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Empire Energy Group Ltd

Re-Initiation Report

Primed for a big 2023

Empire Energy Group Limited (ASX:EEG) is an oil and gas producer/developer, with onshore Northern Territory (NT) and US oil/gas assets. EEG has the largest tenement position in the highly prospective Greater McArthur Basin, which includes the Beetaloo Sub-basin. The NT energy basins are fast developing as strategic high calorific gas bolsters for east coast Australia's future domestic requirements, growing Gladstone LNG ullage and potential supply for Darwin's expanding LNG export terminals, amid funding support from territory and federal governments. Empire Energy represents a pure, independent and highly leveraged exposure to the transformational potential of the NT basins. As more data comes to hand and gas markets continue to tighten, we expect the economic confidence level to grow and highlight that EEG is sitting on an extensive and pervasive gas resource. The current phase of drilling and evaluation puts the company on the cusp of the commercial pathway with flow results likely from the Carpentaria-3H and -2H in the next month. Early commercialisation looks tantalisingly close. We reinitiate coverage of Empire Energy Group Limited with a valuation range of $0.68-$1.03/share with a mid-point (base case) of $0.83/share. Our base case represents a >400% premium to the current share price. We expect the share price discount to materially unwind as new data crystallises the development model and the company moves towards a final investment decision (FID) and first gas over the next 18 months to two years.

Business model

Empire Energy Group Limited (EEG), is an oil and gas development and production company, focused on maturing its portfolio of onshore, long-life oil and gas fields. The company holds substantial exploration acreage across the world-class McArthur-Beetaloo basins in the NT and is actively progressing evaluation activity to support reserve bookings and underpin early gas development and sales opportunities. In practical terms the company can be considered to be in a pre-development phase. **Success from this point could see EEG on an accelerated path to first gas.** With continuing evaluation works in train, 2023 will be focussed on defining the field development model. EEG will continue to benefit from three grants under the federal Beetaloo Cooperative Drilling Program for up to $19.4mn, receiving $1.3mn through the December quarter.

On the cusp of commercial certainty

Significant progress has been made specifically and regionally across the Beetaloo Basin over the last twelve months with more to come through 2023. Recent Australian Energy Market Operator (AEMO) analysis highlights a material potential shortfall on the east coast emerging over 2023 and is projecting an increasing reliance on imports to 'plug the gap'. Testing results (IP30 data) due around end-Feb could define the development model and underpin an economic platform for NT gas supply. The NT gas industry is still at a nascent stage but the supply and pricing projections suggest NT gas should be deliverable into east coast markets at scale, on a cost-competitive basis. Empire Energy has recently reported excellent operational results, delivering frack completion and drilling of the C-3H well significantly under budget. In our view, **the company continues to be the capex cost leader in the basin**.

Valuation of $642m or $0.83/share at the mid-point

Whilst valuing pre-development phase assets is a subjective exercise, particularly considering financing and the timing uncertainties, data to hand and the declaration of 2C volumes do support a high degree of confidence on the commercial potential. The resource opportunity is massive based on consistent geology and the next twelve months could deliver material de-risking outcomes - type curve, first reserves, next step gas agreements and a gas project FID. We value the declared resources against a Darwin LNG export gas price (at netback) assigning a discretionary RaaS risk overlay to determine a low-high NAV range. We set a base case (mid-point) valuation of $642mn ($0.83/share) to EEG, with an upside case to $770mn ($1.03/share). Against a reference share price of $0.18/share, this suggests the market is risk weighting the EP 187 (Carpentaria option) at around 22% of our ascribed value. The success case at Carpentaria could deliver valuation upside well in excess of our base case…such is the nature and attraction of gas plays in the proof-of-concept phase.

Energy

17 February 2023

Share Details

ASX code	EEG
Share price (16-Feb)	$0.18
Market capitalisation	$139M
Shares on issue	773M
Net cash at 31-Dec-22	$17M
Free float	~47.3%

Share Performance (12-months)

Upside Case

- Success cases at currently evaluating Carpentaria (-2H, -3H and -4V) wells delivering above expectation testing data
- Delivery of initial 'P' certification to underpin commercial development case
- Securing a binding offtake agreement and/or a farm-in partner to offset market perceptions of future equity dilution

Downside Case

- Frack performance of C-3H in particular falls below expectations
- Extension of gas price cap scenarios to include 'new developments', negatively impacting project rates of return
- Continuing financing reliance through equity issues on weaker field data resulting in excessive share dilution

Board of Directors

Alex Underwood	Managing Director/CEO
Paul Espie AO	Non-Executive Chairman
Dr John Warburton	Non-Executive Director
Peter Cleary	Non-Executive Director
Louis Rozman	Non-Executive Director
Paul Fudge	Non-Executive Director

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RaaS
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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 highly-leveraged play on the emerging McArthur/Beetaloo basins gas province in Northern Australia. Since the resumption of drilling activities in 2020, EEG has made material progress towards crystallising a definitive commercial model, through innovative and capital-cost leading, well designs. The prospectivity of the McArthur/Beetaloo gas plays has been confirmed with a number of successful tests over the last two years and all that is left, is to tick the last boxes on well performance…effective stable flow rates. There is an increasing need for new gas supply at scale and EEG is strongly positioned on a first-mover supply basis. The company is progressing a test and evaluation campaign across three wells in its Carpentaria Project in EP187, where extensive flow testing will support upgraded reserves and resources certification; and underpin Front End Engineering and Design (FEED) studies already underway. We would highlight that EEG already holds certified 2C volumes >550Bcf and (low-end) Prospective Resources >12.5Tcf. With the approvals processes, offtake and access agreements broadly in place, the company is well placed to sanction first-stage gas delivery around end-2023. The plays are not without risk both operationally and financially but current activity can materially unwind the operational risks and EEG, we suggest, is well placed financially to conduct its work commitments over the next 12 months without recourse to further equity capital. Holding its tenements at 100%, provides additional financing options through partnering. It's all there for EEG to deliver.

Investment Case - 2023 could be a year of material delivery

In our view, Empire Energy Group Ltd is on the cusp of a material re-rating that can be delivered over the next 12 months -

- The company is evaluating the productivity of the highly successful Carpentaria-3H (C-3H) well with **gas breakthrough expected around end-Feb and an important IP30 result around mid-Mar.**

  If an IP30 flow rate of 3mmcfd/1,000m **(refer p.10)** is broadly considered to be the operational benchmark to underpin commercial confidence, then EEG with a materially lower capital and operating costs base sits comfortably under that requirement **and in many respects is already there**. The company is **(second phase) testing the Carpentaria-2H well** after a period of shut-in and re-pressurisation. Results should be to hand as per the C-3H timeline.
- Both C-3H and C-2H data could be sufficient to underpin a **material uplift in certified 2C volumes by mid-year.**
- Testing will be continuous and **provide IP90 data to support firm commercial sales arrangements** (volumes and pricing).

  Financial Investment Decision (FID) by end year - Delivering a project sanction on a staged gas development by end-2023 is not unrealistic particularly given the in-principle progress already made on landowner/land council, offtake and transport agreements; and the Government approvals process. **In some aspects EEG may be tracking well ahead of other operators and…this will crystallise a first mover advantage.**
- The success case sees development drilling commencing in 2024.
- On a lower capex base…drilling and testing at half the cost of peers, we suggest **the company is well funded for all works through to FID** without recourse to further equity capital on RaaS assumptions and guidance. **FEED works are already underway for a (early commercialisation) Carpentaria Pilot Project.**
- Deliver flow rates, deliver material resources increases and deliver FID**…the re-rating will follow.**

Risk-Adjusted Valuation Range Of $502mn-$770m

We ascribe a value range for EEG from $0.68-1.03/share **with a mid-point (base case) of $0.83/share,** noting the closing share price of $0.18/share (16-Feb) represents a 74% discount to the low end of the NAV range and in isolation can be considered a risk weighting of ~68% to our assigned value of the 2C resources.

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

		Risked range (A$m)			
		Low	Mid	High	
Northern Territory					
Contingent Resources		$328	$378	$479	2C volumes certified to 554Bcf of which 396Bcf (~70%) are attributed to EP 187 and 295Bcf to the mid-Velkerri B zone.
Prospective Resources		$147	$202	$242	2U volumes are largely associated with ex EP 187 and ex-Pangaea tenements and represent longer-dated gas potential. The geological confidence level is relatively high on the look-through, but realisation will require extensive drilling campaigns.
US Onshore		$39	$48	$66	Benefitting from higher US gas prices…these assets are self-funding.
		$514	**$629**	**$788**	
Net cash/(debt)			$17		
Corporate			($5)		
TOTAL		**$525**	**$640**	**$799**	
Shares issued (mn)	773	$0.68	$0.83	$1.03	

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

We would highlight that this discount is not unusual compared to the unit values the market is applying to the sector. However, **flow data and updated reserves declarations due before mid-year, should close the 'value gap'** and underpin a resource rating as commercial outcomes become more tangibly demonstrable as per **Exhibit 2.**

As will become apparent through this report, we suggest **EEG is the leveraged exposure to NT gas development opportunities**, holding more acreage, some at advanced stages, on a significantly lower capital and (likely) operating cost base.

There is a timeline to first gas (**refer Exhibit 8**) that is there for the company to deliver and 2023 activity, already underway can provide the platform – **a defined economic case with reserves by end-2023.**

Our modelled value range is dependent on assumed commodity prices, which we initially set against a Darwin FOB price of ~A$12/gj for gas and the Brent crude forward curve. We overlay a discretionary RaaS risk weighting to account for the remaining uncertainties on timing and operating costs. The risk weighting should unwind as new gas data comes to hand over 2023, independently of commodity price changes.

With testing results and a project FID potentially delivered by end-2023, on balance we'd expect to see a material increase in certified (de-risked) attributable gas volumes. It may even be possible for an initial declaration of reserves (P volumes) given the conditional gas offtake agreements and high probability of first gas production in under five years.

The magnitude of the potential asset re-rating can come via two streams as outlined in **Exhibit 2** which shows the market pricing of comparable east coast gas plays on a reserves metric basis – EV/2P and EV/(2P+2C).

We highlight that these metrics provide only a relative comparison and should not be considered on an absolute basis in isolation, although indicatively they can point to the quantum of rerating opportunity assuming gas into the east coast market and similar product pricing.

A. Increasing 2C volumes

Flow rates and more wells = more certainty across a greater area and will deliver a material increase in certified 2C volumes.

Empire and Tamboran (TBN.AX) as exposures to the same play in the same basin, should price broadly in line on resources booked in the same category (all other things being equal) and by extrapolation, more 2C equals more EV…the bigger the upgrade the higher the share price should trade.

We would argue that on lower capex, with a lower economic threshold, EEG should reflect a higher metric value.

B. Increasing volumes and converting P from C

Exhibit 2 shows the higher multiple derived from 2P (bankable) gas on a volume weighted average of $0.94/gj (ranging $0.74-1.33/gj). We note the reserves VWAP is pricing at an uplift of >4x to the company's current resource metric.

More and lower risk gas should translate into a higher price. **Exhibit 2** clearly shows that in a potential $12/gj gas market, **EEG is a highly leveraged gas company, significantly under-priced for its resource potential.**

Exhibit 2: Reserves/resources metrics highlight the sector has cheap gas

Company	Ticker	Share Price	Capitalisation A$mn	EV A$mn	2P Gas PJ	3P PJ	2C PJ	EV/2P A$/boe	EV/2P A$/gj	EV/2(P+C) A$/gj
Vintage Energy	VEN	0.091	68	68	51	105	105	7.38	1.34	0.44
Blue Energy	BLU	0.051	94	75	71	298	1,086		1.05	0.05
Central Petroleum	CTP	0.075	55	70	73		188	5.41	0.96	0.27
Comet Ridge	COI	0.170	170	160	195	372	354	4.82	0.82	0.29
Empire Energy	EEG	0.190	147	120			554			0.22
Tamboran Resources	TBN	0.220	312	285			1,488			0.19
Galilee Energy	GLL	0.160	54	45			3,012			0.01
Vol Weighted Average				372	389				0.96	

Reserves* adjusted against last production data where applicable

Source: Company and ASX data; share prices as of close of trading 14-Feb

SWOT Outlook – 2023 Can Be A Game Changer

SWOT weightings skew to the positive, particularly given the rerating potential of testing programmes through to mid-year and definition of the commercial development case.

