&Cs of the debt facility the company holds hedging obligations at a minimum, for the duration of the loan period. The hedging position as at 31-Dec-2022 is outlined in **Exhibit 10.**

The quarterly data shows that historical hedging has negatively impacted the company's realised oil price, particularly through the quarterly data as noted.

In response, the company has been shifting the weight of hedges in place to collars rather than vanilla swaps, allowing the company to capture more of any upside in oil prices, particularly through 2024-2025.

In fact, the hedge book is 'in the money' compared to our price deck through this period.

The company has been meetings its obligation of capital repayments of US$1mn per quarter with US$12mn debt outstanding as at 31-Dec-2022.

We are comfortable the company can continue to meet debt servicing requirements through the forecast period whilst maintaining sufficient working capital to maintain its aim to continue a modest lease management programme **(refer p.12).**

Whilst it is unlikely, the maintenance and growth strategies of the company are dependent on delivering sufficient working capital from operations or other sources. Partnering discussions are in progress, however, we cannot discount further resort to equity or debt markets through the forecast period.

A Risk Assessment

The most critical factor in determining and delivering any project is, in our view, the prevailing commodity price outlook. Oil prices are the bulwark on project economics, particularly in early-stage developments. Rather than a comprehensive assessment of all operating risks, we highlight a few key areas that we consider the most critical for the company and investors over the next 12-24 months.

Commodity prices

It is beyond the scope of this report to enter into a detailed discussion of the dynamics of the oil and gas markets, except to highlight the strong and recent variability in short-term oil price forecasts.

Exhibit 11: Commodity price outlook – we use a forward-curve approach

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	LT
WTI	76.24	72.27	68.70	65.65	62.93	60.39	58.00	55.93	54.20	52.80	51.60	**60.80**	**70**
AUD	0.6905	0.6960	0.6940	0.6883	0.6833	**0.7167**	**0.75**						

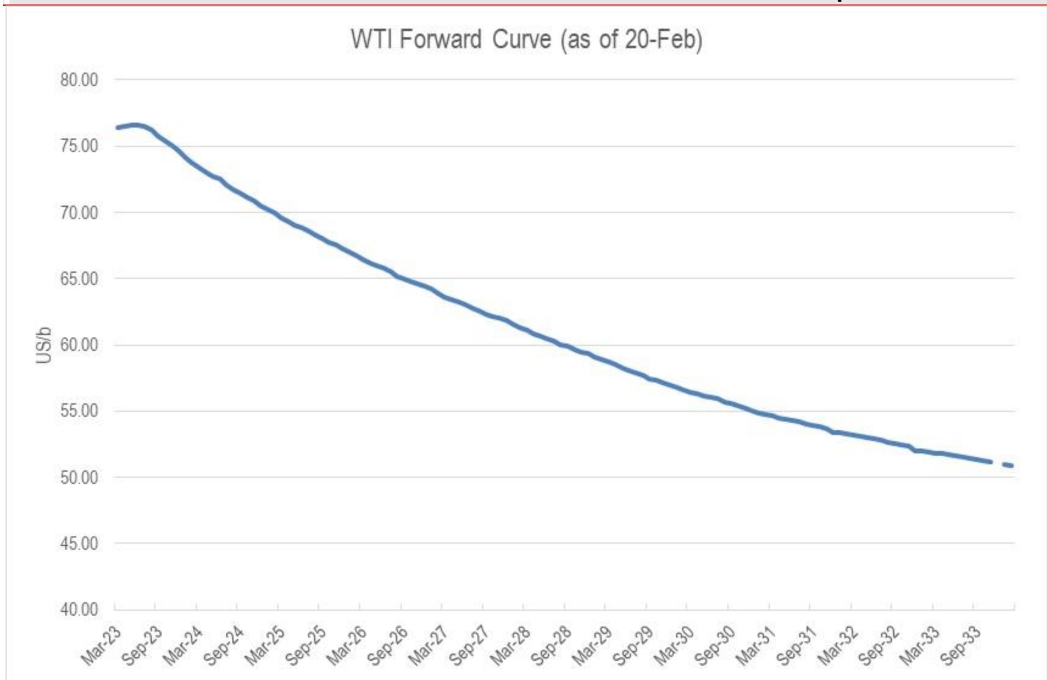
Source: barchart.com (FC data); RaaS estimates

Please note that TMS crude oil prices to the LLS (Louisiana Light Sweet Benchmark), which we assume trades at a US$2.50/b premium to WTI.

We use a forward-curve approach, renewing the price deck on a quarterly basis out to the end of the curve and extrapolating to our long-term assumptions (**bold**), which we set as the required price to justify new investment and development across the cycle.

Given the number of active participants in the forward commodity (and currency) markets on a daily basis as evidenced by the number of transactions, we consider the forward curve as a default proxy for market consensus and sentiment; and more likely to be reflective of investment valuations and current stock pricing.

