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Empire Energy Group Ltd

Scoping Report

Energy

23 December 2019

Forging new frontiers

Empire Energy Group Limited (EEG.ASX) is a junior hydrocarbon producer and explorer with onshore unconventional oil & gas shale reservoir assets. EEG holds the largest acreage position in the highly prospective, potentially global-scale, long-life, northern Australian McArthur-Beetaloo basins. Empire is demonstrably a 'two basin play' with the majority of its prospective acreage in the McArthur Basin. The company also owns established oil/gas producing assets in the US (New York and Pennsylvania). EEG has been listed on the ASX since 1984, with board and management recently augmented in preparation for fresh strategic investment growth initiatives. Having raised $12m mid-November, EEG has a number of event drivers over the coming 12-months, aimed at transforming the company into a strategically-important, long-life Australian onshore energy cash generator. The company has net cash holdings of ~$5m (gross cash is ~$15m). In the McArthur-Beetaloo Sub-Basin, the company's first $5m (est.) vertical drilling programme is due to begin in 2Q 2020, targeting the Velkerri shales. The Basin is fast developing as a gas-rich (and potentially liquids-rich) answer to east coast Australia's future energy security, with strong policy support from both the Northern Territory (NT) and Federal governments. Crystallising Empire's inherent value potential is dependent on successful drilling outcomes and its capacity to secure the best strategic funding mix thereafter.

Scope

This report has been commissioned by Empire Energy Group Limited to present investors with an analysis of the opportunities emerging for the company over the next 12 months. Due to the early phase nature of EEG's exploration assets, investors should consider this a high-risk investment. High risk investments should be a small part of a balanced portfolio.

Business model

Empire Energy Group (EEG) is a junior oil & gas producer/exploration company, focusing on maturing its portfolio of onshore, long-life oil and gas fields. The company holds substantial exploration acreage in Australia's Northern Territory McArthur-Beetaloo basins. Although EEG's NT assets are at an early exploration stage, given the high prospectivity of the region, success from the company's 2Q 2020 drilling programme could see cashflows generated within 24-36 months, assuming links and upgrades to existing pipeline infrastructure are undertaken in time. Empire's NT assets could benefit from look-through revaluations should particularly Santos (ASX: STO) and Origin Energy (ASX: ORG) report drilling success from their adjacent acreage over their 2020 work programmes.

Valuation

Valuing early phase exploration assets is a subjective exercise, particularly when work programmes and financing are uncertain. We base our indicative valuation on typical NPV values across a range of pricing scenarios, using low and high resource estimates. We apply discretionary probability weightings to pricing, volume and success factors, which we believe are reasonable, given the commercial operating environment and available data. We assign a base valuation of $160m ($0.61/share) to EEG on the current share count of 262.5m. If we include in-the-money options, the base valuation is $0.56/share. The current share price of $0.435/share suggests the market is appropriately weighting the asset base for the current operational and corporate risks facing the company. We observe a number of event drivers lining up for EEG's portfolio over the coming 6-12 months which have the potential to generate a sizeable uplift in NAV.

Historical earnings and RaaS Advisory estimates

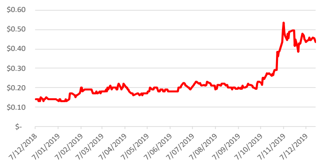
Year end	Revenue (US$m)	Gross Profit (US$m)	NPAT reported (US$m)	OCFPS (AUD cps)	EPS Adj (AUD cps)	Price/Book (x)
12/18a	14.3	5.0	(15.9)	(0.15)	(1.41)	35.1
12/19e	6.7	1.7	(7.4)	(9.87)	(6.13)	4.1
12/20e	4.4	1.2	(3.0)	0.64	(1.47)	5.1
12/21e	4.5	1.2	(3.0)	2.06	(1.40)	5.5

Source: Company data, RaaS Advisory Estimates for FY19e, FY20e and FY21e

Share details

ASX Code	EEG
Share price	$0.435
Market Capitalisation	$114.2M
Shares on issue	262.5M
Net cash	~$5M
Gross cash	~$15M

Share performance (12 months)



Upside Case

- Drilling success in McArthur-Beetaloo Basin generates significant commercial outcomes for EEG's EP187
- Seismic program proves the eastern extension of the Beetaloo Basin into EP187
- Drilling success generates high-value LT strategic partner & funding options

Downside Case

- McArthur-Beetaloo Basin EP 187 2Q 2020 drilling is unsuccessful, negatively impacting value of remaining NT permits (EP180-188)
- Continuing financing through equity issues highly dilutive to future capital growth
- Fracking success in NT/Qld pushes onshore energy prices to sub-economic levels

Board of Directors

Alex Underwood	Managing director/CEO
Paul Espie AO	Non-Executive Chairman
John Gerahty	Non-Executive Director
Dr John Warburton	Non-Executive Director

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Table of contents

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Empire Energy Group Ltd

Empire Energy Group Ltd (EEG.ASX) has been listed on the ASX since 1984 and represents a combination of a mature small-scale, low-risk, conventional production on the US East Coast and early frontier exploration plays in Northern Australia, with current net-cash. While modest cashflows and extensive well management expertise are being generated from conventional reservoirs in EEG's acreage in the US's largest shale gas basin, the Appalachia, the real excitement is being generated from EEG's significant exploration tenements in the McArthur-Beetaloo basins of Australia's Northern Territory. These regions are considered highly prospective for hydrocarbon commercialisation and are "open for business" again, following the lifting of a 2-year moratorium on hydraulic fracturing in the territory in April 2018. Further project definition awaits vertical drilling results on EEG's EP187 tenement situated along the Beetaloo Basin's Velkerri shale formations, where large volumes of unconventional gas resources have already been identified. EEG is set to commence a 1-well programme in 2Q 2020, dependent on securing a suitable drilling rig. Positive results could evolve EEG's current Prospective (P50) of 1.85bln Boe (11 Tcfe) to a Contingent resource (2C), placing the company in an even stronger strategic position to negotiate with potential future funding partners. Santos (ASX:STO) and Origin Energy (ASX: ORG) are two Australian listed majors with farm-in arrangements already in the area. Both are also conducting horizontal well programmes in the coming months, aimed at quantifying the region's overarching economic potential. We would also expect Asian and US corporates to take an interest. The key longer term, risk is the need for infrastructure construction and expansion to link the well to domestic and export markets.

Exhibit 1: RaaS's Empire Energy Group Valuation Range

In A$M		Risked Range (A$M)			Risk	Low	Mid	High	
		Low	Mid	High	Weight		A$/share		
Northern Territory									
Gas	100%	$72	$108	$244	4%	$0.27	$0.41	$0.93	Risking and valuing exploration assets is somewhat
Oil	100%	$23	$35	$78	4%	$0.09	$0.13	$0.30	arbitrary and down to the discretion of the valuer
US Onshore									
Appalachian		$9	$17	$26		$0.03	$0.06	$0.10	Key sensitivity here is the assumed gas price – US$2.40 in FY20 and US$2.44 in FY21
Sub total		$104	$160	$347		$0.40	$0.61	$1.32	
Net cash/(debt)		$5	$5	$5					
Corporate costs		($5)	($5)	($5)					
TOTAL		**$104**	**$160**	**$347**		**$0.40**	**$0.61**	**$1.32**	**Based on current shares of 262.5m**

Source: RaaS analysis; risk-adjusted ranges based on company data; regional farm-in valuations and weighted by applying the RaaS risk overlay
The Base Case ascribed to the Marcellus assets assumed the continuation of the New York state ban on hydraulic fracturing. The Low Case assumes Pennsylvania introduces new taxes on gas drillers to pay for infrastructure upgrades, rendering some of EEG's wells sub-economic to operate. The High Case assumes New York state lifts the ban on fracking.

Risk Adjusted Valuation

We have evaluated EEG's portfolio against a range of risk factors based on our assessment of prevailing operating conditions. These factors include, but are not limited to, commodity prices, location, phase of exploration, timing and scale of work programmes, potential timeline to development, and funding costs.

We value EEG using estimated values for Prospective Resources adjusted for our discretionary probability weighting (1-risk%), to derive a gross portfolio worth. These probability weightings are subject to change as the company delivers its next phase of exploration results.

We believe that the majority of EEG's current market value (~85%) is being derived from its early stage Northern Territory exploration assets. These Prospective Resource estimates could be subject to significant adjustments following the results of planned drilling and well testing, both by EEG and in adjacent tenements.

We note the significant subjectivity inherent in underpinning such valuations.

Acreage holdings – intrinsic value considerations

Ultimately the exact volume of resources associated with any single project is only fully understood at the time of final abandonment. The range of uncertainty in recoverable volumes typically decreases with increasing project maturity. Prospective Resources, by definition, have a far wider range of uncertainty than Reserves associated with a project that is already in production.

EEG's NT portfolio holdings are dominated by estimates of Prospective Resources [potentially recoverable volumes associated with a development plan that targets as yet undiscovered volumes] and 'in-ground' volumes, based on tenement area drilling success probabilities – categories falling into the high-risk end of the risk spectrum. EEG also holds several potentially prospective permits that have yet to be granted land access, let alone having any "in-ground" volumes attributed to them, due to the lack of available seismic and drilling data.

Despite residing at the high end of the risk spectrum, exploration remains the cheapest way to generate additional (potentially transformative) value to an asset base – certainly in the initial work programme phases. The allure of exploration discoveries lies in their "look-through" economics, which can provide a ready sense of future worth to investors well before development cashflows actually begin.

The value of frontier discoveries can be delivered either a) once production commences or b) at earlier investment stages, via farm-in arrangements at pre-drill value estimates. Obviously, the more drilling that can be undertaken before farm-in deals are negotiated, the more value that can be retained for existing equity holders, notwithstanding the dilutionary effects of funding expensive drilling programmes and the requirement for positive drill results.

Valuation Considerations

Calculating the NPV economics of unconventional shale gas projects is strongly correlated to a combination of the reservoir characteristics and fracturing parameters (including pressure; thickness; porosity; permeability; initial gas saturation; absorbed gas content; fracture half-length; fracture conductivity & fracture spacing) and gas price scenarios, with an eye towards the best areas of estimated ultimate recovery (EUR).

Conventional drilling is cheaper than unconventional drilling and is a shorter process. However, by introducing fracking, which opens up the rock to allow hydrocarbons to flow more quickly, the economics can improve, a) due to faster flow rates (on average 2.7 times faster in the US shale experience) and b) the repeatability along a chosen shale zone.

Equally, little is known whether production will be 100% "dry gas" or whether output will include higher value "liquid" hydrocarbons, which would result in a small increase in operating costs and a large increase in potential production revenue. The net effect of a liquids rich development is that it significantly improves project economics. Empire's 2020 drilling programme should better define the liquids potential in EP187.

The value of EEG's exploration assets is an inherently subjective exercise and dependent on a number of discretionary probability factors, including historical results, prevailing commercialisation considerations, as well as the company's ascribed drilling probability of success (POS) and the RaaS-analyst risk weightings, particularly regarding the valuation attributable to conversion from Prospective Resources (U volumes) and resource-in-place estimates into "commercially-viable" outcomes.

Further complicating matters is the fact that hydraulic fracturing in the early stages of evaluation will have a strong R&D element associated with it. Optimal designs may only be found after extensive attempts, particularly so for low-porosity; low permeability fine-grained reservoirs.

A typical shale gas well takes a hyperbolic decline curve path, where production in the initial period (typically 3-6 months) is very high, relative to the average monthly production rate over the life of the well. A well's production declines rapidly from this initial production rate and can continue to produce for a long period of time (eg 20 years) at very low levels.

Encouragingly, the Origin-Falcon Amungee NW-1H hole was subject to an extended production test for 57 days in 4Q 2016 and exhibited **very little decline in gas rates** over the period.

We suggest holding a tenement position >56,000 sq km is far too large for EEG to evaluate optimally. We would also highlight extrapolating prospectivity over all the permits (not all acreage is created equal). For instance, at this stage, the Beetaloo Sub-Basin is considered more prospective than the McArthur Basin shales (eg the

Barney Creek formation), due to the latter's variability in shale thickness and organic content and more frontier nature.

From a practical perspective, even though all historical Beetaloo Velkerri results have been encouraging, none of the region's tenement holders have reached definitive economic outcomes to date and certainly nothing is yet defined within EEG's own acreage.

EEG has confirmed with the University of Adelaide in 2013 that a number of its zones in the Velkerri and Barney Creek areas contained shale intervals with oil, oil-condensate and wet gas generation potential.

The company believed at the time that its northern tenements held up to 8 potential conventional structures, together with a large highly prospective unconventional target within the tenement area to drill up. The benefits of a liquids discovery over a gas discovery for EEG would include easier and speedier development, as well as fewer infrastructure requirements.

We have applied a quasi-Monte Carlo valuation matrix methodology to the current U (Prospective) volume estimates published by EEG for its EP 187 permit following its 2014 drill programme. Within this approach, we assume a conversion range of 5-15% from U to C (Contingent) volumes, taking into account typical associated (POS) exploration risks. We subsequently apply a higher probability range of 25-75% to convert from C to P volumes, based on typical global industry averages, reflecting the commercial conversion from resources to reserves.

Following on naturally from a reserve estimate, is the derivation of a commercial project (NPV) returns. Again, by reverting to typical global industry averages, we have assumed that any project commercialisation would assume to be priced by applying a c.15% return on average received prices. We have applied a well-head netback gas price of A$5gj (derived from the Darwin LNG export facility), together with an FOB oil netback price of $A90/b, lining up with prevailing market conditions.

Fresh Results on their way

We need fresh exploration results to better visualise EEG's potential value. We expect regional "read-through" drill results to begin flowing again from April 2020, after a 5-year hiatus, initially from the Origin-Falcon hole results, followed by initial flow test results from the Santos-Tamboran work programme and then EEG's own results, likely to be ready by next August-September.

Farm-In Read-Throughs

The recent Armour Energy 70% farm-out deal concluded with Santos on 4 December, over the adjacent South Nicholas basin provides a potential read-through to the type of agreement we suggest, EEG could negotiate. Armour had already released a best estimate prospective resource of 4.9 trillion cubic feet of conventional gas and 30Tcf of unconventional gas over its acreage, after drilling the first hydraulic fracturing well (Egilabria 2DW1) in Australia to flow hydrocarbons to the surface back in 2014. Its Santos deal involves an up-front payment of A$15m, together with a free-carry work programme commitment of up to A$64.9m on the relevant permits.