Exhibit 3: SWOT indicates more upside than downside

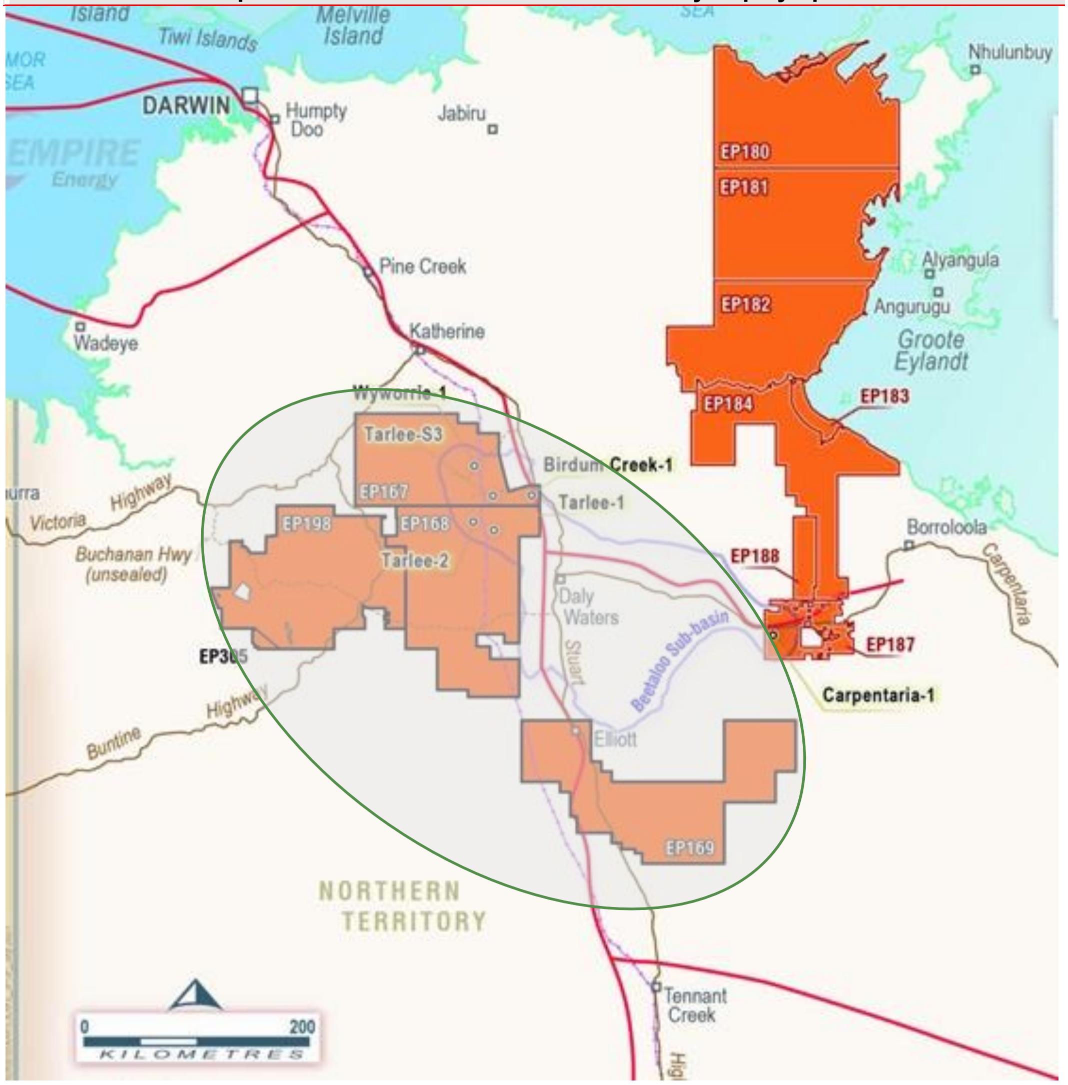
Strengths	**Comments**
Strategic holdings across the basin	Post the Pangaea acquisition (May-2021) the company holds a material spread of highly leveraged acreage across all of the plays currently under evaluation - the shallow, Velkerri shale gas in the east and deeper (liquids rich?) Kyalla targets in the west.
High working interests	The company holds its acreage at 100% working interests, providing 'financing through partnering' options, particularly as early works continue to de-risk the gas opportunity. **On a success case, future issued capital dilution should be minimised**.
Demonstrated capex cost leader...	...EEG continues to deliver drilling and frack stimulation campaigns under budget with a focus on the shallower (EP 187) areas where the commercial threshold for production will be significantly lower than other JVs.
Lower commercial threshold	On lower capex, early commercialisation requires lower sustaining gas rates.
Proximate to infrastructure hubs	Ready access to pipelines underpins the path to market.
MOUs with APA and the NTPWC	...underpin the economic case and **we suggest gives EEG a lead on competing Joint Ventures**.
Local and federal government support	The NT operating environment is based on the recommendations contained in its Fracking Enquiry report, providing an equal and stable operating platform. Federal Government support comes from the grants approved under the Beetaloo Cooperative Drilling Program for up to $19.4mn.
Weaknesses	**Comments**
Large exploration portfolio	At a high level, the total number of tenements under management is too large to be exploited in an optimal fashion - the company can only finance on a narrow focus basis at this time and will be reliant on 'look-through' results in those parts of the portfolio not currently being drilled.
Financing still largely dependent on equity markets in the short-term	NT gas plays can still be considered in a proof of concept/pre-development phase where unit capital costs are relatively high and not fully supported by cashflow from the company's US production assets.
Permit land access	Several EEG portfolios have yet to finalise access requirements.
Market continuing to apply a high-risk weighting to the gas opportunity	**Markets are waiting for the de-risking event** - the set of data definitively underpinning the commercial case. We are confident that current drilling and testing campaigns can provide that certainty by end-2023.
High working interests	**What is a strength can also be a weakness.** Carrying costs at a sole risk (100%) level is expensive through early phases of activity and can mean relatively slow progress. We'd suggest that much of the heavy lifting from an exploration perspective has been done with data to come, likely sufficient to generate interest from potential third-party partners.
Opportunities	**Comments**
The macro investment thematic continues to be supportive	ACCC/AEMO projections point to a **material east coast gas supply shortfall from mid-2023** and increasing in the absence of new supply. There is a significant window of opportunity for new gas into the east coast market.
Gas remains a critical part of the path to renewables	The path to renewables is set, however, renewables work best with gas until such time as storage efficiency and costs are more favourable. Whilst the sun always shines and the wind always blows, it doesn't necessarily do that where and when its needed and **batteries cannot guarantee a base load generation case**.
Closure of coal-fired, base load generation is accelerating	As coal fired generation is replaced by renewables, the base-load electricity system is showing evidence of increasing instability - SA being the current example. Gas remains the most reliable back-up system.
'Tram-track' geology	The highly correlatable and consistent nature of the geology means if it 'works' at Point A, it likely works at Point B which should translate to 'more for less' in capex terms.
NT gas plays provide 'scale'	Where else can you go for new gas at scale? Beetaloo gas production is 'on the cusp'. Alternative gas opportunities are long(er) dated and comparatively expensive - rig rates are rising and prospects sizes remain modest.
Threats	**Comments**
Federal regulatory uncertainty	The imposition of a $12/gj price cap for new contracts in 2023 and a **"...reasonable pricing provision",** highlights the political uncertainty associated with gas policy and potentially the direction of future government regulation.
Funding	Debt financers are reducing their support for fossil fuel projects and where they are still prepared to lend, are potentially imposing more restrictive and carbon-offset based covenants.
EEG is not the only NT operator	There are competing JVs in the NT although we suggest they are focussed on and require different end markets. The highly correlatable nature of the geology means success for one can be extrapolated into others…there is somewhat of a race to be first to market and this extrapolates to competition for funding.
EEG is not the only company chasing new gas	There are numerous gas options being pursued in other gas basins, most notably in Queensland CSG and offshore Victorian conventional targets. However, the timeline to market is not certain and success cases may not provide supply at scale.

Source: RaaS analysis

Tenement position – sometimes more is more

With the successful acquisition of the Pangaea JV assets by EEG in May-2021, the company **now holds a dominant acreage position across the Beetaloo and McArthur basins** adding material upside to its Contingent Resource holdings and providing multiple play opportunities.

Exhibit 4: A broad spread of tenements across a wide variety of play options



Source: Company data
Ex Pangaea assets consist of eps -167, -168 -169 and -198 as circled

At the time of the acquisition, we commented that the Pangaea acquisition provided EEG with a materially bigger footprint across all the important basin metrics, confirming our view that **the company was the best leveraged exposure to the emerging northern basins plays**. In relative and absolute terms, the opportunity/play set for the company has more than doubled.

Importantly the major gas zones may contain significant volumes of associated gas liquids, which we see as a critical factor for early commercialisation options and ultimately high operating margins. The company's resource estimates point to liquids-gas ratios of 6b/mmcf (@ 2C) and 25b/mmcf (@ 2U) – **refer Exhibit 7**.

The Pangaea acquisition was important in increasing the company's leverage to the lower Kyalla Formation in particular which has been the focus of activity for other JVs and similarly will be for the next phase of evaluation activity through the Pangaea tenements.

The lower Kyalla has been modelled as having the potential for 414-1,164Mb* on a regional basis.

(*) Volumetric resource assessment of the lower Kyalla and middle Velkerri formations of the McArthur Basin' – Revie, D. Mar-2017

The company will shoot a seismic programme and drill a well (but not test) in the Pangaea tenements later in the year, to further calibrate the geological model and tie back to regional results.

EEG holds a strategic tenement position, straddling the major pipeline infrastructure in the territory, with exposure to all play opportunities on a regional basis.

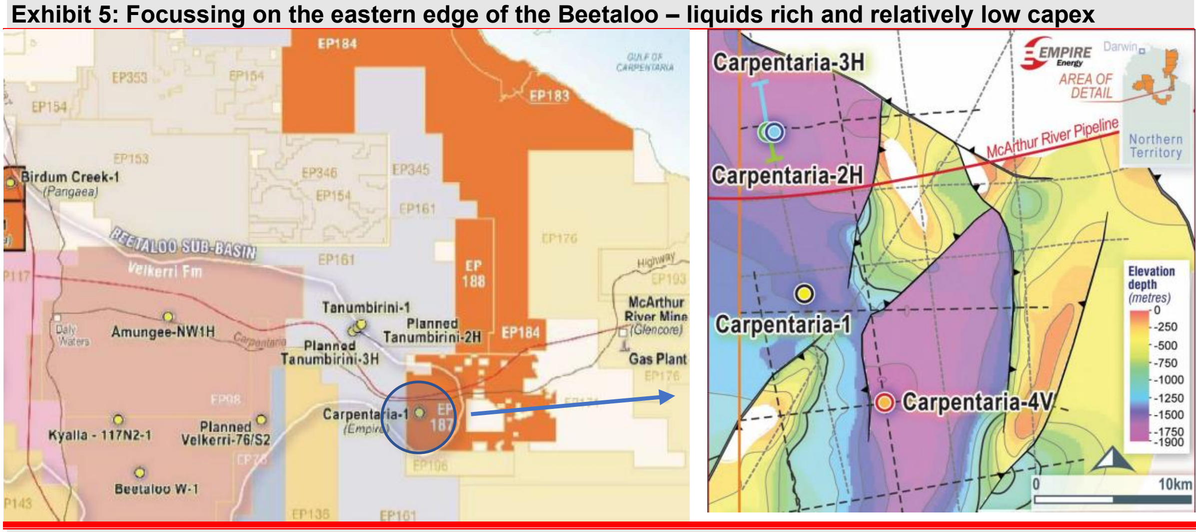
Critically, EEG has captured opportunities for local and large-scale supply on both the eastern and western edges of the basins, with ready access to pipelines with ullage…gas can flow east-west and north-south.

