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Empire Energy Limited (EEG)

20 April 2020

Chasing a big gas pay day

Recommendation: BUY

Our View

We are initiating coverage

East coast gas supply remains a key investment thematic, with a strongly supportive macro environment. New sources of supply will be required and the Beetaloo/McArthur basins have been identified by the Federal Government and APPEA as a critical part of the solution. Within that context Empire Energy represents one of few pure, independent and highly leveraged exposures to the transformational potential of the province, with a number of direct and indirect re-rating events in train. The plays and opportunities are at an early stage of evaluation but the process of resource definition (volumes, flow rates and liquids contents) can lock in a significant valuation base on success.

The next significant step for EEG is to drill and evaluate (through fracking) its first well, Carpentaria-1 in EP187, which can be directly correlated to the neighbouring Santos (STO.ASX) success at Tanumbirini which flowed >1.2mmcfd on test. Both Santos and Origin (ORG.ASX) activity can provide look through support from their respective testing programmes, however, the prevailing CoronaVirus travel restrictions have pushed out field results for perhaps another 12-months. We suggest, the confidence level associated with the gas potential is relatively high and EEG is sitting on an extensive gas resource – it's more about operating and commercial definition than exploration.

There is intrinsic value in the asset base that will be defined by successful drilling results and ensuring the company is resourced and financed to capitalise on market opportunities.

Key Points

The next phase for the Beetaloo/McArthur basins is more drilling when conditions allow. There are multiple, basin wide field programmes set to resume when restrictions are lifted which will provide definition on the massive resource potential of the province. Early results are encouraging – the target shales are pervasive, organic contents are high and initial testing results are encouraging with flow rates >1mmcfd.

Empire Energy is a highly leveraged, independent investment opportunity. The NT basins are dominated by big companies. EEG represents the most leveraged, independent play with holdings >5,250acres and Prospective Resources ('U') of >4.2Tcf at the P_{90} level. Although the timing is somewhat fluid, we think EEG will be drilling and testing its first well inside the next 12-months which, on success, should enable the company to book a significant proportion of gas as a Contingent Resources ('C') – a precursor to commerciality.

Intrinsic value points to transformational upside. We value the company using a risk weighted conversion of U volumes at 6% and applying a commercial outcome, which translates to a range of $62-322mn ($0.24-1.22/share).

Recent asset transactions support the mid- and high end of the range which suggests upside of some 5x (from the low-point).

The capitalisation of the company translates to a look-through unit gas value of <1c/mcf (P_{90} level) and there is growing confidence in the commercial potential from historical data.

We set our recommendation at **BUY** with a **Target Price of $0.24/share**, equivalent to our low-point valuation to reflect the current technical, market and operating uncertainties.

Summary (AUD)

Market Capitalisation	**$49mn**
Share price	**$0.185**
52 week low (23-Mar-20)	$0.13
52 week high (5-Nov-19)	$0.55

Share price graph (AUD)

Source: Yahoo Finance

Key Financials (US$000s)

US$	2019	2020E	2021E
Production (kboe)	385	294	303
Revenue	**5,397**	**4,660**	**4,580**
EBITDAX	724	779	575
EBIT	**(10,034)**	**(3,421)**	**(4,014)**
Underlying NPAT	(16,075)	(3,851)	(4,014)
EPS (Acps)	**(9.3)**	**(2.3)**	**(2.4)**
Growth (%)		na	na
PER (x)		nm	nm
EV/EBITDAX (x)		(16.2)	0.6
CFPS (Acps)	**(4.1)**	**(2.0)**	**0.3**
PCF (x)		nm	nm
ROE (%)		na	na
ROA (%)		na	na

Empire Energy Limited - Summary of Forecasts						EEG	$0.185

ORDINARY SHARES	M	262.8	Fully Diluted	M		320.6
OPTIONS	M	57.8				
MARKET CAP	A$mn	48.6				66.6

PROFIT & LOSS SUMMARY (US$000s)					
Year end December		2018	2019	2020E	2021E
Commodity Price Assumptions					
Realised oil price	**US$/b**	**59.86**	**59.76**	**36.90**	**39.16**
Realised gas price		3.24	0.00	2.49	2.36
Exchange Rate		**0.7452**	**0.6958**	**0.6389**	**0.6290**
Total Revenue		**6,593**	**5,397**	**4,660**	**4,580**
Cost of sales		(4,723)	(4,189)	(3,881)	(4,005)
Gross Profit		**1,870**	**1,208**	**779**	**575**
EBITDAX proxy		**1,870**	**724**	**779**	**575**
Other revenue		0	0	0	0
Other income		**2,192**	**155**	**200**	**200**
Write downs/impairments		0	(1,167)	0	0
Finance costs		**(801)**	**(637)**	**(430)**	**(365)**
Other expenses		(8,399)	(11,397)	(4,400)	(4,424)
EBIT proxy		**(4,339)**	**(10,034)**	**(3,421)**	**(4,014)**
Profit before tax		(5,138)	(11,838)	(3,851)	(4,014)
Taxes		(115)	(135)	0	0
NPAT Reported		**(5,254)**	**(11,973)**	**(3,851)**	**(4,014)**
Underlying Adjustments		(10,714)	(4,102)	0	0
NPAT Underlying		**(15,968)**	**(16,075)**	**(3,851)**	**(4,014)**
Margins on Sales Revenue					
EBITDAX		**28.4%**	**13.4%**	**16.7%**	**12.6%**
EBIT		91.9%	nm	nm	nm
NPAT Und		**nm**	**nm**	**nm**	**nm**
Change on pcp					
Total Revenue					
EBITDA			nm	nm	nm
EBIT			**nm**	**nm**	**nm**
NPAT Adj.			nm	nm	nm

PER SHARE DATA					
Year end June		2018	2019	2020E	2021E
Shares Outstanding	M	2,313	263	263	263
EPS Und	**A cps**	**(1.4)**	**(9.3)**	**(2.3)**	**(2.4)**
Growth (pcp)		*na*	*na*	*na*	*nm*
Dividend	**cps**				
Franking	%				
OCF per Share	**A cps**	**(0.2)**	**(4.1)**	**(2.0)**	**0.3**
NTA per share	A cps		7.5	5.8	3.5

KEY RATIOS					
Year end June		2018	2019	2020E	2021E
$D_N/(D_N + E)$	**%**	**49%**			
ROE	%	na	na	na	na
ROA	**%**	**na**	**na**	**na**	**na**
(Trailing) Debt/Cash	x	0.0x	0.0x	0.0x	0.0x

VALUATION MULTIPLES					
Year end June		2018	2019	2020E	2021E
PER	**x**		**na**	**na**	**na**
Dividend Yield	%				
FCF Yield	**%**		**-22.3%**	**-11.0%**	**1.8%**
EV/EBITDA	x		0.0x	-16.2x	0.6x

BALANCE SHEET SUMMARY (US$000s)				
Year end June	2018	2019	2020E	2021E
Cash	4,157	9,882	7,052	308
Property Plant & Equip	31,241	26,633	25,204	31,529
Exploration	0	141	127	114
TOTAL ASSETS	**64,071**	**39,650**	**33,033**	**32,593**
Borrowings	24,369	6,481	5,244	4,694
TOTAL LIABILITIES	**42,701**	**25,985**	**23,218**	**26,791**
TOTAL EQUITY	**21,370**	**13,665**	**9,816**	**5,802**
Gearing dn/(dn+e)	49%			

CASH FLOW SUMMARY (US$000s)				
Year end June	2018	2019	2020E	2021E
Operational Cash Flow	**2,828**	**1,267**	**117**	**450**
Net Interest	(2,974)	(1,885)	(430)	(365)
Taxes Paid	0	0	0	0
Other	(115)	(135)	(30)	(30)
Net Operating Cashflow	**(261)**	**(754)**	**(342)**	**55**
Exploration	0	0	(1,000)	(6,000)
PP&E	(49)	0	0	0
Petroleum Assets	(168)	(1,848)	0	0
Net Asset Sales/other	359	20,008	92	(305)
Net Investing Cashflow	**(120)**	**17,407**	**(1,250)**	**(6,250)**
Dividends Paid				
Net Debt Drawdown	(7,878)	(18,497)	(550)	(550)
Equity Issues/(Buyback)	11,677	8,037	0	0
Other				
Net Financing Cashflow	**3,785**	**(10,693)**	**(1,238)**	**(550)**
Net Change in Cash	**3,404**	**5,961**	**(2,830)**	**(6,745)**

PRODUCTION					
Year end June		2018	2019	2020E	2021E
Crude Oil	kb	127	89	3	3
Nat Gas	mmcf	1834	1778	1748	1801
TOTAL	**kboe**	**432**	**385**	**294**	**303**

RESERVES & RESOURCES					as of	31/12/2018
Northern Territory	P90	P50	P10	P90	P50	P10
		Gas (Bcf)			Oil (Mb)	
Barney Creek Fm	3,304	8,699	20,172	66	174	403
Velkerri Fm	383	1,192	3,086	8	24	62
Woologorang Fm	524	1,185	2,371	10	24	47
TOTAL	**4,211**	**11,076**	**25,629**	**84**	**222**	**512**
US				1P	2P	3P
Gas	Bcf			24	34	38

EQUITY VALUATION			Risked Range			
NT	***Low***	***Mid***	***High***	**Low**	**Mid**	**High**
Gas	*$35*	*$88*	*$222*	$0.13	$0.33	$0.84
Oil	*$12*	*$29*	*$74*	$0.04	$0.11	$0.28
US Onshore						
Appalachian	*$17*	*$23*	*$28*	$0.07	$0.09	$0.11
	$64	***$140***	***$323***	**$0.25**	**$0.54**	**$1.24**
Net cash/(debt)	*$3*	*$3*	*$3*			
Corporate costs	*-$5*	*-$5*	*-$5*			
TOTAL	***$62***	***$138***	***$322***	**$0.24**	**$0.53**	**$1.22**

Source: Company data; Analyst estimates, priced as of close of trading 17/04/20

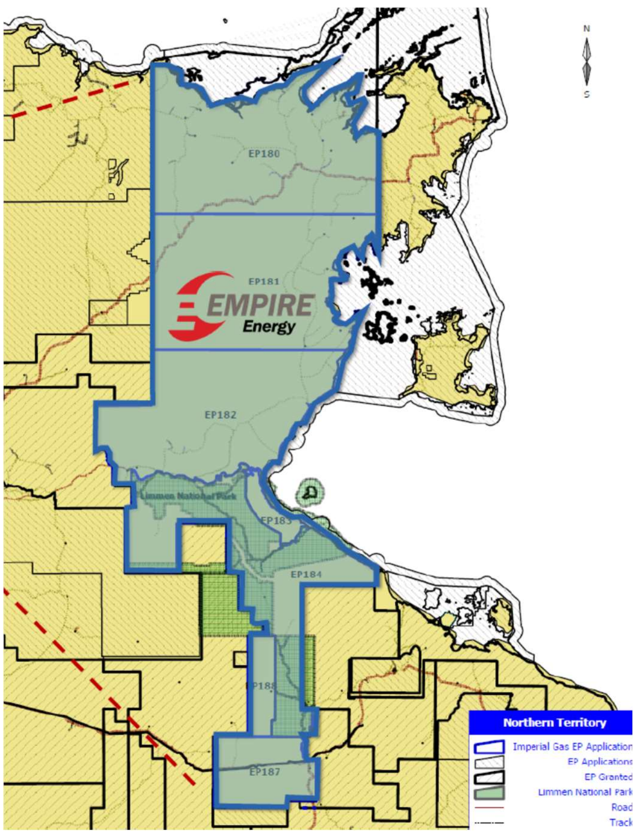
An emerging gas play of transformational potential

Empire Energy Group (EEG) is a junior oil & gas E&P company, holding acreage in the onshore US (Appalachia) but is dominantly a play on its potentially transformative exploration portfolio across the Australian Northern Territory, McArthur-Beetaloo basins.

The company generates cashflows from its conventional operations in the Appalachia, but these operations are largely consumed with debt servicing and provide a modest amount of working capital. The assets drawing significant investor interest are the exploration tenements in the McArthur-Beetaloo basins, where the potential of the plays is seen as perhaps providing large-scale gas developments to support east coast supply and the proposed Darwin LNG hub.

We look at the company and assets from technical **(p.6-12),** financial **(p.13-20)** and operating perspectives **(p.21 25)** highlighting the investment opportunities and operating risks, set against a still supportive gas supply thematic

Figure 1: Controlling a trend – contiguous acreage provides a strong regional footprint



Source: Analysts estimates

In broad terms these basins are considered to hold over 245Tcf of gas potential collectively and although exploration results to date support increasing confidence that large discoveries (and projects) can be proven, we have to note that exploration in the region must be considered to be early stage at this time with commensurate associated risks and uncertainties.

To put the gas potential in context, 1Tcf is approximately equivalent to 20Mt of LNG against a global export market of 316.5Mt in 2019 (~16Tcf).

It's worth highlighting that the EEG assets will benefit from look-through outcomes on adjacent acreage, provided by the completion of the drilling programmes (currently suspended under CoronaVirus restrictions) of Santos (STO.ASX) and Origin Energy (ORG.ASX). We think activity could recommence by the end of 2020 perhaps but realistically may take closer to 12 months.

- Santos plans to evaluate two horizontal wells (Tanumbirini-2H and Inacumba-1H) through a multi-stage fracking campaign with lateral sections of up to 2,000m;
- Origin is aiming to determine the liquids potential and producibility of its recent wells to confirm the development economics.

We outline these campaigns to highlight that EEG will benefit from regional activity – it will not be de-risking its assets in isolation.

Drilling is the next step (when conditions allow). EEG recently completed and evaluated a 231km^2 2D seismic survey, reporting 'better-than-expected' results, supporting its geological model and confirming the extension of prospective geology into its areas with significant thicknesses and shallower depths. This has positive implications for drilling costs and perhaps increased liquids potential. The data, through the seismic grid can be directly connected to the Tanumbirini-1 (STO.ASX) well which delivered >1.2mmcfd on test.

The next step is to drill a well, which is likely to be deferred by up to 12 months (originally targeting a mid-2020 spud) to evaluate the liquids-rich mid-Velkerri (primary target) and Kyalla Shale formation (secondary target). On success the company suggests that first production could be delivered within a further 24-36 months, notwithstanding the need for linking infrastructure as the region is somewhat 'disconnected'. We are increasingly confident there is a commercial gas play in these assets.

A transformational investment. EEG is the only independent ASX listed junior explorer in the McArthur and the explorer with the largest tenement position in the region.

EEG holds its acreage at 100% and currently carries Prospective Resources of >11Tcf and 222Mb at the P_{50} level across its three target horizons. This demonstrates the scale of the opportunity and leverage to success within the portfolio. Positive drilling results could (should) underpin a significant conversion to a contingent resource, however, for that to occur we will need to see supporting flow rates.