EEG executed a deal with AEP (American Energy Partners) on 24 December 2015, involving an upfront cash payment of US$7.5m, with a further US$7.5m payable as certain conditions were met. For the first 3 years (Phase One), AEP would be responsible for 100% of the work programme, up to US$60m (*including up to $15m spent over the first 2 years*). For Phase 2, EEG would have the option to self-fund or seek AEP assistance for its 20% share of a commercialisation work programme up to US$500m in value. That transaction did not proceed due to the passing of the founder Aubrey McClendon.

Permit Values – Northern Territory

The EP187 permit is the most advanced of the exploration portfolio, given:

a) land access clearance has been granted

b) the significant amount of regional drilling data available on "open file" with the Northern Territory ministry and its own historical drill results

c) recent EEG seismic programme with results expected in January 2020 and

d) planned 2020 drilling programme with approvals well advanced.

EEG is strategically choosing to initially focus on EP187, given the large amount of regional exploration expenditure being invested to firm up prospectivity in EEG's surrounding tenement areas and that the Velkerri shale is considered the largest unconventional gas prospect of the entire region.

Any farm-in achieved by EEG could generate a market value higher (or lower) than our ascribed NAV. Historical results achieved both by EEG and neighbouring tenement holders suggest, on a speculative basis, that the Beetaloo Sub-basin could achieve net returns of A$1 billion a year once fully operational. Much still needs to be achieved to actualise such sizeable returns, but we can see the attraction for upstream companies and investors alike.

EEG needs to achieve much heavy-lifting first, including

a) achieving successful drilling results

b) gaining a NT commercialisation permit

c) commercialising and distributing via links into regional infrastructure

Ascribing value to assets which lie at the conceptual pre-drilling stage can be arbitrary and typically reflected in the larger ranges between high-mid-low valuation scenarios. We note that this is the nature of small-cap stocks such as EEG, whose portfolio is dominated by large exploration "prospective resources". Where EEG benefits is in having a "great address in the right neighbourhood".

Land access negotiations with native title holders paused during the fracking moratorium and will recommence in 2020. We are not implying there is no intrinsic value in these assets, but rather are reflecting the very early stage nature of the activities and risks associated with ascribing timing and value to any future exploration activity with any confidence.

Investment in exploration companies is by definition a speculative undertaking but generally underpinned by the transformational potential of the assets and this applies to EEG where the success case outcomes on a number of projects in the portfolio offer 'multiples' points of upside.

The most critical variable in our valuation risk overlay will be any material positive changes (such as drilling success by EEG or regional tenement holders; or a farm-in partnership) that may have a multiplying effect on a read-through basis to other parts of EEG's portfolio.

Exhibit 2: Reserves as at 31 December 2018

Reserves - As of Dec 31, 2018	Oil (Mbbls)	Gas (MMcf)	MBoe	Capex $M	PV0 $M	PV10 $M
Reserves (Reserves)						
Proved Developed Producing	1,700	48,183	6,070	$29	$97,645	$34,337
Proved Developed Non-producing	579	-	476	$1,403	$14,145	$7,340
Proved Behind Pipe	361	-	139	$583	$5,054	$5,054
Proved Undeveloped	1,021	3,597	1,581	$14,807	$31,603	$8,172
Total 1P	**3,660**	**51,781**	**8,266**	**$16,821**	**$157,018**	**$54,904**
Probable	319	6,986	3,368	$8,968	$23,930	$3,986
Total 2P	**3,979**	**52,479**	**11,634**	**$25,798**	**$180,948**	**$58,890**
Possible	1,752	3,936	2,378	$24,590	$63,185	$11,967
Total 3P	**5,731**	**56,415**	**106,828**	**$50,388**	**$244,133**	**$70,856**
Prospective Resource P(50) - Aust (NT)	222,000	11,076,000	2,068,000			

USA Reserves by: Graves & Co Consulting
Northern Territory Resources by: Muir & Associates P/L and Fluid Energy Consultants

Source: Company data Note that most of the US oil reserves were part of the Mid Con assets sold to Mai Oil in September 2019

Permit Values – US Marcellus & Utica

The methodology applied to value EEG's portfolio of mature US conventional gas and oil producing assets using EEG's published reserve base is as follows. We have taken EEG's last reserve statement's proved and probable (2P) reserves of 57,038 MMcf, an average long term natural gas price of US$2.20 Mcf, which is lower than the US$2.80 Mcf used in the company's last reserve statement, the average long term AUD/USD exchange rate of $0.7285 and applied a unit NPV of 10%, 15% and 20% to obtain a low, medium, high valuation respectively of A$9m-A$26m with A$17m at the mid-point. EEG's Appalachian assets are listed on the balance sheet at a total recoverable amount of US$12.7m (A$17.6m) which includes both the existing conventional production and underlying shale rights (~US$5m).

SWOT analysis – NT drilling success potentially game-changing

As is typical for small resources companies, SWOT analysis reveals a fairly even spread between risk and reward.

Fresh investors are therefore taking a leap of faith that next year's NT drilling commencement will prove successful, generating significant strategic optionality and uplift to EEG's future value.

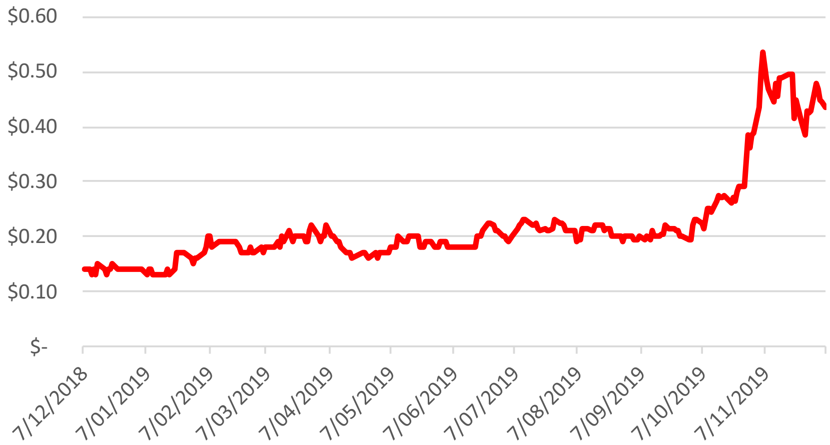
Exhibit 3: SWOT Analysis

Strengths	Comments
New Basin – first mover advantage	NT McArthur/Beetaloo holdings provide transformational "company-making" upside upon success
High equity retention across the portfolio	100% interest retained, providing stronger strategic optionality for partnering and financing (upon further drilling success)
Board & Management	Key Board & Management figures hold well-known distinguished corporate reputations; gained from large multi-national corporate experience at strategic, commercial & asset levels, with strong capital raising records
Assets proximate to infrastructure-hubs	Ready access to pipelines and plants enhances success factor economics
Low sovereign risk	Assets are located in low-risk developed jurisdictions with stable democratically-elected, transparent political regimes, financial stability & pro-carbon energy policies in the interests of self-sufficiency
Operational Experience	In-house well development & management expertise in the US Marcellus
Weaknesses	**Comments**
Exploration portfolio too large to be rapidly exploited by company's existing production & capital base	US production's marginal cashflows provides limited capex funding; NT permitting commitments will become more onerous: 24-month forward capital commitments estimates of up to $20m
Portfolio imbalance	Large NT exploration asset holdings relative to small US cashflow producing assets
Permit land access	Several EEG permits have yet to negotiate land access
Capital constraints/financing and reliance on short term equity markets	Raising funds (via equity or farm-ins) on a well-to-well success basis is not optimal for maximising funding access, pricing & forward planning from a position of strength & certainty
Portfolio almost exclusively exploration in nature	High risk nature of activity – at best Probabilities of Success (POS) on any well is likely to be in the order of 20% Energy exploration is highly capital-intensive Potentially long lead times to development post-drilling success
High equity retention across the portfolio	Where apparent strengths are actually weaknesses: large % interests carry burdensome sole-funding requirements, until assets are sufficiently evaluated to rate among third party partners, investors, debt funders as being of development potential.
Opportunities	**Comments**
Supportive macro investment theme – empowering Australia's East Coast energy supply self-sufficiency	The macro environment is strong and we suggest sustainable. Gas supply-demand scenarios suggest significant opportunities for new entrants. Local gas prices to remain high enough to incentivise further developments.
NT McArthur-Beetaloo project holdings as a new frontier with significant large corporate interest	Drilling success could attract rapid farm-in partnership(s) or M&A interest
Gas buyers can support additional supply sources	Players such as Santos have identified multiple potential gas end markets for Beetaloo basin gas
Threats	Comments
Regulatory regime reversal	Australia's main political parties support developing further gas as a "transition-fuel"; however opinions could reverse if Australia's electorate grows increasingly concerned about tackling the climate impact of carbons
Funding Access	Removal of debt & equity support for carbon energy businesses eg EIB
Accelerated development of renewables	Renewables (solar/wind) expand faster than expected as replacements to meet all Australia's future energy requirements; while investment & operating costs become competitive
Beetaloo Basin's hype proves entirely unfounded	Unconventional hydraulic fracturing developments fail
Rush to market too successful - earlier development success by other parties blocks access to infrastructure & customers & flood market, reducing pricing to sub-optimal returns	New provinces such as Beetaloo are being touted as sources of supply with scale to offset the likelihood of LNG imports. However, the addition of significant, new gas volumes could negatively impact the pricing and supply dynamics for smaller operators.

Source: RaaS analysis

Recent share performance discussion

Exhibit 4: Empire Energy's 12-month share performance



Source: Thomson Reuters, ASX

EEG remains the ONLY independent ASX listed junior explorer in the McArthur and the explorer with the largest tenement position in the region.

We believe EEG's recent share price activity has chiefly been propelled by the recent investment announcements made by Santos within the Northern Territory, who believes the Beetaloo to be the most prospective multi-Tcf shale basin (>500 Tcf) in Australia and on a world class scale. We note Santos has announced a farm-in deal into Armour Energy's NT Nicholson Basin assets and the US$1.4bln acquisition of Conoco's Darwin LNG and the Barossa gas field Operator interests. Origin Energy also indicated its belief in the prospectivity of the Beetaloo Basin during its recent investor day.

In our view, these announcements alerted the market to the high regard Santos holds towards the Northern Territory frontier oil & gas basins. These basins will deliver future optionality to supply its Darwin LNG export facility and potentially supply east coast Australian markets via either Jemena's Northern Gas pipeline; its own purpose-built line to join into its existing Moomba-Adelaide pipeline or even to join its Ballera gas hub piping into South West Queensland. Onshore sales options are becoming an increasingly viable, given the depletion of Cooper Basin conventional reserves. Empire's balance sheet repaid/deleveraging and strengthening of the board and management team over the past 2 years has also further enhanced the market's perception of the company.

We anticipate investors will be watching all future public drilling announcements from the Beetaloo sub-basin with keen interest in coming months, particularly from Santos (in JV with privately-owned Tamboran Resources) and Origin Energy (in JV with Falcon Oil & Gas). These will be the first publicly-available horizontal drilling results since the 2-year moratorium on fracking was lifted in the Northern Territory in April-2018. Notably EEG's tenements lie directly adjacent to the tenement on which Santos will be appraising its own Beetaloo sub-Basin recoverable gas options, particularly those within the Velkerri B shale formation. EEG's permit EP187 has already reported a prospective recoverable gas resource of 3Tcf lying within the Velkerri Shale.

Exhibit 5: Timeline of recent events

Date	News & Events of regional significance
10.12.19	Falcon Oil announces that drilling of the horizontal section of the Kyalla 117 N2-1H appraisal well had commenced. Phillip O'Quigley CEO of Falcon commenced that "ongoing evaluation of the Kyalla 117 N2-1 vertical appraisal well is very encouraging. The drilling of a 1,000-2,000 metre horizontal well in the Lower Kyalla shale has started"
03.12.19	Santos announces within its investor day presentation that the Tanumbirini-1 4 stage stimulation is complete and that the well is on flow-back
21.11.19	EEG raises $A12m in an over-subscribed placement to fund working capital & its 2020 Beetaloo EP187 drill program [30m shares @40 cents; via Morgans & Blue Ocean} (post-raising: 232,534,301 shares on issue)
13.11.19	EEG completes 231km 2D seismic program on EP187; 2 months (Feb2020) data processing to select drill pad locations within the Velkerri Shale formation for up to 2 wells in early 2Q 2020. With funding in place, EEG awaits NT EMP approvals and a signed contract with a drill-rig supplier.
20.11.19	Origin/Falcon: Kyalla 117 N2-1 Beetaloo appraisal well drilled to vertical depth of 1895m – showing "elevated gas shows with relatively high C3-C5 observed". 1000m horizontal fracturing to go ahead over the Top End wet season, then undergo extended (90 day) flow test. Final results due 2Q 2020.
30.10.19	EEG appoints David Evans as COO
23.10.19	Santos/Tamboran receives EMP approval for EP161 hydraulic fracturing program for 3 wells a) Tanumbirini-1 b) Tanumbirini-2H c) Inacumba-1H across November, then run a 90-365day test program. Positive early signs were reported at the Santos Investor Day (0.3.12.19) with gas shows being reported to surface.
23.10.19	EEG begins its first NT Ministerial-approved 2D seismic work program since the 3-yr moratorium
15.10.19	Armour Energy farm-out to Santos for EP172 & EP177 permits (10m acres) in the South Nicholson Basin, in exchange for a 70% A$65m operating interest. Armour is now seeking additional farm-in partners for its remaining Glyde & McArthur basin permits (774m acres) – deal concludes 4 December 2019
14.10.19	Santos acquires Darwin LNG stake from ConocoPhillips for US$1.39bln to become Operator (lifts stake from 11.5% to 68.4%); aims to sell down 25% to SK E&S to hold a net 43.4%; also buys Conoco's offshore Bayu-Undan (life end: 2022) & Barossa stakes; discussing offtake volumes from 2024 … Barossa FID expected early-2020 (contract 60-80% volumes 10yrs prior to FID) – assumes US$65/b oil – 20 yr life
	Darwin LNG has approvals to expand from 3.7mtpa to 10mtpa
09.10.19	Recommencement of hydrocarbon drilling in the NT – following a 3-yr moratorium.
	Origin/Falcon spud Kyalla 117 N2-1 appraisal well to test shale liquids-rich gas flow potential down to a depth of 1750m. The well is 32kms north of the Beetaloo W-1 vertical well drilled in 2016.
30.09.19	EEG completes sale of its US MidCon (Kansas/Oklahoma) energy assets covering c.16k acres for US$19.25m to Mai Oil and significantly reduces total debt from US$24.8m to US$7.5m
26.09.19	EEG receives Ministerial consent to commence $1.5m 2D seismic program on EP187 tenement
13.08.19	Origin/Falcon receives NT Environmental Management Plan (EMP) for Kyalla 117 N2 well appraisal
26.10.18	EEG corporate recapitalisation concludes; Macquarie Bank converts A$5.43m debt to equity, becoming largest equity holder (14.7%); agrees new US$26.5m debt facility. EEG raises further A$15m equity via share placement
06.08.18	EEG consolidates issued capital on a 1:10 basis

Source: Company reports; NT Department of Environment & Natural Resources https://denr.nt.gov.au/onshore-gas/environment-management-plan/approved-emps

Upcoming Activities

Significant further news flow is expected in coming months which is likely to impact EEG's investor interest levels. The Origin-Falcon JV plans to continue working across the NT's Top End Wet Season (typically November-April with up to 600mm of rain). After waiting without activity since 2016, Basin tenement holders are eager to firm up the region's full quantum and type of hydrocarbon flows (unconventional and perhaps conventional also), as well as its commercial capabilities. High hopes are held that results with prove game-changing, with enough gas (and liquids) proven to allow supplies both for hydrocarbon exports via Darwin and stable grid supplies into Australia's East Coast to keep the lights well-lit for many decades to come.