Focus on EP187

Empire has identified the western edge of EP 187 as the focus of its work since the resumption of field activity post the lifting of the Northern Territory Government moratorium imposed during the Fracking Enquiry.

The company has renewed its tenure over EP 187 for a five-year term effective from the start of 2022 - tenure is not an issue across the Carpentaria area.

Exhibit 5: Focussing on the eastern edge of the Beetaloo – liquids rich and relatively low capex



Source: Company data

With the tenement being on the Beetaloo Basin margin, the Velkerri Shale primary target horizons are shallower with materially lower drilling costs and potentially greater frack efficiency than wells drilled further west in the 'deeps'.

Work undertaken and completed on EP 187 since the resumption of activity -

- The acquisition of 160km of infill 2D seismic (Charlotte survey)
- Drilled and tested –
  - **Carpentaria-1V**

    …positive results from Carpentaria-1 (drilled late-2020), intersecting the Velkerri Formation as prognosed at **nearly 1,000m thick and shallower at this location than in analogue wells.** Although not a totally unexpected result it was clearly and significantly better than pre-drill expectations, confirming a 'wet gas' (high calorific) interval.

  - **Carpentaria-2H (C-2H)**

    The C-2H vertical section intersected ~192m of potentially liquids rich, gas pay across the four expected shale zones, versus ~191m at the C-1V location – that's very consistent across a section of 11km and underpins a **high level of geological certainty with respect to the continuity and consistency of the shale target zones.**

The horizontal section of the well, placed entirely within the Velkerri B target zone, reached 1,345m with a total well length of 3,150m. Operational time was 39 days from drilling commencement to rig release at a total cost of ~$11.1mn.

Testing delivered strongly encouraging flow rates, settling to a stable rate of 1.8mmcfd after 51 days prior to the well being shut-in. Over the testing period the gas rate averaged around 2.2mmcfd (extrapolated to 2.4mmcfd/1,000m) with a peak rate of >11mmcfd – refer **Exhibit 6.**

Noting the usual caveats on confirming decline rates, EUR's etc, the flow rate **starts to get into the realm of comfortably commercial**, noting that in a development sense the cost of these wells will be significantly lower.

The well has been undergoing a pressure re-balance and 'soaking' and is scheduled to be tested further in the current work campaign, providing a second set of test results to feed into economic models.

Exhibit 6: Comparison data – more bang for the buck for EEG

	Carpentaria-3H	Carpentaria-2H	Tanumbirini-2H	Tanumbirini-3H
Frack Stages	40 stages planned completed	21	11	10
Frack Interval	~50m as planned	~45m	60m	60m
Hz section	2,632m Longest hz section in the basin to date of which 1,989m was stimulated	927m	1,000m of which 660m was stimulated	1,000m of which 600m was stimulated
Peak flow		>11mcfd	*4.0mmcfd*	*~10mmcfd*
Stabilised flow			2.1mmcfd	3.1mmcfd
IP30 – actual / scaled to 1,000m		2.4 / 2.6 mmcfd	- / 3.3mmcfd	- / 5.2mmcfd
Other flow data		2.1mmcfd on Day 30 1.8mmcfd on Day 51 Ave over IP51 / 2.2mmcfd	2.1mmcfd on Day 90	1.6mmcfd on Day 90
Days testing		51	In production since Jan-2022 but not continuously	First gas in Feb-2022
Total Length	4,460m	~3,150m	4,598m	4,857m
Est. well costs	Drilling costs reported at **~$10mn** Fracking costs reported at **$17.3mn**	Drilling costs reported at **$11.1mn**	Total costs - **$50-55mn/well** (Analyst's estimate)	
		Subject to extended production test. CO2 levels less than 1%	Tanumbirini normalised rates exceed the nominal commerciality threshold as indicated by Tamboran Resources. IP90 flow data will be released before EOY CO_2 levels at 3-4% from each well STO (operator) has indicated it planned to install completions for the resumption of well testing.	

Source: (Various) Company data

- **Carpentaria-3H (C-3H)**

The delivery of the C-3H well was an outstanding operational result both on an operational and budgetary basis. Analogue wells in deeper parts of the basin had reported issues with drilling

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and completing long horizontal sections, **for EEG to complete a 2,632m lateral in the Velkerri-B horizon was an exceptionally good outcome.** As reported the lateral section was over 90% contained within the target horizon.

The total well length was 4,460m, with the company casing and cementing 4 ½ inch production tubing in the horizontal section in only two days.

C-3H was drilled from the same well pad as the C-2H well, but in the opposite direction (**refer Exhibit 5 (RHS)**). The horizontal section of the C-3H well was placed in the Velkerri B shale approximately 150m deeper than in the C-2H lateral. Incrementally higher pressures from the additional depth may deliver higher production rates on test.

The operational efficiency of the drilling and completion demonstrates that the geology in EP 187 is suitable for effective and rapid development operations.

The well was drilled on time and ~$5.9mn under budget in 39 days from commencement to rig release on 21 November 2022…the same time as per the C-2H well with 40% more hole.

EEG successfully completed a 40 stage frack programme on a 50m spacing at ~18% under budget. At 40 stages, the C-3H well represents the first true test of a 'development' well model in practical terms.

We believe, EEG is a step ahead of the other operators in the basin on an operational and capital basis.

- The **Carpentaria-4V** well reached a total depth of 2,000m in 12 days and has been cased and completed at a cost of $9.8mn, with the option to add a lateral (horizontal) section at a later date.

  The well intersected the target sequence as prognosed, intersecting the primary zone approximately 150m deeper that at the C-3H location.

EEG holds approval for up to seven horizontal wells on the EP 187 tenement granted in mid-October 2021 by the NT government and supported by traditional owners.

For a details on the regional geology we refer readers to the **RaaS EEG Scoping Report (23-Dec-2019)**

Flow rates will attract attention

The critical consideration the market and the company wants to see to underpin commercial certainty and a rerating is flow rates.

We reference a Falcon Oil and Gas Investor Q&A from 20-Jan and comments from the CEO, Philip O'Quigley who indicated that it considered the commercial threshold to be an IP30 rate of 3mmcfd/1,000m, which would also underpin an EUR of 12Bcf/well.

https://lnkd.in/etv5J_tp

This is the rate that would likely trigger a pilot development, but noting that wells in the Amungee prospect area (refer Exhibit 5 (LHS)) are deeper with higher unit capital costs**. On balance, the threshold for EEG is likely to be material lower.**

We highlight the empirical capital cost advantage to Empire, referencing recent ASX releases and quarterly reports –

	Total Well Length	Drilling Cost	Hz Length	Frack Stages	Frack Cost	Total Cost	Total Cost 'scaled'
Carpentaria-3H	4,460m	$10.0mn	2,632m	40	$17.3mn	$27.3mn	
Amungee-2H	3,883m	$21.3mn	1,275m	24*	$12-14mn**	$33-35mn	$45-48mn++

* Amungee frack programme as planned

** We assume frack costs on a par with the C-3H budgeted cost of $0.5-0.55mn/stage

++ We assume additional drilling costs as per the unit cost/m (~$5.500/m) and apply it to a scaled hz length; we scale up frack costs on a pro-rata basis

Note these are RaaS assumptions and may only reflect indicative cost differences in an evaluation n what we consider to be a sense.

We expect drilling and completion costs to materially reduce for all operators in a development phase, where economies of scale will apply, but believe Empire can retain a significant cost advantage in the order of 1/3 (33%) – *RaaS estimate.*

On an enduring capex advantage, we suggest the commercial threshold would, in a practical sense, **be lower than 3mmcfd/1,000m** but would highlight the reference point of the C-2H well, which delivered an initial IP30 of ~2.6mmcfd (**refer Exhibit 6).**

We suggest the testing data, likely to hand by end-Feb, has a high probability of delivering the commerciality threshold and supporting a FID outcome.

Building resources and reserves

In Feb-22, EEG commissioned Netherland Sewell & Associates (NSAI) to update the resource assessment across EP 187. Indicative Contingent Resources were assigned specifically to the area covered by the Charlotte 2D seismic survey seismic and the Carpentaria-1 and -2H wells and at this stage represents only a very restricted part of the company's tenement holdings **(Exhibit 5)**.

We highlight material increases in the booked gas volumes specifically ascribed to the Carpentaria development area (EP-187) which is the focus of the company's current drilling and testing campaign.

Revised 2C volumes now stand at 396Bcf with more testing data to come. That is a very good number for early works and represents a strong base for commercial planning.

Test data from C-3H and next phase works on C-2H will underpin a reserves review likely to be completed around mid-2023. **We'd expect a material de-risking and upgrading across portfolio allocations**.

We highlight that the recent resource revisions have not been extended to the liquids content of the gas, with company advice indicating that NSAI requires more flow testing data in order to confidently underpin a recoverable estimate.

Whether a separate and producible liquids phase is present remains to be proven, what can be stated confidently on the data to date is that, **Carpentaria gas at a minimum can be considered as 'high-calorific'**.

As the Australian market trades gas on a calorific rather than volumetric basis (in joules versus cubic feet), the higher the calorific value, the lower the gas volume required for any particular supply contract – this outcome should provide material economic flex in determining what defines a commercial flow rate.

Exhibit 7: The numbers are large with higher 'C' and maybe 'P' to come (Carpentaria Only)

Area	Reservoir	Contingent Resource (100%) Net Sales Gas (BCF)		
		Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)
Carpentaria	Velkerri C	21	84	319
Carpentaria	Velkerri B	60	295	938
Carpentaria	Velkerri Intra A/B	-	7	14
Carpentaria	Velkerri A	-	10	21
Total*		**81**	**396**	**1,292**

Source: Company data

Exhibit 8 below sets out EEG's holdings across all of the NT.

Exhibit 8: Empire Energy Group holdings in all of the Northern Territory

Zone	Unrisked Net Contingent Resources Liquids (MMBBL) Estimate			Unrisked Net Contingent Resources Sales Gas (BCF) Estimate			Unrisked Net Prospective Resources Liquids (MMBBL) Estimate			Unrisked Net Prospective Resources Gas (BCF) Estimate		
	Low (1C)	Best (2C)	High (3C)	Low (1C)	Best (2C)	High (3C)	Low (1U)	Best (2U)	High (3U)	Low (1U)	Best (2U)	High (3U)
Kyalla*	0.8	3.0	11.1	0.8	4.5	27.7	88	378	1,571	184	857	4,891
Mid Velkerri*	0.1	0.5	3.0	138	549	1,680	82	419	2,062	10,744	31,018	89,217
Barney Creek*	-	-	-	-	-	-	-	-	-	1,633	11,053	45,380
Total*	**0.9**	**3.5**	**14.1**	**138.8**	**553.5**	**1,707.7**	**170**	**797**	**3,633**	**12,561**	**42,928**	**139,488**