Exhibit 12: A 12-month turnaround – markets are now bearish on the oil price outlook



Source: barchart.com

Crude oil prices have been highly variable across 2022 with the early strength reflecting a post-COVID economic rebound and supply uncertainties related to the Russian invasion of the Ukraine. The waning in oil prices becoming more pronounced in Q4 22 is dominantly down to inflation and forced economic 'hand-brakes' as applied by global central banks.

We add that rising costs on lower oil prices are putting pressure on marginal developments in more mature areas with deferral of some growth operations.

In some ways this is a plus/minus outcome for ATS.

Pluses:

- ATS has an entry-level opportunity of scale – other operators are increasingly being forced to address growth strategies and current inventories perhaps sooner than would otherwise have been the case.
- Lower productivity on falling prices could accelerate abandonment capital expenditure and companies would rather deploy capital on growth, not 'end-life' operational costs.
- Re-evaluation of where capital gets deployed specifically and holistically.

Minuses:

- Other operators/potential partners may just dial the capital flow back and focus on capital management options and try to ride out the current trough rather than deploy capital into notionally riskier areas.
- Other operators may see falling prices as opportunity to squeeze other lease holders (say, ATS in the TMS) for lower entry prices.
- …falling prices may be the opportunity to consider alternate (renewable) energy streams.

The threat from renewables has not abated

This refocus of the business model is also being driven by greater investor pressure pushing for more climate-beneficial outcomes and government decarbonisation policies.

Industry participants refute the idea that oil and gas demand may have peaked and assert that long-term energy demand is growing not shrinking, that renewables lack scale and the fundamentals of their existing businesses have not changed…that there will be no permanent demand destruction.

At a minimum we expect persisting oil price volatility through 2023 as global economies grapple with continuing post-COVID related economic issues.

We note current industry commentary:

"Geopolitical events and severe weather that disrupt the supply of crude oil and petroleum products to market can affect crude oil and petroleum product prices.

"The volatility of oil prices is tied to the low responsiveness, or inelasticity, of supply and demand to price changes in the short term. Crude oil production capacity and the equipment that uses petroleum products as its main source of energy are relatively fixed in the near term.

"The large changes in world oil prices in the past decade demonstrate how all of these factors can influence oil prices, and they demonstrate the difficulty in making projections for oil price".

Source: www.eia.gov

Geology…still an area of and uncertainty in development terms

On a generic basis, early-stage plays come with a higher inherent risk, even allowing for discoveries (actual and analogue) and developments.

The TMS Core area appears well mapped and defined, however, we have highlighted in our geological discussion (**refer Appendix A**) the nuances to the play even within the core area, particularly with respect to the fracking aspects; and the potential need to even better define the notional sweet spots within the TMS Core.

The play is comparatively considered somewhat higher risk because of the relative lack of development wells compared to other US onshore plays, which just adds a layer of uncertainty and is perhaps one of the reasons potential new entrants to the play are waiting. However, that perspective always come back to a chicken-egg situation - where is the 'tipping point' where industry and markets can declare the play adequately 'de-risked' for investment? At the moment, it's probably just 'one more well'.

The risks per se don't lie with the geology in an absolute sense, but rather with the geology in a developmental sense as the model is still in an evolutionary stage.

It should be noted that geology can also surprise on the upside – reservoir parameters and flow results can exceed expectations with positive implications for reserves and capital costs, but all of this needs to be determined through continued development drilling.

Technology and operating risks are real – further sustained flow rates and gas recovery data are needed to underpin type curves

Our discussion in the section, 'The TMS Model' **(p.7)**, illustrates how new entrants have been trialling different frack methods, using slickwater. The aim of using an alternate frack design was to see if it could generate improved medium-term productivity but on initial indications, it appears as though the outcomes have may not been as effective as modelled.

It is suffice to reiterate that the evolution of completion design/optimisation in the TMS remains in the early stages and like all other plays, should see improved performance as more wells are drilled and operators come up the knowledge curve.

Financing – including hedging

Given the early-stage nature of the play, unit capital costs are likely towards the higher end of the range with little in the way of the economies of scale that can be provided by bigger campaigns and an optimised development design (frack type and numbers of stages).

In the current inflationary environment, particularly with still relatively strong utility on rigs, the risks capital costs are to the upside and in the absence of a partner, ATS must operate in a capital-conservation mode and in-field investment becomes a balancing issue between continuing to prove the commercial opportunity and potential dilution.

Against a 31-December balance sheet position of net debt (US$4.2mn), there is limited flexibility for the company to pursue a material field campaign in 2023 as we see it, in the absence of a capital raise through partnering or equity issue, as the most likely options.

The company has been hamstrung by the hedging conditions associated with the Macquarie Bank facility, which has materially capped returns from production over the strong oil price period of 2020-2022.