Exhibit 6: Upcoming activities

Companies	Activity scheduled
Origin / Falcon (Aiming to replicate Cooper-Eromanga Basin business scale)	Kyalla shale well: flow test results due 2Q 2020 Velkerri shale well: begin 2Q 2020; flow test results due 4Q 2020 (aiming for liquids-rich gas flows under production test conditions) Stage 3 follow-on: 2Q 2020 begin long-lead preparations for further 2 horizontal wells
EEG	1Q 2020 seismic results, 2Q 2020: 1 well drilling programme
Santos / Tamboran Resources	2Q 2020: a) EP161 Tanumbirini-1 extended flow test results b) drill/stimulate/flow test two horizontal wells
Santos / Armour Energy	2020 South Nicholson planning; 2021: 2D seismic & well tests
Hancock Prospecting	2H 2020: 2D seismics & 1-3 well vertical exploration drilling planned
Pangaea Resources	Awaiting NT EMP notification

Source: Company reports; NT Department of Environment & Natural Resources

The first step – focusing on the NT

EEG Business Strategy

Since the NT moratorium on fracking was officially lifted on 16 July 2018, EEG has undertaken a significant strategic pivot, turning away from its mature US oil and gas production assets and back towards home soil, reducing debt in the process.

With the first post-moratorium regional drilling programmes finally receiving NT government approvals in August 2019, excitement is building fast that shale gas production in the Beetaloo sub-basin could begin as early as 2021-22. The NT Fracking Inquiry economic assessment modelling suggested peak gas volumes could conservatively reach up to 910 PJ/annum by 2040, generating total annual revenues worth up to A$7.3b by applying today's price environment. Given the province must almost be considered speculative in nature with very few wells drilled, there is much work to be done to firm up the extent of both the gas and oil potential.

Empire's stated business strategy is to maintain its principal focus on firming up the value of its extensive NT acreage, while considering initiatives to improve the value of its US assets, potentially in readiness for a trade sale.

EEG has already completed the sale of its MidCon (Kansas) assets for US$19.25m in late-September. EEG's remaining US interests are located in the Marcellus and Utica Shale acreage within the Appalachia, servicing Pennsylvanian and New York State's gas consumption. Empire holds its Marcellus Shale and Utica Shale acreage at minimal cost on the balance sheet.

EEG completed an additional (over-subscribed) $12m capital raising in late-November 2019, taking the company to a "net cash" position, in preparation for its 2020, 1-well work programme, planned for its EP187 Beetaloo south-western tenement area. The aim is to evaluate the potential of the Velkerri shale formations as the primary objective and the Kyalla shale as the secondary objective.

The company is now fully funded for next year's drilling programme and EEG must secure its NT drilling approvals and the services of a drill rig. Origin/Falcon have contracted the services of Ensign Australia to supply Rig 963 for its 2019 programme, with an option to extend the contract into 2020. EEG may be able to share.

Exhibit 7: EEG's acreage by location

Location	Total (gross acres)	Marcellus	Utica
NY*	262,260	262,260	127,757
PA	15,198	8,293	6,975
NT	146,000,000		

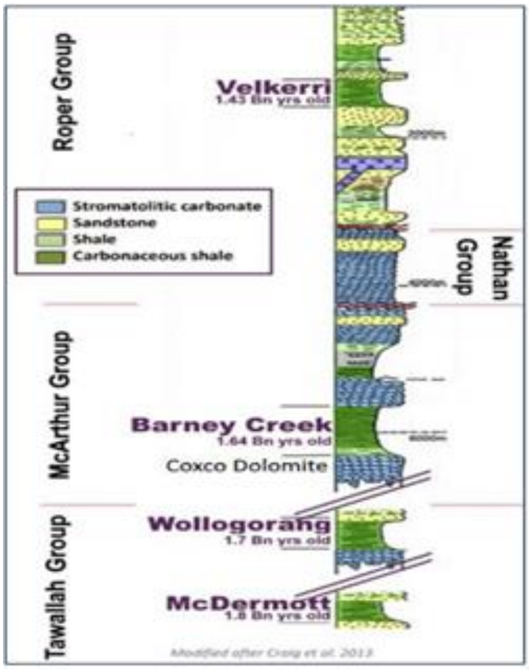
Source: Company reports *Note: EEG's NY acres are not approved to conduct unconventional drill programs due to the State fracking ban

Australian portfolio

Shale in Australia

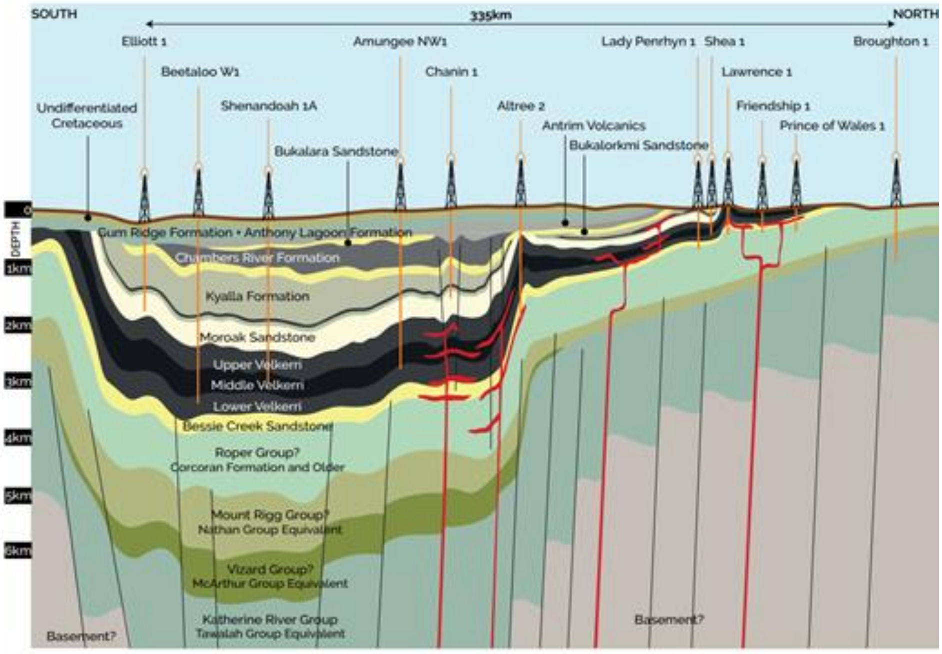
Some 27 Australian eastern and northern basins are considered prospective as tight and/or shale gas plays, with four of them at the appraisal stage, including McArthur, Cooper, Gippsland and Isa with a further five at the exploration phase, encompassing the Amadeus, Bowen, Clarence-Moreton, Georgina and Otway (onshore) basins. Activity in the Eromanga Basin has ceased due to poor results.

Exhibit 8: McArthur – Beetaloo shale formation focal points



Source: Company reports

Exhibit 9: Beetaloo South-North schematic cross-section showing Kyalla and Velkerri formations



Source: NT Department of Primary Industry & Resources

There **are 4 key shale** formations which are of most interest within EEG's tenements: Kyalla; Velkerri; Barney Creek; and Wollogorang-McDermott in the Tawallah Group.

The **Kyalla** formation (within the Roper group) is the shallowest of EEG's four target formations and hence regionally has the most well penetrations and has been studied in some detail. The formation overall comprises interbedded siltstone, mudstone and very fine-grained quartz sandstone, having a gross thickness of up to 900m. It has informally been separated into three source rock intervals comprising the lower, middle and upper Kyalla shale units, with most commercial interest being ascribed to the lower Kyalla shale unit, which has recorded elevated levels of hydrocarbon gas-liquids.

The **Velkerri** shale formation (within the Roper Group) is up to 1.43b years old (Meso-Proterozoic) and up to 600m thick, with laminated black carbonaceous siltstones & mudstones with sandstones beneath. These are located in the south-western areas of EEG's permits, EP 184, 187, 188, which cover an area of 2,500 sq km. Brittleness due to favourable mineralogy indicates the shale formation should be readily amenable to hydraulic fracturing, with solid hydrocarbon potential. An independent P50 resource containing 1.2 Tcf and 24 mmbo has already been ascribed to EEG's permits.

The **Barney Creek** shale formation is up to 1.64b years old (Palaeo-Proterozoic) and has a thickness of up to 900m, with anoxic (without-oxygen) sulphur-rich black gas shale and dolomites beneath. This formation is located across the majority of EEG's permits, which cover an area of over 25,000 sq km. The formation may be one of the oldest petroleum systems in the world. Mineralogical and rock property investigations indicate the Barney Creek formation is amenable to hydraulic fracturing, as evidenced by low clay mineral content augmented by extensive dolomitic diagenetic cements. An independent P50 resource containing 8.7 Tcf and 174 mmbo has already been determined within EEG's permit zones.

The **Wollogorang-McDermott** shale formations (within the Tawallah Group) are up to 1.8bln years old (lower Proterozoic) containing dolomitic sediments with a thickness of up to 100m and TOC (total organic carbon) levels of up to 7%. An independent P50 resource conservatively containing 1.2 Tcf and 24 mmbo has already been determined within EEG's permit zones, which cover an area over 6,000 sq km. BHP had originally drilled into the McDermott formation in 1995, with live oil shows reported.

Commercialisation – speed and potential

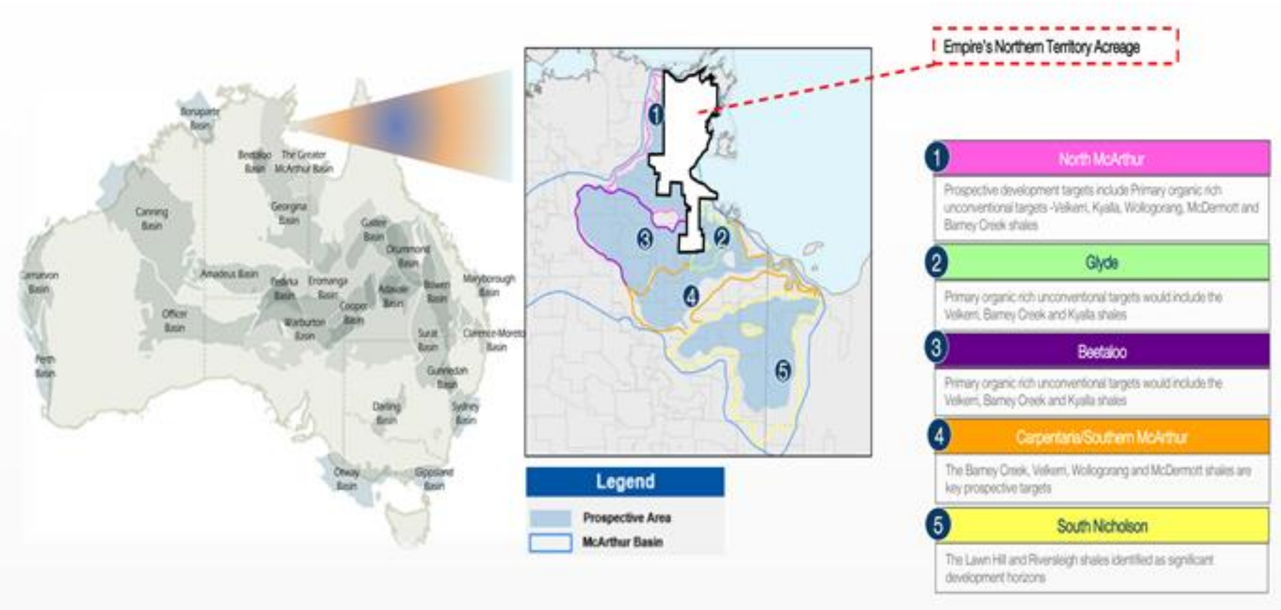
Recent studies have suggested shale gas production in the Beetaloo sub-basin could commence as quickly as 2021-22, assuming infrastructure linking into the Northern Gas Pipeline and/or Moomba pipeline has been built to supply Australia's east coast markets. Gas production under various Inquiry scenarios foresaw initial rates beginning at 33.4 TJ/day in 2022, rising to as much as 1000 TJ/ day by 2035/40. Feedstock from the region could also begin to replace some of the supplies for Santos-run Darwin LNG facilities. This would require expanding the Amadeus Gas pipeline infrastructure.

