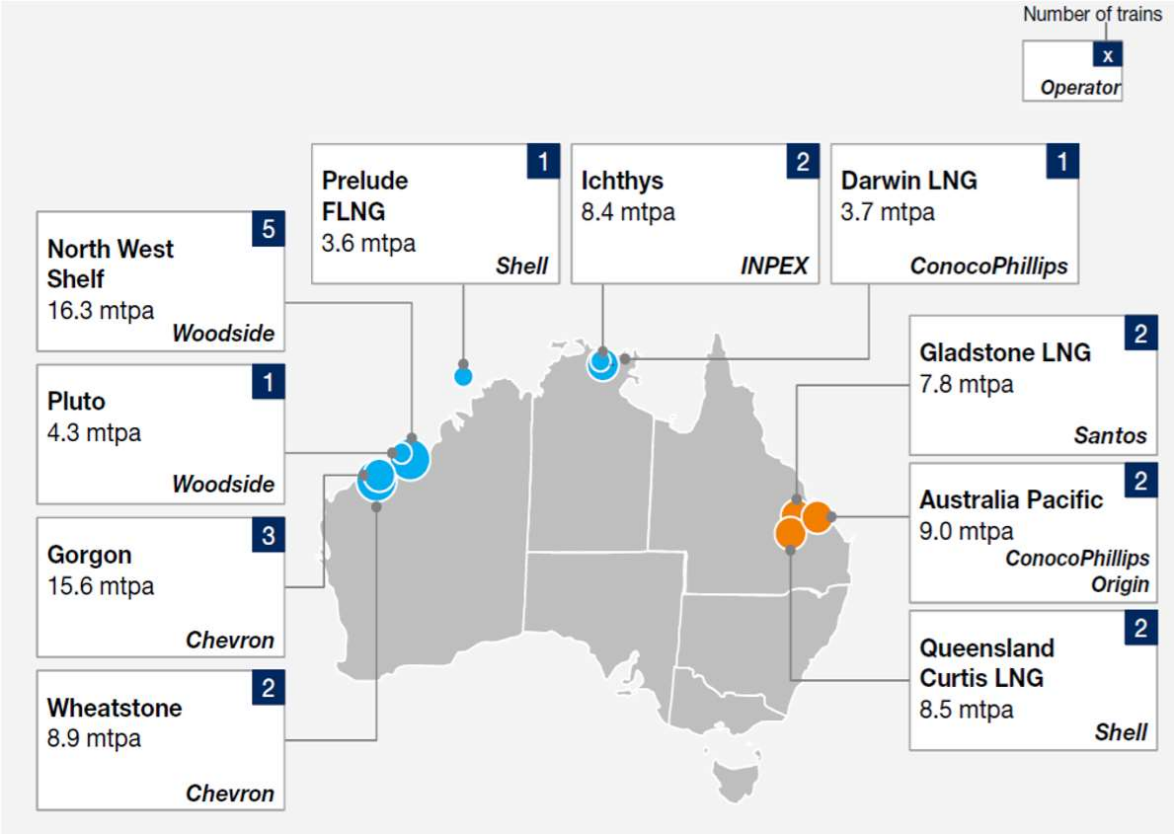
AUSTRALIAN LNG OUTLOOK
MORE SUPPLY STILL TO COME



AKap Energy

JANUARY 2019

Contents

Summary

Don't write-off further Oz LNG growth: We think the market is underestimating global LNG supply in the early to mid-2020s from current facilities: initially we look at Australia, which became the world's largest LNG exporter in November (~80mtpa or 25% of global supply). Our analysis of Australian LNG supply suggests that production in the early to mid-2020s will be much higher than market expectations of falling production as fields move into decline. We think production could grow to around 95mtpa by the mid-2020s due to substantial upside to the nameplate capacity on existing facilities, tie-backs and new developments keeping existing facilities full and utilizing new brownfield LNG trains. Australia's key advantages versus LNG projects elsewhere are the low offshore upstream operating costs, cheap shipping costs to Asia, an investor friendly environment and having a huge installed base of LNG infrastructure and associated cashflows. Relative to its size Woodside should be the biggest beneficiary. **Our main conclusions are:**