Whilst further or refinanced debt options may still be a consideration, the industry is operating in an environment of rising rates and falling prices – not an ideal combination.

We do highlight again though that 'what may be a weakness can also be a strength', noting that the hedge book as per **Exhibit 10** is in the money compared to our assumed oil price deck.

However, any new hedges entered into from this point will be into a weakening price market.

There are always cheaper capital options in a portfolio and additional well workover could be undertaken through 2023 in the absence of new (green fields) drilling.

Given the cost of debt and share price discount to attributable NAV, the best source of financing that can be pursued by ATS is partnering and we reiterate the attraction of the TMS even at an early stage:

- Early-mover advantage provides early-bird pricing;
- Expected operating margin improvements as the play knowledge increases and batch activity comes into force – returns will only improve from here;
- It's an oil play at (a minimum) 92% oil cut; and
- Short lead times to production – there's a network and market on the doorstep.

We suggest this would likely make the play very attractive to any number of US operators who may also see the potential to leverage their own expertise.

Operating and services costs

Not surprisingly as it is an issue being faced across industrial and resources sectors, the industry is being adversely impacted by the unprecedented tightness in the labour market.

There are many skilled operators who left the services industry (either forced or voluntary) and have not returned due to the pull of transferable skills to renewables or completely reskilling and moving into newer professions altogether; and labour tightness means rising costs and delays.

The industry is also experiencing a period of rampant inflation, although on falling commodity prices the intensity of demand for services may be somewhat peaking and persistently lower crude prices will eventually result in returns normalising.

At this point though we are still of the view that the risk is to the upside on costs.

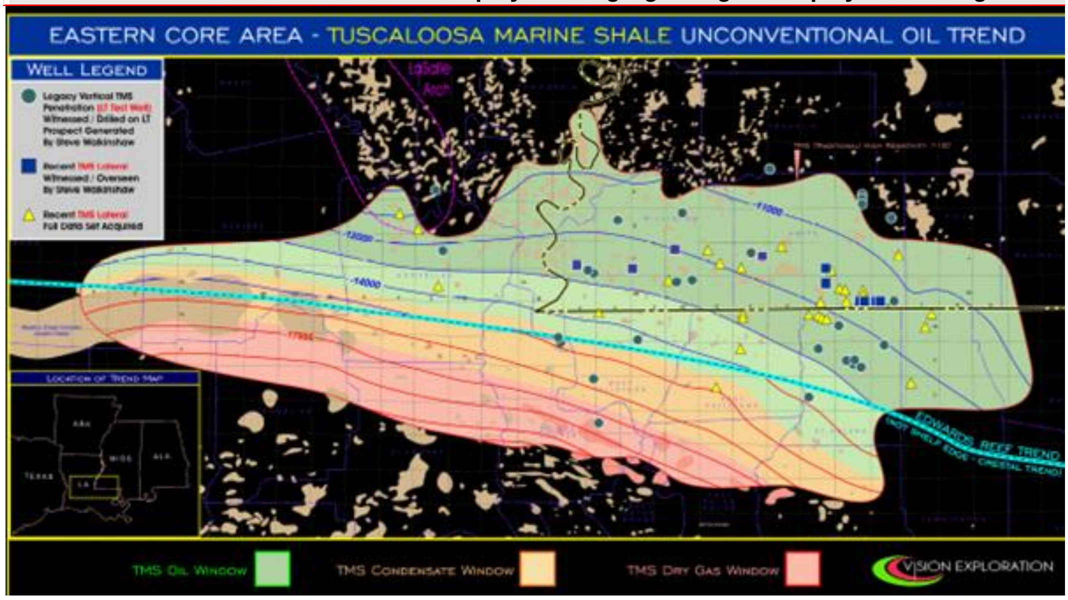
Appendix A - Tuscaloosa Marine Shale: A Nascent Transformational Oil Play

Currently, the TMS Trend is considered as one of the deepest and challenging unconventional oil trends in the onshore US. Drilling to date has been somewhat sporadic with <100 wells drilled in the play, however, a core area has been defined and areas within that core are emerging as commercially important sweet spots. The further identification and exploitation of these sweet spots now becomes the strategy as the trend matures and develops.

Source: www.visionexploration.com

The Tuscaloosa Marine Shale (TMS) is a Late Cretaceous formation, straddling the Southwest Mississippi–East Louisiana area across the Gulf Coast region of the United States. The discovery of the play was initially made in 1950 by the Humble Oil & Refining Company which recorded a strong influx of oil and gas from the Middle Tuscaloosa section at a depth of 11,646 feet (3,550m) in a test well.

Exhibit 13: The TMS is a well-defined oil play with high-grading of the play continuing



Source: www.visionexploration.com

The play has been considered somewhat as a 'teaser' with early wells recovering fluids on test of between 85%-100%, light crude oil (38°–45°API) and liquids-rich natural gas, from depths ranging between 10,000-15,000 feet (3,050-4,570m).