The value proposition is transformative. Ascribing a value to the Empire Energy portfolio as an early stage exploration play is a somewhat subjective exercise. Given the relatively high level of technical uncertainty associated with the NT assets, we run a low-med-high case against the prospective resources rather than trying to determine 'a specific' value, with more quantitative data required to better define the intrinsic worth. The value range highlights the upside potential on success.

We value the company at $0.24/share at the low-point of the NAV range, applying the highest risk outcome to our underpinning assumptions, reflecting the early stage of evaluation and currently uncertain environment. It's worth noting and we suggest, the mid-point case of $0.53/share could be achieved quite rapidly upon 'normalisation'; of operating conditions – this approximates the highest trading point over the last 12 months ($0.55/share, 5-Nov-2019).

On weaker market sentiment, the stock is currently trading significantly below our Target Price (reference share price $0.185/share – close of trading 17-Apr), which we think is an attractive entry point for a moderate-risk exploration opportunity. On a 12 month timeframe, we believe activity will recommence in the NT and deliver strong re-rating outcomes.

We set our Target Price at $0.24/share in line with our low-point valuation, with a BUY recommendation.

Figure 2: The valuation demonstrates the transformational potential of shale gas success

			Risked Range		
		Pr	**Low**	**Mid**	**High**
Northern Territory	100%				
Gas		6%	$35	$88	$222
Oil		6%	$12	$29	$74
US Onshore		100%	$17	$23	$28
			$64	**$140**	**$323**
Net Cash/(debt)				$3	
Corporate costs				($5)	
TOTAL			**$62**	**$138**	**$322**
			$0.24	**$0.53**	**$1.22**
Shares on issue (mn)	263				

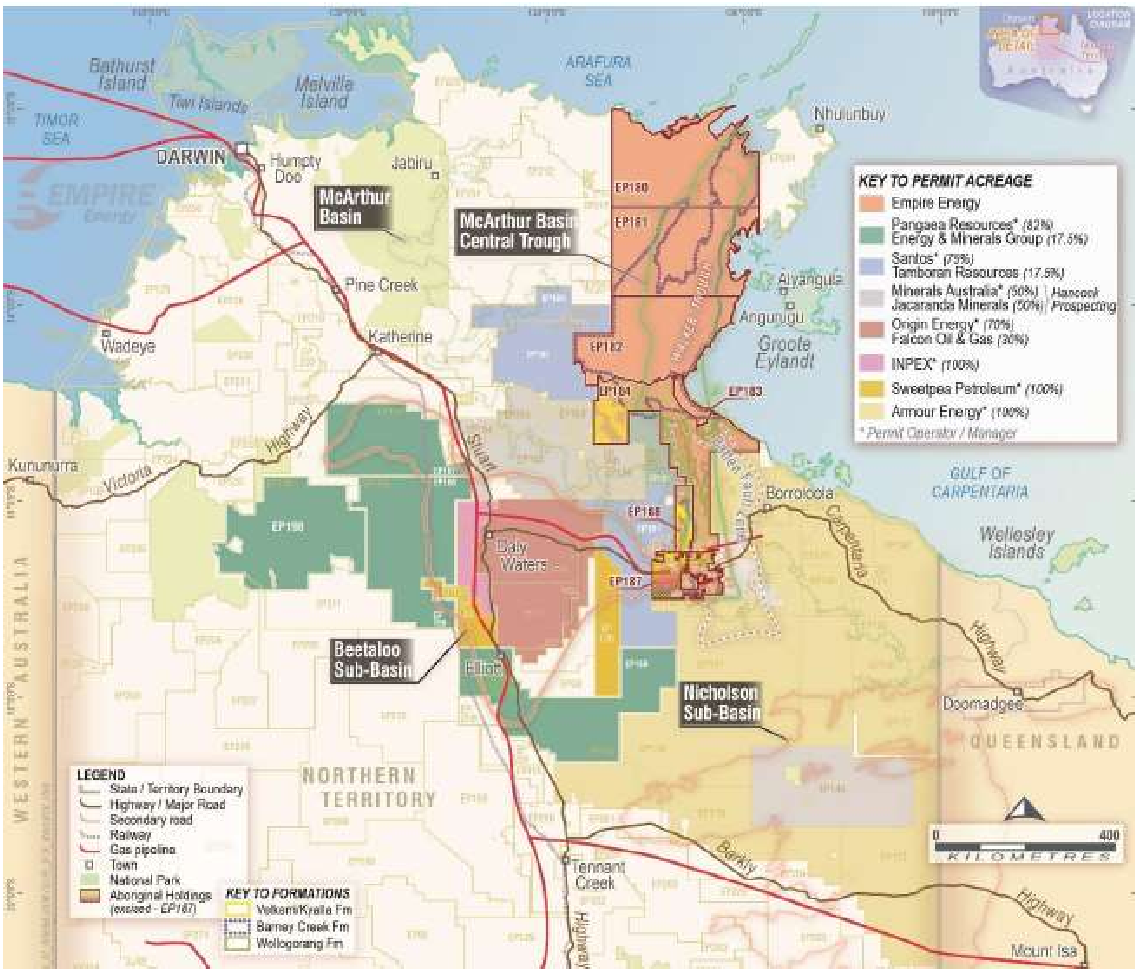
Source: Analysts estimates

A great setting for the next big gas thing

Activity through the Northern Territory is set to ramp up post the lifting of the 3-year government moratorium on fracking The first regional drilling programmes received NT government approvals in August 2019.

Although the NT Government has enacted some exclusion zones and imposed strict environmental conditions, the return to fracking evaluation has and will further catalyse exploration and evaluation activity. Being an early stage play still requiring significant infrastructure development, tangible progress will require significant major investment and balance sheet strength. It's important to highlight that large swathes of acreage are held by relatively few major industry players with strong financial capacity.

Figure 3: EEG holds 5 contiguous permits across some of the most prospective acreage in the territory



Source: Company data

The resource potential has attracted large independent oil and gas companies. Interestingly, the plays and acreage are held by a relatively small number of companies, all holding substantial permit positions.

Activity originally scheduled for 2020 has likely been delayed for up to 12 months we think, although there may be the possibility of evaluation campaigns (frack and test) before end-2020. Certainly, drilling programmes as planned will be bound by the wet season…miss this window and it will be 9-12 months.

NT plays are attracting players of scale…chasing scale

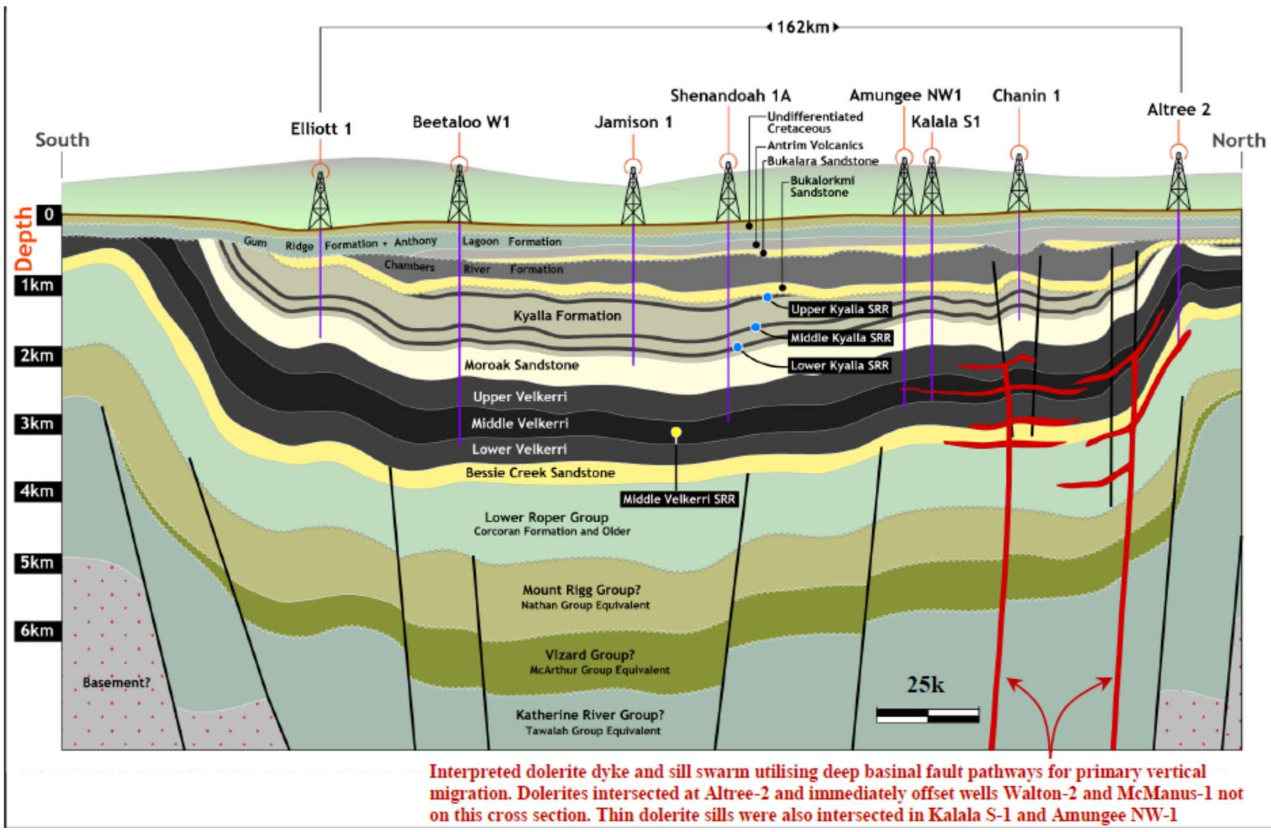
Greater McArthur Basin (Beetaloo sub-basin) - a shale play in a frontier area

The sedimentary basins of the Northern Territory are underexplored. Activity has been spasmodic with less than 60 exploration wells drilled across all the basins and since 2007 only around 30 wells specifically targeting the unconventional opportunities.

There have been some high profile, high level studies conducted on the NT's resource potential:

- Geoscience Australia calculates a potential gas resource of *"…257,276 PJ in shale formations…the vast majority of this concentrated in the Beetaloo Sub-Basin of the McArthur Basin"* with almost 70% of this (178,200 PJ) estimated to occur in the Beetaloo section.
- A study conducted by the US Energy Information Administration in 2015 ("Technically Recoverable Shale Oil and Shale Gas Resources") for Australia estimated that the shale plays of the Beetaloo and Georgina basins could hold up to 262Tcf of in situ gas.

Figure 4: Typical regional basin profile – target horizons are pervasive and the shale plays will be areally extensive.



Source: AEGC 2018 (Altmann et al).

With only a limited number of well data points these estimates and extrapolations must be interpreted with some caution, but the premise of strong prospectivity has been supported by the drilling results to date.

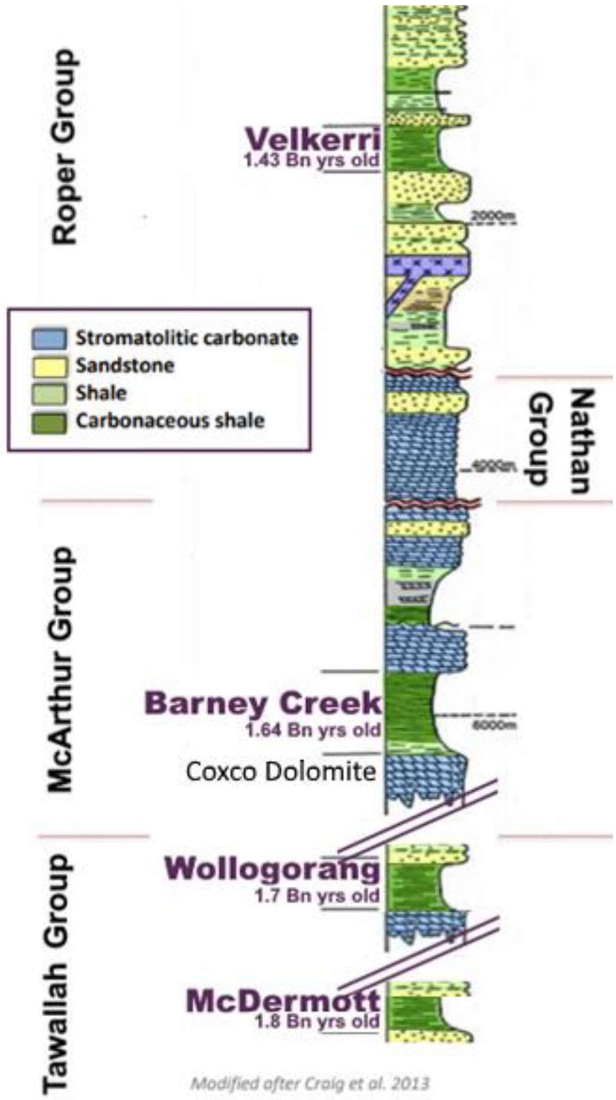
The sedimentary sequences are somewhat 'tram-track' in nature, highly correlatable over long distances and current data suggests shale properties are broadly consistent on a regional basis.

It should be noted from **Fig 4** that where major faulting can be interpreted penetrating the Velkerri and Kyalla formations, this can be accompanied by dolerite intrusions, with the potential to 'bake' the target horizons. We are not aware that any sills or swarms have been recognised in the EEG areas.

Within the McArthur and Beetaloo basins, exploration efforts have focused on the Kyalla and Velkerri formations, which are organic rich with >2% TOC (total organic carbon) by weight, particularly the middle-Velkerri unit which contains three highly prospective intervals, the A, B and C shales, each of which can be considered to be an individual petroleum play. We note that the Velkerri has been recorded as having a $TOC_{(max)}$ of >10%.

Geochemically, the Kyalla and Velkerri formations are considered to lie within the oil to dry gas maturity window with favourable mineralogy, organic geochemistry and maturity for economically recoverable oil and gas.

Figure 5: Stacked, multiple shale targets with the Velkerri and Kyalla at the top of the list



Source: Company data

The McArthur-Beetaloo sequence contains multiple resource opportunities over four **shale** sequences. The multi-zone Velkerri Formation and Kyalla Formation have been the key focus of regional exploration efforts with the potential to host significant liquids plays (oil and wet gas) as well as dry gas.

It's worth noting, EEG ascribes Prospective Resources across all nominated target zones **(ref Fig 16).**

The **Kyalla** Formation in the Beetaloo Sub-Basin has *"…historically yielded consistent high mud gas shows, and multiple oil shows and gas bleeds"* (Source: AEGC 2018, Altmann et al).