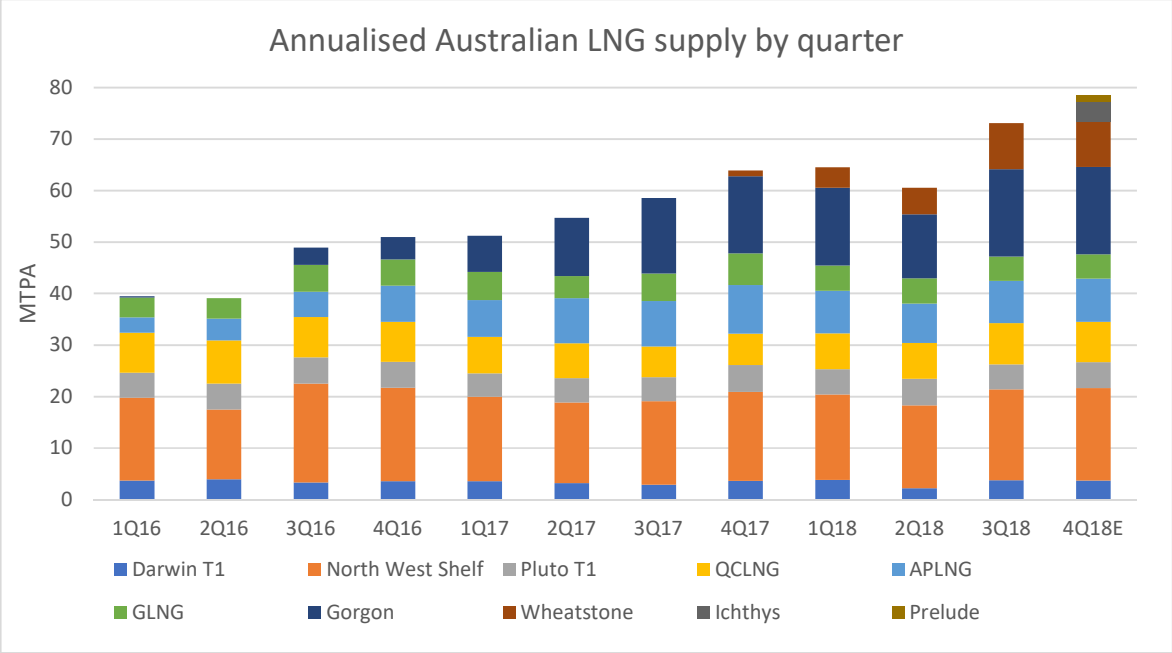
- **Significant growth:** We expect Australian production to grow 27mt by 2020 (almost 50%) from 2017 average production of 57mt and a further 9mt by 2025 from new brownfield projects. There is a large amount of upside to nameplate capacity (~9mtpa) which has already been proven without further debottlenecking – all Australian plants have shown they can run above nameplate capacity. This is the equivalent of 2 LNG trains.
- **Backfill projects and new brownfield trains will be sanctioned:** We are confident that backfill and brownfield expansion projects will go ahead as the economics are favourable. This means existing facilities will stay flat or even grow throughput. We think at least 2 new trains will be sanctioned (likely Pluto and Darwin). There is no shortage of gas with >150Tcf contingent gas resources.
- **CBM to LNG production will grow:** Investment into upstream CBM developments in Queensland is picking up as drilling costs have fallen substantially, improving the economics to fill the ullage in the facilities that only ran at 80% of nameplate capacity in 2017. Nov '18 utilisation grew to 93%.
- **Economics are favourable:** Upstream development costs offshore for future projects are <$1/MMBtu (e.g. Scarborough) and still <1.5/MMBtu with liquids rich projects (e.g. Browse), pipeline costs can likely be shared between multiple developments, new LNG trains on existing sites are cost competitive globally (~$750/t), upstream opex is also relatively low (e.g. Pluto & NWS <$0.7/MMBtu), there are very low shipping costs to Asia ($1.50/MMBtu advantage vs. US Gulf) and accelerated depreciation allows spending to be offset against current taxation.
- **Huge current FCF:** Given the cash flow generation from the base projects, companies are willing to take FID with low volumes contracted for shorter time periods – e.g. Woodside is willing to move forward with Scarborough once it is 50% contracted at long term contracts of only 10 years.
- **Chevron/Shell and Woodside are the key players:** We see 3 groups of LNG companies in Australia, the international majors (e.g. Chevron/Shell), which account for over half of net capacity; the LNG buyers (mainly Asian), which own a quarter of capacity; and the remainder are the Australian listed LNG companies. Woodside has the highest relative exposure and most ambitious growth plans.
- **Other countries' base production could surprise too:** We see a similar story in a number of other countries (e.g. Qatar, Egypt, Oman), which we will examine in future reports. We believe that this results in the market under-estimating supply from the existing LNG liquefaction base.

Australian LNG production

Australia accounted for almost 20% of global LNG supply in 2017, having exported ~56mtpa (+28% y/y), and 71mmtpa of capacity by year end. Another 17mtpa was added in 2018, to reach 88mpta capacity, once Prelude is on line. We estimate 2018 production grew 12mt y/y to 69mt. It should over-take Qatar as the world's largest producer and indeed did so on a monthly basis for the first time in November. We estimate Q4'18 annualised supply was close to 80mtpa, which is almost double the level at the beginning of 2016.

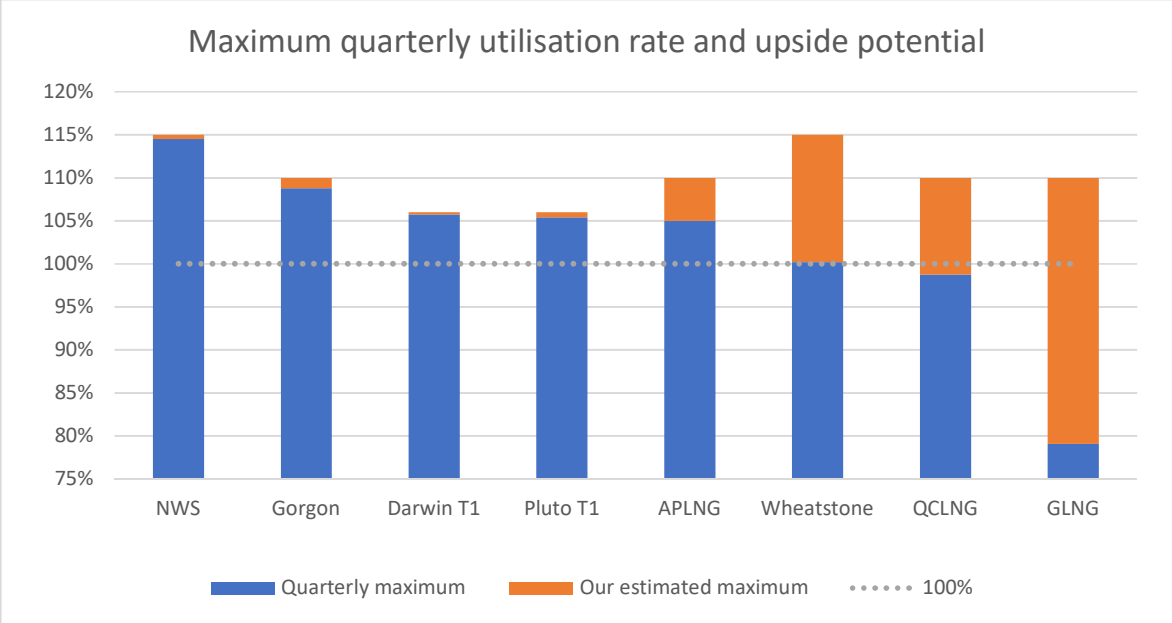
There are several projects that have demonstrated the ability to produce above nameplate capacity and therefore we estimate that the effective nameplate capacity is actually 97mpta. Therefore, there is around 40mpta of potential upside to 2017 exports – this is the equivalent of 14% of 2017 global supply. Western Australia will be, on its own, the world's third largest LNG exporter.