Source: Company data

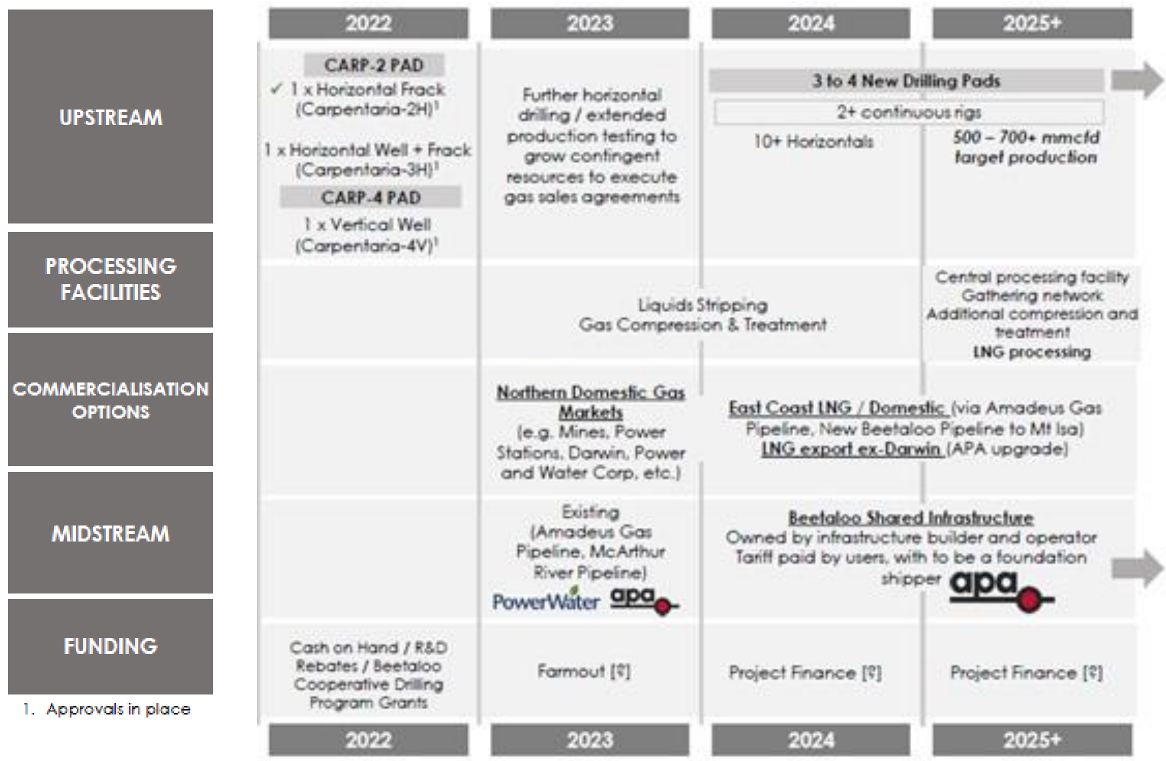
On The Cusp With A Timeline To First Gas

The company has set an ambitious timeline to project start-up as outlined in **Exhibit 8**, with further works already underway and planning to be development drilling in 2024.

We have already highlighted that the company holds approvals for the drilling up to seven wells (another four post the completion of the current campaign), which could be drilled later in 2023, should there be a need, as indicated to *"…grow contingent resources"* and subject to financing.

We expect the company to be in a position to certify 2P volumes and convert (finalise) gas sales contracts to underpin a project FID by end-2023.

Exhibit 9: A timeline and a plan to first production



Source: Company data

What could a development project look like?

Exhibit 8 suggests the potential for a 500-700+mmcfd project, which is not unreasonable given the scale of the resource opportunity and nature of the geology which lends a high degree of confidence to commercial extrapolation. **If the success case works at Carpentaria, then it's highly likely to work on an extended regional basis.**

We reiterate from earlier commentary that the geology and characteristics of the target shale are very consistent as noted across the 11km between the C-2H and C-1V wells (**refer Exhibit 5 (RHS)).**

Any-development project will probably be undertaken on a phased basis, with local gas supply supporting an extended commercial proof of concept and providing important early cash flow and operational experience.

The company has identified a number of opportunities in local power generation for township and mining operations that could aggregate to a 'starter' project of around 25TJd (9PJ pa) of high calorific gas.

This may only require 3-4 wells from one drilling pad and be in production sometime in 2024. **At a gas price of say $10-12/gj, a project at this scale would generate $90-108mn pa** at ramped supply, at low operating cost with the gas likely requiring only minimal processing and compression.

A successful Phase 1 project would represent an important 'proof of project' model providing a substantial operational and finance base on which to build, delivering important initial cash flow to would support further financing (debt and partnering options) whilst minimising dilution of the capital base.

Fracking will be required

The optimal fracking method is still to be determined but we'd expect by the completion of the C-3H testing the company will be in a position to be absolute about the preferred methodology.

We note that the C-3H well has been completed using a variety of frack methods in a similar fashion to the C-2H well, so to a degree there remains an evaluation element to the operations although the skew to gel and hybrid methods points to the likely preferred style(s).

Frack Style	Slickwater	Crosslinked Gels	Hybrid*	HVFR**	Total Stages
Carpentaria-3H	3 stages	16 stages	21 stages	nil	40
Carpentaria-2H	7 stages	8 stages	4 stages	2 stages	21

* Slickwater and Crosslinked Gels
** High Viscosity Friction Reduction

Contribution analysis from the C-2H and -3H wells will be important in determining the optimum frack programme.

Sustainable flow rates and gas recovery data are needed to underpin type curves

There have only been a relatively small number of exploration and appraisal wells drilled across the Beetaloo Sub-basin to date, with critical gas discoveries made in 2015 by Origin Energy at Amungee NW and by Santos at Tanumbirini, prior to the Carpentaria wells.

Being somewhat proximal to EEG's current operating area, the results at Tanumbirini-1H (T-1H) provide confirmation of the Velkerri play potential on a regional basis. The T-1H well tested with an initial peak gas rate of ~10mmcfd and an average rate of 2.3mmcfd over the first 90 hours of testing.

The Carpentaria-1V drilled by EEG confirmed high calorific gas in the Velkerri Shale, but at a shallower depth and over a greater proportion of the formation compared to analogue wells in the deeper sections of the Beetaloo Basin.

The next suite of testing will need to be conducted over a longer time period, perhaps up to 180 days to better define production curves, models and forecasts, although the broad parameters to underpin commerciality are....

- Wells with lateral (hz) completions of up to 3,000 and c.60 frack stages

- Development well costs maxing at $40mn
- IP30 flow rates of at least 3.5mmcfd/1,000m (average) – by extrapolation a 3,000m completion should deliver above 16mmcfd
- EURs per well of at least 10Bcf

…to deliver all in costs of $5.00/mcf, although targeting costs below $2.50/mcf

The listed assumptions are to a large degree based on the transfer of US onshore development and operating costs into an Australian (NT) context. Whilst it is not unreasonable to suggest the US onshore (Marcellus Shale) as a comparative analogue, it has not historically been the case that 'what works in the US also works in Australia', but it has to start somewhere and only a suite of additional data will determine and define the economic model with certainty.

In many respects, EEG is already ahead of that curve, particularly on horizontal completion length, frack density and well cost.

We highlight that current drilling and completion costs have not been optimised and EEG is expected to progress along the cost learning curve in much the same way as experienced by CSG producers. There are a number of areas that have been identified for cost reduction, including but not limited to -

- Sourcing a local supply of frack sand;
- Having a more permanent logistics base with dedicated equipment located in the basin;
- Mobilisation/demobilisation costs are quite excessive at the moment with few rated rigs available to complete the well designs. This action may evolve in parallel with the timing of development campaigns when operators move into a more continuous drilling phase.

Financing

Given the early-stage nature of exploration and evaluation in the region, capital costs trend towards the high end and on sustained financing becomes a balancing issue between proving the commercial opportunity and dilution.

Empire's US onshore gas assets generate a positive EBITDA but in practical terms this is insufficient to fund the greater capital requirements for the Beetaloo activity, which EEG has been funding from a combination of Government grants, R&D rebates and equity capital. These are likely to remain the primary source of financing through the evaluation phase and up to FID, we suggest.

The company's position as a low-cost operator is extremely beneficial and should ensure the remaining budgeted activities through end-2023 (testing, FEED, seismic and drilling) are covered with overs to the FID point.

EEG, under the Beetaloo Cooperative Drilling Program **has approval for grant funding of up to $19.4mn to** *"offset 25% of the cost of seismic acquisition and the drilling, fracture stimulation and flow testing of three horizontal appraisal wells"* in EP187.

The company appears well financed to deliver the currently planned testing and evaluation and FEED activities through to a potential project sanction point by end-2023/early-2024. We estimate as follows -

			Running balance	
Opening balance	31-Dec	**$23mn**		Unaudited estimate
less remaining Carpentaria costs		($10mn)	$13mn	Covered by grant funding
R&D rebates and Government Grants		$18mn	$31mn	Estimates only
Undrawn debt facilities		$10mn	**$41mn**	

We suggest there is sufficient working capital to adequately ongoing FEED studies and; acquire seismic and drill (but not frack) a well in the Pangaea plays (**refer Exhibit 4**) at a location to be determined, but we suggest, able to be tied into the area of current regional activity.

On balance, EEG could exit FID with a cash balance around $8-10mn.

At FID, financing becomes project based, would likely be secured against reserves and gas agreements and would be debt financeable to a significant degree. This should also be the point at which partnering options become more attractive on a de-risked basis.

The attraction to third parties is somewhat obvious –

- entry level opportunities of scale;
- attractive pricing of Australian domestic and export markets versus US markets;
- cheap in US dollar terms
- existing export facilities in Darwin
- proximity to Asian markets

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

Local Partnering options are likely fewer as the sector is thin, Santos already has a presence and Woodside (WDS.ASX) has no end game for NT gas, but as a very left field option, perhaps Hancock could be the wild card.

Hancock is already present in the basin, actively seeking gas on a regional basis, having aligned with Posco International Corp on the acquisition of Senex Energy and if current WA activity is anything to go by, looking for more.

We would also include in the list of potential partnering options, any of many Asian trading houses who have a long and successful history of Joint Venturing in Australian gas plays.

In order to minimise dilution at the issued capital level, the company has recently secured a debt facility with Macquarie Bank as a working capital option and potential precursor to any project finance facility, under the following terms and conditions; -

- Total facility A$15mn comprising -

  A. A$$10mn **revolving credit facility** as described -

     "…(a)vailable funds are linked to (60% of) the forthcoming year's estimated tax rebate under the Australian Government's Research and Development ("R&D") Tax Incentive Scheme."

     This is expected to provide the company with a better mechanism to smooth capital availability, effectively working on the credit card if required. Funds can be applied to NT exploration and appraisal activities, general working capital and G&A.

  B. A$5mn **performance bond facility** as described -

     "…to meet the tenement environmental bond obligations through letters of credit in favour of the Northern Territory Government on a non-cash-backed basis which releases current and potential future cash held as security."

The company has indicated that the facilities may wrap into a future project debt facility upon booking reserves and gas sales agreements – as part of the financing required to deliver FID.

The repayment date at end-2025 is consistent with the ambition to be in production by 2025.

Exhibit 10: In a rising interest rate world, the facilities look fairly priced

Key Terms	Details
Lender	Macquarie Bank Limited
Borrowers	▪ Imperial Oil & Gas Pty Limited ▪ Imperial Oil & Gas A Pty Limited
Guarantor	Empire Energy Group Limited and Borrowers
Establishment Fee	$225,000
Security	▪ First ranking security over all present and after-acquired property of each Borrower ▪ First ranking security over the Guarantor's shares in each Borrower, plus featherweight over the Guarantor's other assets
Utilisation Fee	1.5% of utilisation
Commitment Fee	40% of Margin
Margin	▪ Facility A: 5.5% p.a. ▪ Facility B: 10% p.a.
Interest Rate	Margin plus BBSW
Financial Covenants	▪ Ratio of current assets to current liabilities of at least 1.00 to 1.00 ▪ Minimum cash balance in the Borrowers and Guarantor of at least $5 million (or its equivalent in any other currency or currencies)
Repayment Date	31 December 2025
Repayment arrangements	▪ Facility A: on receipt of relevant R&D Tax Incentive payment ▪ Facility B: on release of environmental bonds after rehabilitation

Source: Company data

Appendix A - Making the case for NT gas

The investing market can see the thematic – rising gas prices in a supply constrained environment, but as an early-stage opportunity, there is a residual degree of uncertainty remaining across the potential role of NT gas supply from both operational and financial perspectives. When we add the continuing overlay of issues related to Federal energy policy and recent imposition of gas price caps, we can somewhat understand why NT gas options are in a 'buy-the-fact' zone from an investors perspective, but therein lies the opportunity.

We draw on recent ACCC analyses and AEMO gas utilisation data and cite from the following ACCC publications where highlighted –

ACCC Gas inquiry 2017-2025 Interim Report (July 2022) – published 1-Aug

ACCC Gas inquiry 2017-2025 Jan 2023 interim report – Preliminary gas pricing – published 14-Nov

In determining whether the Beetaloo gas opportunities are physically and commercially realistic we believe two high level questions need to be answered.

Is NT gas needed?