Evaluation operations at the Shenadoah-1A well demonstrated that the lower Kyalla was amenable to fracture stimulation and would flow gas to surface (economics rates have not yet been established though).

The **Velkerri** Formation is up to and over 800m thick, consisting of laminated black carbonaceous siltstones and mudstones with underlying sandstones.

Importantly the Velkerri should be readily amenable to fracturing given its favourable mineralogy (low clay and high silica levels making the rocks somewhat brittle) and as confirmed by the successful stimulation and production test of the Amungee NW-1H well.

The **Barney Creek** shale formation has a recorded thickness of up to 900m, containing sulphur-rich black shales. It is present across most of EEG's permits and is considered readily frackable.

The **Wollogorang-McDermott** shale formations have a recorded thickness of up to 100m with TOCs up to 7%.

The focus of EEG's exploration efforts will be directed towards the Velkerri and Kyalla plays where prospectivity and economic potential can be supported by regional drilling results; the sequences are thicker and the depth to target is shallower

Seismic hits the mark as a precursor to drilling

EEG has chosen to choosing to focus initially on EP187, which lies within a designated area of known 'prospective source rocks' (**Fig 6**) with a direct seismic tie into the adjoining Santos permit (EP161) and reference well at Tanumbirini-1.

The company has recently completed its interpretation of its 231km^2 2D seismic survey indicating the results strongly supported its geological model and provided more technical encouragement ahead of its proposed first well, Carpentaria-1. Importantly the survey has been integrated with existing regional data and directly ties back to the 'hard data' point at Tanumbirini-1.

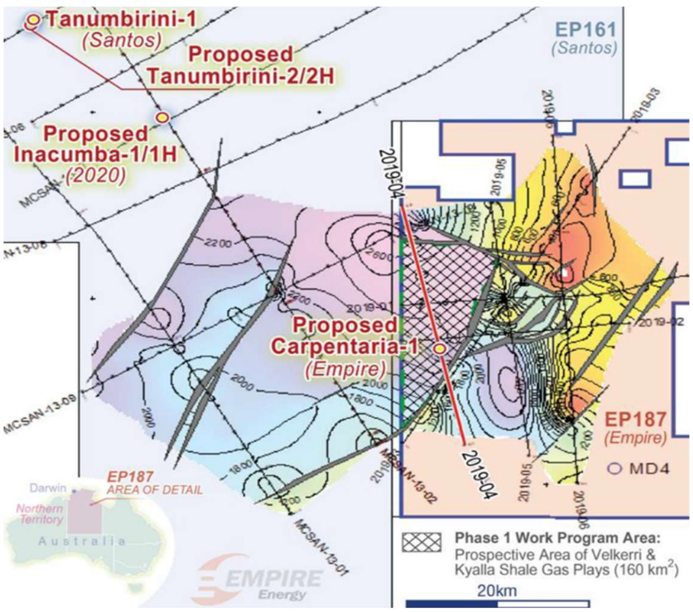
Although the well lies some 76km to the north-west, EEG's seismic grid intersects existing surveys. The company doesn't believe there is any significant velocity issue impacting the data and are confident that their seismic picks and depth conversion are valid. As the cross-sections indicate (**Fig 4**), broadly the target sequences are quite 'tram-track', and correlations across distance can be made with a relatively high degree of confidence.

We would caution that given the distance and lack of control points there must be an intrinsically higher level of risk associated with the interpretations just yet, which can ultimately be confirmed by drilling.

The survey did specifically confirm:

- the extension of Beetaloo shale formations into EP187;
- the south-western flank of EP187 does not reveal major faulting although displacements of a smaller scale are evident at Amungee (**Fig 10).** The absence of large-scale faulting significantly underpins the confidence of the Carpentaria-1 drilling site from a geological perspective.
- the mid-Velkerri sequence can be confidently interpreted into EP187 as a thick, continuous formation that can be directly correlated to Tanumbirini-1 (~76km to the north-west).

Figure 6: Interconnected of seismic grids and well tie lends confidence to interpretations



Source: Company data

The target zones (Kyalla and Velkerri) are shallower at the proposed Carpentaria-1 drilling location **(ref Fig 7)**, by perhaps 1,000m at the Velkerri B level.

The Kyalla is calculated to be 100m thick, versus 140m thick at Tanumbarini. With the Velkerri sequence at around 600m thick.

Being shallower, the company postulates that the Kyalla may have the potential to be more liquids rich based on publicly available data, but what that translates to in terms of a liquids ratio remains conjectural.

Previously this zone was considered to be a higher risk opportunity, getting thinner towards the east

The mid-Velkerri 'B' will remain the primary focus of work but it's very likely the drilling programme will be modified to better evaluate the Kyalla and if warranted include direct sampling. The success case could deliver considerable upside;

With both the Kyalla and Velkerri intervals interpreted to be ~1,000m shallower through EP187, compared to the EP161 (Santos), the potential for both dry and wet gas intersections should be higher, with a concommitant reduction in drilling and evaluation costs…EEG will get more bang for its buck here.

Empire has advised that the necessary approvals have been received for the drilling of Carpentaria-1 although the timing is somewhat vague under current circumstances. The proposed Carpentaria-1 well is planned to be drilled as a vertical completion with the initial phase aiming to confirm the seismic data and evaluate targets for organic content and engineering properties (is it amenable to frack). To that end an extensive coring and sampling component is being budgeted for.

The prognosed total depth of the well is ~2,900m with the Kyalla Shale at 1,200m and Velkerri at 2,200m

The vertical well will be suspended pending evaluation of all data. As indicated in the company release:

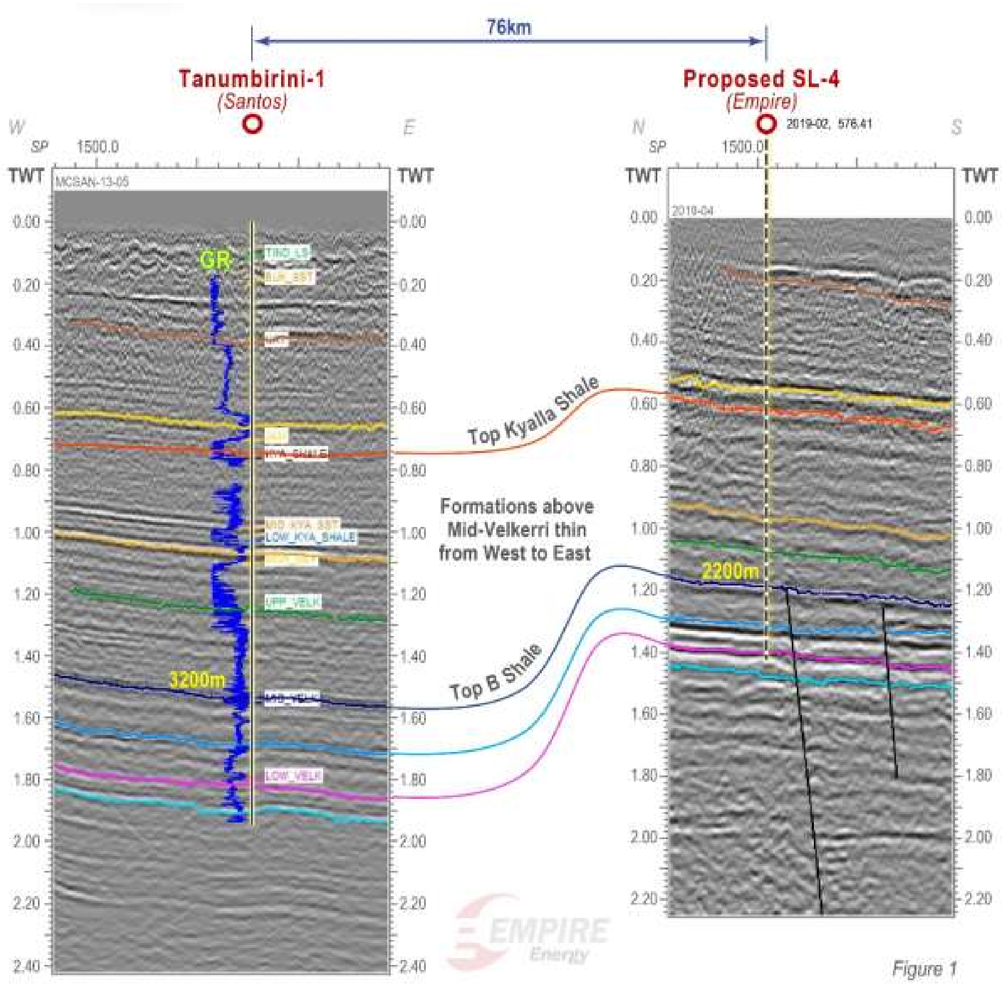
"Further evaluation would most likely involve a vertical fracture stimulation of the Velkerri Shale followed by the drilling and fracture stimulation of a horizontal well section to carry out an extended production test".

Testing data will allow the company to assess the likely recoverable volumes in the designated work area (noted as being 160km^2) and perhaps be able to book an initial Contingent Resource. In addition, EEC will be able to determine more definitively the resource potential in terms of product…crude oil vs natural gas liquids vs dry gas.

A successful result at Carpentaria could (should) deliver a major re-rating outcome.

The indicative timing to complete both phases of work once drilling commenced, would be about six months noting that frack programmes require water monitoring bores with at least six months of data to establish a base line before being undertaken. The timing of any drilling is to be confirmed but we suggest is most likely around mid-2021.

Figure 7: Correlation of Carpentaria-1 (SL-4) to Tanumbirini – targets shallowing and thinning somewhat



Source: Company data

There are geological risks

The entire Beetaloo-McArthur basins province must be considered speculative in nature given the early-stage nature of all exploration activities to date. The drilling and evaluation campaigns as currently planned for 2020 (assuming they will be conducted at a future point), can provide important definitive data but the addition of 3-4 extra wells may only lift the confidence level on a local basis rather than regional.

With only approximately 30 wells drilled into the unconventional plays to draw from, the technical knowledge associated with the resource potential is 'thin' and all active exploration and evaluation has more than an element of R&D embedded within it, especially in terms of fracking efficiency.

As with all geological provinces, although the seismic acquired to date provides broad support to regional models, there will be variation that may require very different project to project solutions…after 60 years as a developed and extensive production hub even a well understood province like the Cooper Basin can throw up significant surprises.

Every data point will add to the knowledge base and data from the Santos activity around Tanumbirini should be confidently extrapolated into EEG acreage but ultimately EEG will need to drill wells (vertical and horizontal) and frack to confirm its own geological interpretations and opportunity sets.

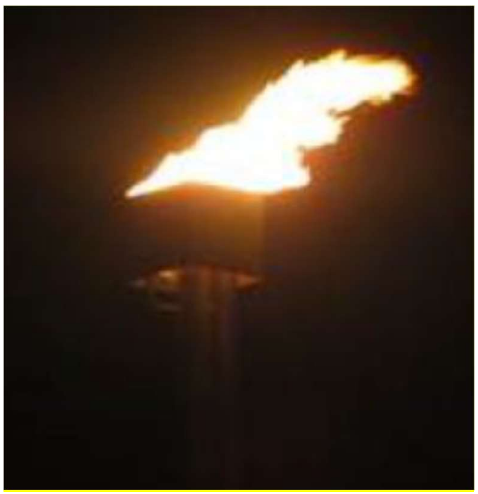
The Beetaloo Basin has been compared to the U.S. onshore, Marcellus Shale play which sets a comparative in terms of style and potential but can't be considered as a direct production analogue just yet. Certainly, the STO and ORG campaigns as planned will go some way to putting more definition around the economics of the province.

The potential benefit from postponement of field work is that EEG can prioritise and focus on the integration of all local and regional data. Whilst geological studies are rarely exciting, we can point to the benefits derived from a similar ‘enforced’ hiatus to drilling in the Cooper Basin resulting from the floods of 2010, where the geological conclusions from a deeper technical dive set the platform for the opening up of the prolific Western Flank plays.

We acknowledge the differences in drilling density and understanding between the Cooper Basin and Beetaloo-McArthur basins, but with the data set over the NT plays growing, a more detailed evaluation of the play opportunities and engineering requirements can only add long term benefits.

Key drilling results

Figure 8: Brief unassisted gas flare from hydraulic fracture stimulation stage 5 at Shenandoah-1A within the lower Kyalla SRR.



We restrict our evaluation here largely to wells drilled from 2015 as representing the most appropriate analogues to the design and activity being proposed by EEG.

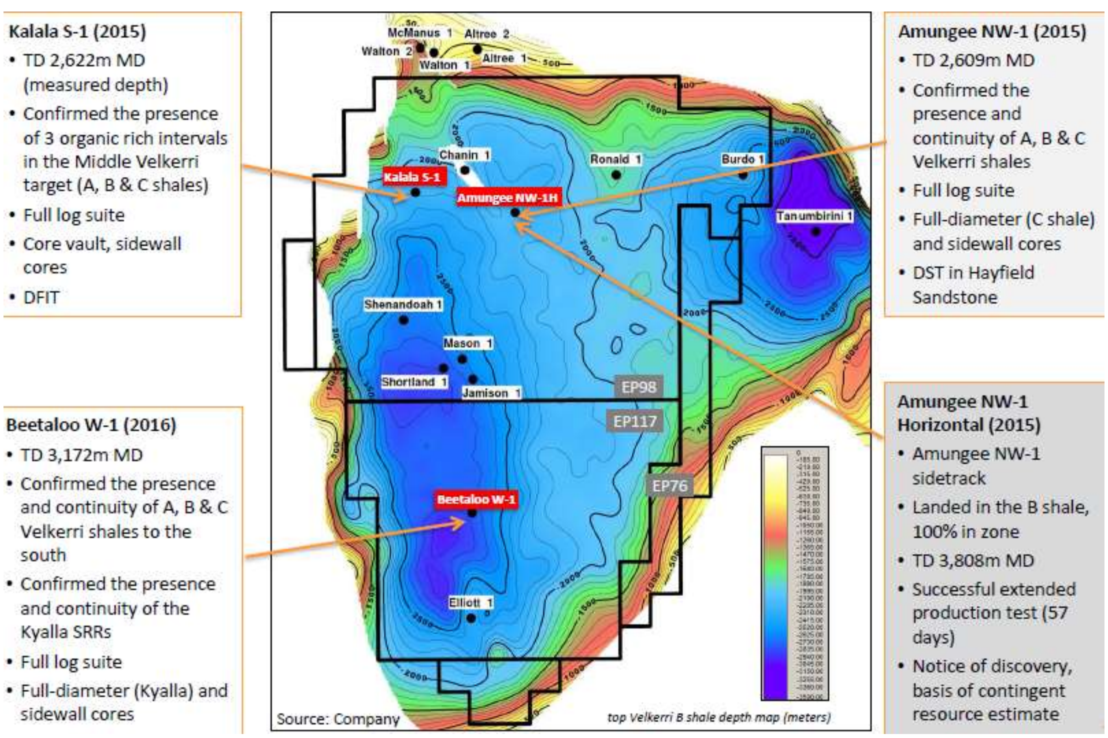
It’s worth mentioning the Shenandoah-1 well (2011) which was fracked and tested the mid-Velkerri and Kyalla zones, successfully flowing gas between 50-100mcfd.