In reality, with maintenance factored in and the lack of sufficient supply in areas such as Queensland we expect actual production in 2020 from these plants to be around 84mpta (95% utilisation). This utilisation rate is still meaningfully higher than the global average over the last 5 years of ~75%. November 2018 annualised exports of 79mpta are only 5mpta shy of this and this was prior to Ichthys ramp-up and Prelude coming on line (combined 12.5mtpa of capacity).



Source: Company Data; AKap Energy estimates

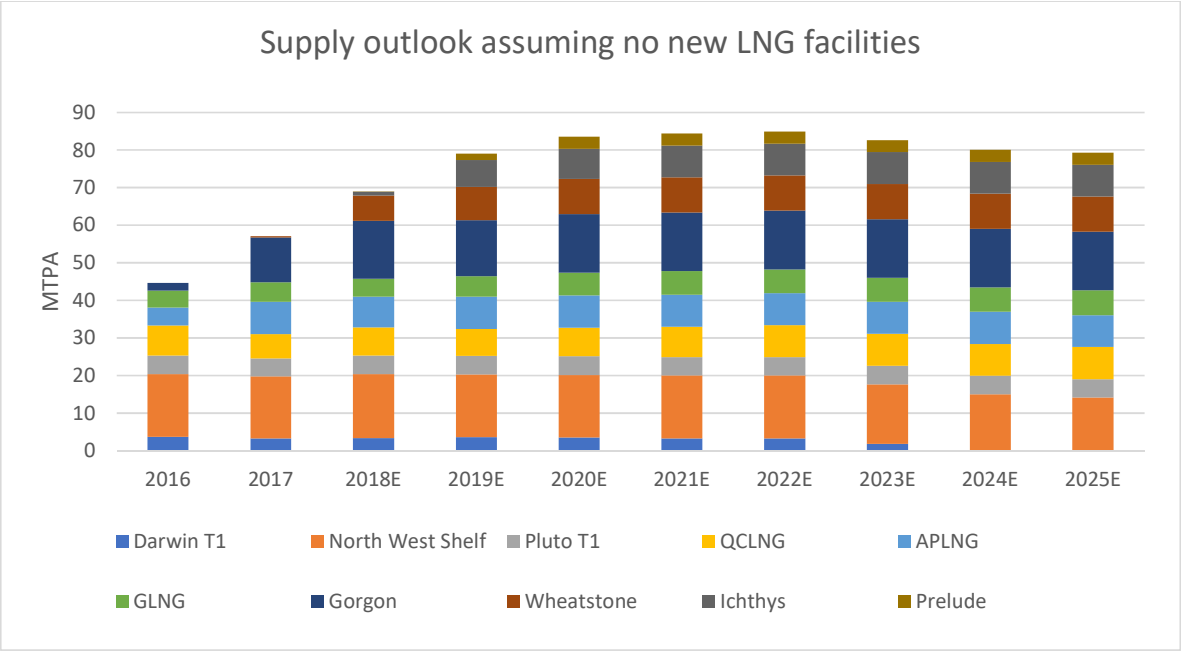
The chart below shows the maximum rate that the LNG plants have run at versus nameplate capacity for an entire quarter. Although all the plants have shown the capability of running above nameplate, Wheatstone has shown the ability to run at 15% above capacity but hasn't done it for an entire quarter as yet and the two Queensland plants haven't had sufficient gas supply to run above nameplate.