The short answer is yes.

The ACCC in its analysis of the impediments to competitive gas pricing in east coast markets concluded that there were a number of structural factors that needed to be addressed including –

- The need for **"…(g)reater diversity and more timely supply"**
- "…enforcing compliance with work programmes"
- "…introducing a **third-party access regime for upstream infrastructure".**

Notwithstanding project specific risks, we interpret this as positive for NT supply options, particularly as the "…highly concentrated" nature of east coast supply "…dominated by the three LNG exporters and their associates" with "…influence over close to 90% of the 2P reserves (in 2021)" supports the need for development of gas projects outside of the control and influence of the existing infrastructure hubs.

Ultimately, we read this as a call for more gas, from more areas, more rapidly.

Naturally this can only come at a cost.

In a physical sense, new gas supply is required on the east coast for domestic consumption (domgas), certainly in the medium term, with under-utilised export facilities set to aggregate incremental volumes at the margin and existing production operations battling the decline curves.

Although not significantly relevant for NT gas options in the 'now', the immediate short-term issues as highlighted by the ACCC, project up to 56PJ of nominal supply shortfall on the east coast in 2023 requiring redirection of volumes away from export spot markets.

This is a 'pinch of salt' territory on ACCC projections as it represents a worst-case scenario –

"…**if all the excess gas of LNG exporters is sold in overseas markets, then the domestic east coast gas market is likely to be 56 PJ short** of the gas needed to meet forecast demand for 2023".

The latest ACCC Interim Report indicates, LNG exporters expect to produce 167PJ of 'excess gas' (above contractual commitments) and since 2018, these projects **"…have exported at least half – and more frequently around 70% - of their excess gas to overseas spot markets".**

Assuming the same trend applies, then to fill the gap, only ~33% of the 'excess gas' would need to be made available to satisfy the domestic supply gap but that comes with opportunity cost, which ultimately comes down to pricing.

…and pricing is the critical limiting factor on NT gas supply at scale, we suggest.

We are aware of firm and potential new supply coming to market in the period to 2025, including but not limited to -

- Beach Energy (BPT.AX) has 'completed gas' waiting to be connected into its underutilised Otway Gas Processing Plant from a next phase of Thylacine-Geographe development, although we suggest that should already be figuring into the ACCC analyses.
- Cooper Energy (COE.AX) plans to deliver gas from its Offshore Otway Basin, OP3D project by mid-2025, through the underutilised Athena Gas Processing Plant. This project is cum-successful appraisal, rates are yet to be determined, FID is yet to be delivered and we suggest the timing remains uncertain on issues related to the Federal Government's gas policy, notably the 'reasonable pricing' provision. As indicated by the company from the most recent quarterly release, if FID is not taken in May, then the first gas target for winter 2025 will be pushed back. We consider the probability of gas success (in principle) to be very high and note the Athena plant has a nameplate capacity of 150TJd and is currently supplying <30TJd, however, the risk is growing.

Similarly -

- Comet Ridge (COI.AX) will be looking to take FID on two projects across 2023 at Mahalo (Main block) in Joint Venture with Santos (STO.AX) and Mahalo North. In combination both of these projects could ultimately deliver 100+TJd, with first gas at a small scale by early 2024.
- Santos Limited (STO.AX) at Narrabri. Anecdotally we understand there is potentially significant resistance to the development plan at a land-owner level with uncertainties related to the upcoming NSW State Government election on a projected change of government, that could impact the timing and approvals process. In some ways, Narrabri looks as far away from commercial certainty as it has ever been.
- Galilee Energy (GLL.AX) hopes to declare initial reserves at its Glenaras Project in 1H23, although delivering initial production by 2025 remains uncertain.
- Blue Energy (BLU.AX) is currently appraising its northern Bowen Basin CSG play with the potential to declare maiden reserves perhaps by mid-2023. Production requires sufficient scale to justify new pipeline connections into the Queensland network.
- Arrow Energy (unlisted) has sanctioned the first phase of its Surat Gas Project. With drilling having commenced in 2020, the project includes over 600 wells aiming to produce ~300TJd over 27 years, primarily for export. The project is underpinned by a gas sales agreement with the QCLNG Joint Venture.
- Senex Energy (unlisted) announced plans for a A$1Bn expansion in its Surat Basin gas operations (Aug-2022), looking to increase production to 60PJpa by end 2025. Management has indicated the increase in supply would *"…mostly be directed to the domestic market"*. As at its last published financial update (Feb 2022), SXY was already producing ~27PJpa.

  We highlight that as a consequence of the Federal Government's recent decision to apply gas price and supply controls, the company has announced a pause to its gas expansion project (22-Dec).

- ExxonMobil and Woodside (WDS.ASX) announced plans in Mar-2022, to increase gas deliverability form the Bass Strait (Gippsland Basin) project at a gross cost of A$400mn, though the expansion of the Turrum filed and development of the Kipper Gas Project. The two new projects are planned to deliver up to an additional 200PJ through 2028, of which 30PJ would be produced in 2023. AEMO data to date points to a measurable increase in gas supply over 2022, however, we'd suggest the 2023 projection should already be factored into the ACCC forecasts which point to a potential shortfall through the next twelve months.
- A number of companies/Joint Ventures will be conducting exploration with various degrees of risk across the next 18 months with some potential to bring gas to market sometime in 2025, but success cases will likely result in incremental additions by that date.

However, all the projects as listed require material capital and sustaining capital investments including new pipeline inter-connections. Additionally, these projects may not provide the scale of production growth or reserves potential to create a fundamental shift in supply particularly after accounting for the decline curves in major production hubs and under-utilisation of export facilities.

Are import facilities the wild-card?

Assuming the approvals process is navigated in a timely manner, perhaps an import facility could be operational sometime in 2025, but the issue will be securing new gas in a currently rampant global gas market, where paradoxically if cheap gas could be sourced, that would very likely be reflected in export netback pricing contracts in any case.

Independent analyses reported from Energy Quest indicates initial LNG imports, potentially from 2025 becoming a significant contributor to supply in both NSW and Victoria from 2029 (**refer Exhibit 10**).

Shouldn't this be considered to represent at least a supply gap opportunity that could be filled from other local sources?

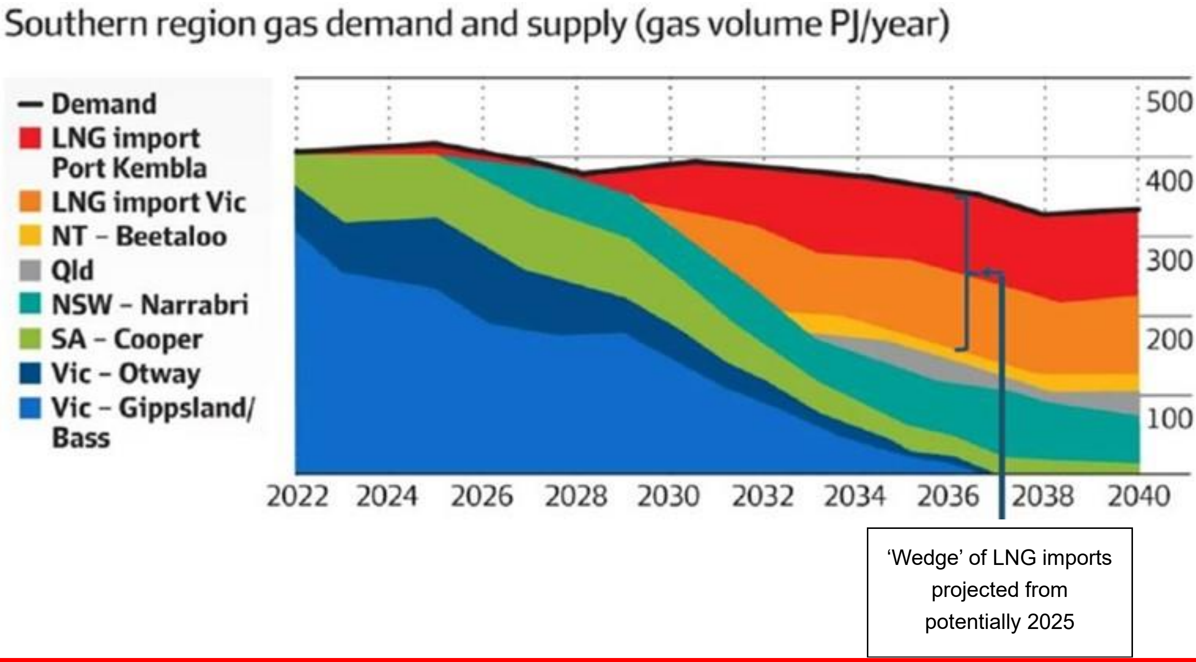
Importantly once operating, an import terminal(s) would set an import parity pricing (+) benchmark for gas supply at the margin into gas hubs.

Interestingly and anecdotally, the possibility of extending the term of a gas-price cap (RaaS scenario only) and 'reasonable price' provisions under which the Government of the day would set individual contract prices, could (would?) make the economics of LNG import options somewhat problematic depending on the differential of the supply-demand prices. The scenario shown in **Exhibit 6** highlights the material role being projected for 'import' volumes.

Against this operating backdrop, there is certainly a material supply opportunity for NT gas to flow into eastern markets, although definitive progress has to be delivered in the next twelve months in terms of the well development design and production model (type curve) templates, which we discuss further in the report.

The NT gas resource potential is of sufficient scale with supportive, consistent geology to provide a high degree of confidence once development models are finalised.

Exhibit 11: A worst-case scenario? There's a projected gas import wedge available to fill organically



Source: AFR (7-Nov) from Energy Quest data

Will NT gas work economically?

At what gas price? At what gas rates? At what scale?

The gas industry in the NT is in a nascent stage and these are the parameters currently being evaluated across the play. The aggregate work being conducted by EEG and other basin operators over the course of 2023, should go a long way to defining the development model and answering that question.

There is always risk associated with emerging geological provinces as the pre-production technical and capital risks are the highest.

This is also the highest risk period on activism and protest for the anti-fossil fuel groups. Nominally the easiest place to stop something is before it has started and until commercial gas developments are delivered, the 'noise of opposition' will continue to be shrill and loud.

Early-stage evaluation is expensive and in some respects the NT gas opportunity will be a significant capital sink for some time – this is the nature of 'discovery', both technical and economic until costs can be normalised on a commercial success case.

Prevailing investor and analyst perceptions of the economics of the Beetaloo Sub-basin are being somewhat skewed by current exploration and evaluation costs, which are high but won't reflect the unit costs achievable in a development situation, where wells will be drilled and completed on a batch basis.

Despite the perceived commercial advantages associated with Queensland CSG opportunities there has been very little tangible progress in bringing gas to market and new CSG plays with potential scale are at a similar position on the commercial risk curve, in our view.

We suggest Beetaloo (NT) unconventional gas developments compares favourably to CSG as a fill the gap supply option, particularly on the basis of scale – the next tranche of Queensland CSG will not be cheap and is likely to be incremental.

In that regard the success case of NT gas can be somewhat thought of and modelled using the pharmaceutical industry as an analogue – the second gigajoule of gas may only cost around $5-6, but the first gigajoule can cost $'00s of millions and in the case of gas export projects - billions.

Of critical importance is the determining of the type curve.

We cite from the RaaS EEG initiation report April-2020 –

ACIL Allen ('ACIL') conducted a comprehensive economic assessment of the potential development scenarios that could arise from a shale-gas industry in the NT as part of that government's Fracking Inquiry.

ACIL specifically highlighted the assumptions its modelling had to make with respect to type curves given, at the time of the report there had only *"…been one successful horizontally drilled shale gas well for production testing (Amungee NW-1H)"* commenting that whilst the test was positive *"…the well involved only 11 frack stages. A typical horizontal well will have at least 20 frack stages and in most cases many more"* and *"…production testing was conducted only for 57 days".*

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

We note that the economic scenario modelling 'maximises' the potential deliverable volumes at 1,000TJpd, which we mention only to highlight the resource potential required to underpin this scenario would be in the order 7,000-7,500PJ or ~7Tcf assuming a 20-year production life.