Whilst not absolutely commercial, the test results demonstrated the prospectivity and commercial potential of the target sequences.

Activity increased through 2015-2016, on the back of a A$200mn farm-out deal between Falcon Oil & Gas and Origin Energy/Sasol where four vertical wells were drilled ostensibly to provide technical data and better define the commercial potential of the region

Source: Falcon Oil & Gas

Figure 9: Key wells drilled by ORG…noting best results to date in the north of the block



Source: Falcon Oil & Gas AGM Presentation Dec-2019

The critical well in this campaign was **Amungee NW-1H**, a vertical that was subsequently completed and tested in a horizontal section.

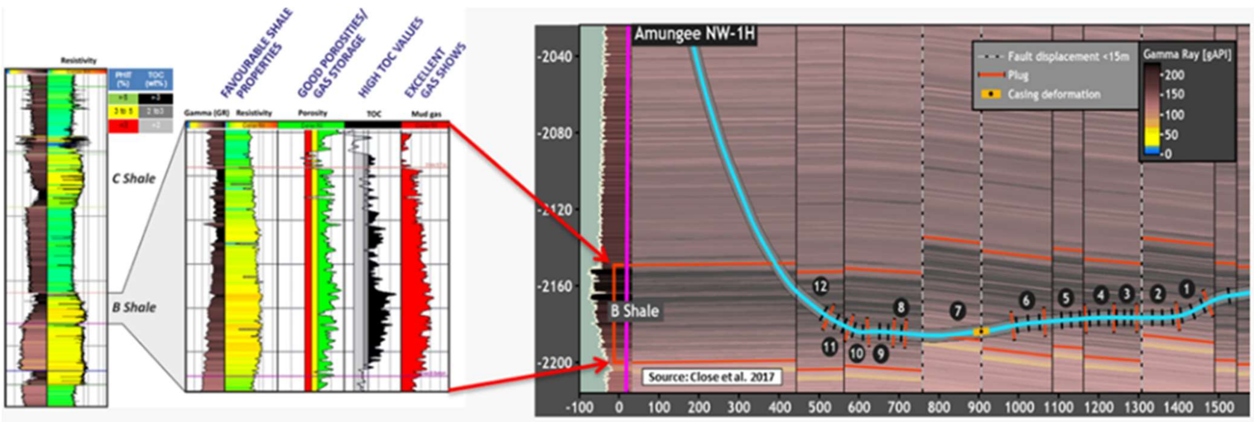
The early works provided important support for the geological model;

- proving yhe pervasive nature of mid-Velkerri shales as a continuous, stacked play;
- confirming the three organic rich target intervals in the mid-Velkerri (A, B, C shales) at gross thicknesses up to 500m and net pay in the B-C shales >50m;
- confirming TOC levels of 3-4%, sufficient for gas volumetrics and high gas-in-place density; and
- geomechanics supportive of 'frackability'.

Amungee NW-1H was completed with 11 frack stages over a 1,000m lateral in the mid-Velkerri 'B' shale and tested between 1-1.5mmcfd. The average gas was reported as C1 - 92.5%, C2 - 2.87%, CO_2 - 3.84%, N_2 - 0.64%, C3 - 0.13%, C4+ - 0.02%, so low inerts with some liquids potential.

We would highlight one aspect from the Amungee horizontal completion and that is the extensive small-scale faulting through the mid-Velkerri B shale as evident in **Fig 10**. Whilst it is not 'full seam' displacement, it doesn't have to be in a 50m thick zone to add a layer of complexity to placing the completion with the potential for not all frack zones to be optimal.

Figure 10: Amungee cross-section shows small scale faulting is prevalent adding some risk to outcomes



Source: Falcon Oil & Gas website

The ORG/Falcon JV has progressed Kyalla-117 N2-1 appraisal well **(Fig 11).** The primary aim of the well is to evaluate the potential of previously identified, liquids-rich gas fairways in both the Kyalla and Velkerri plays. The evaluation plan includes a provision for the completion of a 1,000-2,000m horizontal section in the Kyalla reservoir and a 90-day flow test..

The Kyalla-117 N2-1 well spudded on 9-Oct-2019 with the Kyalla Shale recorded as nearly 900m thick at this location [*note this thins to 100m in the EEG acreage – refer **Fig 3** for relative positions of ORG v EEG holdings].*

The three Kyalla target zones (lower, middle and upper) were estimated to be between 75-125m gross thickness, each of which showed elevated gas readings with relatively high C3, C4 and C5 volumes, indicative of a potentially significant liquids content to the gas.

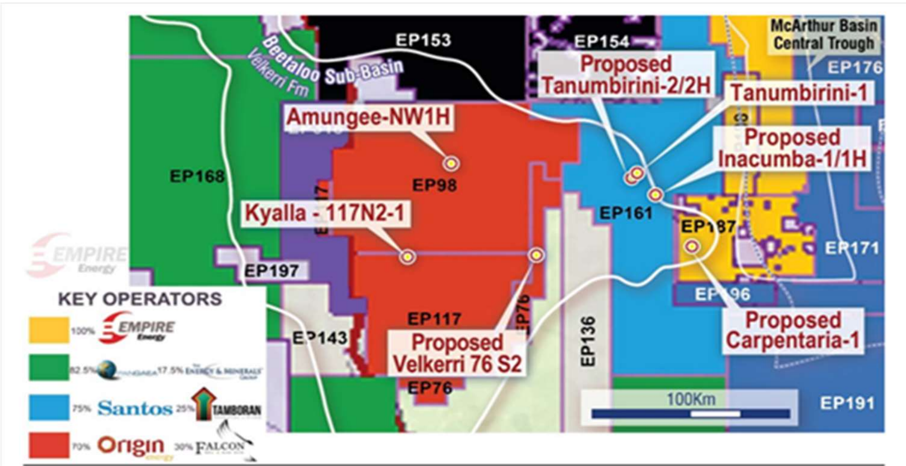
The well was initially suspended due to operational issues with hole stability and was subsequently plugged at 700m for another zone within the Kyalla to be evaluated. A new lateral section was completed along 1,579m in the Lower Kyalla.

Under CoronaVirus restrictions this well has been suspended with a resumption of activity (fracking and testing) tentatively scheduled for 2H'20 and the Velkerri 76 S2 well, originally planned to spud 'now', unlikely to be drilled for perhaps 12 months. The JV is currently in a mandatory water monitoring/base line data gathering period ahead of the returning to the location for the next phase of frack evaluation, when operating circumstances allow.

The recent results from the Santos evaluation of its **Tanumbirini-1** well confirm the gas potential of the mid-Velkerri shale sequence. The well was fracked over four stages and flowed at rates of rates of over 1.2mmcfd as recorded. The preliminary gas composition indicated the stream contained >90% methane, <5% total inerts and 3% ethane – very similar to the composition results from the Amungee NW-1 well.

Also, similarly to the ORG/Falcon JV, STO plans to book an initial contingent resource estimate post completion of the Tanumbirini evaluation campaign.

Figure 11: Location of proposed ORG wells in relation to EEG and STO activity



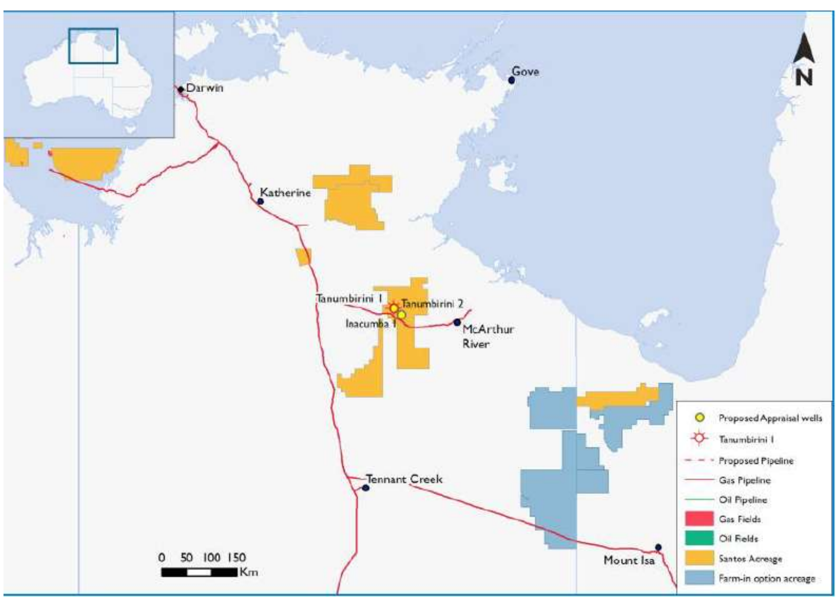
Source: Origin Energy

The company plans to use the Tanumbirini results as the basis of an appraisal campaign of two horizontal wells (Tanumbirini-2H and Inacumba-2H) now likely to be drilled sometime in 2021 we think, with both expected to be subject to multi-stage frack evaluation programmes.

Interestingly STO has been building a business in the NT with significant development potential, through the $2Bn acquisition of the ConocoPhillips WA/NT assets, which consolidates a LNG footprint in Darwin through the Darwin-LNG project with expansion approvals for up to 10Mtpa. Progressing the development of the offshore Barossa Gas Field goes to providing back-fill options, but expansion will require additional gas resources, which the Beetaloo and McArthur plays could provide.

Kevin Gallagher (STO Managing Director) has indicated that while it is *"…still too early to determine if gas from the Beetaloo and McArthur basins would be sent through the Darwin facility"* it was a key consideration in the ConocoPhillips purchase.

Figure 12: Santos onshore permit holdings – establishing a basin dominant position



The company has also entered into a ~$95mn farm-in deal with Armour Energy in the South Nicholson Basin.

The acreage is complimentary to its own asset but increasing its footprint across the shale plays in close proximity to pipeline routes.

We see this as a clear intent to ramp up exploration efforts, post CoronaVirus restrictions.

Source: santos.com (2019 Results presentation)

Financials, valuation and Target Price

Through the forecast period, earnings will not be a significant factor in the investment decision (**refer SUMMARY Financials p.2**) as such we don't detail the earnings outlook noting that the company does have producing assets in the US as outlined following.

US assets are largely self-supporting

The company has residual production assets in the onshore US, now largely only gas producing and providing a modest revenue stream. Whilst these assets are not material to the company overall, they are secured against the company's debt and as such have the potential to impact short-term financing. In that regard it's worth a brief overview to place the assets in context.

After the divestment of its Kansas assets (effective date 30-Sep-2019), the company now only holds a suite of acreage in the Appalachia of Pennsylvania, where it has been active since 2006 and in the 4Q'19 period produced ~0.45Bcfe being overwhelmingly gas. On a quarterly basis these assets are generating ~US$1.2mn with ~US$0.5mn of EBITDAX (ex-field).

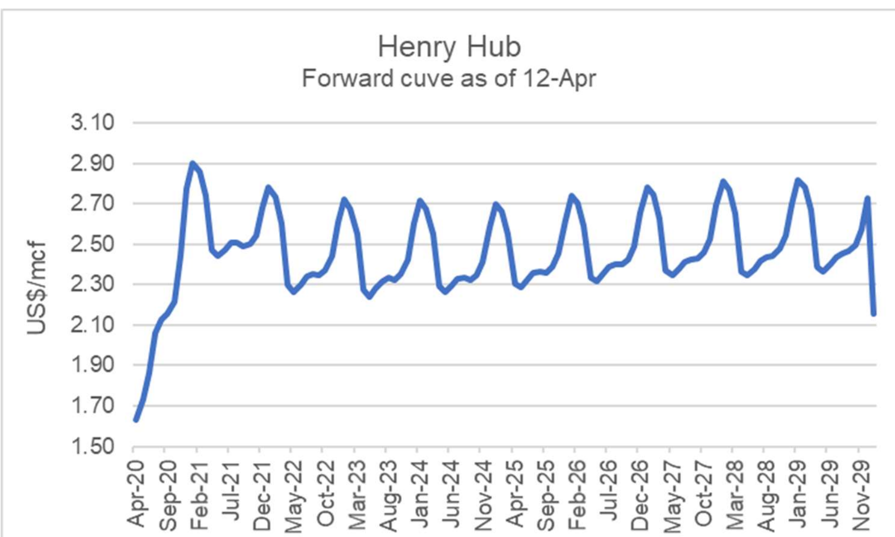
Figure 13: A year of Appalachian production – impacted by low gas prices

	1Q19	2Q19	3Q19	4Q19
Net Gas (mcf)	429	434	435	441
Net Oil (kb)	0	1	1	1
TOTAL:(mcfe)	432	439	438	444
Realised gas price (US$/mcf)	**2.92**	**2.88**	**2.71**	**2.60**
Gas Revenue (US$000s)	**$1,253**	**$1,250**	**$1,179**	**$1,147**

Source: Company data

Due to an unseasonally mild winter, US Nat Gas prices are materially lower and forecast to remain at sub US$2/mcf through to the next US winter. These are tough operating conditions acting as a natural constraint on its cash generating capacity, however, the company has hedged ~80% of its anticipated FY20 PDP gas volumes at US$2.50/mcf (**Fig 15)**, with additional hedges over some 25-55% of producing reserves in place until end-2022.

Figure 14: Appalachian production – suffering from low gas prices



Source: barchart.com

Although there is potential within the assets, we'd suggest the current gas price regime makes the economics of new wells marginal at best, but even so, it is unlikely to be a business that can be material compared with the value potential of the NT plays.

EEG continues to seek margin improvements in the business and during the last reported quarter indicated:

- it had commenced construction on a new gas connection directly into a local utility saving tariff charges of up to US$160,000 per annum; and
- closed its Pennsylvania office to reduce on-going corporate costs.

Whilst important, it is improvement at the margin. If the US onshore business is to become significant it needs higher gas prices and growing production.

Figure 15: Gas hedging – largely locked in at US$2.50/mcf

2019 NATURAL GAS - HENRY HUB - NYMEX – Swaps				
Period	Swap Price	Premium	Product	
Jan 20 – Mar 20	$2.91	-	227,500	mmbtu
2019 NATURAL GAS - HENRY HUB - NYMEX – Options				
Period	Floor Price	Premium	Volume	
Jan 20 – Dec 20	$2.50	$0.23	1,440,000	mmbtu
Jan 21 – Dec 21	$2.50	$0.23 - $0.37	600,000	mmbtu
Jan 22 – Dec 22	$2.50	$0.23 - $0.35	300,000	mmbtu

Source: Company data (2109 Annual Report)

The Company sells its gas products primarily to owners of domestic pipelines and refiners located in Pennsylvania and New York states. Unfortunately, none of its NY assets, totalling 262,260 acres, can be fracture stimulated, due to the State's hydraulic fracking moratorium which has been in place since 2010.