Source: Company Data; AKap Energy estimates

Australian LNG growth potential

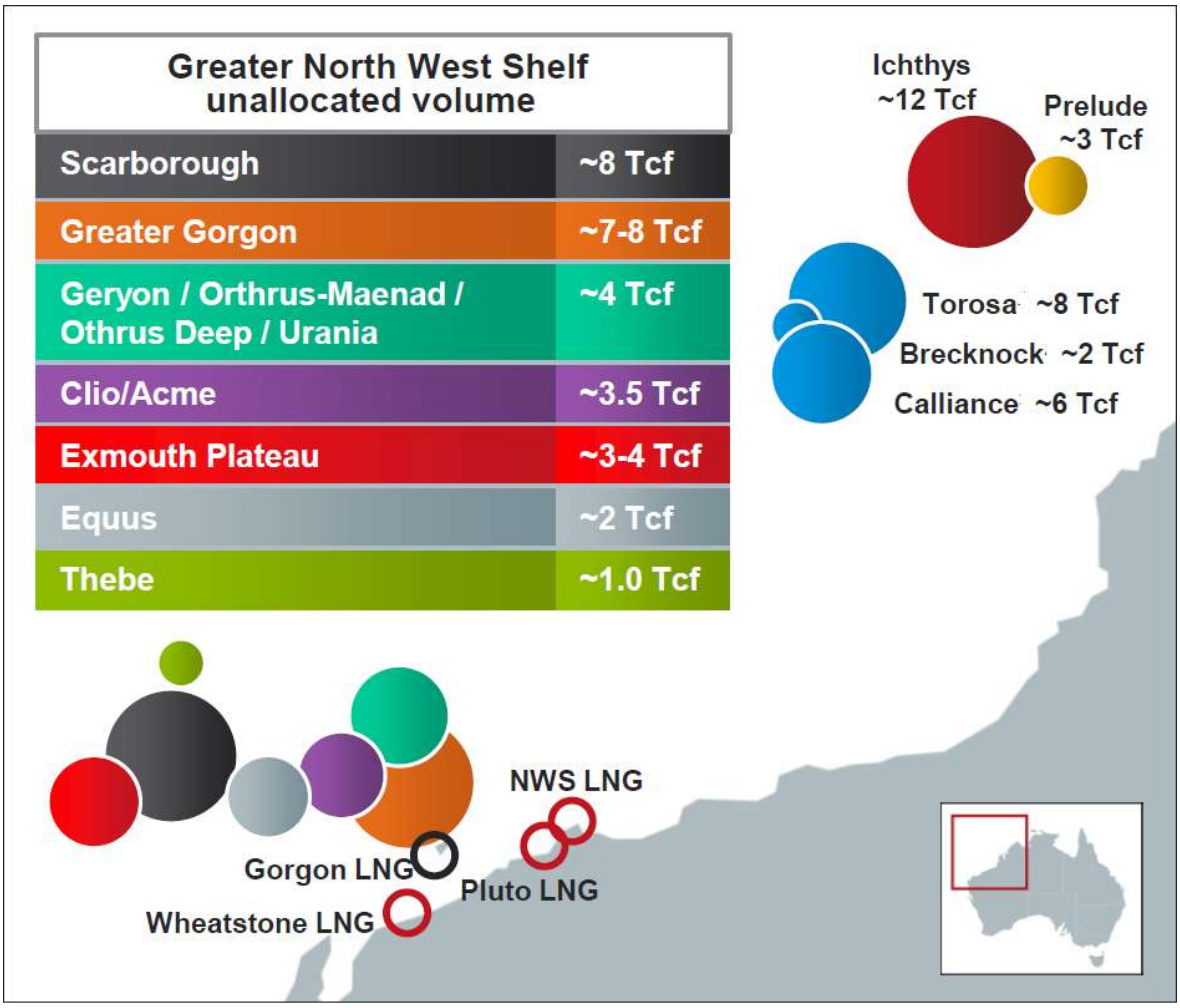
Many may be writing off Australia's prospects of further LNG growth in the 2020s, with forecasts actually suggesting a fall in production as legacy fields (e.g. NWS fields and Bayu Undan) move into decline, questions over the resource in Queensland and rising domestic demand. The main impediment for further projects proceeding is the reminder of the cost blow-outs on the recent projects, meaning that the expectation is that future projects will be unprofitable. However, there is no shortage of gas in Australia – we estimate at least 60Tcf of discovered undeveloped offshore resource that could go towards future LNG projects.



Source: Company Data; AKap Energy estimates

Brand new greenfield onshore or large scale FLNG projects don't appear viable but there is much lower cost opportunities for debottlenecking at existing plants (e.g. most plants have shown the ability to run at >10% of nameplate) and there is room for cost effective expansions at existing plants being studied (Darwin and Pluto). The most likely expansions are at Pluto, Darwin and Ichthys with the potential to also add more trains at Gorgon and Wheatstone further down the line. Expansion costs should be much more reasonable and globally competitive than the initial greenfield projects. For example: Woodside estimates a $700/t expansion cost at Pluto vs. the initial >$2,000/t cost for the first train. With the sanction of Pluto T2 and potentially Darwin T2, Australia's LNG export capacity should easily exceed 100mpta by 2025.

Key Western Australian undeveloped gas resources

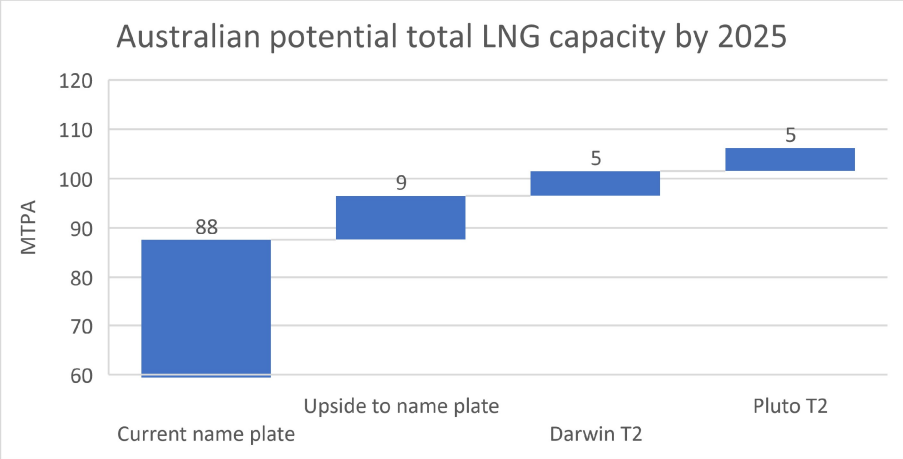


Source: Woodside presentation

The legacy LNG plants in Australia are NWS (1989), Darwin (2006) and Pluto (2012) – production has been forecast to decline from these plants in the 2020s, however there are several fields that were previously considered for standalone developments that are now likely to extend the plateau of these projects into the 2030s. The 15Tcf Browse field is being considered for NWS, the Pyxis discovery and the recently purchased 9Tcf Scarborough field operated by Woodside are backfill and expansion options for Pluto. Equus is also likely to supply Pluto/NWS. Conoco is expecting to use the 4Tcf Caldita-Barossa field as backfill for Darwin. There are a number of projects vying for supply to either a second train at Darwin or to Icyths in the future: 2.7Tcf Bonaparte cluster (Petrel, Tern and Frigate), 2Tcf Cash Maple, 2Tcf Crown & Lasseter, 3Tcf Evans Shoal and 3Tcf Greater Poseidon. Given the number of projects, it seems likely that a second train would go ahead. There is authorisation for up to 10mmpta of production at Darwin versus the 3.5mmpta from T1, meaning the second train could be up to 6.5mmtpa.