Exhibit 10: EEG's permit areas and resource potential

Formation	Permits	Geological factor discount	Area m acres	Units	P90	P50	PV10
Barney Creek	EP184, EPA180, 181, 182,183,188	50-90%	3,559	Bcf	3,304	8,699	20,172
		50-90%		MMBO	66	175	403
Velkerri	EP184, 187, EPA188	50%	315	Bcf	383	1,192	3,086
		50%		MMBO	8	24	62
Wollogorang	EP184, 187, EPA188	90%	1,384	Bcf	524	1,185	2,371
		90%		MMBO	10	24	47
Total				**MMBOe**	**851**	**2,238**	**5,183**

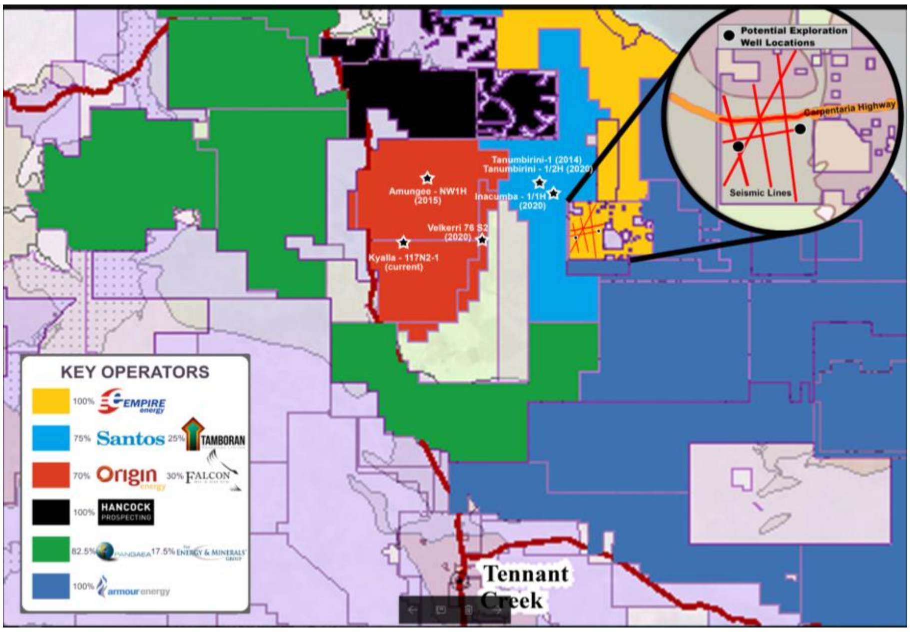
Source: Company reports; Note: EEG's P(50) resource is equivalent to over 13 Tcf

Exhibit 11: Empire Energy's Northern Territory acreage location



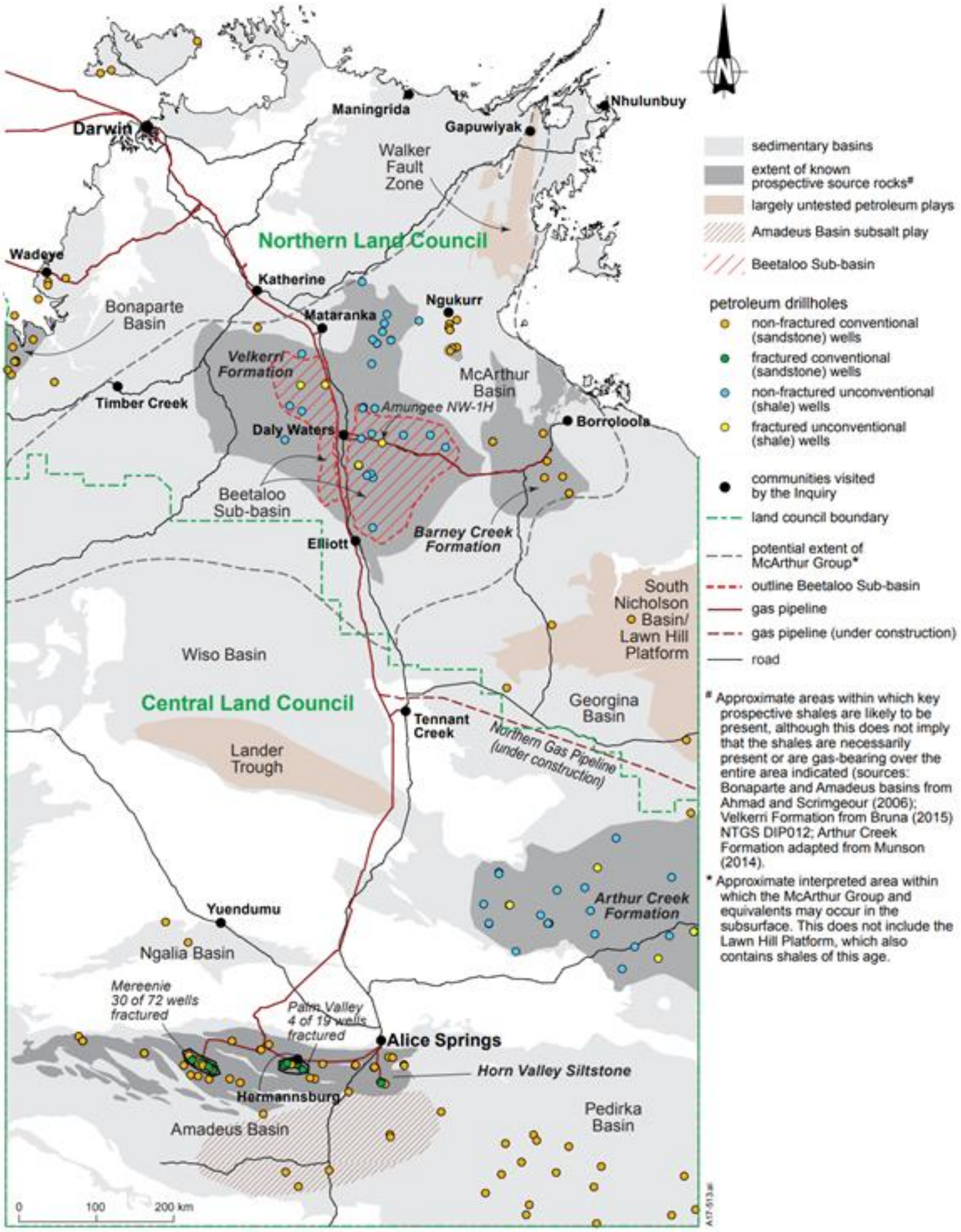
Source: Company reports

Exhibit 12: Potential exploration well locations with the Origin/Falcon Velkerri 76 S2 well included



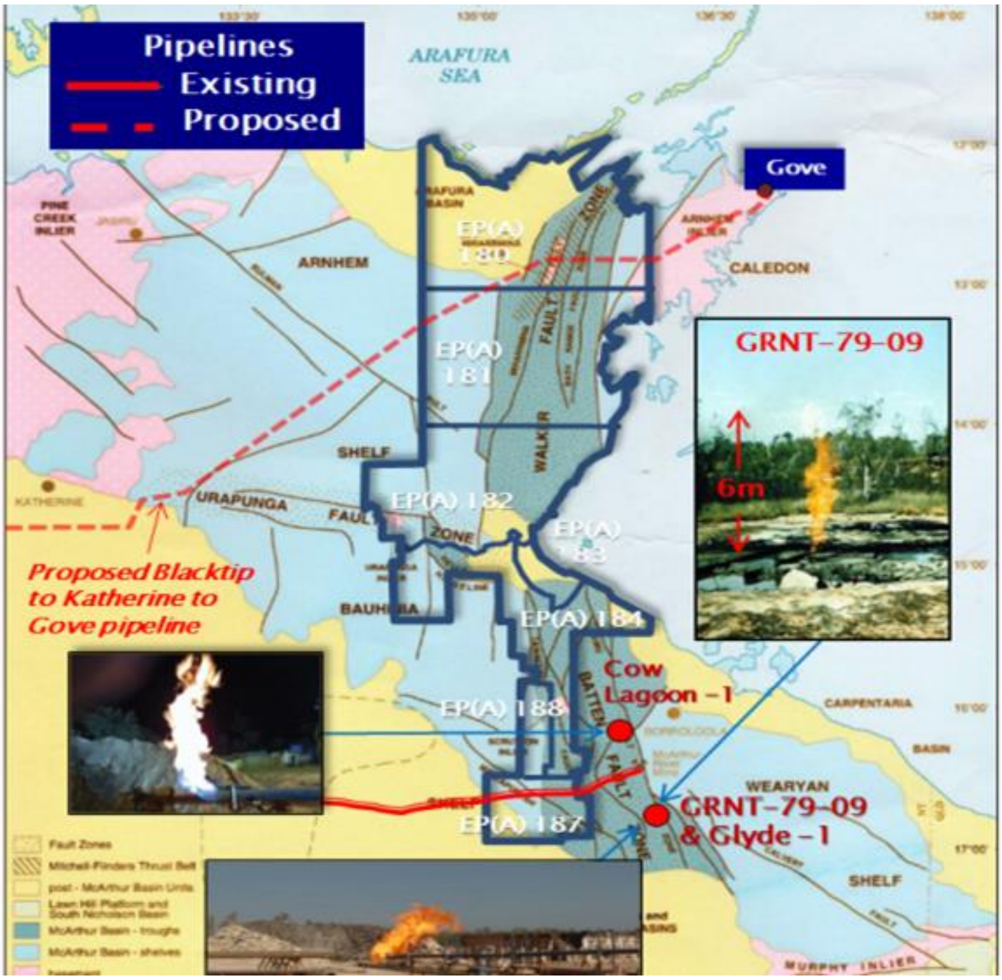
Source: Empire Energy Group

Exhibit 13: McArthur and Beetaloo basin locations



Source: NT Department of Primary Industry and Resources

Exhibit 14: Permits proximity to existing and proposed pipelines



Source: Empire Energy Group

EEG's permits constitute a high risk/high reward frontier play, with very low historic exploration maturity, aimed at identifying both oil and gas targets which may be contained within the various layered black shale reservoirs.

The ~1.5Bn year old Proterozoic region is considered strongly prospective for fuel and is currently undergoing a significant ramp-up in appraisal activity by a number of major Australian oil and gas operators, including Santos and Origin, following the NT moratorium lift in April-2018. Over $800m has already been drilled or committed to future developments within the province. The Basin is being compared to the rich hydrocarbon basins of Oman, Siberia and Southern China. Success could be transformational for Australia's future energy security.

Following the lifting of the 2-year Northern Territory fracking moratorium covering onshore shale activities in April-2018, the road is finally clear for Empire to begin firming up the economic value of its McArthur-Beetaloo Basin holdings.

Empire intends to drill a well in 2Q subject to the granting of environmental approvals (a five-year term) and sourcing a drilling rig. The five-year approval period will be beneficial should the first wells prove successful, by providing the company significant operating flexibility to build out further drilling activities on its EP187 permit.

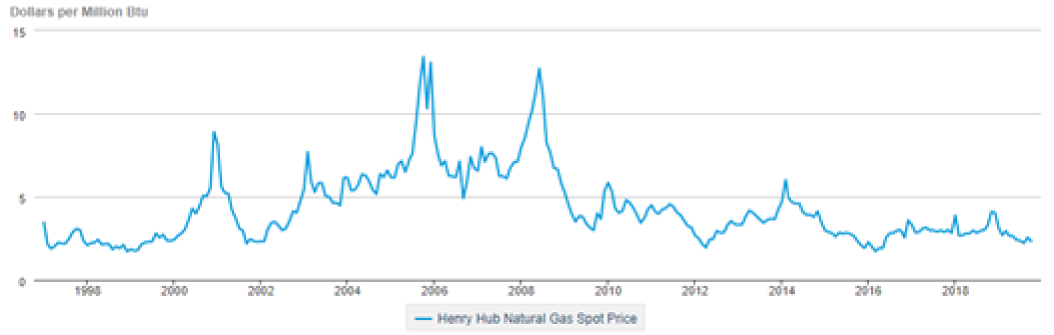
All approved NT EMPs can be seen here: *https://denr.nt.gov.au/onshore-gas/environment-management-plan/approved-emps.*

EEG recently completed a 230km 2D seismic survey over EP 187 in mid-November 2019. The results are currently being evaluated and integrated with existing open file data, to select the best drilling locations.

EEG's main intended regions of operation have no pastoral stations or agriculture and few permanent communities on them. EEG can draw on a workforce from the surrounding communities of Ngukurr, Numbulwar, Hodgson Downs, and Borroloola, as well as communities farther afield. This will provide opportunities for training and infrastructure development, without adversely impacting the environmental, social and community values.

US Portfolio

Exhibit 15: Henry Hub Natural Gas Spot Price (in US$)



Source: EIA

In the US, EEG is producing ~4,700mcf/d of gas and ~9bopd of associated liquids, generated from its 13.7mm boe 2P Appalachian reserve holdings in Pennsylvania. 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.

Low gas prices, remaining below US$3/mBtu, are straining the cash-generating capabilities of the US business. EEG is prudently protecting its NYMEX downside pricing risks via a long-standing put option and swap hedging strategy, with FY20 PDP gas volumes being ~80% hedged at US$2.50/mBtu. Additionally, EEG can monitor each individual well on a daily basis, optimising each well to produce profitably.

At current gas prices, new development drilling in the Appalachia is uneconomic, crimping growth potential, with the company choosing to maintain production rates at existing wells only, supplemented by the occasional well acquisition program where achievable at profitable rates. The outlook for NYMEX and WTI pricing is dependent on a number of factors, including macro and seasonal demand; and US onshore gas supply growth (or contraction) rates.

EEG first entered the US in March 2006, negotiating a JV with American Natural Resources LLC Pennsylvania, as part of a strategy to target and acquire hydrocarbon assets in the Appalachian Basin ready for IPO, leveraging the local contact network built up by former executive chair, Bruce McLeod.

The Appalachia is the oldest oil and gas producing region in the US, crossing the borders of New York, Pennsylvania, Ohio, West Virginia and Kentucky). EEG first commenced a natural gas development program in Cambria county, Pennsylvania, with all 20 of the first development wells proving successful. EEG held a 61% net revenue interest in any output generated. Over the years, EEG has continued to buy and sell acreage, funded by Macquarie Bank loans. Empire does not presently intend to add to its US asset holdings.