EEG holds a 61% net revenue interest in any output generated and does not presently intend to add to its US asset holdings.

Debt and debt covenants

EEG holds a debt facility provided by Macquarie Bank, against its US gas assets. The weakness of spot and short-term gas prices through the first three months of 2020 resulted in the company breaching its debt covenants (based on the net present value of the Proved Reserves, which should be 1.5x net debt).

Given the current soft outlook for gas prices in the US, EEG has renegotiated its facility agreement with Macquarie, securing *"a waiver of existing and potential breaches to the financial covenants under the debt facility for all quarterly covenant tests until 31st December 2020 (inclusive)".*

As part of the covenant waiver terms, the company has made an additional principal repayment of US$687,500, in addition to its scheduled quarterly repayment of US$137,500. As a result, outstanding debt has been reduced to US$6.675m.

The term of the debt facility is Sep-2024, with minimum quarterly repayments of US$135,000 secured against the Appalachian gas revenues. Macquarie holds a first call against the US assets in the event of a default but can call against the Australian assets in the case of a shortfall.

The company has completed a restructure and recapitalisation of the company over the last 18-months, refinancing its Macquarie debt Oct-18), undertaking a 10:1 issued capital consolidation (May-19) and raising A$12mn through a placement (Nov-19) at A$0.40/share.

Valuation and Target Price

Assigning values to exploration plays is a highly subjective exercise with a significant level of intrinsic error (risk), commencing with the Prospective Resources assessment, which by nature is based on a very limited set of data points (few wells). Implied values derived from this starting point are likely to be subject to significant change as more quantitative data is acquired, both directly and indirectly. The nominal valuation ranges as estimated should be used in an indicative sense only, to reflect the potential of the assets and stage of evaluation – earlier stages mean higher risk.

Trying to 'quantify' what are qualitative assets is a difficult and conjectural process, but all exploration does have an intrinsic value that is sometimes higher in the early phases of evaluation. A number of methods can be used to determine a base value, including but not limited to:

- at a minimum it's worth the value of the work programmes as bid;
- look-through estimates from indirect results that can be extrapolated into neighbouring assets, however, those assets need to be 'worked' to demonstrate the upside on a tangible basis;
- transaction/farm-in deals, directly or indirectly, that provide a 'real-estate' valuation and can be an important benchmarking option; and

- nominal project NPVs using working/producing analogues assuming an economic case is deliverable. As an example, we note ACIL Allen ('ACIL') conducted an economic assessment of potential development scenarios as part of the Fracking Inquiry Report but highlighted a number of issues in determining the underlying assumptions.

An economic gas simulation

As part of the NT Fracking Inquiry, ACIL Allen ('ACIL') conducted a comprehensive economic assessment of the potential development scenarios that could arise from a shale-gas industry, assuming with the lifting of the moratorium, an exploration and appraisal phase from FY19-FY21 with production from FY22.

Intrinsically and in light of the current restrictions, that timeline looks somewhat tight and would likely result in small scale production, commensurate with the existing infrastructure network. The scenario modelling 'maximises' the potential deliverable volumes at 1,000TJpd, which we mention only to highlight the resource potential required to underpin this scenario would be in the order 6,000-6,500PJ (~6Tcf at the mid-point) assuming a 20-year production life.

We would also add that the modelling makes significant assumptions with respect to type curves noting that ACIL used:

"…its own type curves, rather than using estimated type curves for gas fields in the Northern Territory. This is because there has been one successful horizontally drilled shale gas well for production testing in the Northern Territory: Origin Energy's Amungee NW-1H. The results of this test were positive, but (could not) be used for our type curve assumption for three reasons:

- *The well involved only 11 frack stages. A typical horizontal well will have at least 20 frack stages and in most cases many more.*
- *The well's production profile was atypical, with a very low initial production rate and an almost perfectly flat production curve.*
- *The well underwent production testing for 57 days. This…(makes) development of a type curve problematic*

ACIL…adopted a "single average type curve" for modelling. In reality, every well will produce a different type curve."

Source: Scientific Inquiry into hydraulic fracturing in the Northern territory – Final report

ACIL estimated for its maximum production scenario:

- capex of c.$9-10bn (life of project); and
- all in operating costs of ~$4/gj (cash breakeven cost)

The scenario analysis was finalised in 2018 and the estimates are likely to be reasonable but we'd suggest with upside of perhaps up to 20% on capex and costs, although the critical underlying assumptions are based on 'dry gas' projects. It's reasonable to assume that gas discoveries could have a significant liquids component if not an oil leg. That may complicate the engineering somewhat, but would provide significant operating margin.

Herein lies the embedded risks to valuing the assets…there's simply insufficient data at this stage to point towards a basic development scenario which will be very dependent on assumed gas prices.

The investment capital assumption reinforces the premise that financing could be an issue for smaller capitalised companies, although EEG by virtue of its 100% working interests, has options.

There are major direct and indirect (potential) de-risking events likely to occur, perhaps from end-2020 from the STO/ORG and EEG drilling campaigns, particularly with respect to establishing gas flow data and liquids contents, so any valuation we ascribe in this report is subject to likely large changes as new data points define the operating parameters.

Prospective resources underpin our valuation assumptions

Empire holds significant volumes categorised as Prospective Resources (unproven by drilling results), based on independent resources estimates, existing information and 3D modelling conducted in 2015 (and updated in 2017). The estimation was conducted over only a portion of the company's acreage with the results as outlined in **Fig 16**.

On a P_{10} basis the recoverable unrisked Prospective Resource was calculated to be >25Tcf (gas) and >500Mb of crude oil.

We believe the estimation was subject to significant cut-off restrictions:

- shale thickness was limited to a maximum of 150m (noting in some areas shale thickness is expected to be >2,000m); and
- the location's hydrocarbons were discounted by 75% to account for the potential variation in rock quality and the lack of control (wells).

Although we cannot directly extrapolate a conversion of Prospective Resources into reserves as we might for CSG volumes in Queensland, the study serves to highlight the transformational potential of the plays within EEG's acreage, noting these volumes only cover a portion of the holdings, in the southernmost permits, in the area designated 'McArthur Basin' in **Fig 19**.

The large shale and tight gas resource potential of the McArthur Basin is still relatively poorly understood and insufficiently quantified, however, drilling campaigns being undertaken and completed through 2021, have the ability to lift confidence levels and add some quantitative certainty on success.

We have chosen to apply a three-step risk weighting methodology to the Prospective Resource (U) volumes as booked on the Velkerri at P_{50} level permit as a base, being the focus of early works and the beneficiary of look-through extrapolations from STO work programmes. Overall, we commence with a Prospective Resource of ~4,000Bcf. We note that EEG has not booked any U volumes specifically against the Kyalla Shale zone as yet, which will be targeted as part of its own drilling activity.

Therein lies the issue with assigning starting points and hence values to early stage assets.

Figure 16: Prospective Resources as calculated - EEG aims to declare initial 2C volumes around end 2020

		Permits	Acres (000s)	P_{90}	P_{50}	P_{10}
Northern Territory						
Gas	Bcf					
Barney Creek Fm		EP184, EPA180, -181, -182, -183, -188	3,559	3,304	8,699	20,172
Velkerri Fm*		EP184, -187, EPA188	315	383	1,192	3,086
Wollogorang Fm		EP184, -187, EPA188	1,384	524	1,185	2,371
TOTAL			**5,258**	**4,211**	**11,076**	**25,629**
Oil	Mb					
Barney Creek Fm				66	174	403
Velkerri Fm				8	24	62
Wollogorang Fm				10	24	47
TOTAL				**84**	**222**	**512**

Source: Company data, * Velkerri Fm estimates include Kyalla Shale

As a **first step**, we convert U volumes to C (Contingent Resources) using a 5-15% range that should reflect the error margin embedded within the initial estimate and take into account typical exploration risks. In broad terms, we should be confident that the target horizons have sufficient organic richness, are 'continuous' through the area of assessment and likely to be producible, however, moving away from well control by definition lowers the confidence level (mathematically).

As a **second step** we then apply a higher probability range of 25-75% to convert from C to P volumes, which we base on typical global industry averages that reflect the commercial conversion from resources to reserves. The range is wide which captures a best-case scenario of high confidence in the extrapolation of data points – lateral continuity of targets and consistent geological properties, which can be the case for unconventional (CSG and shale gas) opportunities. The low end takes into account the starting error margin and issues associated with defining 'P' volumes – market opportunity, production rates etc.

Figure 17: A conservative and highly risked NAV range underscores the transformational upside opportunity

			Risked Range			
		Pr	**Low**	**Mid**	**High**	
Northern Territory	100%					
Gas		6%	$35	$88	$222	After discounting and averaging, we assign a success factor of only 6%.
Oil		6%	$12	$29	$74	
US Onshore		100%	$17	$23	$28	Based on recent EEG Independent Assessment adjusted for 2019 production
			$64	**$140**	**$323**	
Net Cash/(debt)				$3		Company is 'net cash pre-drilling'
Corporate costs				($5)		
TOTAL			**$62**	**$138**	**$322**	**A low case 30% premium to the reference price (18.5cps close of trading 17-Apr)**
			$0.24	**$0.53**	**$1.22**	
Under SPOT scenario			**$0.15**	**$0.33**	**$0.76**	US$32.61/b, 0.6169 AUD, US$1.88/mcf
Shares on issue (mn)	263					

Source: Analysts estimates; spot pricing (investing.com)

The **third step** derives the nominal value based on assumed unit NPV returns derived from typical global industry averages. Most oil and gas projects will generate a NPV of between 10-20% of the average received commodity price X produced reserves.

The commodity price assumption is the critical aspect of this methodology and the key sensitivity. There are two distinct markets into which EEG could sell gas - east into the domestic gas network and north-west into the Darwin export hub, which have different price benchmarks.

- For export markets we apply a well-head netback gas price of c.A$4.85/gj (from the Darwin LNG export facility), based on a long-run FOB oil netback price of c.$A75/b.
- For east coast gas markets, we apply a well-head netback gas price of ~A$4.00/gj assuming tariffing charges to Wallumbilla of ~$4.00/gj and a long run contract price of $8.00/gj.

We calculate a valuation and set a 12month Target Price at $0.24/share noting that this value is subject to potentially significant upside adjustments over the next 12-18 months on results from field activities that could materially change our outlook and weightings.

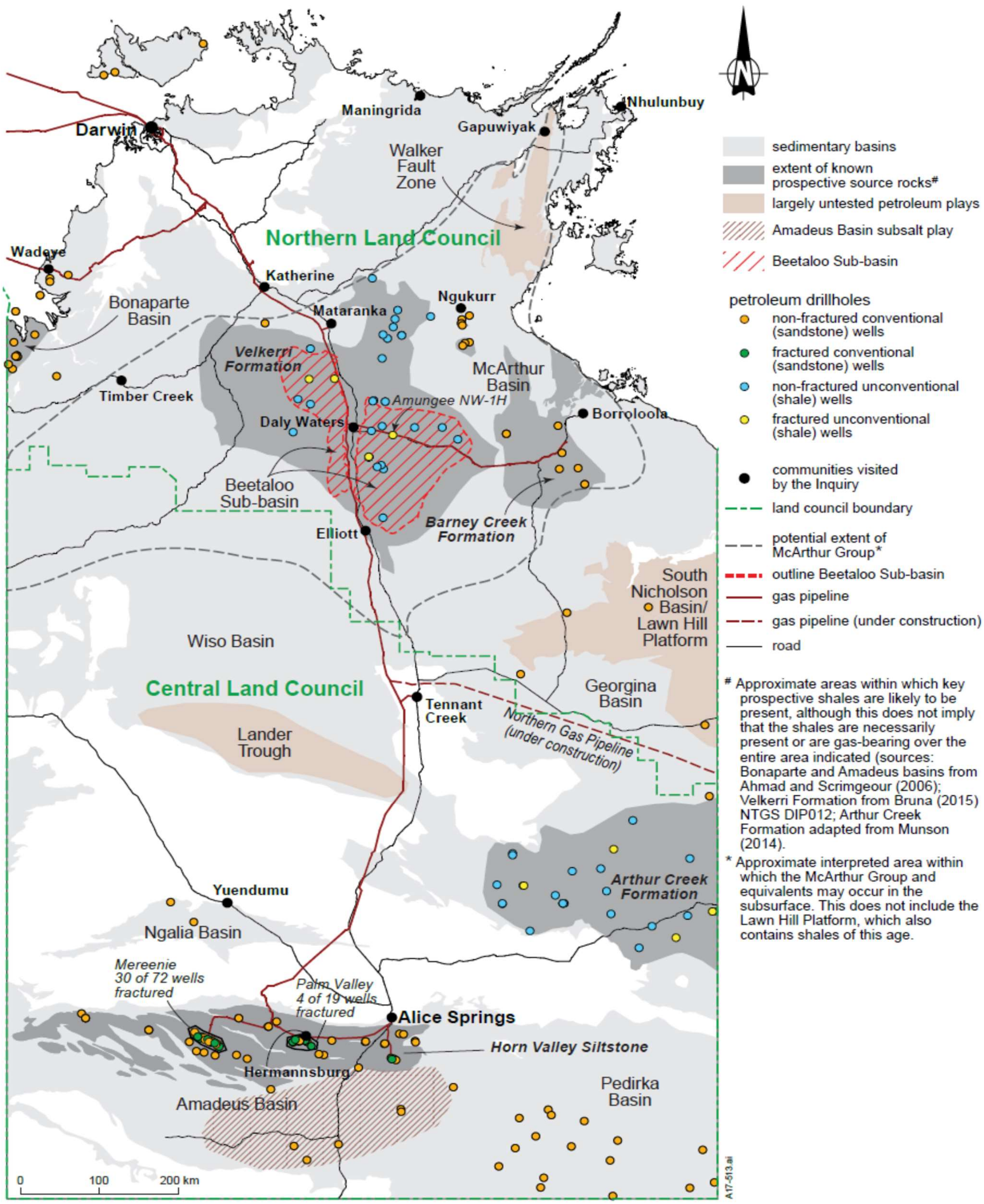
The estimated NAV is quite sensitive at this early stage to commodity price assumptions with spot values generating a significant decrease in value but largely reflecting the market uncertainties at the low-point of the range.