The ACIL modelling was finalised in 2018 and assumed all in operating costs of ~$4/gj (cash breakeven cost) based on 'dry gas'. Four years hence and in an inflationary world, we suggest that figure as more likely to be closer to ~$6/gj but that should also be considered as a broad estimate only.

Gas Specification

It's reasonable to assume and early data supports the premise that gas discoveries will have a significant liquids component. In some ways that may complicate the engineering, but would provide a potentially significant operating cost offset and ultimately provide an additional revenue stream (for example bottled LPG for domestic or transport use).

Evaluation results to date, from the EEG, STO and Origin Energy (ORG.AX) wells provide a partial look-through to the commercial success case.

The gas composition is highly favourable.

Commentary released from the drilling of the EEG Carpentaria-1 and -**2H** wells (Aug-2021/**Sep-2022**), reported the gas composition in the target mid-Velkerri Shale as –

- 76% / **83%** methane (natural gas),
- 21% / **14%** LPGs and;
- 3% / **3%** inerts (of which only 0.74% / **0.88%** was CO_2)

Gas analysis from the Velkerri-76 well (Falcon Oil & Gas/Origin Energy JV) supports the liquids rich potential of the assumptions -

- In wet gas window, with very good LPG yields;
- 7.7% porosity and 4.3% TOC by weight (total organic carbon) - the sequence is relatively organically rich;
- ~80% methane (natural gas), 20% LPG fraction, with likely very little CO_2

A path to market

Notwithstanding the somewhat disconnected nature of the eastern gas pipeline network, there is a path to market for Beetaloo gas on a local and regional (at scale) basis, through the existing under-utilised facilities and planned, new additions subject to threshold gas aggregation.

In Oct-2021, EEG signed a MOU with APA Group (APA.AX) to explore gas development opportunities which we suggest, puts a stake in the ground for development options.

Although it's early stage and consists of mostly conceptual strategies, it is part of the morphing of the Beetaloo gas plays into a greater whole. It's a good outcome for EEG (APA as a pipeline operator is well regarded) and allows it to concentrate on the upstream aspects of the play.

APA operates the readily-expandable 1,658km, 120TJd Amadeus Gas Pipeline (AGP), from the Amadeus Basin near Alice Springs, north to Darwin, primarily feeding local electricity generation.

APA is separately investigating the development of new "common-user" transmission lines to service east coast markets from the NT to Mt Isa, whilst enlarging the AGP to support new Beetaloo gas. The AGP already connects with Jemena's 622km, 106TJd Northern Gas Pipeline (NGP) at Tennant Creek into Mt Isa, which in turn connects into APA's extensive east coast transmission grid.

The APA MOU deal terms do not preclude EEG from seeking pipeline user agreements with the 330km, 16TJd Daly-Waters (McArthur River) Gas Pipeline, owned by the NT Power & Water Corporation (NTPWC), which connects into the APA Amadeus line at Daly Waters.

The company has also signed a MOU with the NTPWC as the basis of future potential gas sales and pipeline access, noting that the NTPWC owns and operates the McArthur River Pipeline, linking that mine into the APA Amadeus -Darwin connection.

As with the APA agreement, it's very early stage but from an EEG perspective it begins to add some tangible options to its 'Rapid Commercialisation Strategy', that could deliver an initial, small project based on works to date and planned around the Carpentaria gas area.

NTPWC is the NT's largest provider of gas, electricity networks, water and sewerage services, distributing electricity to over 244,000 people, spanning 1.3mn km^2 across the state.

The MOU with APA is a particularly good fit for EEG's western (Pangaea) assets whilst the NTPWC MOU provides smaller access and a potential customer...**in this regard the company has stolen a bit of a march on the competing JVs we suggest.**

It's a good outcome for EEG (APA and NTPWC provide 'access + customer') but the missing plank is still the definition of the economic case, which should be underpinned by the direct and indirect activity in-train over the next 12 months in particular.

Progress requires definition on the development model.

The current testing campaigns from EEG and other operators should provide a sense of the 'physical' - how many wells, in what configuration, to recover (commercialise) how much gas, at what capex…and we could indicatively be at that point by mid-2023.

This should also lead, in the case of EEG, into reserves certification and the confirmation of timing and size of early commercialisation options.

It could take materially large gas volumes to prompt APA to enter formal pipeline design studies but there now appears to be a race to get pole position in NT infrastructure expansion.

APA already owns the Amadeus to Darwin pipeline that runs N-S with a nominal capacity of ~120TJd but is currently running at ~45TJd with gas supplied from the fields at Palm Valley, Dingo and Mereenie, which is unlikely to become materially larger.

There have been ambit claims over a Meerenie to Moomba connection but that was largely predicated on dedicated, new STO and Central Petroleum (CTP.AX) supply, which has not emerged.

Should sufficient volumes, be aggregated in the Beetaloo we believe that plan could be repurposed to flow gas south from a Beetaloo tie-in point and provide a link into the Moomba hub – this is a speculative option only.

Jemena owns the Northern Gas PL (NGP) which connects into APA's line at Tennant Creek and runs E-W to Mt Isa. It is currently the only connection into the east coast grid with a nominal capacity of ~106TJd.

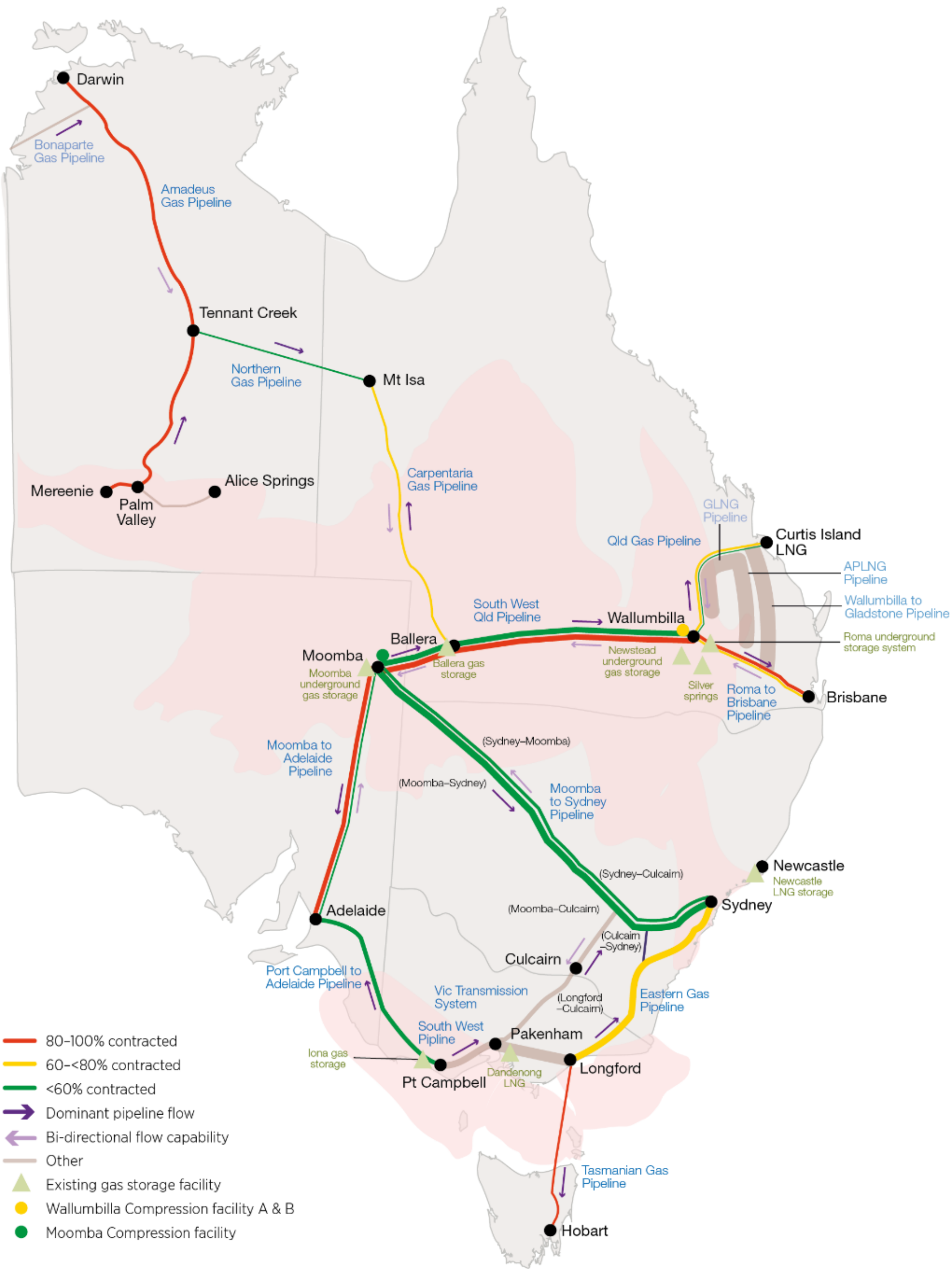
Jemena is looking to expand this line as a gateway for NT/Beetaloo gas into the east coast, subject to gas availability – and gas availability is an issue. It was reported in the AFR (13-Oct,-2022) that gas flows along the NGP had ceased in early September due to a sharp reduction in output at the offshore Blacktip Gas Field. Although field deliverability issues had been evident over the previous twelve months or so, production rates had decreased to the point that Jemena was reportedly unable to continue to operate the pipeline safely.

APA could be looking to build its own E-W link from the Amadeus-Darwin PL to Mt Isa as an alternative pathway to Jemena.

By aligning but not irrevocably committing to APA, **EEG has essentially put a stake in the ground on how it will get 'scale' gas to market, without precluding any other infrastructure options**.

On a 'Field of Dreams' analogy, deliver the gas reserves at scale and the infrastructure path to market will emerge. It's going to be quite competitive on locking in capacity and hence very dependent on which upstream ventures can bank the first mover advantage.

Exhibit 12: NT needs to be better connected – gas first and pipelines follow



Source: Company data

Gas Prices…

…and ultimately it comes down to gas price as the stake in the ground on project economics.

Forecasting future gas prices is the unicorn, particularly given the political issues associated with energy prices through the transition period to renewables. There is the spectre on potentially persisting gas price caps and increasingly shrill noises being made by commercial and industrial gas users (C&I) on economics, job losses and capacity closures.

As a long-term, arms-length observer I can point to history and suggest that the upstream industry commentary has been highlighting/warning on rising gas prices for at least the last 15 years, with increasing volume.

APPEA recently (1-Dec) released a commissioned study into the impacts that imposing a nominal $10/gj gas price cap could have on future gas supply and unsurprisingly came out against the proposal, suggesting that short-term gains would be offset by long-term supply issues.

KEY points of the APPEA study -

- "Price caps do not address the cause of high domestic prices – **lack of new gas supply and volatility in demand from the electricity market** with the transition to renewables does"
- "**The long-term net effect of a price cap is to increase demand with lower prices and decrease supply with lower economic returns** – the opposite of what is required."
- …(historically) price caps **decreased the incentive for exploration and risked long-term supply** because capital investment would be deferred or redeployed to markets with higher prices.

We reiterate from previous commentary in this report that the ACCC has concluded there a number of structural factors needing to be addressed including –

- The need for **"…(g)reater diversity and more timely supply**
- "…enforcing compliance with work programmes"
- "…introducing a **third-party access regime for upstream infrastructure".**

We find it difficult to reconcile how a gas price cap helps the above and the recent decision imposing a price cap of $12/gj appears to have been made with a political bias and not necessarily (and certainly not solely) on an economic basis.

Anecdotally, we believe gas buyers have been approaching existing or emerging gas producers pre-emptively on 2023 east coast gas supply and have been discussing prices in the range of A$15-20/gj.

There is somewhat of a disconnect between the headline noise and what is happening on the ground in a practical sense.

If we use early-stage guidance as outlined previously that suggests a cash breakeven for NT gas at scale is in the order of $5-6/gj, then a notional $12/gj price at Wallumbilla (although this is only in force for new gas supply in 2023) would likely be well sufficient as an ex-hub price to support NT gas into the east coast, in our view (after financing and amortisation).