EEG's Mid-Con assets, sold in 2019 for US$19.25m

Exhibit 16: Mid-Con Pre-Sale Work Enhancement Program

Well Name	Working Interest (%)	Net Revenue Interest (%)	Net Capital Investment	Gross Production Rate (BOPD)	Net Revenue Interest Production Rate (BOPD)	Gross Cumulative Production (barrels)	Net Revenue Interest Cumulative Production (barrels)
Carmichael A #15	93%	79%	$ 14,296	3	2.5	340	268
Kollman #15 - Stage 1	84%	71%	$ 14,142	-	-	-	-
Carm-Koll WU #3	93%	79%	$ 12,215	-	-	110	87
Carmichael A #16	93%	79%	$ 62,643	32	25	2,104	1,667
Kirkman #2	91%	77%	$ 48,759	15	12	2,237	1,730
Helmers Unit #1	86%	73%	$ 41,972	12	9	1,791	1,306
Kollman #15 - Stage 2	84%	71%	$ 15,912	16	11	966	690
Siefkes A #13	78%	66%	$ 45,137	45	30	1,560	1,031
Siefkes #12	89%	77%	$ 10,694	1	1	78	60
TOTAL			$ 265,771	124	90	9,186	6,838

Source: Company reports

On 30 September 2019, EEG announced the sale of its Mid-Con (Kansas assets), purchased in Dec-2010, to Mai Oil Operations Inc for US$19.25m. Outstanding debt was reduced by US$17.3m to US$7.5m, with the remaining US$1.5m of the sale proceeds applied to working capital and growth project options. In 2018, prior to sale negotiations, EEG undertook a work enhancement program on its Mid-Con (Kansas) assets. The primary motivation aimed to validate the value of the assets to potential acquirers. A total of US$265k was invested to carry out workovers and re-completions on 10 wells from Nov-18 until Jan-19 to increase production rates to 90 bbl/day.

Following the sale, Empire retains a stake in the positive cashflow Appalachian gas production assets in New York and Pennsylvania, together with shale acreage in the Marcellus and Utica areas of New York State, which are on the balance sheet at a minimal holding cost.

Financials

EEG operates on a December year end and currently reports in US$, reflecting the location of the company's current operating assets. In striking our forecasts, we have used the following commodity prices/exchange rates.

Exhibit 17: Commodity and exchange rate assumptions used

Assumptions		2019E	2020E	2021E
Realised oil price	US$/b	60.03	53.43	51.72
Realised gas price	US$/mcf	2.86	2.40	2.44
Exchange Rate	A$:US$	0.6945	0.6807	0.6848

Source: Nymex WTI Crude – CME Group, US Gas Prices - EIA.gov, Investing.com – AUD/USD

Our revenue forecasts assume that the US Appalachian assets generate respectively 1,728 Mcf, 1,702 Mcf and 1,685 Mcf in 2019, 2020 and 2021 and sold at the prices listed in the table above. Expenses include field costs and all in lifting costs.

Exhibit 18: P&L forecasts

Year ending Dec 31	FY19e	FY20e	FY21e	In US$000's
Revenue	6,670	4,450	4,472	Revenue generated by US assets (assuming US$2.40/mcf gas price in FY20 and US$2.44/mcf in FY21
Expenses:	(5,167)	(3,292)	(3,313)	FY19 includes $0.2mn of Exploration Expense Writeoff
Gross Profit	**1,503**	**1,157**	**1,159**	
Other revenue/income	208	200	200	
Net Loss	(7,389)	(3,019)	(3,020)	Expected to remain in loss through forecast period.
EPS (A$ cps)	(6.13)	(1.47)	(1.40)	

Source: RaaS estimates

Debt Reduction Programme

EEG began 2018 with debts of US$38m. By year end 2018, these had reduced to US$24m, following a $5.3m debt-to-equity swap with Macquarie Bank (at 14.68% interest) and a separate equity capital raising securing a net $11.7m in August 2018. So far this year, EEG has sold its US Mid-Con production assets to raise US$19.25m and subsequently raised a further $12m via an investor share placement. As a result, the company is now in a net cash position of ~A$5m (A$15m in gross cash and US$7.5m in project finance set against the Appalachian free cashflows). We expect A$5m will be applied to next year's 2Q, 1-well drill program. Although the intangible value of becoming "net cash" is hard to quantify, EEG management has gained significant additional negotiating flexibility now in dealing with potential farm-in suitors.

The company has also put in place a new US$7.5m 5-year debt facility with Macquarie Bank on improved terms which will see the cashflow after operating cost from Appalachia gas production service this debt. Our forecasts reflect debt repayment form the US operations as set out in our Balance Sheet and Cashflow forecasts below.

Exhibit 19: Balance sheet forecasts

Year ending Dec 31	FY19e	FY20e	FY21e	In US$000's
Cash & Equivalents	9,888	9,873	4,949	
PP&E & Development	30,897	33,662	40,112	
Exploration	410	369	332	
Total Assets	43,486	44,783	46,274	
Debt	7,575	6,052	4,037	Debt repayment from US operations
Total Liabilities	24,353	27,129	29,274	
Total Net Assets/Equity	19,133	17,654	17,001	
Net Cash/(Debt)	2,313	3,821	912	

Source: RaaS estimates

Exhibit 20: Cashflow forecasts

Year ending Dec 31	FY19e	FY20e	FY21e	In US$000's
Operational Cash Flow	205	138	429	
Net Interest	(1,919)	23	45	
Other	(84)	(30)	(30)	
Net Operating Cashflow	**(1,799)**	**132**	**444**	
Exploration	0	(6,000)	(4,000)	
PP&E	(113)	0	0	
Petroleum assets	(19)	0	0	
Net asset sales	19,725	(382)	(694)	
Net Investing Cashflow	**17,794**	**(6,250)**	**(6,250)**	
Net debt drawdown	(17,936)	(1,998)	(2,015)	
Equity Issues (after costs)	7,739	8,101	2,897	Assuming in the money options are exercised in FY20 & FY21
Net Financing Cashflow	**(10,209)**	6,103	882	
Net Change in Cash	**5,787**	**(15)**	**(4,924)**	
Closing net cash	**2,313**	**3,821**	**912**	

Source: RaaS estimates

We also anticipate that the current in-the-money options (~52.85M) are exercised in FY20 and FY21, delivering an additional US$11m in equity capital. Note that on our estimates net cash at the end of FY21 falls to US$0.9m, flagging the possibility that additional capital may need to be raised in FY21.

Risks Assessment

Normally the most critical factor in determining and delivering any resources project is, in our view the prevailing commodity price. 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.

Permitting and Title

The NT Government owns all petroleum assets in the State and therefore has full control over the granting of concessions for energy exploitation purposes. Any exploration permit is granted for 5 years, with two further 2-year renewals available to applicants (covering a total of 9 years). However, at each renewal, a company must reduce each permit's acreage by 50%.

A retention licence can then be granted, with a 5-year renewal term, aiming to provide security of title over discoveries that are being made commercial; then a production licence. A 10% gross value at wellhead royalty will be levied on any successful flows sold commercially.

An "Access Authority" must accompany the granting of any exploration permit. This has been a sticking point in the region. Negotiations must be successfully concluded with landowners, which may include Pastoralists or Tradition Owners, covered by various commonwealth and state acts, including the Aboriginal Land Rights (NT) Act 1976 and the Native Title Act 1993.

Below we set out the permissions granted on EEG's permits.

Exhibit 21: Permit permissions EP184 and EP187

Permit	Permissions granted
EP184	5-Feb-14 (ALRA & Native title lands – St Vidgeon)
EP187	23-Jun-13 ALRA

Source: Company data

Exhibit 22: Permit permissions EP180-183 and EP188

Permit	Permissions
EP188	Recommencing Traditional Owner Negotiations in 2020
EP180	Recommencing Traditional Owner Negotiations in 2020
EP181	Recommencing Traditional Owner Negotiations in 2020
EP182	Recommencing Traditional Owner Negotiations in 2020
EP183	Recommencing Traditional Owner Negotiations in 2020

Source: Company data

Applications have been made by EEG in 2010 to secure permits over the EP blocks: 180-183 and 188. Discussions remain ongoing with the various landowners to gain access authority to those tenements. Traditional Owners have a 5-year right of veto, with no effective right of appeal available under the Aboriginal Land Rights (NT) Act 1976 (ALRA). All these applications require consent under the ALRA before they will be granted.

In June 2019, the NT Government instituted a "Petroleum Reserve Block" policy that affords the Territory the ability to declare parks and reserves; sites of conservation significance and Indigenous Protected Areas as "reserved blocks" over which an exploration permit cannot be granted.

Negotiations however are ongoing with the NT authorities to provide a workable and equitable win-win solution for both side over Empire's impacted blocks. It is highly likely Empire's difficulties negotiating access authority with landowners has been held back due to these same "reserve" concerns.

Empire has also applied for permits EP319 – 342 which were non-consent areas within EP187.

There is a risk that community pressure results in a return to the moratorium against fracking, although at this point the Northern Territory Government appears supportive of development of the region.

NT petroleum royalties

The Northern Territory is the ultimate owner of all below ground minerals and hydrocarbons. Energy royalties in the Territory, charged in consideration of gaining extraction rights, are payable at the rate of 10% of gross value at the production wellhead. There are 3 methods by which gross value can be determined: a) arm's length sales contract; b) comparable sales (time; quality; quantity) or c) net-back basis by subtracting reasonable post-wellhead costs from actual sales or market value at the first point of sale. Negotiations were suspended with Traditional Owners during the moratorium and will recommence in 2020 with on-country meetings planned through the Northern Land Council.

There is always a risk that the government increases the royalty rate or imposes additional tariffs that limit the financial viability of development.

Native title

Six of EEG's permits lie on Aboriginal freehold lands. Exploration access therefore requires approval from Traditional Landowners, which are the Yolngu people of East Arnhem Land,. There are 5 main clan groups, including Gumatj; Rirratjingu; Djapu; Madarrpa and Dhalwangu. The remaining land lies either on Native Title areas or in the Limmen National Park. EEG has been negotiating with Traditional Landowners for access to some of its permits for nearly 10 years. Ongoing infighting amongst local community groups could prevent finalisation of these access discussions.

Financing

Some of the key funding risks we see for Empire Energy are as follows:

- East Coast commodity prices decline due to increased supply resulting in reduced favourable metrics on EEG's projects;
- Key partnerships are formed among other players, leaving EEG stranded on JV options
- Banks restrict lending to new fossil fuel projects
- Community opposition to fracking projects restricts access to equity and debt capital

Environmental/Geopolitical

Globally, there is increasing demand for countries to reduce carbon emissions, which in turn is leading to a shift away from fossil fuels. Pressure is likely to continue on governments which permit fossil fuel development which in turn could lead to increased regulations constraining operators' ability to commercialise projects. While frameworks are in place, public pressure could result in these being amended to adopt more stringent requirements.

Technical

Drilling will likely require 50-60M litres of water to stimulate each horizontal well. There is a risk that access to regional aquifers is denied by local communities in preference for horticulture irrigation and faming. Other technical issues relating to water include the aquifer yield rates and water salinity levels.

Although we rate the regional potential highly based on the 2014 and 2015/16 drilling results, there remains the risk that the formations don't continue into EEG's permits or are too irregular to make commercialisation feasible. Until seismic further derisks the plays, this will remain a key risk. Seismic will demonstrate continuation of the shales into EP187.

To market; to market

Assuming commercial extraction is proved, EEG will have 3 primary options to market:

a) Sell domestically into the local mining community
b) Sell to Darwin for LNG export
c) Sell domestically to east coast Australia markets via either the Wallumbilla or Moomba hubs including Gladstone located LNG projects which remain short gas

The key benefit of having so many sales options for McArthur-Beetaloo supplies will be the ability for Producers to arbitrage between domestic and export demand differentials and consequent pricing conditions.

LNG Export Market Dynamics

Global seaborne LNG shipments in 2018 reached a record 316-320mt, up c.30mt (10%) yoy, with a further 35mt supply increase expected in 2019. Over 100mt is under construction, largely related to building export outlets for US shale gas. Meanwhile highlighting the beginning of the developing near-term seaborne LNG oversupply situation, 2018's total LNG seaborne demand was c.10mt below supply, at around 308mt, although up from 284mt in 2017 and tripling since 2000.

China became the world's largest importer of gas (pipeline & LNG) in 2018, with purchases amounting to 90.4mt. Japan is still the world's single largest seaborne importer of LNG (with a third supplied by Australia), although its demand is expected to taper as the country's nuclear capacity, comes back on-line, opening the way for China to surpass it. Korea is in third place (importing c.35mt annually).

The US is growing its LNG export capacity with five export LNG trains opened, including Sabine Pass and Cove Point (an import terminal retrofit), , with the potential for up to 14 additional export sites for a total liquefaction capacity of ~10 Bcf/day (76mtpa) by 2021.

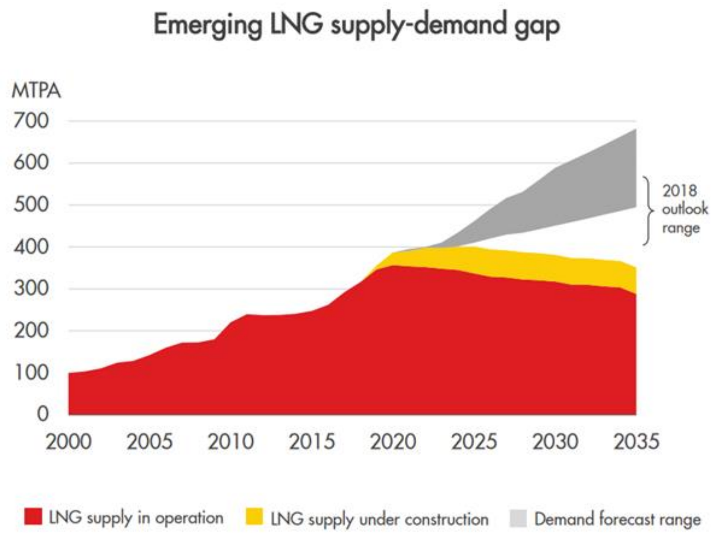
Russia has expanded its export capabilities with the opening of Yamal in 2017 and Sakhalin in 2018. New trains and improved utilisations in Australia, Cameroon and Qatar have also added to the increased output.

Australia has recently surpassed Qatar to become the world's largest LNG exporter, supplying over 10 Bcf/day (76mtpa). Since 2011, Australia's installed LNG export capacity has increased from 2.6 Bcf/d, to 11.5Bcf/d (c.87mtpa) in 2019, with 8 new LNG projects coming on-line since 2012.

Future global demand growth is expected to be underpinned by Asia, particularly Vietnam, Thailand, China, India and Korea. Europe is expected to grow, given thermal replacement initiatives and declining domestic supplies, either taking piped gas from Russian or via LNG cargo imports from those such as Qatar and the US. China is also set to receive more piped gas from Russia, with the opening of the 175 Bcf Siberia line in 2020.