Figure 18: Sensitivity to commodity assumptions supports our view the market is pricing at the bottom of the range

	Commodity Assumptions			NAV (A$/share)		
	Aust Gas/mcf (well head net back)	Crude Oil/b A$	US Gas/mcf	Low	Mid	High
TC assumptions	$4.62	$74.19	$2.40	$0.24	$0.53	$1.22
Spot (9-Apr)	$2.75	$52.86	$1.88	$0.15	$0.33	$0.76
TC Premium	60%	40%	28%	60%	61%	61%

Source: Analysts estimates; barchart.com

Figure 19: EEG acreage covers the 'Walker Fault Zone' in the north through Borroloola in the south, noting the mapped zones of prospective source rocks.



Source: Fracking Inquiry (Final Report). *The grey areas show the extent of the known prospective shale gas source rocks. The taupe areas are those that are considered to have the potential prerequisites for shale gas to occur. but have not yet been tested by drilling*.

Financing and economics

Any consideration of risks must take into account the capacity of the company to fund appropriate work programmes in a timely fashion, particularly holding such a large, contiguous acreage portfolio at a 100% working interest. With all portfolios, fund allocation is paramount and there is a risk that some prospective plays could be underfunded, pushed back in the time line or even lost under the relinquishment requirements of the tenement, for lack of funding.

Although that is likely to be a low risk through the investment horizon and forecast period, there will be logistics and work programme issues.

Figure 20: Options base provides adequate working capital to end-2022

Options Issued	Exercise Expiry Date	Exercise Price	Potential capital raise	
906,250	31-Jul-2020	$0.32	$0.29mn	
36,218,754	26-Sep-2020	$0.30	$10.87mn	
600,000	26-Oct-2020	$0.30	$0.18mn	
1,900,000	30-Dec-2021	$0.30	$0.57mn	
12,000,000	31-Dec-2021	$0.30	$3.60mn	
1,700,000	30-Dec-2022	$0.30	$0.51mn	
2,800,000	30-Dec-2022	$0.60	$1.68mn	
56,125,004			**$17.94mn**	**Exercising all the options would represent an increase of ~21% against the current issued capital base.**

Source: Company data

Financing can also be pursued through option exercise and partnering. As of 17-Feb EEG had issued ~56.1mn unlisted options, exercisable at various dates and strike prices, up to 30-Dec-2022 and from 30-60cps. If all options were exercised the company could access ~A$18mn.

At this point, with the company looking to focus on one play with the potential for early production, financing via equity markets is not an unreasonable option, although the turmoil driven by CoronaVirus issues for instance, underscores the volatile nature of markets and risks associated with any substantial equity capital raising (at any time) – can capital be raised in the amounts required and at an acceptable dilution factor?

The financing capacity of the options is a direct function of the results each stage of exploration and evaluation delivers and the share price at the time. Successful outcomes should deliver re-rating points, which should translate higher share prices, but market risk factors can be at play here as evidenced by recent falls related to CoronaVirus concerns.

We would also highlight the uncertainties with respect to this financing options, specifically if market weakness persists up to and beyond 26-Sep-2020 (in the short-term) and particularly against a reference share price 17.5cps close trading 9-April.

Holding acreage at high working interests has historically been the small company strategy, especially through early stage exploration where initial programmes (particularly seismic) including first wells are financeable through equity markets. Large equity positions then provide capital opportunities through partnering (farming out).

It is a strategy that has worked both in principle and practice, but can be a process that in this case EEG, may not able to completely control from a timing and value perspective.

The NT permits are tightly held with few participants at this stage which makes a contiguous acreage holding intrinsically valuable. We'd expect the company to seek a partner at some point and there are natural partners – existing asset holders adjacent to or chasing the equivalent prospects.

The company's portfolio also looks attractive from the perspective of a strong footprint for a new entrant into the plays. We'd suggest that to maximise/optimise an entry value EEG will need to deliver sufficient positive data to demonstrate a 'tangible' value within a limited budget and/or be prepared to progress on a sole-risk basis.

Any price or promote paid by an incoming party will be a function of its own strategy, the evolving economics of the play, the number of competing opportunities and the number of interested parties…two parties make an auction (of sorts). Large companies have also been known to 'wait out' smaller operators.

Should regional results continue to deliver positive outcomes, then the resource potential could catalyse a 'land grab' in a similar fashion to the asset scramble over Queensland CSG some 10 years ago. We are not advocating that this is the likely or even realistic outcome, only that seeking and securing a partnering option comes with a significant degree of uncertainly generally driven by factors outside the company's direct control.

Geological and engineering outcomes need to be supported by a robust commercial environment. Determining what reserves and flow rates are required to support a project ultimately come down to realisable gas prices and the supply opportunity. As an analogue, there have been some gas finds of scale in WA recently, but in an 'over supplied' domestic market, on gas prices of $3.50-4.00/gj, with only small offtake opportunities…the implied intrinsic value is low and economics for new developments look challenged.

Where Beetaloo/McArthur projects may enjoy a commercial advantage is the potential for NGLs (natural gas liquids) and oil, by providing a high(er) margin revenue stream that can come as a by-product of producing the gas. The liquids potential is yet to be defined so consideration of the impact on volumetric and flow rate thresholds is somewhat moot. If the gas price environment and supply opportunity is poor, it will be harder, longer and more expensive to derive a commercial outcome.

It is beyond the scope of this report to discuss in detail the gas supply opportunities beyond some higher-level anecdotal comments as follows:

- east coast gas supply remains constrained with no new discoveries of scale. Industry has been developing incremental supply additions only
- developed and undeveloped 2P reserves have been trending downwards, particularly with negative revisions under the new reserves reporting guidelines
- the decline rates on current producing fields are accelerating as JVs reduce decline mitigation activities
- exploration expenditure remains stagnant and there is little 'elephant hunting' going on
- the recent ACCC and AEMO reviews indicate east coast supply-demand may remain 'in balance' through the medium term, but that pre-supposes all company's development plans are carried out with conversion of significant 2C volumes to 2P. In addition, we suggest there's an element on exploration success built into the market balance conclusion.

As the data moves away from 2020-2021, the level of uncertainty around the supply equation increases with a significant margin of error.

The east coast requires new, large scale sources of supply and should be a realistic market for new volumes out of the NT pending infrastructure additions and capacity.

We expect east coast gas prices to remain strong with long-term prices at the hub in the $9-10/gj range…commercial for potential Beetaloo/McArthur basins Projects we suggest.

Alternatively and in addition, the NT Government wants to establish Darwin as a world-scale energy export hub, building on its closeness to demand centres in Asia and abundant nearby natural gas resources. The city is already the location for two LNG exporting facilities (Ichthys and Darwin LNG), with a total capacity of 12.6Mtpa which the government is hoping can be expanded.

Within this context, new supply from the Beetaloo/McArthur would need to be cost competitive versus with offshore options and be dependent on global supply opportunities, but LNG expansion plans would require gas production of scale – as a rule of thumb every 1Mt of LNG requires 55PJ of gas, so supply into a 3Mtpa train would equate to ~450TJpd.

Scale gas needs time and investment so as an extension of start-up developments would seem to be a realistic long-term expansion option, or perhaps require volumes from multiple projects.

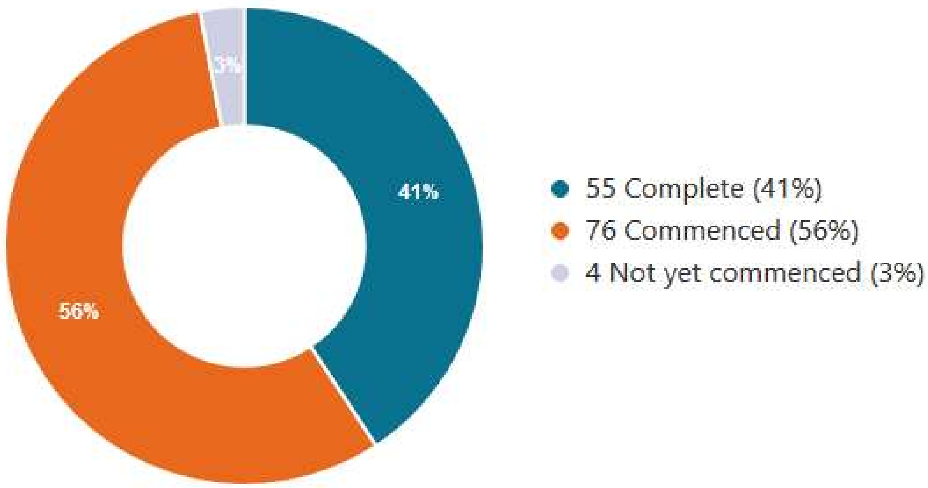
Market definition is yet to formalise so at this stage, must be considered to represent an uncertain outcome in timing and magnitude, particularly with STO and ORG ahead in the development queue.

Northern Territory and macro-operating environment

NT operating environment – regulation will increase but we suggest will still be manageable.

The NT Government is still in the process of implementing all 135 of the recommendations as suggested in the Fracking Review, some of which we suggest are quite onerous particularly with respect to seismic levels associated with the fracking process.

Figure 21: Progress on implementing the recommendations of the Scientific Inquiry into Fracking



Source: https://hydraulicfracturing.nt.gov.au

In generic terms both Origin and Santos have indicated the new regulations are workable, but it is unknown as to what the impact will be in operating and capital terms, particularly on smaller explorers with the company resources required for community engagement, compliance, regulation and other areas.

Whilst the opportunity set does require a balance sheet (capital), it's often the smaller operators that are the nimblest and keenest to work their assets. Big companies require scale to justify investment economics, so can take longer to generate critical mass. Smaller companies can chase smaller commercial outcomes and would likely be better able to take advantage of the current infrastructure capacity. We suggest it would be a poorer outcome if the regulatory environment was weighted to the big end of the sector.

Under the new regulatory conditions, companies will be required to undertake pre-exploration monitoring of methane emissions (Recommendation 9.3), weed surveys (Recommendation 8.2), groundwater quality (Recommendation 7.5) and; well and environmental management plans (numerous recommendations). These activities are required to establish an environmental baseline and should be conducted over a six-month period prior to any activity.

We would draw specific attention to Recommendation 5.7 that *"…to minimise the risk of occurrence of seismic events during hydraulic fracturing operations, a traffic light system for measured seismic intensity, similar to that in the UK, be implemented."*

As of the most recent update this item was some 25% completed with a target date of 31-Dec-2021. The update advises that "*…the Department…has commenced work with independent scientific experts to formulate an appropriate system for measuring seismic intensity in the Northern Territory."*

Source: https://hydraulicfracturing.nt.gov.au/action-items/5.7

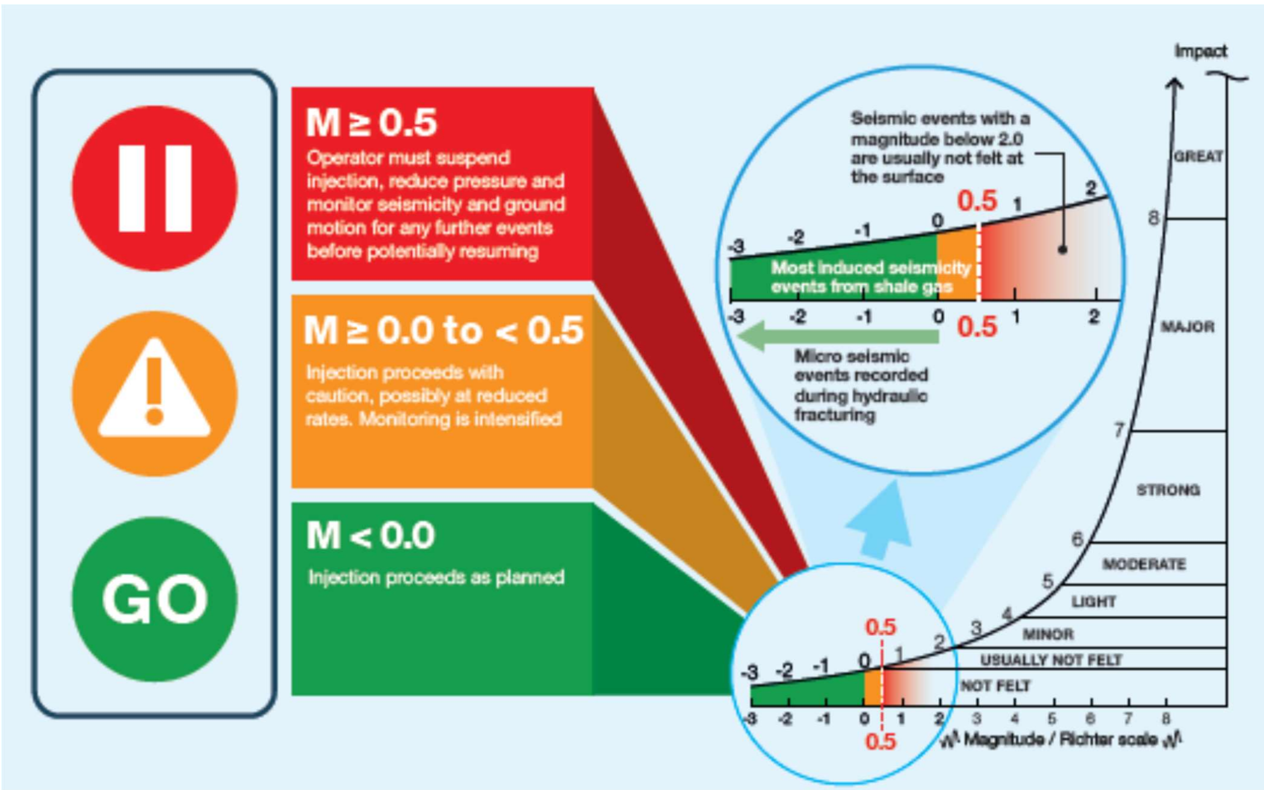
We would be concerned for the potential of this particular area of regulation to almost stop work before it gets going, particularly if it is as restrictive as the current system in use in the UK whereby *"…(the company) must seismically monitor all activity within the site and operate within defined seismic limits capped at 0.5ML, above which work must be suspended (18 hours) and the impacts assessed before being allowed to proceed."*

Within populated areas in the UK there is a high level of anxiety with regard to the potential impacts of induced seismicity on structures and dwellings and whilst it is outside of the scope of this report to debate the merits or otherwise of the specifics of the UK system, it can be seen from **Fig 22** that the lower limit at which fracking activity must cease is set, in our view, unrealistically low, particularly as data available on the BGS website (British Geological Survey) reports that *"…seismic events in the range 1.5-2.0 do occur reasonably regularly throughout the UK* (and) *earthquakes with magnitude <2 are not usually felt and if they are felt then by only a few people very close to the earthquake"*.

Source: http://www.earthquakes.bgs.ac.uk

We would suggest that the imposition of a system with the same magnitude restrictions is unworkable in a practical sense and would certainly delay the commercial timeline.