Gorgon and Wheatstone have had some teething problems after being brought on line, which is not unusual for LNG facilities. However, these now seem to have been ironed out, so we think the focus will shift to debottlenecking and producing at higher than nameplate capacity. The upstream performance appears to have been strong at these fields, so the limiting factor will likely be the downstream facilities.

Icyths and Prelude are still to reach capacity, so we will have to wait and see if there is debottlenecking potential in these facilities too.



Source: Company Data; AKap Energy estimates

The table below shows 60Tcf of resource that is under consideration for development as either backfill for existing facilities or alongside new planned trains at existing facilities.

Australian LNG growth options

Fields	LNG plant	Size (Tcf)
Backfill		
Barossa	Darwin	4
Equus	NWS	2
Clio-Acme	NWS	3.5
Browse	NWS	15
Crux	Prelude	2
Pyxis	Pluto	1
Transborders	New FLNG	2
Arrow CBM	QCLNG	5
New trains		
Scarborough	Pluto	9
Petrel, Tern and Frigate	Darwin	2.5
Cash Maple	Darwin	2
Crown Lasseter	Darwin	2
Evans Shoal	Darwin	3
Greater Poseidon	Darwin	3
Chandon, Geryon, Orthrus and Maenad	Gorgon	4

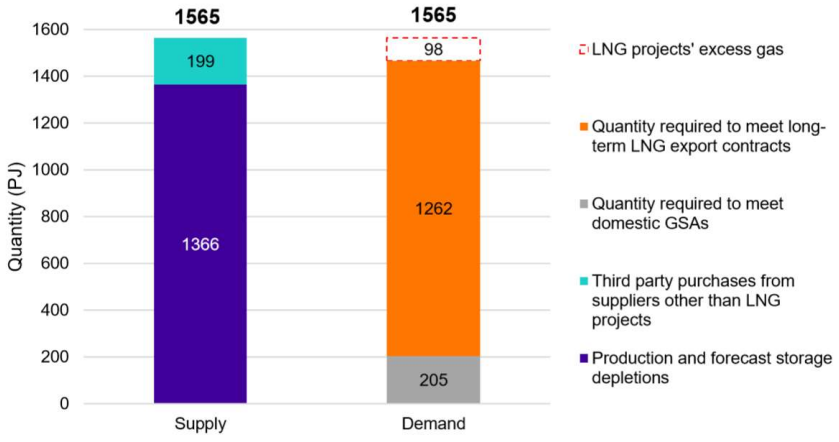
LNG imports

Following domestic gas shortages or potential shortages in Victoria and New South Wales there are plans to import LNG into the region. With five proposed projects we expect at least one to go ahead but we don't see these affecting plans to grow LNG exports from Queensland. However, the imports could well be supplied from other Australian export projects.

Source: Australian Department of Industry, Innovation and Science

The Australian Competition and Consumer Commission has been conducting an inquiry into the East Coast gas market and in July 2018 concluded that there was a significant improvement in the gas supply outlook of the East Coast Gas Market. This was due to lower estimated consumption from gas fired power stations, higher production from producers in Victoria and gas coming from the new Northern Gas Pipeline. The East Coast Gas Market saw more gas sold onto the domestic market after the completion of plant testing and domestic prices fell to more in line with export parity. Gas prices are likely to remain being highly influenced by LNG netbacks.

Forecast supply-demand balance of the Queensland LNG projects for 2019



Source: ACCC data

Australia's competitive advantage

Although Australia is associated with cost blow outs, it has a few of major advantages over greenfield LNG projects elsewhere.

- **Infrastructure:** First, after a $200B spend, there is ample existing infrastructure to be used that new developments can backfill with minimal downstream costs. For example, the NWS partners have suggested a US$2.10/MMBtu toll for future production into the plant, which at the low end of the range of tolling fees being offered in the US. There is also the opportunity for brownfield developments (e.g. Pluto T2 will be much cheaper than T1).
- **Shipping cost:** The shipping distance from Australia, into the key demand markets of Asia leads to a significant cost saving versus projects from the Americas, Northern Russia or West Africa. At a day rate of $75,000, we estimate ~US$1.50/MMBtu saving shipping LNG from Australia to China versus from the US GoM.
- **Low opex:** When the offshore fields are the developed, the operating costs are low as the wells are generally prolific, long-life producers (up to 300mmcf/d per well). For example, operating costs at Pluto and NWS are <$0.7/MMBtu.
- **Liquids rich LNG:** Although some of the upstream developments are higher cost, many offshore fields benefit from a relatively high liquids content, generally obtaining close to Brent pricing and hence significantly boosting the economics. For example at Ichthys 40% of the production is liquids so on an mtpa equivalent basis the total production is ~15mpta rather than just the 8.9mpta nameplate LNG capacity.
- **FCF generation:** Crucially the existing LNG projects throw off substantial FCF that than be re-invested into further projects. Australia will be exporting >4Tcf a year of LNG: worth about $40bn including liquids at $8/MMBtu LNG pricing and $60/bbl Brent and we estimate FCF to the companies will be >50% of this or $20bn after costs and taxes.
- **More spot volumes:** Existing cashflow and the use of existing facilities means that there is less need to secure long-term contracts on the vast majority of LNG volumes, making projects easier to sanction.
- **Tariffs on US LNG:** With China introducing tariffs against US LNG, this is another factor that makes Australian LNG more competitive.
- **Huge gas resources:** There are around 40 stranded offshore gas discoveries in the 0.5-5Tcf range in Australia totalling 65Tcf, so there is no shortage of gas to develop. In total there is an estimated 150Tcf of contingent resources in Australia.

There are risks as the stigma of the previous LNG projects may cause operators and investors to back away from investing in new projects. Labour costs and unions are a significant impediment, but this was caused by multiple concurrent LNG projects, which shouldn't be the case in the future. There is also the risk of windfall taxes on the LNG sector, however most corporates view Australia as a relatively low risk region to invest into.