The TMS ranges in thickness from 500-800 feet (~150-245m) but the bottom 120-150 feet (35-45m) is considered to be the hydrocarbon risk target zone. Extrapolating from a 1997 Louisiana Geological Survey estimate, the shale play is considered to have a reserve potential of ~7Bnb.

Source: www.rbnenergy.com/AAPG Memoir

With now >80 horizontal wells completed in the TMS, a high-graded area has been identified and designated as the 'core' area of the play towards the eastern end of the trend (encompassing the SW Mississippi and Florida Parishes). To date, this core area has proven to be the most commercially important part of the play **(refer Exhibit 3).**

As an unconventional oil target, well completion techniques require horizontal drilling and hydraulic fracturing (fracking) technologies to reach economic viability for extraction.

Although drilling has been conducted on a limited and localised scale since the 1980's, the 'modern' era is considered to have commenced in 2011 with the drilling of the Weyerhaeuser 73H-1 (73H-1) well by Encana as reported by Vision Exploration.

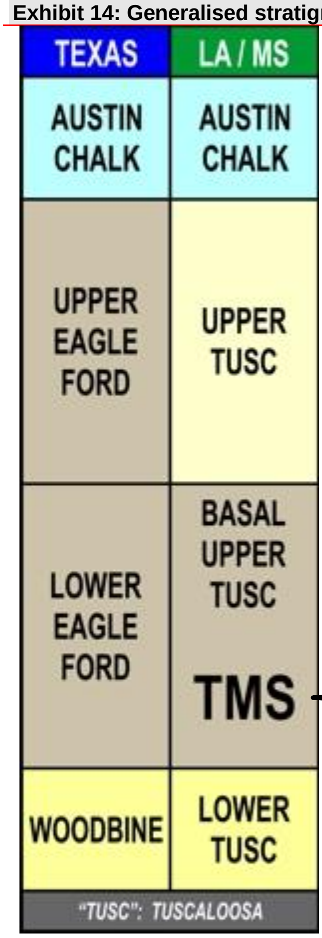
"The 73H-1 lateral, bottomed at a measured depth of 18,164 feet (TVD 12,662 feet) in side-tracked hole after drilling a 6,117 feet (~1,865m) lateral in the lower TMS and completed with a 17-stage frack. In its first full

month of production (December 2011), the well produced at daily rate of approximately ***600bpd and 248mcfd demonstrating the commercial potential of the trend."***

The well also demonstrated the completion risks associated with the play with saltwater egress from the underlying sandstones of the Lower Tuscaloosa, which had been unintentionally fracked.

It should be noted that the vast majority of water produced in the ATS areas is in-situ in nature rather than from underlying intervals.

Exhibit 14: Generalised stratigraphic section showing the relationship to the prolific Eagle Ford play



The TMS in the key Eastern Core Area Trend, is a fissile micro-fractured marine shale with as expected, low intrinsic porosity (2-4%) and poor permeability, averaging <0.02 millidarcies – this is tight. The TMS is a source rock and contains >95% of all of the hydrocarbons trapped within the Tuscaloosa sequence.

In certain areas, the shale contains numerous thin sandstones and siltstones that can develop locally into thicker and more coarse-grained lenses with porosities as high as 8%. The wells drilled to date suggest the most productive section lies at the base of the unit, where there is a 3-4m thick, highly naturally fractured geologic interval.

At the base of the TMS is bounding unit informally labelled the "Pilot Lime" which is typically 25-30 feet (8-9m) thick and is considered as a confining zone ('basement') limiting the downward propagation of frack energy and maximising the fracture stimulation of the overlying TMS.

At the very top of the Pilot Lime is a thin sandstone ('Richland Sand') deposited over most of the Eastern Core area. In localised areas this sand is good quality, saturated with oil and gas and has been suggested as a potential storage unit although **production data to date suggests sandstones provide only a minimal contribution to oil output**.

Immediately overlying the TMS is a sequence of marine shales, silts and sandstones (basal Upper Tuscaloosa [bUT]). This interval is brittle and easily fractured. In the areas where the bUT is heavily fractured, the interbedded sandstones and siltstones have been reported as *"…highly charged with TMS-sourced oil and gas, at abnormally high pressures"* with *"…the combined interval both fracture and pressure-connected"*.

Source: www.visionexploration.com;and www.naturalgasintel.com

Although the TMS is a depositional equivalent to the Eagle Ford it differs importantly in geological character, containing significantly greater sand and silt components compared to a chalk dominant/calcareous through the Eagle Ford. The TMS is a more complex, deeper water environment and its clay/silt content presents some geological challenges that has limited the progress of development associated with the play.

We note the TMS core is the area of the play with sufficient well density to provide geological control consistent enough for development. **The TMS Core area is the optimal location for the play on a regional basis.**

Encana was particularly active across the TMS over 2011-2014, drilling some 15 wells in 2014 which have formed the basis of the current type curve model, with production histories extending from 8-10 years.