Figure 22: ‘Traffic light’ schematic as applicable in the UK indicating the restrictive covenants imposed on operations



Source: AJ Lucas

On more general issues:

All petroleum assets in the Territory reside with the government and transition through a usual Exploration Permit (EP), Retention Licence (RL) and Production Licence (PL) process common to all states and territories. In some respects, the tenement tenure terms are more generous than in other states. For instance, EP’s are granted for up to nine years as an initial five-year term, with two-x-two-year renewals. There is a relinquishment requirement of 50% at each renewal, to prevent land-banking. Ostensibly these terms are more generous than say, for Queensland.

However, granting of permit seems to be a more stringent process up front particularly with respect to the Native Title aspects with the need for an Access Authority that must be negotiated with the traditional landowners. Traditional owners have a 5-year right of veto, with limited right of appeal and activities at any time need landowner approval.

Figure 23: NT permit status…significant acreage remains in final negotiations

Lease	Holder	Status	Current Area	Area Units	SqKm	Applied Date	Grant Date	Notes
EP180	Imperial Oil & Gas	Application	199	blocks	14810	12/04/10	N/A	ALRA proposals lodged 04/02/19- now in negotiation
EP181	Imperial Oil & Gas	Application	182	blocks	14423	12/04/10	N/A	ALRA proposals lodged 04/02/19- now in negotiation
EP182	Imperial Oil & Gas	Application	172	blocks	12502	12/04/10	N/A	ALRA proposals lodged 04/02/19- now in negotiation
EP183	Imperial Oil & Gas	Application	22	blocks	857	12/04/10	N/A	ALRA proposals lodged 04/02/19- now in negotiation
EP184	Imperial Oi & Gas	Granted	173	blocks	11170	12/04/10	21/08/13	work program suspended to 19/03/19
EP187	Imperial Oil & Gas	Granted	52	blocks	2988	12/04/10	20/03/15	work program suspended to 20/08/19
EP188	Imperial Oil & Gas	Application	27	blocks	1448	12/04/10	N/A	ALRA proposals lodged 17/12/18- now in negotiation

Source: Company data (ALRA = Australian Land Rights Act)

The company remains in negotiation over six permits as per **Fig 3**, noting that field activity at this stage can only be conducted on EP's -184 and -187. Whilst we see all parties moving towards an equitable agreement at some point, the timing of finalisation remains conjectural and there is always some risk that consent will not be granted or the terms of access are too restrictive. We believe in various forms that EEG has been negotiating with Traditional Landowners for access to some of its permits for nearly 10 years.

All approved NT EMPs can be viewed here: *https://denr.nt.gov.au/onshore-gas/environment-management-plan/approved-emps*

The NT Government reserves the right to declare parks and reserves; sites of conservation significance and Indigenous Protected Areas as "reserved blocks" over which an exploration permit cannot be granted or be rescinded.

The NT Government charges a production royalty at an ad valorum rate of 10% of gross value at the wellhead, with adjustments for reasonable post-wellhead costs. Whilst small, there is always a risk that royalty rates can change or fresh charges can be imposed, perhaps as a form of carbon tax. Royalties and charges should not be a critical risk to a project's ultimate economic viability but can erode returns at the margin.

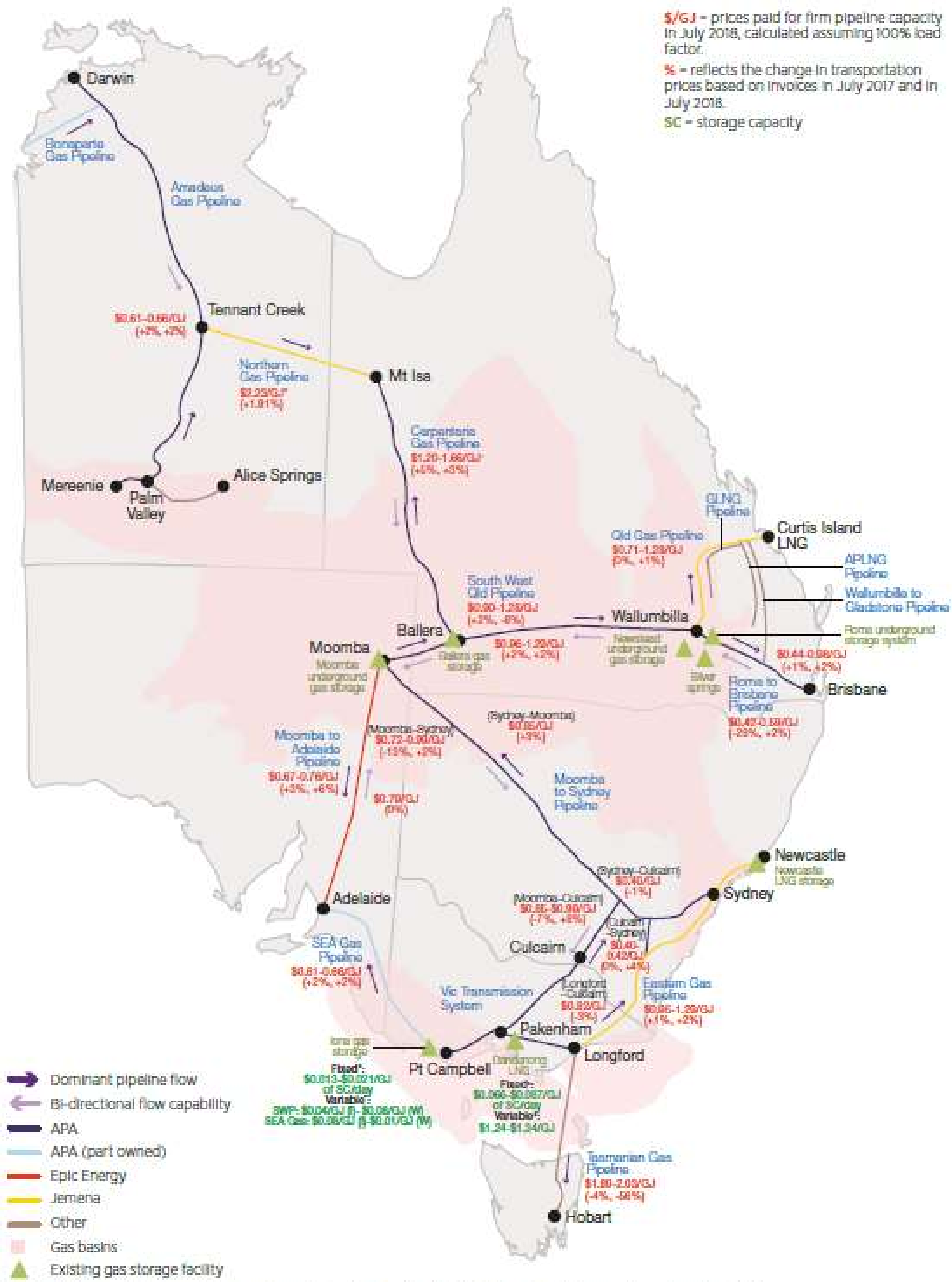
Def: An *ad valorum* royalty is an impost whose amount is based on the value of a transaction or of property. It is typically imposed at the time of a transaction – in this case a wellhead cost.

Infrastructure

The Northern Territory (NT) has aims to assist in the development of regional infrastructure to support its aim to create a Darwin LNG hub and to link into the eastern gas markets.

The transmission gas pipeline network at this point is limited to the Amaedus and Northern gas pipelines, which would require significant upgrading and expansion.

Figure 24: Tariffing charges suggest margins to the Wallumbilla hub could be challenging, transport to Darwin is the volume play



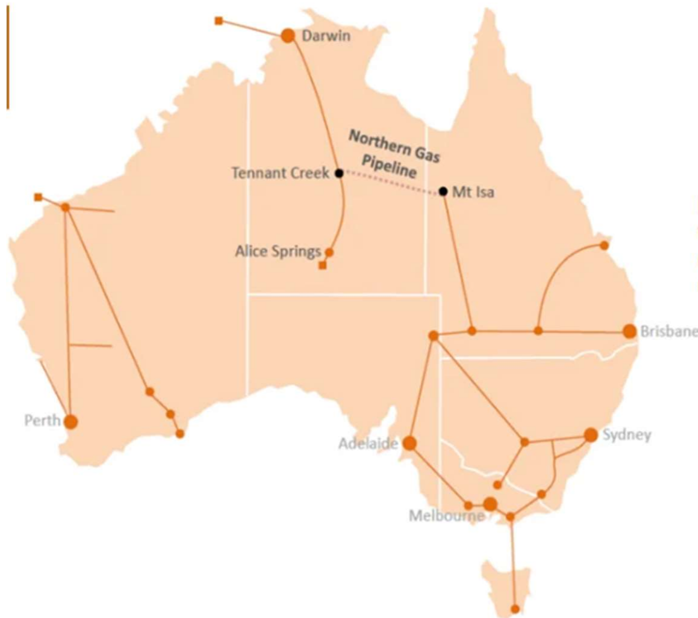
Notes: The transportation and storage prices are based on invoices in July 2018 provided by operators, and exclude GST.

Source: www.accc.gov.au

We suggest gas via the Northern Pipeline to say Wallumbilla could attract tariff charges in the order of >$4/gj (**Fig 24**) and we note Jemena was cited in some 2018 press reports as suggesting Beetaloo gas could be delivered to Wallumbilla for around $6-7/gj. This would not generate sufficient economic margin in the upstream (netback to field), unless gas prices were more likely to be in the order of $9/gj. There is significantly more to play out here yet.

Infrastructure construction and expansion to provide capacity to end markets is a significant and key risk to commercial outcomes.

Figure 25: NT infrastructure network is still developing



The Jemena Northern Pipeline is a 12", 622km long, 90TJpd (32PJ) capacity link connecting the Amadeus PL with the Queensland Carpenteria PL and onto the regional gas hub.

Jemena has commissioned preliminary planning and studies for an expansion of the pipeline capacity of up to 700TJpd (255PJ) at notional capex of $3-4Bn and notionally a direct connection into (say) Wallumbilla.

The Amadeus Pipeline is a 12", 1,512km long line that was commissioned in late 1986. It is now bi-directional bringing gas south from the offshore Blacktip Gas Field and transporting Meerenie-Palm Valley gas north. The capacity of the line is similar to the Northern PL at around 90TJpd.

At this stage we believe there is significant capacity on the Northern line but overall, restricted throughput availability.

Scale production will require a large capacity expansion.

Source: AFR (14/12/18), "Jemena's $800m NT pipeline opens market for northern gas"

Other risks, directors and management; and shareholding

We have previously outlined some key and obvious areas of uncertainty but note this is not a complete or fully comprehensive list of the associated risks as we see it. It should also be noted that whilst we try to address the risks individually, they are connected – solving or addressing risks in one area may certainly impact the others, so should be considered in total.

CoronaVirus

The impact of the CoronaVirus has become immediately manifest in the closure of state and international borders; and restrictions on travel. Exploration has been deemed as a non-essential business activity within the current definition and within the NT, particularly with activity on indigenous lands, the government will be especially vigilant to minimise the risk of spreading the infection.

The international travel ban also precludes access to many industry specialists in fracking and testing that are based in places like Singapore and the Middle East – in effect field activity will be severely curtailed with the timing on restrictions somewhat open-ended. NT field activity is also seasonally constrained around the wet season, so missing slots now probably translates to delays of up to 12 months.

Administrative activity could also be severely curtailed with the granting of permits (new or renewed) dependent on securing agreements with the traditional owners, which will require 'on-country' meetings. Although there is no work requirement until formal approvals are obtained, EEG had scheduled meetings with the traditional owners for areas adjacent to those already granted…we suggest the timing of these meetings is now strongly at risk.

Travel restrictions will impact all operators in the territory so there is also a significant risk as to the timing and completion of the look-through drilling and testing campaigns scheduled by STO and ORG.

As a result of CoronaVirus related issues:

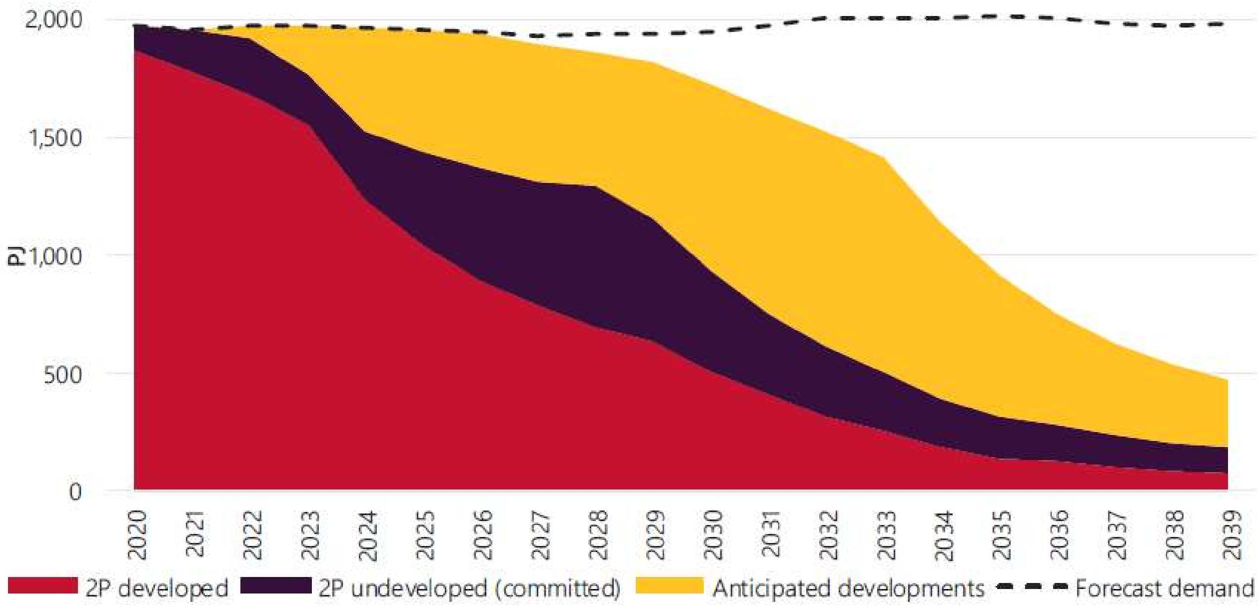
- Santos has indicated its work campaign is unlikely to be restarted in 2020.
- Origin Energy has announced activity on Kyalla-117 has been paused since 25-Mar with the drilling of the Velkerri flank well (Velkerri 76 S2) is now likely sometime in 1H'21.