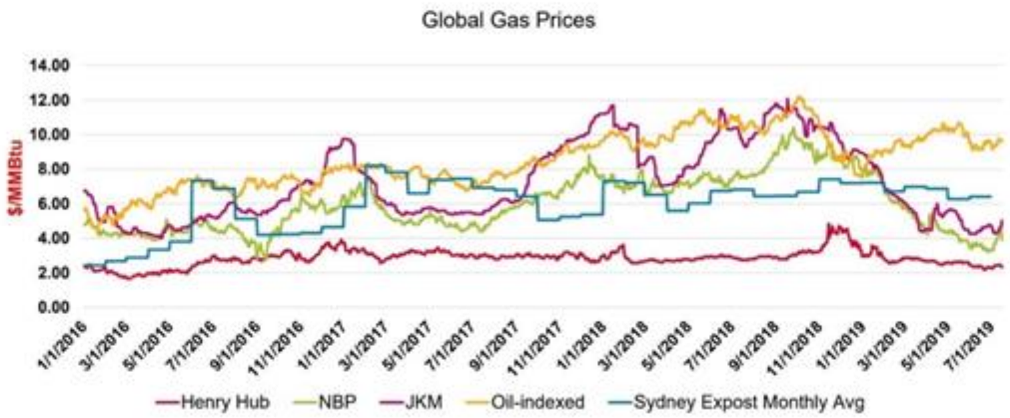
Despite the strong overall Asian growth drive in coming years, with global LNG demand forecast to reach 450mt by 2030 and up to 700mt by 2035, there are concerns the market may be in oversupply until at least 2023. However, forecasters such as Shell, believe a supply deficit will re-emerge from 2025.

Exhibit 23: Emerging LNG supply-demand gap



Source: Shell LNG Outlook 2019

Exhibit 24: Global gas prices



Source: Platts Note: oil indexed calculated as 13% x Brent +$1

Seaborne LNG price setting mechanisms

Given inadequate liquidity and the ability to switch between fuel sources, global LNG prices had traditionally been linked to a basket of crude oil prices adjusted on a three-month lag with contract re-openers, typically every five years. Since these indexed prices were typically agreed as part of long-term bilateral contracts, which further stilted liquidity, no separate observable pricing mechanisms developed for the internationally traded gas sector, despite having potentially separate fundamentals to oil.

A growing number of disruptive influences in recent years is serving to chip away at these traditional LNG pricing practices. With the more recent demand pull from Asia and supply push from the US and Australia, the LNG market fundamentals are increasingly de-coupling from oil, causing pricing parameters to becoming more fragmented. With more and more tonnes sold on a spot basis (up to 45-50% of total cargoes via global traders), the increase in observable daily cargo prices is allowing a range of new representative price indices to develop, particularly the JKM (Japan Korea Marker) daily price marker.

Potential downstream customers for the McArthur-Beetaloo

a) The local mining community (Domestic Industrial Supply)

Exhibit 25: Proximity of McArthur-Beetaloo to local mining centres

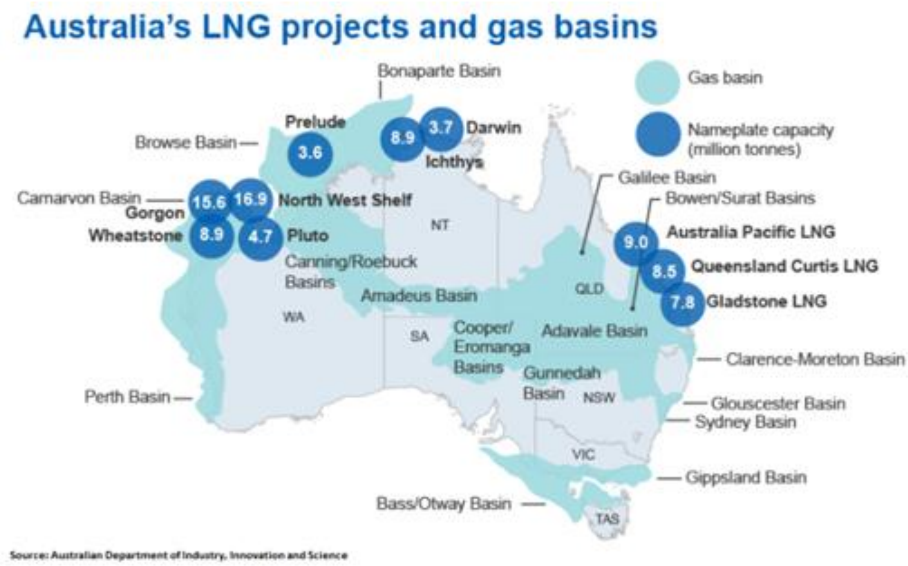
Source: Company data

The McArthur-Beetaloo basins are strategically located near several existing mining centres including the Gove bauxite mine (80kms away and with an expected mine life until 2032) and the Glencore McArthur River zinc/lead/silver open cut (which has recently been given NT government approval to 2048 and pending its Aboriginal Areas Protection Authority certificate clearance). An existing gas pipeline already travels west-east through EEG's EP 187 permit. However, some considerations include:

- Individual mine requirements are likely to be small particularly with the shut-down of refinery operations at Gove in 2013
- Likely need to aggregate for critical mass to commercialise a significant development, but small contracts could provide the opportunity at least for early cash flow to support financing of large-scale expansions opportunities
- Supply options will be dependent of new infrastructure development (pipelines) which come with their own economic requirements.

b) Australia's north-east gas-Liquids exporting community

Exhibit 26: Australia's LNG projects and gas basins



Source: Australian Department of Industry, Innovation and Science

Exhibit 27: Australian LNG operations

NT LNG	Total LNG Capacity (mtpa)
Darwin LNG (since 2006)	3.7 (single-train) (~200PJ/yr)
Ichthys LNG (since Oct/Nov 2018)	8.9 (2 trains)
QLD LNG	**Total Capacity (mtpa)**
Australia Pacific (since Oct 2016)	9.0 (2 trains)
Queensland Curtis (since Dec 2014	8.5 (2 trains)
Gladstone (since Oct 2015/May2016)	7.8 (2 trains)

Source: Company reports
Note 1: Clients of the 3 Qld LNG facilities include China, Singapore, South Korea, Japan, Malaysia and India
Note 2: Darwin exports c.200 PJ /year

For Australia's north and east coasts, the "capital-heavy" LNG export investment has already been made. Darwin has two LNG export terminals, while a further three have been constructed on Queensland's Curtis Island near Gladstone.

In October, Santos announced the purchase of ConocoPhillips' 56.9% operator stake in the Darwin LNG plant increasing its working interest to 68.4% of the asset (although intends to sell down a 25% stake to SK E&S) and will take over the role of plant operator. The plant has a capacity of 3.7mtpa, with (critically) approvals to expand to 10mtpa.

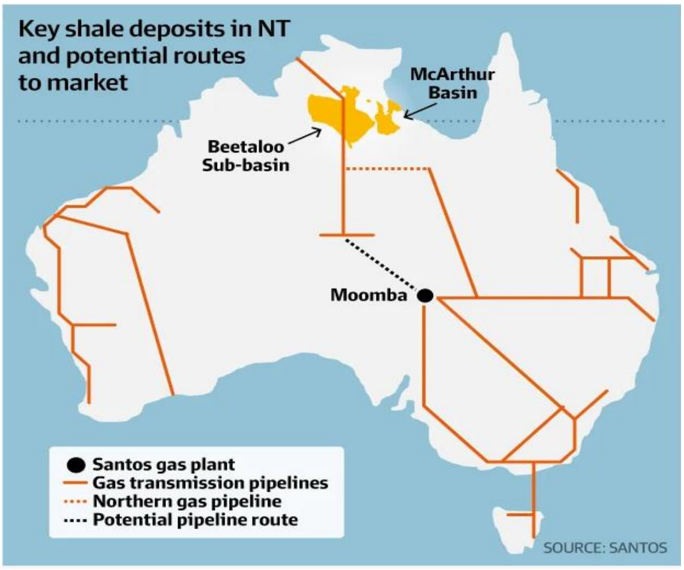
The Bayu-Undan field is providing existing feedstock for the Darwin plant but is expected to be depleted by 2023. At that time the Barossa is expected to provide long term gas supply. Santos anticipates making a funding decision in early 2020, subject to contracts for 60-80% of the volumes being signed for Barossa. Barossa would be developed via a floating production, storage and offloading (FPSO) unit and a 260-km pipeline into Darwin LNG. Spending has been estimated at $4.7bn, with first gas forecast to flow from 2024.

Some key themes beginning to emerge include:

- NT Government has declared intention to make Darwin a LNG hub
- Looking for multiple trains either as brownfields expansions of greenfields builds
- EEG opportunity is to be a third-party supplier of gas into this emerging gas hub – details as to how it will operate (a traditional model or the US gas tender model) are yet to crystallise and expansion plans are yet to be announced
- Provides a potential pathway of scale – given the suggested size of the resource scale will be required to provide a meaningful development and commercial platform (underpin the capex costs of infrastructure – wells, plants, gas gathering and compression, pipelines)

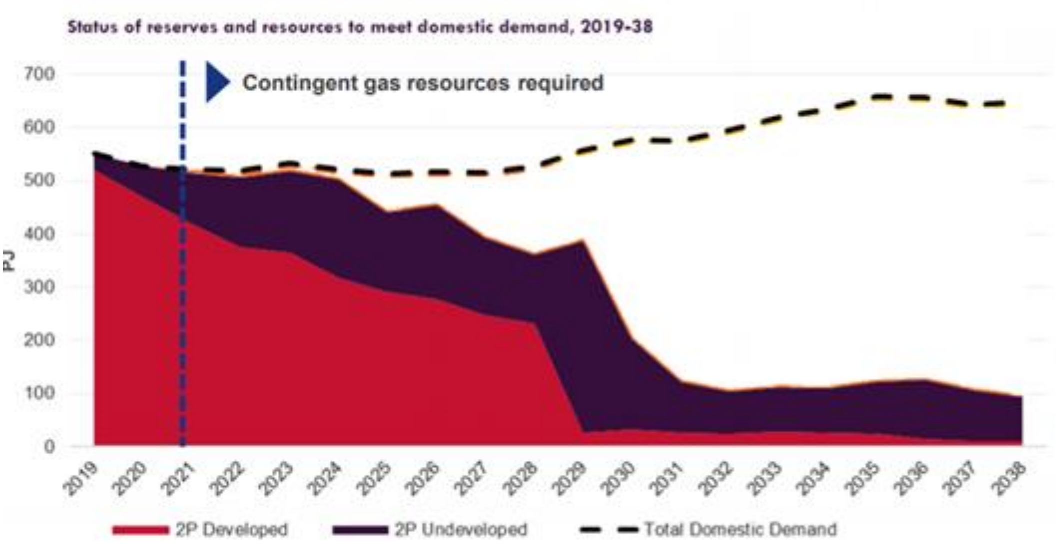
Darwin's other LNG project is the $47b INPEX's Ichthys facility, with capacity of 8.9m tonnes a year, is fed from the 12 Tcf Ichthys offshore field via an 890km pipeline.

Exhibit 28: NT shale deposits and access to markets



Source: Santos

Exhibit 29: Status of reserves and resources to meet domestic demand 2019-2039



Source: Jemena September 2019 presentation

c) Australia's domestic pipeline community

Exhibit 30: Northern Territory regional pipeline capacity

NT Regional Pipelines	Total Capacity
Amadeus (Mereenie)-Darwin 1629km pipeline (bi-directional / conventional)	16-24 PJ/year Could also build connection to Moomba hub
Northern Gas 622km Pipeline (since Dec 2018) (Jemena: JV China State Grid/Singapore Power)	73 PJ/year (200 TJ/day) (Tennant Creek-Mt Isa) Supplies either Brisbane or Gladstone LNG Connects Amadeus to eastern states hubs via Carpentaria to Ballera (East to Wallumbilla or West to Moomba) (Incitec Pivot Mt Isa = 1/6th foundation client)
Proposed Southern NT pipeline – linking Amadeus to Moomba	Requires > 200 TJ/day gas supplies to offer competitive transmission costs

Source: RaaS observations

Australia's east coast is facing a significant energy supply gap, particularly as "climate activists" push for faster reductions in carbon emissions generated by traditional coal plants. Meanwhile the NT pipeline infrastructure is not currently developed for the types of volumes being discussed from the McArthur-Beetaloo in the long-run, with significant pipeline expansions required. Jemena Limited, a JV between China State Grid Corp Ltd and Singapore Power Ltd, it has the potential to expand the capacity of the pipeline linking the NT with Qld, by up to 7 times, of course this would be dependent on upstream companies defining the requisite gas reserves to support the investment. Equally Santos would like to see a pipeline built between Amadeus and its Moomba hub, however, this would require at least 200TJ a day of gas flows to justify transmission netback costs.

Board and Management

Empire Energy has an experienced and distinguished 4-person board, which has been appreciably augmented over the past year, with the additions of Paul Espie and John Gerahty. The Board's skill sets now include substantial large independent board and international industry experience, across investments, finance and large energy corporates. We consider the skill base of the Board to be appropriately positioned to address the company's future strategic investment direction and decisions. While diversity has to yet feature, the Board has a stated governance policy to achieve 33% female representation by 2025. The Audit & Risk Committee consists of John Gerahty (Chair) and John Warburton. The Remuneration Committee consists of Paul Espie (Chair) and John Warburton.

Board of Directors

CEO and Managing Director Alex Underwood began at the company in March 2018 fresh from Commonwealth Bank's Singapore Natural Resources division, where he spent two years specialising in upstream oil and gas debt and equity financing. Prior to that, Alex worked at Macquarie Bank in Sydney and in Singapore in the Energy Markets team. Alex began his career at BHP Billiton Petroleum as a finance graduate in Perth and Melbourne.

Non-Executive Chairman Paul R. Espie (AO) is a highly-regarded Australian banking executive with significant independent board experience. Paul ran BAML's Australia/NZ/PNG operations and was also Chair of the Australian Infrastructure Fund, Oxiana Limited, during development of the Sepon copper-gold mine in Laos (2000-2003), as well as Cobar Mines P/L following a management buyout in 1993. Paul is currently a director of Aurelia Metals Limited; a fellow of the Australian Institute of Company Directors; a Trustee of the Australian Institute of Mining & Metallurgy, Education Endowment Fund and a Director of the Menzies Research Centre. Paul joined the Board as Chair in 2018.