Encana eventually sold its holdings to Australis Oil & Gas. Australis, as noted, operates and produces from 31 (29 net) of the wells drilled through the initial phase of activity (2011-2014).

Australis also operates wells completed in its initial development campaign undertaken in 2018 and 2019. These wells have (refer Stewart/Taylor commentary from earlier in the report) clearly demonstrated consistently high oil productivity.

The following data is somewhat dated but remains relevant simply in terms of progress along the development pathway:

RBN Energy wrote in a 2014 article that…"*Goodrich Petroleum reported on its 3Q14 conference call that there had been 52 horizontal wells drilled in the TMS as of October 2014, with 21 of those coming in 2014"* compared to *"…more than 16,300 permitted wells in the Texas Eagle Ford through August 2014"*.

https://rbnenergy.com/never-give-up-can-higher-crude-prices-revive-the-tuscaloosa-marine-shale-play

A look back…

It's worthwhile taking a look at the TMS in the context of Encana's outlook and insights at the time of its significant move into the play and precursor to commencement of the 'modern' exploration phase (2011-2016).

We provide this commentary for historical context as Encana was in a period of significant expansion which included acquisitions in the Permian and Eagle Ford with **the TMS identified as a material production growth opportunity and a top five oil opportunity.**

In a Jul-2014 presentation the company outlined the reasons it was attracted to the play, initial results and importantly its intention to accelerate development activity.

Exhibit 15: 'Why we like the TMS play'

- **Emerging oil asset with massive upside potential**
  - Estimated 4 - 5 BBoe of PIIP
  - Potential to produce >50,000 bbls/d
- **~80% of Encana's 200k net acres is Tier 1 land**
- **Demonstrating achievement of type curve across Tier 1 acreage**
  - 7 of 10 last industry wells meeting normalized type curve (ECA 7 for 7)
- **LLS pricing advantage**
- **Favorable regulatory environment**
- **Demonstrating achievement of type curve across Tier 1 acreage**
  - Wells drilled YTD 2014 generally meeting normalized type curve expectations
- **Cost improvements continue to be achieved**
  - Mathis and Lewis wells demonstrated record drilling times
  - Progressing well completion design
- **Plan to complete appraisal of play by year-end**
- **6 net (10 gross) wells drilled YTD as of June 30th**
- **2 rigs currently running**

Source: Encana corporate presentations – Nov-2013/Jul-2014

We note that the wells drilled in 2014 remain on production with type curves continuing to demonstrate favourable productivity on a comparative basis.

Appendix B– Board and Management

We like the *'been there, done that'* nature of the Australis board who can draw on the collective experience of establishing and growing a business (Aurora Oil & Gas Limited) focussed on the unconventional onshore oil and gas play in the Eagle Ford Shale in the USA. Aurora listed with a capitalisation of ~A$30mn before being acquired **by Baytex Energy Australia Pty Ltd** in June 2014 for an enterprise value of A$2.6bn.

The company is able to build on its technical base and expertise in the new Tuscaloosa Marine Shale play, being a complimentary opportunity to the Eagle Ford.

Ian Lusted - Managing Director and Chief Executive Officer [BSc (Hons.) from York University, Member SPE]

Mr Lusted was appointed Managing Director and CEO of Australis on 12 November 2015. Previously **Mr Lusted was Technical Director of Aurora from Apr-2008 until Aug-2013.**

Ian has extensive international oil and gas experience, dating from 1991 with Shell International in upstream operations in the North Sea, South East Asia and onshore Europe. Ian leveraged this experience and in 1998 established Leading Edge Advantage (LEA) specialising in advanced drilling project management. He consulted to and led a number of multi-discipline project teams that implemented **world-first technology applications**. In 2005, Ian was appointed as the Technical Director for Cape Energy, a private oil and gas company, with operations in Australia and the Philippines where Cape Energy was a key participant in moving the offshore Galoc field to development status. In Aug-2007 he joined Aurora assuming the role of Technical Director shortly thereafter. Working with a small technical team supplemented by contractors, Aurora made significant contributions to the early evaluation and operational activity within the Sugarkane Field (Eagle Ford).

Jon Stewart – Non-Executive Chairman

Mr Stewart was appointed as the Non-Executive Chairman of Australis on 12 November 2015. **Jon was a founder and was director of Aurora from Feb-2005 until its acquisition by Baytex,** holding the positions of Executive Chairman and CEO until separating the roles in 2012. He is a highly experienced industry executive with considerable international exposure through various roles throughout Australia, North America, the United Kingdom, and the former Soviet Union. He has been directly involved in the in the management of oil and gas exploration and production companies; structuring and financing transactions; and delivering on the broader strategic development of companies including financing through international equity and debt markets.