Ichthys stake sale

TOTAL's sale of a stake in Ichthys was an interesting data point for Australian LNG projects. TOTAL agreed in November to sell a 4% stake in the project for $1.6B (EV basis as includes cash and debt) to the operator Inpex. The price implies $100k per boe/d of production or ~$15/boe of 2P reserves. Inpex is a logical buyer for the asset: as operator it knows the asset extremely well but may be somewhat surprising as it already has large exposure with its stake now growing to 66% as TOTAL drops down to 36% from 40%.

This is a rare transaction in the Oz LNG space sets a marker price for other assets in the country. For example, if we value Woodside's 8mpta of net capacity at it would be worth $22B.

The deal puts a gross value of US$40B on the asset, which although it sounds hefty shows that there has been a negative return on investment. The capex budget for Ichthys was $34B at FID; it ended up costing $45B and came on line over a year late.

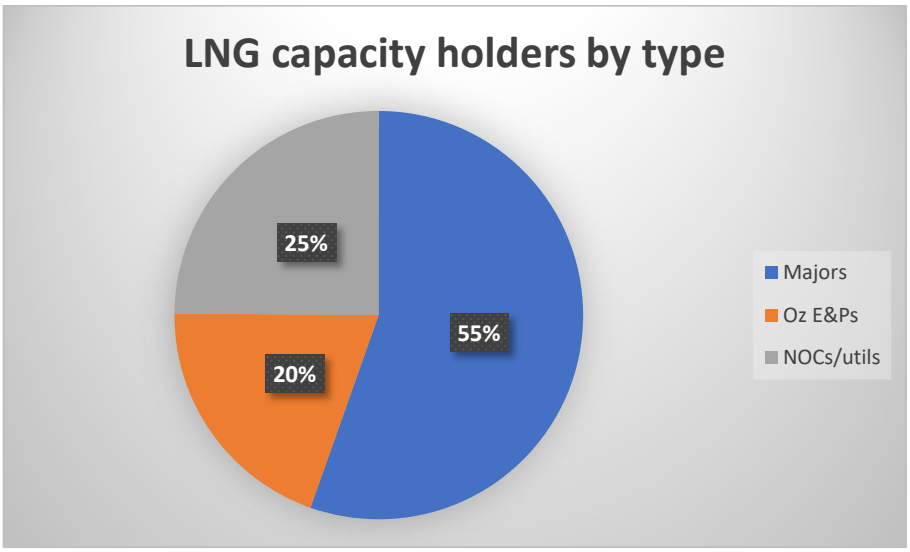
Based on our model at $60/bbl Brent and $9/mcf LNG FOB price Ichthys will generate $6.8B of gross revenue and $4.7B of operating cashflow (pre-interest) – we expect no cash tax for a number of years given the high capex depreciation.

It is not simple to place a valuation on a $/t basis as 40% of the production is liquids. The plant has 8.9mpta of LNG export capacity but there is a large proportion of LPG (1.7mtpa) and condensate (100kbbl/d) – so the equivalent amount of LNG is 15mtpa. Based on just the LNG capacity it implies a valuation of $4,500/t of capacity, however including the liquids it falls to $2,700/t which we think is a more comparable number to use versus other projects in Australia. This is not an appropriate valuation multiple to use for US projects as in the US the gas is purchased, whereas in Australia it is generally owned and integrated into the project.

Ichthys raised $20B of project finance debt against the project – it's worth noting that at YE'17 TOTAL had provided $8.5B of guarantees on the debt taken out against Ichthys. Therefore, a chunk of the cash flow from the project will go towards debt servicing and repayments. Assuming a 5% interest rate on the debt there will be $1B of interest per annum leaving $3.7B of cashflow, implying that Inpex is paying >10x cashflow for the asset.

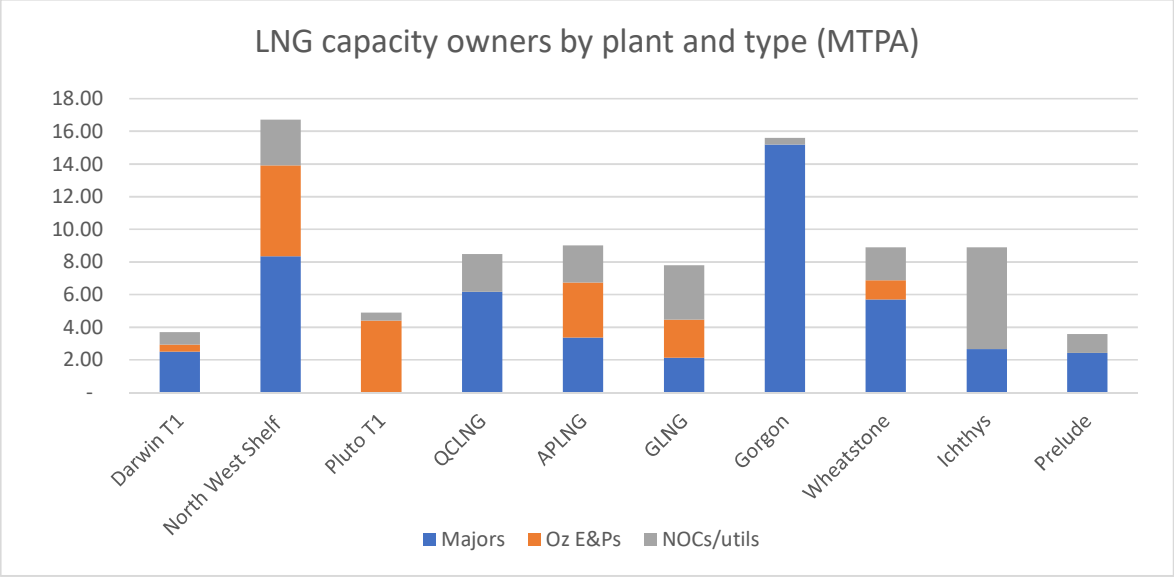
Australian LNG companies

There are only five LNG plant operators in Australia: Woodside, Chevron, Conoco, Inpex and Shell (once Prelude comes on-line). We see the LNG players split into three major categories: International oil majors (e.g. Chevron, Shell etc.), domestic LNG producers (e.g. Woodside and Santos) and the LNG buyers which are mainly state-owned Asian companies (e.g. Kogas, Sinopec and Inpex).