How much margin and flex within these estimates is subject to how material any operational progress is over the next 12 months.

We model a base case contract gas price in Queensland through 2023 as $12/gj derived from commentary provided by upstream companies (suppliers) and against a modelled LNG price netback of $15-13/gj (oil prices in backwardation) underpinned by a 2023-2025 Brent oil price range of ~A$125 (declining) to A$113/b over that period.

Source: Forward Brent and AUD curves – 2 Jan

In its presentation materials associated with the acquisition of ORG interests in the Beetaloo Basin, TBN cited its gas agreement with ORG, at a Brent price (c.US$90.60/b and 0.67 forex = c.A$135/b) delivering a gas price in the range of A$12-15/mcf (A$13-16/gj), implying a slope of around 0.1*(A$) Brent at the mid-point…for 2025 delivery, against sell side consensus commodity forecasts (c.A$100/b), that would be around A$11/gj.

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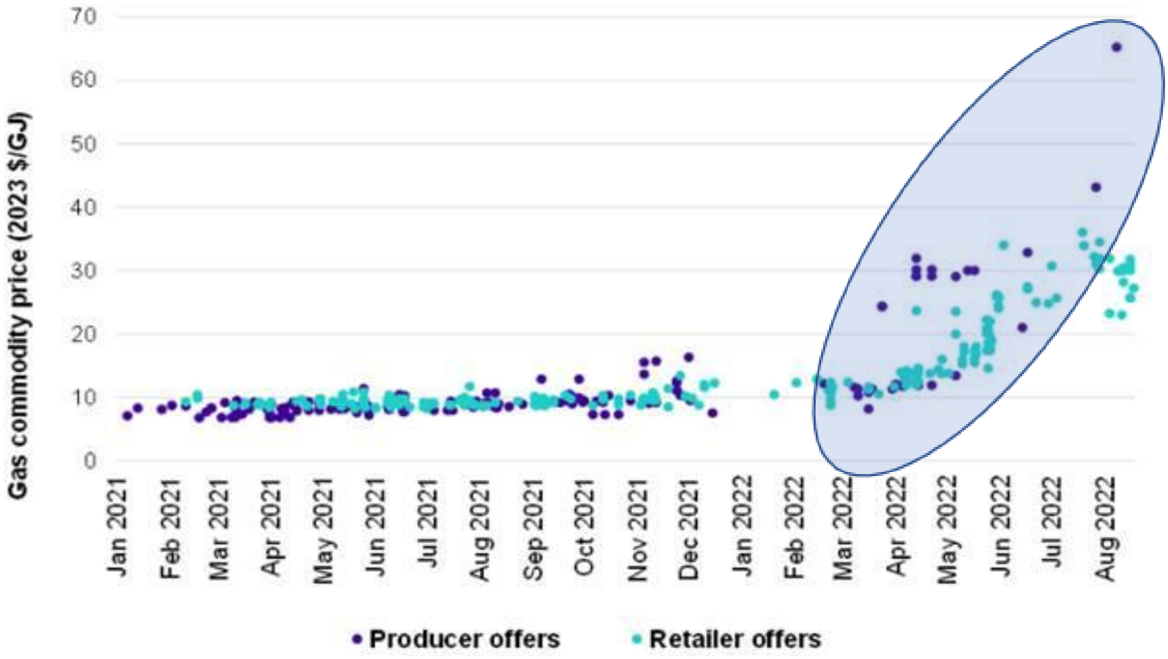
Exhibit 13: The latest AEMO data points to a wide range of gas price bids and offers for 2023



Source: AEMO data

If there is a risk to the forecast gas price outlook it lies in the government's imposition of a 'a mandatory code of conduct' and **"reasonable pricing provision"** and how that works in an absolute sense.

Is the reasonable pricing provision based on a cost-plus model, which imposes an arbitrary cap on returns based on a 'theoretical' rates-of-return, but in practice ignores all the inherent risks in getting from exploration to production?

<u>The ACCC has been publishing gas market analyses based on a LNG net-back model, so surely that should be the benchmark, we suggest.</u>

These mechanisms represent a shift away from a free-market pricing model, with the government potentially 'price setting' on a permanent basis. Ultimately and paradoxically, it could result in less gas in the domestic market and more heading to export.

That sounds like the extreme edge of the range of outcomes, but if taken to that extreme it will almost certainly restrict new field investment – capping the upside whilst exposing projects to the downside in an operating environment where the cost base is only going one-way. We have said this previously but each subsequent tranche of gas in developed provinces comes at a higher base cost.

Importantly and we have suggested this previously, the reasonable price provision would significantly impact the business case for LNG import terminals. I find it difficult to reconcile how an import project would be able to source gas internationally, after transport and re-gas costs that would be profitable at $12 at the outlet flange of a terminal.

On an import basis, the reasonable price could only be 'import parity plus' and would certainly not be cheap.

The devil will be in the detail.

In the immediate short-term, the impact on the business model for EEG is negligible in practical terms, but it's the next policy steps that are uncertain. In many ways, the Federal Energy policy beyond 2023 remains opaque.

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Appendix B– More than just the Beetaloo…a US leg to boot

EEG first entered the US in March 2006, with a strategy to aggregate hydrocarbon assets in the Appalachian Basin. 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

The play and strategy has been largely successful, notwithstanding the, until recently, low prevailing gas prices. Over the last two years or so on a rising price base, these operations have demonstrated strong operational performance with a significant number of previously shut-in wells returning to production.

Based on the 30-Sep-2022 Quarterly update-

- aggregate production for the 9months was flat year on year with higher liquids recoveries;
- average realised product pricing of US$5.53/mcfe (v US$2.90/mcfe pcp);
- operating margins of 76% (v 59% pcp).

The US assets are linked to a Macquarie Bank credit facility due to mature in Sep-2024 with a coupon rate of LIBOR+650bps and repayment terms of *"…100% of Appalcachia Net Operating Cashflow subject to minimum amortisation of US$550,000 per annum"*. As at 30-Sep, that total facility drawn amount was A$8.4mn (US$5.4mn).

Exhibit 14: Significant production life remaining in the Appalachia play

Reserves - As of Nov 30, 2021	Oil (Mbbls)	Gas (MMcf)	MBoe	Capex $M	PV0 $M	PV10 $M
Reserves (Reserves)						
Proved Developed Producing	46	28,032	28,308	-	$27,809	$15,867
Proved Developed Non-producing	-	155	155	$54	$(155)	$(63)
Proved Behind Pipe	-	-	-	-	-	-
Shut-in	-	-	-	-	-	-
Proved Undeveloped	-	-	-	-	-	-
Total 1P	**46**	**28,187**	**28,463**	**$54**	**$27,654**	**$15,804**
Probable	-	10,177	10,177	$7,809	$23,176	$4,304
Total 2P	**46**	**38,364**	**38,640**	**$7,863**	**$50,830**	**$20,108**
Possible	158	3,916	4,864	$5,102	$14,234	$3,542
Total 3P	**204**	**42,280**	**43,504**	**$12,965**	**$65,064**	**$23,650**
Net production to 30-Sep	(2)	(1,237)				
Adjusted Proved Developed Producing	**45**	**26,795**				

Source: Company data

These operations are continuing to provide a positive EBITDA of around US$1.5-1.6mn per quarter subject to prevailing gas prices.

In the Jun-2021 quarter, Empire commenced a renewable energy leasing initiative, securing agreements with renewable energy project developers for the construction of wind and solar projects on land where Empire holds leases.

During 2021, the company received total cash payments received of US$110,000.

The company continues to progress further renewable energy leasing transactions.

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Appendix C– Board and Management

In our opinion, the company has a board and management with deep expertise across all the requisite areas required to ultimately deliver a development project of scale – from the technical through to the financial. Importantly, their collective experience includes success in project delivery, encompasses specific operational experience in the NT and an extensive contact network throughout Asia, as a potential source for gas (at scale) and securing partnering options.

Board

Managing Director/CEO: Alex Underwood, LLB, BCom (Hons)

Mr Underwood was appointed as Managing Director and CEO of Empire Energy Group Limited on 30th August 2018 after initially joining as the CEO of its wholly owned subsidiary Imperial Oil & Gas Pty Limited 6th March 2018.

Mr Underwood came to the company after a 15year career with Macquarie Bank and the Commonwealth Bank (Australia) specialising in upstream oil and gas investing and financing, in Sydney and Singapore; and commencing his career at BHP Billiton (Petroleum) in Perth and Melbourne.

Chairman/Non-Executive Director: Paul Espie, AO

Mr Espie has extensive directorship and financing experience across the resources industry having held the Chair at Oxiana Limited and Cobar Mines Pty Ltd. During his time at Oxiana, the company was developing the Sepon copper/gold project providing him with experience and insights that can help inform Empire along its developmental pathway to production at scale.

He was the founding principal of Pacific Road Capital, a private equity fund investing in the resources sector internationally and responsible for Bank of America operations in Australia, NZ and PNG.

Mr Espie was previously the Chairman of the Australian Infrastructure Fund and a Non-Executive Director of Aurelia Metals Limited.

He is currently a Fellow of the Australian Institute of Company Directors, Trustee of the Australian Institute of Mining & Metallurgy, Educational Endowment Fund and a Director of the Menzies Research Centre.

Non-Executive Director: Prof John Warburton, PhD, FGS, MAICD

Prof Warburton was appointed to the board of Empire Energy in February 2019 and continues to be a Non-Executive Director of Empire's wholly owned subsidiary, Imperial Oil & Gas Pty Limited having served as its CEO from 2011 to 2014.

He has 35 years of oil and gas industry experience across many facets of the business, local and international; conventional and unconventional; and exploration through development, most notably over 14 years of senior technical and leadership roles at BP and as Chief of Geoscience & Exploration Excellence at Oil Search Ltd.

Prof Warburton was formerly a Non-Executive Director of ASX listed Senex Energy Limited and is a Visiting Professor in the School of Earth & Environment at Leeds University UK.

Non-Executive Director: Peter Cleary, B.Com. & LLB

Mr Cleary was appointed to the board of Empire Energy in May 2020.

He has had a successful career over 29 years in the industry with Santos, the North-West Shelf Venturers and BP in Asia focussed on LNG, pipeline gas and chemicals operations.

Mr Cleary brings an extensive relationship network commercial and government entities and is currently a Director of the Australia Japan Business Co-operation Committee and on the Executive Committee of the Australia Korea Business Council. He is Chair and Fellow of the Australian Institute of Energy (SA Branch).

He previously held positions as a Board member of the Australian Petroleum Production & Exploration Association (APPEA), the Australia China Council and the Australia Japan Foundation.

Non-Executive Director: Louis Rozman, B.Eng, MGeoSc

Mr Rozman was appointed to the board of Empire Energy in March 2021 and brings a wealth of knowledge across the resources sector and experience from numerous senior management positions in the industry, most notably as CEO of CH4 Gas Limited at the forefront of the then nascent coal seam gas industry in Queensland. It's worth noting that the CH4 assets now sit within the Royal Dutch Shell/PetroChina Australian portfolio.

Mr Rozman is a mining engineer and executive with 40 years' experience in Africa, Australia and PNG including as the CEO AurionGold Limited and its predecessor, Delta Gold Limited, with extensive operational experience across development and project financing (including private equity), construction and project management.

With Paul Espie, Mr Rozman was a founding partner and director of Pacific Road Capital Management, a private equity fund investing in the resources sector.

He is a Fellow of the Australian Institute of Company Directors, the Australasian Institute of Mining and Metallurgy and a Chartered Professional (Management). He is the Chairman of the VALMIN Code Committee for the AusIMM and Australian Institute of Geoscientists.

Non-Executive Director: Paul Fudge

Mr Fudge was appointed to the board of Empire Energy in August 2021 post the acquisition of the Pangaea (NT) Pty Ltd. Paul brings significant business and investment experience to the board of Empire, having acquired vast investment experience in onshore Australian oil and gas, including being an early mover in the Queensland Coal Seam Gas industry and in the Beetaloo Sub-Basin.