Non-Executive Director John Gerahty joined as a director in 2018 with wide investment banking and commercial experience. He was a Founding Director of Macquarie Bank and has served on multiple publicly listed boards, including Chair of ARP Group Plc and MPI Mines Ltd. He is currently Chair of the Hardie Grant P/L publishing group, its major shareholder Associated Media Investments P/L and an associated company, AMI Advertising Media P/L. He is also Director of Kaplan Partners P/L and Kaplan Funds Management P/L, as well as his family-owned Liangrove group entities. He was formerly Chair of Sydney Swans, a director of Cricket NSW and a Trustee of the SCG Trust. Of note, John holds an indirect substantial shareholding in just under 5% of the company's equity.

Non-Executive Director Professor John Warburton PhD, FGS, MAICD became a director of Empire Energy in February 2019, having previously served on the Board of the company's wholly-owned subsidiary, Imperial Oil & Gas P/L since 2011, and as its CEO from 2011-2014. He continues to sit on Imperial's board as a non-executive director. A geoscientist by training, John has 35 years of technical and leadership experience across a broad range of international oil and gas conventional and non-conventional; operating and non-operating environments, including new business delivery. His career includes long stints with BP, Oil Search and LASMO-ENI in senior technical and leadership roles. He has been involved in the discovery of commercial oil & gas fields in Pakistan, UK, Kazakhstan, Azerbaijan and PNG and he has published 28 internationally recognised technical articles with particular focus on petroleum exploration in complex fold and thrust belts John is also a non-executive director of ASX-listed Senex Energy Ltd and a Visiting Professor in the School of Earth & Environment at Leeds University UK, where he also served 8 years on the External Advisory Board of "Petroleum Leeds", the centre for excellence in Petroleum Engineering & Geoscience.

Management

David Evans is Chief Operating Officer of the Company (October 2019). Mr. Evans' appointment significantly strengthens Empire's technical and operational capabilities at a time of material expected growth for the Company as it executes its Northern Territory exploration and development programs. Mr. Evans has 30 years' global upstream oil & gas exploration, development and production experience in increasingly senior technical and managerial roles, with significant exposure to Australian and North American unconventional hydrocarbon plays. For the past 3 years, Mr Evans held the role of Chief Operating Officer at ASX listed, US focused, Elk Petroleum Limited. Prior to joining Elk, Mr. Evans held the positions of Chief Technical Officer and Acting Chief Operating Officer with ASX listed company Drillsearch Energy Limited for six years, a period of substantial growth for that company. Mr. Evans holds a BSc(Hons) degree 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. David was also the recipient of the East Coles Corporate Performance Awards 2014 Best Operational Management, Energy Sector.

Ben Johnston recently joined Empire Energy as Vice President Business Development. Ben is an energy sector specialist having worked across M&A, ECM and debt / project finance transactions while at leading banks including RBC Capital Markets and Commonwealth Bank. Ben is a chartered accountant having trained with KPMG and holds an MBA from the Australian Graduate School of Management.

Kylie Arizabaleta is Financial Controller and the longest serving member of the Empire management team. Before joining Empire Energy Group in March 2012, Kylie worked in Chartered Accounting firms specialising in Audit and Assurance Services.

Tim Hull is Vice President in charge of Appalachia Operations in New York and Pennsylvania. He was regional field manager for Range Resources Inc in New York State prior to its acquisition by Empire Energy in late 2009. Mr Hull has had extensive experience in natural gas production and operations, currently managing around 1,800 wells and 300 miles of pipeline.

Shareholder Base

Shares held by insiders

Insiders hold 19.09m shares or 7.3% of shares on issue. Chairman Paul Espie AO holds 4.85m shares and 375,000 options exercisable at $0.30 expiring 26 September 2020. CEO Alex Underwood owns 800,000 shares directly and 1m indirectly, with 150,000 held in escrow until 13 April 2020, as well as 3.15m performance rights, 1m service rights, and 850,000 options exercisable at $0.30 with various expiries. Directors Professor John Warburton holds 194,000 and John Gerahty holds 12.245m shares and 5.562m options exercisable at $0.30 until 26 September 2020.

Directors have invested more than $4.25m in cash over the last 2 years.

Institutional shareholders

Macquarie Group is the largest shareholder in EEG with 26.46m shares or 10.07% of shares on issue. Other notable substantial shareholders are Global Energy & Resource Development Ltd (GERD) which owns 25.7m or 9.79% and Elphinstone Group which holds 13.25m shares or 5.05%.

Dale Elphinstone, was also an early investor in Queensland Gas Company which was acquired by BG Group. His stake in QGC was ultimately worth ~$303m.

Exhibit 31: Financial Summary (In US$'000s unless otherwise stated)

EMPIRE ENERGY GROUP LTD		EEG		
YEAR END		Dec		
NAV	A$mn	$0.61		
SHARE PRICE	A$cps	0.44	Last share price	20-Dec
MARKET CAP	A$mn	114		
ORDINARY SHARES	M	263		
OPTIONS	M	54		

COMMODITY ASSUMPTIONS		2018	2019E	2020E	2021E
Realised oil price	US$/b	59.86	60.03	53.43	51.72
Realised gas price	US$/mcf	3.24	2.86	2.40	2.44
Exchange Rate	A$:US$	0.7452	0.6945	0.6807	0.6848

EARNINGS	US$000s	2018	2019E	2020E	2021E
Revenue		14,252	6,670	4,450	4,472
Cost of sales		(9,253)	(4,954)	(3,292)	(3,313)
Gross Profit		**4,999**	**1,716**	**1,157**	**1,159**
Other revenue					
Other income		2,304	208	200	200
Exploration written off		0	(213)	0	0
Finance costs		(2,976)	(1,919)	23	45
Impairment		0	0	0	0
Other expenses		(20,079)	(7,095)	(4,400)	(4,424)
Profit before tax		**(15,752)**	**(7,302)**	**(3,019)**	**(3,020)**
Taxes		(115)	(86)	0	0
NPAT Reported		**(15,867)**	**(7,389)**	**(3,019)**	**(3,020)**
Underlying Adjustments		(101)	(2,995)	0	0
NPAT Underlying		**(15,968)**	**(10,383)**	**(3,019)**	**(3,020)**

CASHFLOW	US$000s	2018	2019E	2020E	2021E
Operational Cash Flow		**2,828**	**205**	**138**	**429**
Net Interest		(2,974)	(1,919)	23	45
Taxes Paid					
Other		(115)	(84)	(30)	(30)
Net Operating Cashflow		**(261)**	**(1,799)**	**132**	**444**
Exploration		0	0	(6,000)	(6,000)
PP&E		(49)	(113)	0	0
Petroleum Assets		(168)	(19)	0	0
Net Asset Sales/other		359	19,725	(382)	(694)
Net Investing Cashflow		**(120)**	**17,794**	**(6,250)**	**(6,250)**
Dividends Paid		0	0	0	0
Net Debt Drawdown		(7,878)	(17,936)	(1,998)	(2,015)
Equity Issues/(Buyback)		11,677	7,739	8,101	2,897
Other		0	0	0	0
Net Financing Cashflow		**3,785**	**(10,209)**	**6,103**	**882**
Net Change in Cash		**3,404**	**5,787**	**(15)**	**(4,924)**

BALANCE SHEET	US$000s	2018	2019E	2020E	2021E
Cash & Equivalents		4,157	9,888	9,873	4,949
PP&E & Development		52,228	30,897	33,662	40,112
Exploration		0	410	369	332
Other Assets		7,686	2,291	970	1,501
Total Assets		**64,071**	**43,486**	**44,874**	**46,894**
Debt		24,440	7,575	6,052	4,037
Other Liabilities		18,262	16,778	21,077	25,236
Total Liabilities		**42,701**	**24,353**	**27,129**	**29,274**
Net Assets/Shareholders Equity		**21,370**	**19,133**	**17,745**	**17,621**
Net Cash/(Debt)		(20,282)	2,313	3,821	912
Gearing dn/(dn+e)		49%			

nm = not meaningful
na = not applicable

NET PRODUCTION		2018	2019E	2020E	2021E
Crude Oil	kb	127	89	3	3
Nat Gas	mmcf	1,834	1,731	1,702	1,685
TOTAL	**kboe**	**432**	**378**	**287**	**284**
Product Revenue	A$mn	14.0	10.5	4.3	4.3
Cash Costs	A$mn	(5.1)	(4.4)	(2.3)	(2.3)
Ave Price Realised	A$/boe	32.49	27.93	14.97	15.20
Cash Costs	A$/boe	(11.84)	(11.58)	(8.00)	(8.10)
Cash Margin		**20.65**	**16.35**	**6.97**	**7.10**

RESOURCES and RESERVES	Prospective Resources			
		P90	P50	P10
Northern Territory				
Gas				
Barney Creek Fm	Bcf	3,304	8,699	20,172
Velkerri Fm	Bcf	383	1,192	3,086
Wooogorang Fm	Bcf	524	1,185	2,371
TOTAL		**4,211**	**11,076**	**25,629**
Oil				
Barney Creek Fm	Mb	66	174	403
Velkerri Fm	Mb	8	24	62
Wooogorang Fm	Mb	10	24	47
TOTAL		**84**	**222**	**512**
		1P	2P	3P
US				
Gas	Bcf	50.1	57.0	61.0

EQUITY VALUATION						
	Risked Range (In A$M)			Risked Range Per Share (A$)		
NT	Low	Mid	High	Low	Mid	High
Gas	$72	$108	$244	$0.27	$0.41	$0.93
Oil	$23	$35	$78	$0.09	$0.13	$0.30
US Onshore						
Appalachian	$9	$17	$26	$0.03	$0.06	$0.10
	$104	**$160**	**$347**	**$0.40**	**$0.61**	**$1.32**
Net cash/(debt)	$5	$5	$5			
Corporate costs	($5)	($5)	($5)			
TOTAL	**$104**	**$160**	**$347**	**$0.40**	**$0.61**	**$1.32**

RATIO ANALYSIS		2018	2019E	2020E	2021E
Shares Outstanding	M	2313	263	302	315
EPS (pre sig items)	UScps	(1.05)	(4.29)	(1.00)	(0.96)
EPS	Acps	(1.41)	(6.13)	(1.47)	(1.40)
PER	x	na	na	na	na
OCFPS	Acps	(0.15)	(9.87)	0.64	2.06
CFR	x	na	na	na	na
DPS	Acps				
Dividend Yield	%				
BVPS	Acps	1.2	10.5	8.6	8.2
Price/Book	x	35.1x	4.1x	5.0x	5.3x
ROE	%		na	na	na
ROA	%		na	na	na
(Trailing) Debt/Cash	x				
Interest Cover	x				
Gross Profit/share	Acps		9.4	5.6	5.4
EBITDAX	A$M	2.3	1.0	(1.6)	(1.6)

Source: Company Data, RaaS estimates

Appendices

Appendix 1 – McArthur Basin – central trough history

Exhibit 32: Various Regional well tests of significance conducted since 1989

Date	STRIKE ENTITY	STRIKE Area / Type	COMMENTS
December 1979 - April 1980	Kennecott-Amoco	Glyde GRNT 09 corehole Flows: 6mmcfpd (equivalent to 2 Bcf/yr)	Gas blowout – 5-6m flame with condensate & gas (74% methane; 10% ethane; 11% Nitrogen; 3% propane)
2015/2016	Origin	Amungee NW-1H (called the "beetaloo discovery well") Flows: 1.1mmscfd over 57 days	Origin booked 6.6 Tcf contingent resources, proving up Beetaloo gas fracture potential
2014	Santos	Tanumbirini-1 appraisal Flows: gas over 500m interval	Highlights Velkerri B potential

Source: Company announcements

EEG first became involved in the McArthur basin in 2010. Its tenements cover about 80% of the total 70,000 sq km basin area. EEG believes the basin is one of the few global petroliferous regions to retain its integrity since formation, allowing its hydrocarbons to remain well-preserved and at depths conducive to development.

Ocean sediments were believed to be deposited in rich layers of preserved organic carbons (the forerunner to hydrocarbon generation), sealed in by impervious layered shale rock protective barriers. These deposits occurred in low-oxygen (anoxic) environments preventing the organic carbon from being oxidised into CO2, but more likely into hydrocarbons. **This combination is what is chiefly driving the Basin's current excitement: a low carbon dioxide, rich hydrocarbon environment has been created over 2bln years, waiting to be explored and commercialised.**

The two regions EEG and others have identified as the most prospective in the region include the Batten Fault zone in the south and the Walker Trough in the north. Within these zone lies different STACKED shale layers. These have been named the Velkerri shale formation (*thought to be 1.4bln years old*); the Barney Creek shale formation below (*thought to be over 1.64bln years old*); finally lying deeper still are the Tawallah Group shales (which includes the Wollogorang & McDermott shale formations; thought to be ~1bn years old & containing TOC levels up to 7%). These shale formations can also be up to 1.5km thick; with low levels of CO2 (<1%) while composed of 77% C1 (methane); 11% C2 (ethane) and 11% C3 (propane.)

The other interesting insight is that exploration drilling has not encountered any aquifers below 100m depth and any encountered have been small and disconnected, which is great news for local hydrogeology environment management, particularly in light of community concerns. These findings are entirely in keeping with the view that rock formations comprised of dolomite; siltstone and shales are very fine-grained and have low porosity & permeability.

A Prospective resource covering only 25,000 sq km of the trough has been estimated to contain to 25 Tcfe (P10), which only assumes a shale thickness of 150m and discounts the size of the hydrocarbon potential by 75%, due to the lack of drilling data and variability in rock qualities. Separately, EEG estimates its Beetaloo-only Prospective(P10) resource (covering 2500 sq km) to hold ~3.5Tcfe (similar to Australian annual consumption requirements; noting *global annual natural gas consumption lies at ~130 Tcf*).

Rather than comparing to the US Shale basins, EEG prefers to compare the McArthur to the Lena-Tunguska basin in Siberia, given the number of similarities. Interestingly, the basin has yielded over 80 bn bbl of oil and 477 Tcf of gas. The Sichuan and Tarim basins in China (18 bn bbl oil & 9 Tcf gas) and the Oman basin in the Middle East (5.5bln bbl oil & 30 Tcf gas) are also considered to be good proxies.