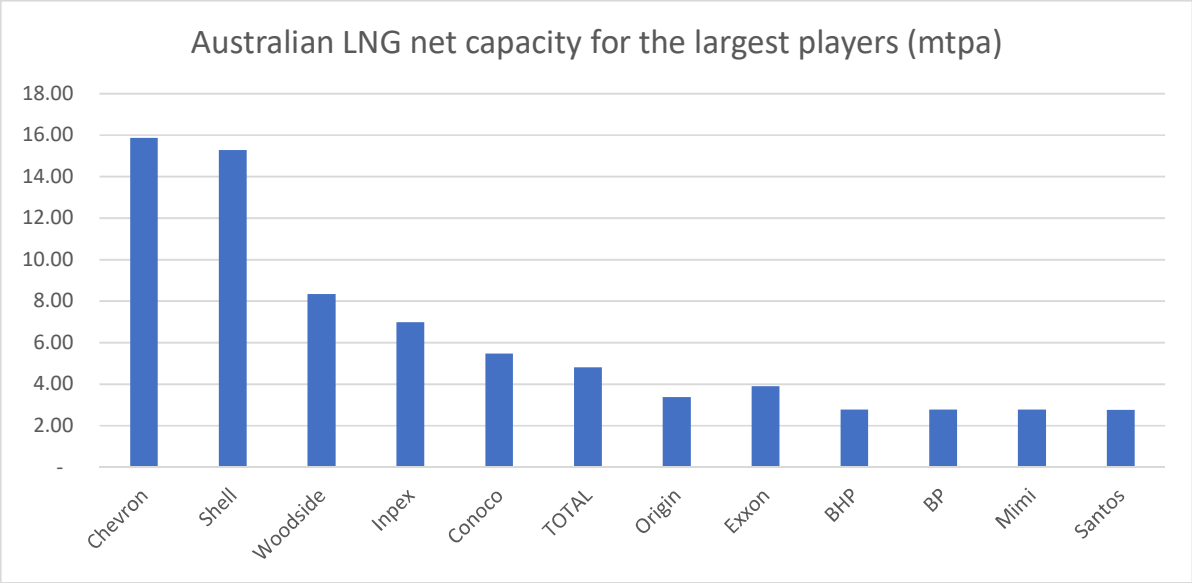
Source: Company Data; AKap Energy estimates

The majors own 55% of the capacity and the two dominant players Chevron and Shell own over a third of the export capacity between them. The LNG buyers own a quarter of the capacity with most of these companies taking stakes alongside signing long-term offtake deals when projects were being sanctioned. The largest of the LNG buyer category Inpex is slightly different as it is an operator with 8% of capacity. Amongst the domestic names, which control 20% of capacity, Woodside is punching above its weight with 10% of export capacity and the most ambitious growth plans.



Source: Company Data; AKap Energy estimates

The different groups have different agendas in terms of what they want out of their investments. The majors are focused on FCF generation to fund dividends and are less likely to plough cashflow back into the assets, especially having been burnt in the past. They are also likely to be concerned about reserve replacement and maintaining production. The domestic players are more likely to want to look to growth and re-invest and this is evident from Woodside's and Santos' expansion plans. The LNG buyers are most concerned about securing the LNG supplies for their domestic market.

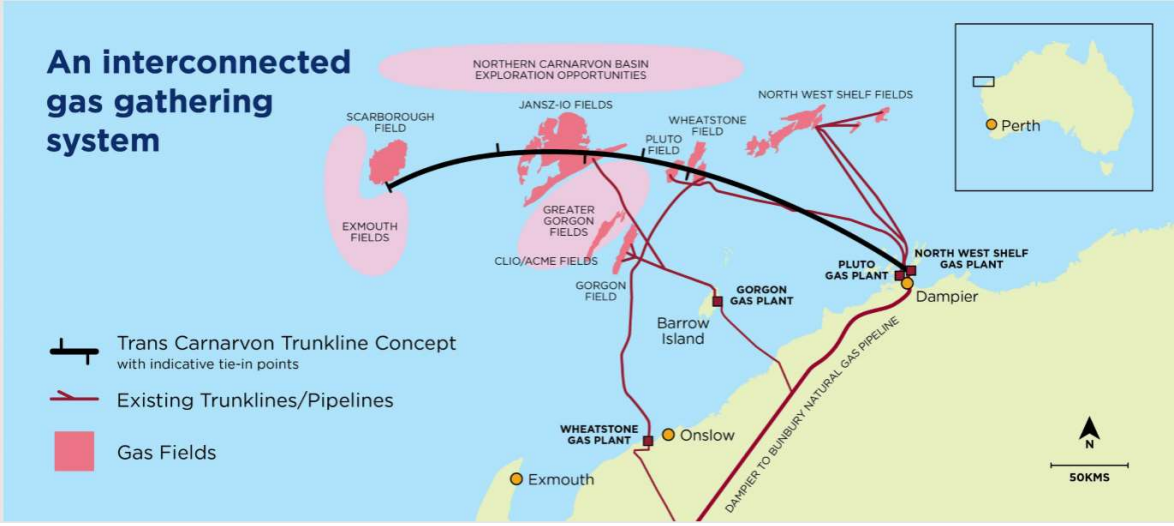


Source: Company Data; AKap Energy estimates

Carnavon Basin

The Carnavon Basin is home to the largest gas resources and LNG export facilities in Australia. Between the four plants: NWS, Pluto, Gorgon and Wheatstone there is 46mtpa of nameplate capacity but actual capacity plus the likely new brownfield train at Pluto should see this grow to 57mpta by 2024. There is further upside beyond this date from debottlenecking and further trains on the existing sites. With the planned interconnector from Pluto to NWS and a second train planned at Pluto the NWS/Pluto plant will in essence turn into one giant facility with a potential capacity of 27mtpa by 2024. Both Woodside and Chevron have proposed pipelines to harvest gas from large undeveloped discoveries in the basin to backfill the existing facilities.