He is the controlling shareholder of Pangaea Resources Pty Limited, the major shareholder in Empire Energy at 18.1% (**refer Exhibit 15**).

Alternate Director: Jacqui Clarke, CA

Ms Clarke was appointed to the board of Empire Energy in August 2021 with over 30 years in professional practice with the Big 4, including more than 16 years as a Partner of Deloitte, Jacqui is an experienced professional with extensive executive track record for building a performance culture, driving profitable growth, developing and executing on strategy and delivering results. Jacqui advises a broad range of groups, including private family groups, entrepreneurial growth companies and not-for-profit organisations.

Her experience extends across Australia, NZ, China and Singapore and covers many industries and sectors including property, professional services, technology, agriculture and oil and gas.

Jacqui is a Chartered Accountant and Fellow of the Institute of Chartered Accountants, Graduate of AICD (Australian Institute of Company Directors), Chartered Tax Advisor and Justice of the Peace.

Exhibit 15: Directors' holdings

	Latest ASX notice	Fully Paid Ordinary Shares	Unlisted Options	Performance Rights*	Restricted Rights	Service Rights
Alex Underwood	17/06/22	2,550,000	Nil	3,894,123 U 1,300,500 V	1,586,579	1,000,000
Paul Espie	09/09/22	10,135,363	704,546^		738,169	Nil
John Warburton	09/09/22	1,044,546	227,273^		328,943	Nil
Peter Cleary	09/09/22	621,546	227,273^		Nil	Nil
Louis Rozman	09/09/22	772,815	159,091^		Nil	1,200,000
Paul Fudge	170/6/22	140,000,000	8,000,000+		Nil	
Jacqui Clarke		Nil	Nil		Nil	Nil

Source: Company data (holdings as of last ASX releases); * V = vested, U = unvested
Unlisted Options: ^ ex-price $0.35, ex-date 14/06/24
Unlisted Options: + ex-price $0.70, ex-date 30/08/24

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Management

Chief Geoscientist: Dr Alex Bruce, PhD

Dr Bruce was appointed Chief Geoscientist in March 2020. He is a well-credentialed oil and gas professional serving in similar roles with other mid-cap ASX oil and gas companies including AWE, Drillsearch Energy and ROC oil. He was most recently with Cooper Basin focused player Bridgeport Energy.

Dr Bruce is the President of the NSW Branch of the Petroleum Exploration Society of Australia and earned his PhD from the University of NSW in Reservoir Characteristics.

His role is to lead the Company's technical analysis and understanding of its Northern Territory assets and the wider Basin.

Chief Financial Officer: Robin Polson, BBus (Commerce); Grad Dip (Applied Finance and Investment)

Robin joined Empire in July 2022 and brings extensive knowledge, built over 20 years in the gas industry in general and the Northern Territory gas market in particular, specifically from his previous tenure as Chief Commercial Officer of Central Petroleum Limited.

Robin has strong relationships and experience working with key gas industry financiers, analysts, producers, transport providers, customers, and relevant regulatory bodies. He also has substantial experience in building and inspiring high performing teams within effective business and risk frameworks.

He has previously worked for almost 30 years with Deloitte and PricewaterhouseCoopers in audit, corporate finance, M&A and; valuation and strategy as well as holding the position of director in investment banking. Whilst at Deloitte his responsibilities focussed on the Australian east coast gas sector. He is a member of the Australian Institute of Company Directors.

Top 20 shareholding register

Exhibit 16: Register is dominated by the top 20

HOLDER	UNITS	%
PANGAEA (NT) PTY LTD	140,000,000	18.11
ELPHINSTONE HOLDINGS PTY LTD	63,000,000	8.15
CITICORP NOINEES PTY LIMITED	34,003,643	4.40
GLOBAL ENERGY AND RESOURCES DEVELOPMENT LIMITED	32,294,969	4.18
SHEFFIELD HOLDINGS LP	31,818,182	4.12
EMG NORTHERN TERRITORY HOLDING PTY LTD	26,515,152	3.43
MACQUARIE BANK LIMITED <METALS MINING AND AG A/C>	26,451,367	3.42
LIANGROVE MEDIA PTY LTD	17,807,500	2.30
ALL-STATES FINANCE PTY LIMITED	17,000,000	2.20
GROSVENOR EQUITIES PTY LTD <NO 2 A/C>	16,029,964	1.07
HSBC CUSOTDY NIMINEES (AUSTRALIA) LIMITED	14,074,327	1.82
CHA QIAN	9,245,000	1.20
ROBMAR INVESTMENTS PTY LIMITED	8,624,069	1.12
NATIOAL NOMINEES LIMITED	8,338,729	1.08
INVIA CUSTODIA PTY LIMITED <KUARKA A/C>	7,190,030	0.93
UNS NOMINEES PTY LTD	8,515,280	0.84
MR ANDREW FORSTER	5,500,000	0.71
NETWEALTH INVESTMENTS LIMITED <WRAP SERVICES A/C>	5,240,817	0.68
MS SWATI SHUKLA	5,200,000	0.67
ONMELL PTY LTS <ONM BPSF A/C>	4,915,141	0.64
TOP 20 SHAREHOLDERS	**479,764,170**	**62.06**
Total Issued Ordinary Shares	**773,121,148**	
Average monthly turnover for the 12-month period to 25-Jan-2023	**7.48mn shares**	

Source: Company data (as of 23/11/22)

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Exhibit 17: Financial Summary

EMPIRE ENERGY GROUP LTD		EEG		
YEAR END		Dec		
NAV	A$mn	$0.68		
SHARE PRICE	A$cps	$0.18	priced as of close trading	16-Feb
MARKET CAP	A$mn	139		
ORDINARY SHARES	M	773		
OPTIONS	M	10		

nm = not meaningful
na = not applicable

COMMODITY ASSUMPTIONS		2020	2021	2022E	2023E
Realised oil price	US$/b	39.48	67.98	94.25	79.32
Realised gas price	US$/mcf	1.96	3.72	6.42	4.21
Exchange Rate	A$:US$	0.6989	0.7514	0.6946	0.6819

RATIO ANALYSIS		2020	2021	2022E	2023E
Shares Outstanding	M	324	612	773	773
EPS (pre sig items)	UScps		(2.41)	(0.54)	(0.14)
EPS	Acps	(2.73)	(2.41)	(0.54)	(0.14)
PER	x		na	na	na
OCFPS	Acps	(0.61)	(5.35)	37.40	2.11
CFR	x		na	na	na
DPS	Acps				
Dividend Yield	%				
BVPS	Acps	13.4	23.8	23.7	24.2
Price/Book	x			0.8x	0.7x
ROE	%			na	na
ROA	%			na	na
(Trailing) Debt/Cash	x				
Interest Cover	x				
Gross Profit/share	Acps	3.7	5.7	5.9	7.6
EBITDAX	A$M	2.9	3.0	6.7	6.8
EBITDAX Ratio	%				

EARNINGS	A$000s	2020	2021	2022E	2023E
Revenue		6,464	8,502	12,662	11,421
Cost of sales		(5,266)	(5,005)	(8,135)	(5,534)
Gross Profit		**1,198**	**3,497**	**4,527**	**5,887**
Other revenue					
Other income		1,039	1,606	1,927	293
Exploration written off					
Finance costs		(755)	(568)	(677)	(668)
Impairment		0	0	(2,705)	0
Other expenses		(8,682)	(14,332)	(8,511)	(6,764)
EBIT		(7,013)	(11,305)	(1,851)	166
Profit before tax		**(7,485)**	**(10,835)**	**(3,983)**	**(877)**
Taxes		(200)	(213)	(213)	(200)
NPAT Reported		**(7,684)**	**(11,048)**	**(4,196)**	**(1,077)**
Underlying Adjustments		0	0	0	0
NPAT Underlying		**(7,684)**	**(11,048)**	**(4,196)**	**(1,077)**

CASHFLOW	A$000s	2020	2021	2022E	2023E
Operational Cash Flow		**(1,970)**	**(7,044)**	**13,796**	**1,686**
Net Interest		(755)	(568)	(677)	(455)
Taxes Paid		(200)	(213)	(187)	(120)
Other					
Net Operating Cashflow		**(2,924)**	**(2,460)**	**20,082**	**1,110**
Exploration		(856)	0	0	(4,181)
PP&E		(12)	0	(133)	(5)
Petroleum Assets		(12,841)	(12,965)	(54)	0
Net Asset Sales/other		0	0	0	0
Net Investing Cashflow		**(12,841)**	**(24,443)**	**(50,419)**	**(7,500)**
Dividends Paid					
Net Debt Drawdown		(1,845)	(817)	(793)	(500)
Equity Issues/(Buyback)		17,640	39,359	28,928	0
Other					
Net Financing Cashflow		**15,795**	**38,542**	**28,550**	**(500)**
Net Change in Cash		**29**	**11,639**	**(1,786)**	**(6,890)**

BALANCE SHEET	A$000s	2020	2,021	2022E	2023E
Cash & Equivalents		14,146	25,650	24,092	17,202
O&G Properties		46,442	34,900	85,635	93,429
PPE + ROU Assets		1,716	1,306	1,328	860
Total Assets		**66,563**	**158,823**	**207,710**	**207,609**
Debt		7,824	8,027	8,120	7,307
Total Liabilities		**36,327**	**49,502**	**80,232**	**80,020**
Total Net Assets/Equity		**30,236**	**109,320**	**127,477**	**127,589**
Net Cash/(Debt)		6,322	17,622	15,972	9,895
Gearing dn/(dn+e)					

NET PRODUCTION		2020	2021	2022E	2023E
Crude Oil	kb	2	2	2	2
Nat Gas	mmcf	1,630	1,676	1,727	1,727
TOTAL	**kboe**	**273**	**282**	**290**	**290**
Product Revenue	A$mn	6.5	8.5	12.7	11.4
Cash Costs	A$mn	(5.3)	(5.0)	(8.1)	(5.5)
Ave Price Realised	A$/boe	23.64	30.17	43.66	39.41
Cash Costs	A$/boe	(19.26)	(17.76)	(28.05)	(19.10)
Cash Margin		**4.38**	**12.41**	**15.61**	**20.32**

RESOURCES and RESERVES	Contingent Resources			Prospective Resources		
	1C	2C	3C	1U	2U	3U
Northern Territory						
Gas (Bcf)	138.8	553.5	1,707.8	12,561	42,928	139,488
Liquids (Mb)	0.9	5.0	14.1	170	797	3,633
TOTAL (Mboe)	**24.0**	**97.2**	**298.8**	**2,264**	**7,952**	**26,881**
US Onshore						
	1P	2P	3P			
Gas (Bcf)	28	38	42			

EQUITY VALUATION	Risked Range			Low	Mid	High
A$mn	Low	Mid	High		A$/share	
Northern Territory						
Contingent Resources	328	378	479	$0.42	$0.49	$0.62
Scenario Weighting	*3%*	*2%*	*1%*			
Prospective Resources	147	202	242	$0.19	$0.26	$0.31
US Onshore						
Appalachian	39	48	66	$0.05	$0.06	$0.09
	514	**629**	**788**	**$0.66**	**$0.81**	**$1.02**
Net cash/(debt)		17				
Corporate costs		(5.0)				
TOTAL	**525**	**640**	**799**	**$0.68**	**$0.83**	**$1.03**
Shares on issue (mn)	773 mn					

Source: RaaS Advisory; Priced as at 16-Feb-2023

FINANCIAL SERVICES GUIDE

RaaS Advisory Pty Ltd

ABN 99 614 783 363

Corporate Authorised Representative, number 1248415

of

BR SECURITIES AUSTRALIA PTY LTD

ABN 92 168 734 530

AFSL 456663

Effective Date: 6th May 2021

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BR is a member of the Australian Financial Complaints Authority (AFCA). AFCA provide fair and independent financial services complaint resolution that is free to consumers.
Website: www.afca.org.au; Email: info@afca.org.au; Telephone: 1800931678 (free call)
In writing to: Australian Financial Complaints Authority, GPO Box 3, Melbourne, VIC, 3001.

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