An east coast market for gas – AEMO data seems to suggest yes

The AEMO Gas Statement of Opportunities was released on 27-Mar and supports our contention that the east coast gas supply thematic still holds. Supply tightness remains with the potential to impact earlier rather than later. In our view, gas prices can't collapse despite the next 6-12 months being somewhat of a void in terms of short-term demand impacts, but capex is being cut, decline curves could be steeper, drilling is falling away...the supply side issue is getting quite serious.

It is interesting that AEMO is suggesting a gas 'shortfall' in the southern regions (specifically Victoria) could impact as early as mid-2023.

Figure 26: AEMO supply demand scenarios being balanced by a YELLOW wedge – that's all 'high-risk' gas at this time



Source: AEMO Gas Statement of Opportunities report (Mar-2020)

In summary (**emphasis added**, *analyst comments in italics*):

The 2020 GSOO projects that:

- Supply from existing and committed gas developments will be sufficient to meet forecast gas demand across eastern and south-eastern Australia until at least 2023, **provided that** liquefied natural gas (LNG) export **spot** cargoes are redirected to meet domestic demand, if required.

We suggest that's an 'if and only if' number . We are concerned that projected decline curves maybe understated, eg Bass Strait and Cooper Basin where circumstances suggest capex will be right at the minimum 'stay-in-business' level and that committed projects get completed without material delay, performing to the model expectations.

- **Southern supply** from existing and committed gas developments **will reduce by more than 35% (163PJ) over the next five years**, despite an increase in committed gas developments in the past year. Unless additional southern supply sources are developed, LNG import terminals are progressed, or pipeline limitations are addressed, gas supply restrictions and curtailment of gas-powered generation may be necessary on peak winter days in southern states from 2024.

There's a lot of moving parts in that bullet point. The magnitude of the reduction suggests six new 'Sole-sized' projects need to be found and producing in the next five years. With the shortfall skewed to the back end of the timeline, new discoveries will likely need to be made in the next two years at the latest to meet that timing. The business case for LNG imports is growing.

- In response to declining production from southern fields, Cooper Energy's Sole project and the Esso-BHP West Barracouta project are committed and expected to start production of sales gas between 2020 and 2022. **These projects alone are not sufficient to slow the decline in production**…(and to) maintain levels of production beyond 2024, **gas from more uncertain field developments will need to progress**.
- Forecasting uncertainty and year-on-year variability has increased since the 2019 GSOO. **Gas supply adequacy forecasts are highly uncertain, particularly between 2022 and 2024** when decline in southern field production coincides with the staged closure of Liddell Power Station.

Predicting field decline rates even with many years of data can be quite an art form. Given there are 'multiple' producing fields in Bass Strait for example, it would be significantly more difficult to predict with any certainty, how the earlier closure of one or two fields could impact the infrastructure as a whole - would there be a cascade effect?

Uncertainties to the analysis and projections include:

- **Several gas fields are forecast to cease production sometime between mid-2023 and mid-2024.** If production ceases earlier, this could create peak winter day supply gaps in Victoria in 2023.

There are outliers to these scenarios, but outcomes all are determined by realisable gas prices...the lower the long run price, the less new gas is available and the greater the reduction in economic reserves.

Global environmental issues, working in a carbon priced world

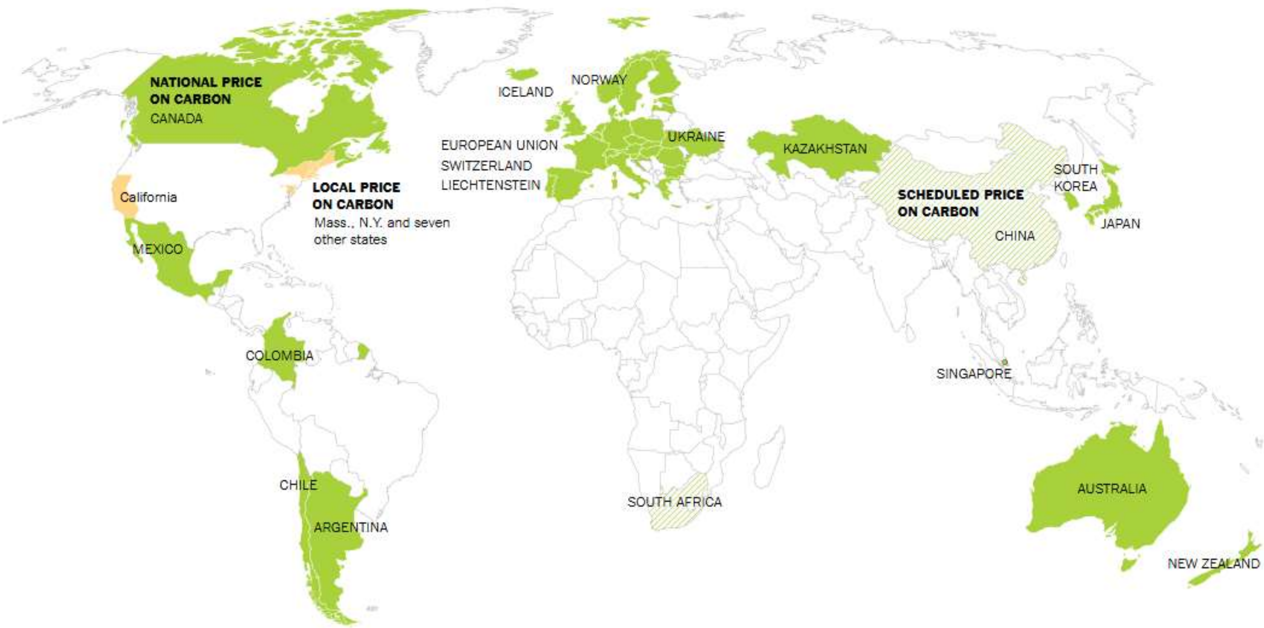
Environmental opposition to the hydrocarbon business in growing – often the debate is not rational and all carbon-based energy sources get lumped together, coal, oil and gas.

It is beyond the scope of this report to debate the merits of climate change or the role of gas within those arguments but given the social licence to operate that energy companies recognise, we highlight the risks associated with changing government positions.

Whilst we think there is an increasing recognition of the positive role that gas can bring to power generation, particularly in combination with renewables and as a replacement for coal, environmental and climate protests do represent a tangible risk to the industry in general and specifically to new exploration provinces. In some ways we can see the NT as perhaps being at higher risk than incremental exploration in established provinces (Central Queensland, Bass Strait, Cooper Basin etc).

The potential for the addition of new cost imposts and serious delays to activity should not be dismissed out of hand.

Figure 27: The reach of carbon prices…it's likely to become an operating norm



Source: https://www.epa.gov/energy/greenhouse-gases-equivalencies-calculator-calculations-and-references

We should also not dismiss the potential for an increase in the carbon impost. Most energy companies recognise the need to account for carbon and are initiating carbon capture and storage initiatives, carbon trading schemes and working towards a carbon neutral operating outcome.

In broad terms and on a global basis, a carbon tax has been imposed across a number of countries including Australia (ref **Fig 27**) with varying degrees of success and at varying levels. In Canada the impost is expected to rise to US$38/t by 2022, whilst the UK is currently imposing a US$25/t charge but we'd expect that to rise. In some ways a global and likely significant price for carbon will become an operating norm.

If a carbon cost of say, US$30/t* ($CO_2$ equivalency) becomes a global standard and using a conversion rate of 53kg⁺ (CO_2 equivalency) per mcf, this would imply a corporate cost of ~A$/2.40/mcf at the well head.

Source: * TC estimate; +https://www.epa.gov/energy/greenhouse-gases-equivalencies-calculator-calculations-and-references

Board and Management

The composition of small company boards and management teams are perhaps more critical than for larger companies as the impact of seemingly incremental decisions can have a magnified impact on the growth and valuation of the company. There is less margin for error and often the Board is a critical source of working capital. Directors have invested more than $4.25m in cash over the last 2 years and hold ~7.3% of the issued ordinary capital of the company.

Empire Energy has an experienced four-person board, providing we think the appropriate skills sets and balance for a company in transition and leveraged to potentially transformational change. There is strong blend of corporate governance, finance and technical experience to set up and guide the company through what could be game changing activity over the next 12-months, requiring strategic decisions to position the company to fund and develop opportunities that could emerge.

Board of Directors

Alex Underwood LLB, BCom (hons), **CEO and Managing Director:** Alex joined the company as in Mar-2018, being appointed CEO and Managing Director in Aug-2018 with a background in the Natural Resources and Energy Markets garnered through positions in the Commonwealth Bank and Macquarie.

Paul R. Espie (AO) Non-Executive Chairman: Paul joined the Board as Chairman in 2018 bringing an extensive bank of experience as an independent board member and in the banking sector, with BAML He has held previous positions as the Chair of the Australian Infrastructure Fund, Oxiana Limited and Cobar Mines

Other directorships: Aurelia Metals Limited and the Menzies Research Centre; a fellow of the Australian Institute of Company Directors; a Trustee of the Australian Institute of Mining & Metallurgy (AusIMM) Education Endowment Fund.

John Gerahty, Non-Executive Director: John has been a director of the company since 2018 and brings significant banking and commercial experience across a wide range of sector. Notably he was a Founding Director of Macquarie Bank and has served as the Chair of ARP Group Plc and MPI Mines Ltd. He was formerly Chair of Sydney Swans, a director of Cricket NSW and a Trustee of the SCG Trust.

Other directorships: He is currently Chair of the Hardie Grant P/L publishing group (and associated companies); a Director of Kaplan Partners P/L and Kaplan Funds Management P/L.

Professor John Warburton PhD, FGS, MAICD**, Non-Executive Director:** John was appointed to the Board of EEG in February 2019, but has been involved with the company since 2011 through its subsidiary, Imperial Oil & Gas P/L as a Director and CEO (2011-2014). John provides the board's technical expertise having garnered some 35 years of international industry experience with BP, Oil Search and LASMO-ENI in senior technical and leadership roles. Those roles have run the gamut of oil and gas opportunities – over conventional and non-conventional; operating and non-operating environments, in Europe, Central Asia, the Middle East, Pakistan, PNG, Australia and New Zealand.

Other directorships: remains a non-executive director of Imperial Oil & Gas P/L and Senex Energy Ltd

Figure 28: The Board (and management) has significant 'skin in the game' and has a key exposure to next phase financing through options

		Ordinary Shares	Performance Rights**	Service Rights*	Unlisted Options			
					No. issued	Expiry	Price	Vesting Date
Alex Underwood	Direct	800,000	3,150,000	1,000,000				
	Indirect	1,150,000			300,000	30.12.21	$0.30	
					300,000	30.12.21	$0.30	13.04.20
					250,000	26.09.20	$0.30	
Paul Espie		4,850,000			375,000	26.09.20	$0.30	
John Gerahty	Indirect	12,245,000			5,562,50	26.09.20	$0.30	
John Warburton		194,000						
Senior Management								
David Evans			362,317					31.12.21
Ben Johnston			153,569					31.12.21

Source: Company data;

*Service Rights vest from 31.08.21 and expire on 30.06.34 with an ascribed Fair Value of $180,000

**Performance Rights vest from 31.08.21 (Underwood) and 31.12.21 and expire on 30.06.34 (Underwood) and 20.12.34. The pool has a combined Fair Value ascribed at $165,208

David Evans has been the **Chief Operating Officer** since October 2019, responsible for the execution of the NT evaluation and development strategy. David has 30 years' of industry experience, previously holding the role of Chief Operating Officer at Elk Petroleum Limited and prior to that at Drillsearch Energy Limited before its acquisition, overseeing a period of rapid and substantial growth through the discovery and development of Western Flank (Cooper Basin) oil and gas fields.

David holds a BSc(Hons) in Geology from the University of London, a Postgraduate Diploma in Petroleum Exploration Geology from Oxford Brookes University and a Master of Applied Science from University of Canberra.

Issued capital and shareholdings

The capital base consists of ordinary shares and options, noting the option base is significant representing an increase in capital of some 21% should all be exercised. Option exercise will depend on the share price performance up to 26-Sep, which represents some nearly 56% of the options as issued.

Figure 29: Capital base is largely ordinary shares and 'out-of-the-money' options

	Number	Expiry Date	Ex Price	
Ordinary Fully Paid shares	263,288,649			As of 17-Feb-2020
Options	*906,250*	*31-Jul-2020*	*$0.32*	
	36,768,754	*26-Sep-2020*	*$0.30*	*Critical date for option exercise*
	600,000	*26-Oct-2020*	*$0.30*	
	3,600,000	*30-Dec-2021*	*$0.30*	
	12,000,000	*31-Dec-2021*	*$0.32*	
	2,800,000	*30-Dec-2022*	*$0.60*	
Total options	**57,275,004**			
Performance Rights	4,362,811			Includes 250,000 of unquoted Rights
Service Rights	1,000,000			

Source: Company data

The register is transitioning but remains dominantly retail, which is unsurprising at this point of the company's strategy. As the NT plays evolve, we'd expect more institutional interest. Liquidity is still somewhat of a problem with an average monthly turnover (last 12 months) of 5.9mn shares by volume (~2% of the register) and $1.9mn by value.

Figure 30: Top 20 hold 49%...but the register is currently thin on wholesale investors

Holder	Amount Held	%
Macquarie Bank Limited <Metals Mining and Ag A/C>	26,451,367	10.06%
Global Energy and Resources Development Ltd	25,711,000	9.78%
Liangrove Media Pty Ltd	12,245.000	4.66%
Elphinstone Holdings Pty Ltd	12,000,000	4.58%
HSBC Custody Nominees (Australia) Limited	8,031,736	3.06%
Citicorp Nominees Pty Ltd	6,919,496	2.63%
Cha Qian	5,145,000	1.96%
Mr Kooi Onn Chye	4,643,363	1.77%
Cheoy Lee Yachts Australia Pty Ltd	4,130,000	1.57%
Grosvenor Equities Pty Ltd <No 2 A/C>	3,597,921	1.37%
Kuarka Pty Ltd <Kuarka A/C>	2,500,000	0.95%
Mr Teik Tatt Oh	2,500,000	0.95%
Mr Andrew Forster	2,500,000	0.95%
Invia Custodian Pty Ltd <Pacific Road Provident A/C>	2,350,000	0.89%
Oracle Financial Planning Pty Ltd	2,101,000	0.80%
Mr Charles Phillip Lowsley Peake	2,003,000	0.76%
John Wardman & Associates Pty Ltd <The Wardman Super Fund A/C>	1,896,487	0.72%
Jetan Pty Ltd	1,715,095	0.65%
RHB Securities Singapore Pte Ltd <Clients A/C>	1,535,029	0.58%
Garfield Super Co Pty Ltd <CCS Pty Ltd Superfund A/C>	1,500,000	0.57%
	129,475,228	**49.18%**

Source: Company data as of 29-Mar-2020

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