Graham Dowland - Finance Director and Chief Financial Officer

Mr Dowland was appointed Director and CFO of Australis on 12 November 2015 having previously been **a founding director of Aurora from Feb-2005.** Ian held the position of Finance Director of Aurora from Nov-2010 until the acquisition of Aurora by Baytex Energy Australia Pty Ltd. He has over 25 years' corporate finance and management experience in the oil and gas industry having previously held director or senior management or advisory positions in Australian, Canadian and UK-listed companies with oil and gas operations in the UK, Russia, Azerbaijan, Indonesia, Australia and New Zealand. Ian is a qualified Chartered Accountant.

Alan Watson - Non-Executive Director

Mr Watson is an independent, Non-Executive Director of Australis having been appointed in May-2016. He is Chair of the Remuneration and Nomination Committee and a member of the Audit and Risk Management Committee.

Alan was formerly an independent, non-executive director of Aurora from Nov-2010 until the acquisition of Aurora by Baytex. He is a banker with 35 years of experience across various global equity markets in Europe and Asia at Barclays de ZoeteWedd Limited, Donaldson, Lufkin & Jenrette Securities Corporation, Lehman Brothers Holdings Inc, and Macquarie Capital (Europe) Ltd, advising on capital structuring, initial public offerings and M&A strategies.

He is currently independent Chairman of ASX-listed funds management company Pinnacle Investment Management Group Limited.

Stephen Scudamore - Non-Executive Director

Mr Scudamore is a highly experienced Australian company director, joining the board of Australis as an independent, Non-Executive Director (NED) in Nov-2016 and is the Chair of the Audit and Risk Management Committee.

Stephen brings extensive corporate experience to the board after more than three decades with KPMG, Chairman of Partners WA, Head of Corporate Finance in WA and National Head of Valuations, KPMG Australia.

He has previously been a NED of Aquila Resources and is currently a NED of Altona Mining and Pilbara Minerals Limited.

Since 2012, Stephen has been on the board of MDA National Insurance Pty Ltd as both a NED and Chair. He has extensive involvement in community organisations as the Chair of Amana Living, a Member of Council and Chairman of the Audit and Risk Committee at Curtin University, and as a Trustee at the Western Australian Museum.

Stephen is a Chartered Accountant with a Master of Arts from Oxford University, a Fellow of the Institute of Chartered Accountants, England, Wales and Australia (FCA), a Fellow of the Institute of Company Directors (FAICD), and a Senior Fellow of the Financial Services Institute of Australia (SF Fin).

Exhibit 16: Directors' holdings

		Fully Paid Ordinary Shares	Performance Rights	Fee Rights
Ian Lusted	24/02/23	29,491,840	10,650,739	
John Stewart	24/02/23	84,262,460		3,727,165
Graham Dowland	24/02/23	26,527,651	7,902,308	
Alan Watson	24/02/23	6,698,298		1,490,865
Steve Scudamore	24/02/23	2,398,586		1,490.865
Total Issue	**24/02/23**	**1,261,196,273**	**18,553,047**	**6,708,895**

Source: Company data (holdings as of last ASX releases)

Management

Malcolm Bult – VP Corporate and Business Development

Mr Bult has over 20 years in the energy industry with extensive and varied experience commencing in the late 1990s with Energy Equity Corporation and progressing through various senior corporate and commercial positions at Woodside Petroleum, Cape Energy before joining the management team at Aurora in Jan-2008 and subsequently Australis. He has considerable practical experience in the areas of farm outs, acquisitions, corporate strategy, business development, investor relations and financial analysis.

David Greene – VP Operations

Mr Greene was appointed as Vice President Operations in Nov-2019 and is responsible for drilling and production operations after previously undertaking the role of Production Manager.

He brings almost 20 years of broad operational experience, beginning his career with Chevron in drilling operations running the gamut in offshore and onshore projects, in the Gulf of Mexico, California and West Africa.

Critically, he has direct experience in operations gained with SM Energy, successfully drilling over 500 Eagle Ford Shale wells, managing both the engineering and operational teams, being promoted to Operations Manager in 2015.

David holds a BSc from The Pennsylvania State University in Petroleum and Natural Gas Engineering, is a member of the Society of Petroleum Engineers (SPE), American Association of Drilling Engineers and has served as a board member for several Houston oilfield-related charity organizations.

Darren Wasylucha – Chief Corporate Officer

Mr Wasylucha was appointed Chief Corporate Officer of Australis on 18 December 2017 having previously held the position of Executive Vice President - Corporate Affairs of Aurora until its acquisition by Baytex Energy in Jun-2014.

As VP Corporate Affairs at Aurora, Darren oversaw the legal affairs of the corporate group across various jurisdictions and managed the execution of corporate development strategies, including capital raising and acquisitions.