GRNT-09 was a hole drilled in 1979 which accidentally blew-out and ignited, sustaining a 6m high yellow smoky gas flare for a full 6 month, until the wet season descended, flowing at the rate of 6mm scf/day and 2 Bcf a year. The well effectively confirmed for the first time the existence & prospectivity down into the Barney Creek shale. It also hinted that petroleum liquids may be associated with these shale-held gases.

POG drilled 23 slim-holes in a 1986-1994 exploration program in the Batten Trough (*southern McArthur area*) which further confirmed oil and gas shows.

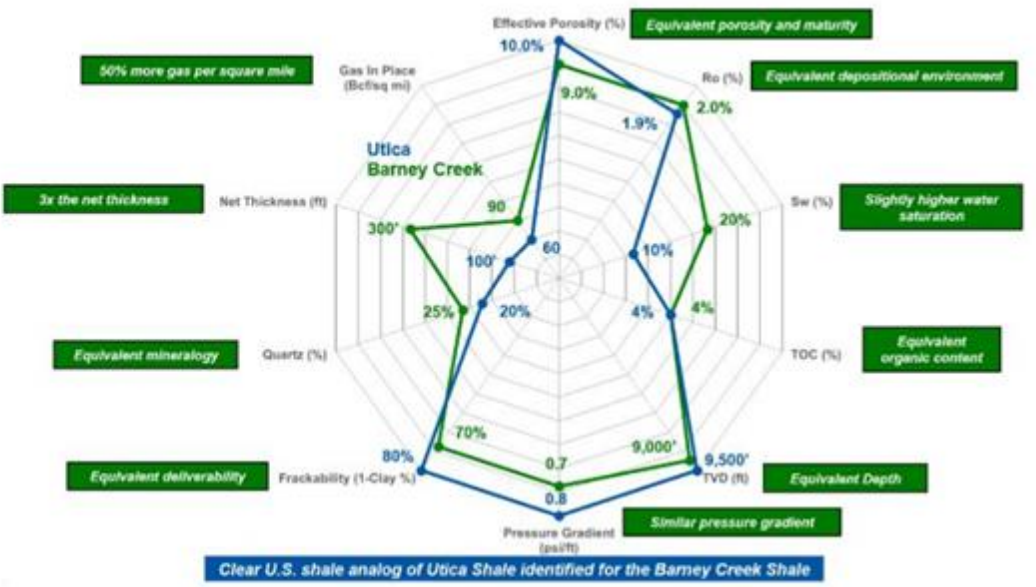
Holes later drilled in 2012 (including Cow Lagoon-1 and Glyde-1) also produced free flowing gas from the Barney Creek shale, generated without recourse to fracture stimulation, while revealing C1 to C7 gases and minimal CO2, suggesting the Trough needs to be explored for both gas and petroleum targets. Interestingly, Research as a Service

Barney Creek source rocks show similar high carbonate- low clay TOC composition characteristics to the Utica shale in the US too, while being up to 3 time thicker. The Utica produces the highest unconventional gas flows rates in the US.

Drilling has yet to target the deeper-still Tawallah Group sandstones for hydrocarbons. These should also have been preserved in a pristine, non-oxygenating form.

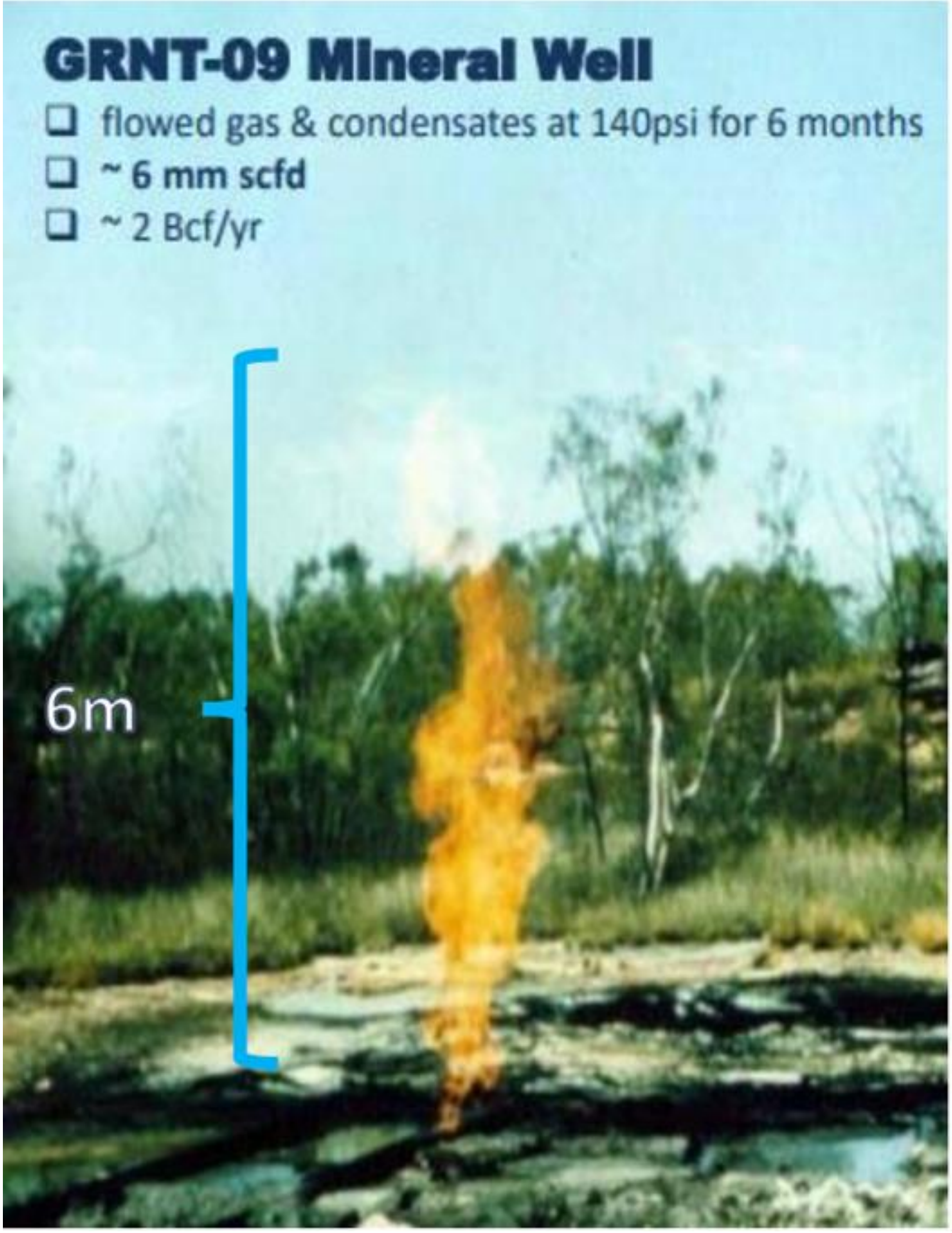
While the Barney Creek formation is considered highly prospective, it is regarded as a higher-risk exploration prospect compared to the Beetaloo sub-basin due to the variability of shale thickness and organic content. They are also considered to contain a far smaller potential resource than the Beetaloo.

Exhibit 33: US shale analog of Utica shale identified for the Barney Creek shale



Source: AEP

Exhibit 34: Kennecott/Amoco GRNT-09 well December 1979



Source: Kennecott/Amoco

Appendix 2 – Beetaloo Sub Basin History

The Beetaloo Sub-Basin extends over an area representing ~30,000 sq km and although not outcropping at surface, contains the NT's most explored shale gas play, having demonstrated the existence of a substantial prospective/contingent shale gas resource within quartz sandstones, siltstones and mudstones deposited in a variety of shallow-marine nearshore to shelf environments. Both the Velkerri and Kyalla gas-rich shale formations are to be found there.

Beetaloo exploration first began in 1984, when CRA (as Pacific Oil & Gas) took on the EP4 and EP5 permits in the northern section of the basin. Encouraged by various drill results developed internally and also from a Bureau of Mineral Resources hole in 1985 (Urapunga 4), POG picked up further permits, including EP23 & EP24 in the north, as well as EP33 in the south in 1988, followed by EP18 (central) and EP19 (western) under JV arrangements. The JV then added EP45 and EP52 to expand its southern basin holdings.

From 1987-1993, POG drilled 12 wells, 4 of which penetrated the Velkerri formation (with "middle Velkerri" displaying the greatest hydrocarbon potential). Bizarrely, POG subsequently withdrew from all permits in 1993, due to uncertainties surrounding interpretation of the structures it was targeting.

Activity fell silent for the next 9 years, until Sweetpea Petroleum became interested in the region and POG's past results. Sweetpea took on EP76 in 2001, then EP98 and EP99 in 2004 and EP117 in 2007. Sweetpea subsequently drilled the Shenandoah 1 well in 2007, just 120m south of the Balmain 1 well, originally drilled by POG in 1992. The hole drilled into the Kyalla formation (at a depth of 1,555m), choosing the location after completing nearly 700km of 2D seismics targeting both conventional and tight gas finds.

Attracted to the region's shale potential, Falcon Oil & Gas then agreed to purchase a majority of the tenements previously held by PetroHunter Energy Corp (Sweetpea's owner) in December 2009, covering all 4 permits (EP76, EP98, EP99, EP117), in a JV agreement structure. Falcon first deepened Sweetpea's Shenandoah 1A well verticals down into the Velkerri formation, as well as conducting on of Australia's **first-ever fracking stimulations** in 2011. 2 zones in the middle Velkerri and one zone in the Kyalla formation were successfully flow-tested.

These encouraging results allowed Falcon to introduce Hess Corporation to the basin, finalising a farm-in in April 2011. Hess funded 3,490km of 2D seismics, costing as much as US$80m over 2 years, to confirm the basin as an active system.

Hess initially agreed to conduct a 5 well drill program. Then in a strange corporate twist, as a result of being caught up in its own huge restructuring exercise, pivoting from an integrated energy company to an upstream company, focused on its Triton Energy assets, Hess failed to meet its drilling commitment deadline (already extended by nearly a year from 2 August 2012 to 28 June 2013). It was forced to forfeit its rights to own 62.5% in 3/4 of Falcon's permits. Separately, Falcon bought out Sweetpea entirely in 2013, in exchange for a 10.7% equity stake.

Having already received unsolicited interest from 4 other majors, Falcon instead turned inwards to Australia to choose its next JV partner, completing a farm-out agreement with Origin Energy & Sasol in August 2014. Origin & Sasol took a combined 70% stake (35% each), in exchange for pledging to complete a 9-well program over 5 years for $A200m. The JV's Beetaloo permits covered EP76; 98; 117, covering 4.6m acres.

While early test data had confirmed the source rocks were of Proterozoic age, this was deemed an investment "risk" since no other unconventional gas plays globally had been identified. This led to 2 further questions needing answers:

A) Is there sufficient resource concentration within the source rocks to justify commercialisation?
B) Can the source rocks be successfully stimulated?

As a result, across 2015 and 2016, the Origin/Falcon JV drilled 4 wells to answer these questions and technically de-risk further investment towards supporting a robust commercial development:

- Origin/Falcon: 2015: Amungee NW-1 vertical well (depth:2611m)
- Origin/Falcon: 2015: Amungee NW-1H vertical well (depth: 3808m total)
- Origin/Falcon: 2015: Kalala S-1 vertical well
- Origin/Falcon: 2016: Beetaloo W-1 (vertical depth: 3173m);
- Origin/Falcon:2016 (September): Amungee NW-1H horizontal fracture stimulation 1100m, targeting the Shale B of the middle Velkerri following the Beetaloo W-1 results.

The Beetaloo W-1 hole proved hugely important by confirming for the first time that the middle Velkerri prospectivity penetrated into the central and southern Beetaloo areas, as well as into north. Meanwhile, starting in September 2016, **Amungee NW-1H** became **the Beetaloo Basin's first-ever horizontally fracture stimulated well.** 11 hydraulic stimulation stages along a 1100m section were tested safely over 57 days, without environment incident.

Importantly, gas flows, regularly reaching 1-1.5 MMscf/d, proved that gas has accumulated in the Middle Velkerri B shale region, along over 80km of shale terrain. The test work also helped identify 3 distinct organic-rich shale intervals, called A, B and C shale in the Middle Velkerri formation. Thickness was estimated to be as wide as 500m, while TOC levels were found on average to reach 3-4%, while offering strong gas shows, confirming the presence of a material gas resource that brings the region into the same league as Australian's other commercial onshore basins.

The data extracted has assisted to improve the geological understanding of the Beetaloo Basin, particularly the Velkerri Middle and Kyalla formations. A **Contingent Resource from these middle Velkerri B results led to an estimate of 6.6 Tcf over a c.1968 sq km area being published by the Origin-Falcon JV.**

Given these encouraging successes, Origin later purchased Sasol's 35% stake in May 2017, becoming Operator with responsibility for 100% of the exploration spend. In a further positive sign, Falcon's farm-out with Origin was amended in August 2018 to deem Stage 1 complete and to begin Stage 2, with a cost cap of A$65m for exploration, including the appraisal of 2 horizontal wells.

Shale B Middle Velkerri is now thought to have similar resource concentrations to the most successful US shale regions, offering 22-43 Bcf/sq km (P90-P10). Meanwhile diagnostic fluid injectivity tests suggests the region may be "over-pressured", with a pore-pressure gradient of 0.52-0.55 psi/ft, a critical success factor employed by the chief US shale plays.

In the next phase for the Origin/Falcon JV, a 3-stage work program is being conducted:

a) prove up the Velkerri shale resource;

b) evaluate liquids potential in the Velkerri & Kyalla shale formations and

c) to "test-the-best" to confirm commercial production rates and estimated ultimate recovery (EUR).

Origin/Falcon's latest well, Kyalla, lies between the Beetaloo W-1 and Amungee NW-1H wells.

The Caveats

While the Origin-Falcon contingent resource of 6.6 Tcf highlights the huge potential of the Beetaloo Sub-basin, no resources in the region are commercial. Further substantial additional drilling and reservoir modelling assessments are required to upgrade to an economic reserve. We suspect this work will require at least another 12-18 months. After that, any decision to move forward to production would likely require a further three years while approvals are gained and the build out of regional infrastructure is completed.

FINANCIAL SERVICES GUIDE

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