He has over 18 years of experience in the areas of corporate finance, securities and corporate governance and prior to joining Aurora, Darren was a partner of one of Canada's premier business law firms, advising on a wide range of Canadian and international public and private companies.

Mr Wasylucha holds an LLB from the University of Victoria, Canada and a BA (Honours) from the University of Alberta, Canada.

Appendix C - Top 20 shareholding register

Exhibit 17: Register is dominated by the top 20

HOLDER	UNITS	%
CITICORP NOMINEES PTY LIMITED	174,403,880	13.83
UBS NOMINEES PTY LTD	65,761,467	5.21
BNP PARIBAS NOMINEES PTY LTD <Agency Lending Drop A/C>	57,476,681	4.56
JK STEWART INVESTMENTS PTY LTD <The Stewart Investment A/C>	33,392,858	2.65
EPICURE SUPERANNUATION PTY LTD <Epicure Superannuation A/C>	26,150,001	2.07
MR ANDREW McKENZIE & MRS CATHERINE McKENZIE <A W McKenzie Super Fund A/C>	24,900,000	1.97
BARREL ENERGY INC	23,100,849	1.83
PASAGEAN PTY LIMITED	20,000,000	1.59
JK STEWART INVESTMENTS PTY LTD <The Leake Street Investment Trust>	15,927,458	1.26
HSBC CUSTODY N0MINEES (AUSTRALIA) LIMITED	15,467,071	1.23
JP MORGAN NOMINEES AUSTRALIA PTY LIMITED	15,053,736	1.19
BNP PARIBAS NOMINEES PTY LTD <IB AU Noms Retail Client DRP>	14,916,219	1.18
EVERZEN HOLDINGS PTY LTD <Lusted Family A/C>	12,281,814	0.97
MR CHARLES ROBERT DIRCK WITTENOOM	10,709,339	0.85
CHESTER NOMINEES WA PTY LTD <M W Wilson Super Fund A/C>	10,000,000	0.79
AVALON VALLEY PTY LTD <The GR & TJ Dowland S/F A/C>	9,700,000	0.77
ICE COLD INVESTMENTS PTY LTD <G & J Brown Super Fund A/C>	9,500,000	0.75
SUGARLOAF VENTURES PTY LTD <SKI Capital A/C>	9,384,246	0.74
MR KANE CHRISTOPHER WEINER	9,045,116	0.72
ZERO NOMINEES PTY LTD <5063463 A/C>	8,754,080	0.69
TOP 20 SHAREHOLDERS	**565,924,815**	**44.87**
Total Issued Ordinary Shares	**1,261,196,273**	
Average monthly turnover for the twelve-month period to 6-Mar-2023	**30.7mn shares**	

Source: Company data (as of 01/02/23)

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Exhibit 18: Financial Summary

AUSTRALIS Oil & GAS LTD		ATS				
YEAR END		Dec				
NAV	A$mn	$0.25				
SHARE PRICE	A$cps	$0.04	priced as of close trading	8-Mar	nm	not meaningful
MARKET Cat	A$mn	51			na	not applicable
ORDINARY SHARES	M	1,243				
OPTIONS	M					

COMMODITY ASSUMPTIONS		2021	2022	2023E	2024E	2025E
Realised oil price	US$/b	68.99	96.62	81.82	76.92	72.66
Realised oil price after hedging	US$/b	55.89	81.78	79.48	79.71	73.84
Exchange Rate	A$:US$	0.7514	0.6946	0.6819	0.6873	0.6829

RATIO ANALYSIS		2021	2022	2023E	2024E	2025E
Shares Outstanding	M	1,238	1,243	1,243	1,243	1,243
EPS (pre sig items)	UScps	(0.2)	0.2	0.1	0.1	0.1
EPS	Acps	(0.3)	0.2	0.1	0.1	0.1
PER	x			nm	nm	nm
OCFPS	Acps	0.3	0.8	0.3	0.4	0.4
CFR	x			15.4x	9.6x	10.6x
DPS	Acps					
Dividend Yield	%					
BVPS	Acps			8.4	8.4	8.6
Price/Book	x			0.5x	0.5x	0.5x
ROE	%			nm	nm	nm
ROA	%			nm	nm	nm
(Trailing) Debt/Cash	x					
Interest Cover	x					
Gross Profit/share	Acps	0.3	0.5	0.2	0.2	0.1
EBITDAX	A$M	3.7	8.8	6.9	5.8	4.8
EBITDAX Ratio	%					

EARNINGS	US$000s	2021	2022	2023E	2024E	2025E
Revenue		22,909	28,378	22,745	20,593	17,034
Cost of sales		(17,341)	(19,097)	(18,596)	(17,127)	(14,648)
Gross Profit		**5,568**	**9,281**	**4,149**	**3,466**	**2,386**
Other revenue						
Other income		769	841	250	250	250
Exploration written off						
Finance costs		(1,906)	(1,113)	(1,047)	(1,009)	(544)
Impairment						
Other expenses		(6,839)	(7,042)	(2,294)	(2,049)	(1,460)
EBIT		(502)	3,080	2,104	1,667	1,175
Profit before tax		**(2,408)**	**1,967**	**1,057**	**658**	**631**
Taxes						
NPAT Reported		**(2,408)**	**1,967**	**1,057**	**658**	**631**
Underlying Adjustments						
NPAT Underlying		**(2,408)**	**1,967**	**1,057**	**658**	**631**

CASHFLOW	US$000s	2021	2022	2023E	2024E	2025E
Operational Cash Flow		**4,304**	**7,750**	**2,657**	**3,522**	**2,475**
Net Interest		(1,199)	(1,217)	(1,397)	(880)	(432)
Taxes Paid						
Other		43	144	1,000	1,000	1,250
Net Operating Cashflow		**3,148**	**6,677**	**2,260**	**3,642**	**3,293**
Exploration		(571)	0	(500)	(500)	(500)
PP&E		(80)	(374)	(100)	(100)	(100)
Petroleum Assets		(1,066)	(2,264)	(1,000)	(1,000)	(500)
Net Asset Sales/other		505	0	0	0	0
Net Investing Cashflow		**(1,212)**	**(2,638)**	**(1,600)**	**(1,600)**	**(1,100)**
Dividends Paid						
Net Debt Drawdown		(4,505)	(5,239)	(4,000)	(4,000)	(4,000)
Equity Issues/(Buyback)		7,898				
Other						1,000
Net Financing Cashflow		**2,980**	**(5,243)**	**(4,500)**	**(4,500)**	**(3,500)**
Net Change in Cash		**4,916**	**(1,204)**	**(3,840)**	**(2,458)**	**(1,307)**

BALANCE SHEET	US$000s	2021	2022	2023E	2024E	2025E
Cash & Equivalents		9,253	7,848	4,008	1,550	243
O&G Properties		55,522	57,016	57,016	57,016	57,016
Exploration & Evaluation		13,379	13,238	13,238	13,238	13,238
Total Assets		**90,828**	**90,383**	**85,110**	**80,859**	**77,868**
Debt		16,697	11,870	8,000	4,000	
Total Liabilities		**28,991**	**24,344**	**14,226**	**9,384**	**5,204**
Total Net Assets/Equity		**61,837**	**66,039**	**70,884**	**71,475**	**72,664**
Net Cash/(Debt)		(7,444)	(4,022)	(3,992)	(2,450)	243
Gearing dn/(dn+e)						

NET PRODUCTION		2021	2022	2023E	2024E	2025E
Crude Oil	kb	410	347	286	258	231
Nat Gas	mmcf					
TOTAL	**kboe**					
Product Revenue	US$mn	22.9	28.4	22.7	20.6	17.0
Cash Costs	US$mn	(14.4)	(16.2)	(13.0)	(11.9)	(9.9)
Ave Price Realised	US$/b	55.89	81.78	79.48	79.71	73.84
Cash Costs	US$/b	(35.12)	(46.57)	(45.30)	(46.23)	(42.83)
Cash Margin	**US$/b**	**20.77**	**35.21**	**34.18**	**33.48**	**31.01**

RESOURCES and RESERVES kb unless otherwise stated		Reserves 1P	2P	3P	Contingent Resources 1C	2C	3C
Proved Developed	Producing	2,475					
	Non-Producing	29					
Probable Developed	Producing		631				
	Non-Producing						
Possible Developed	Producing			812			
	Non-Producing						
Oil	kb				21,070	117,058	211,981
Gas	Bcf				9	66	145
TOTAL	**kboe**	**2,504**	**3,135**	**#######**	**#######**	**117,069**	**212,005**

EQUITY VALUATION	Risked Range Low	Mid	High	Low	Mid	High
A$mn	Low	Mid	High		per share	
Reserves	$76	$95	$119	$0.06	$0.08	$0.10
Contingent Resources	$79	$224	$289	$0.06	$0.18	$0.23
	$155	**$319**	**$408**	**$0.12**	**$0.26**	**$0.33**
Net Cash/(debt)		($6)				
Corproate costs		($5)				
TOTAL	**$144**	**$308**	**$397**	**$0.12**	**$0.25**	**$0.32**

Source: RaaS Advisory; Priced as at 07-Mar-2023

FINANCIAL SERVICES GUIDE

RaaS Advisory Pty Ltd
ABN 99 614 783 363
Corporate Authorised Representative, number 1248415

of

BR SECURITIES AUSTRALIA PTY LTD
ABN 92 168 734 530
AFSL 456663

Effective Date: 6th May 2021

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- who we are
- our services
- how we transact with you
- how we are paid, and
- complaint processes

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In writing to: Australian Financial Complaints Authority, GPO Box 3, Melbourne, VIC, 3001.

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