Chevron's proposed Trans Carnavon Trunkline Concept



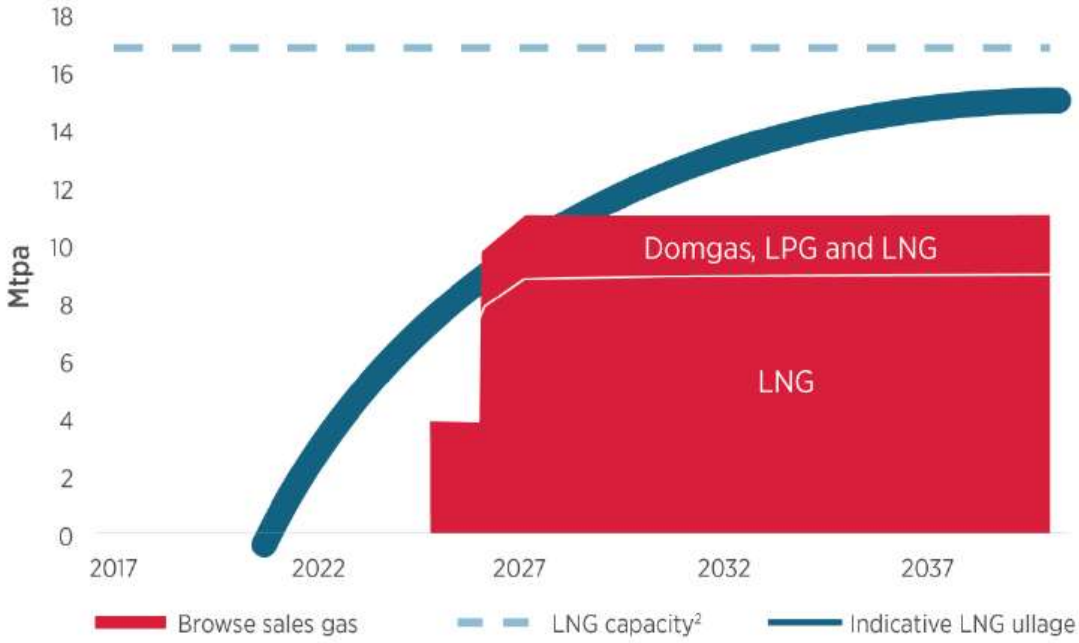
Source: Chevron presentation

North West Shelf (NWS)

We forecast that NWS will produce at or above capacity well into the next decade despite concerns about declining production.

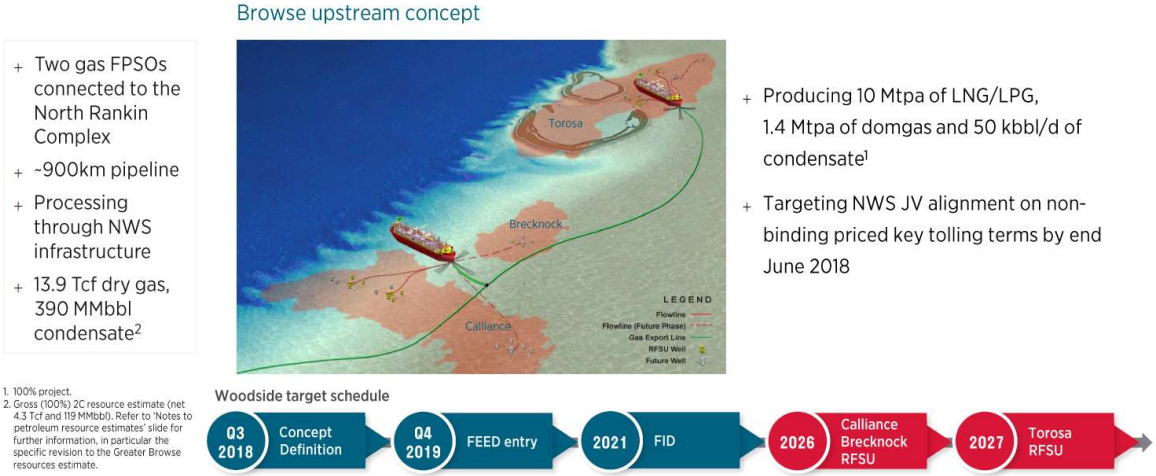
Australia's largest LNG facility is still going strong despite starting up >30 years ago, with high reliability (>95%) and exceeding nameplate capacity. In fact, the facility has regularly been producing above nameplate capacity of 16.7mtpa and is on-track to produce 16.9mtpa in 2018. In Q3'16 the plant actually produced at 19mpta on an annualized basis (14% above nameplate capacity). Recent developments (Persephone and Greater Western Flank phases one and two) keep NWS full until early 2020s and were brought on line at ~$1/MMBtu development cost. Following that there are other potential satellite developments Lambert Deep and Goodwyn South. The plant is also likely to use Chevron's Clio-Acme gas resource, Western Gas' Equus and Woodside's Browse fields to keep the plant full. Woodside and Chevron have both proposed pipeline solutions to monetise stranded gas in the Carnavon basin into NWS. Woodside is also planning an interconnector from Pluto to NWS so if ullage becomes available from NWS it can be supplied from Pluto and vice-versa.

NWS Karratha gas plant ullage outlook from Woodside



Source: Woodside presentation

Woodside is targeting FID on Browse in 2021 with first gas expected in 2026 and the potential to supply 10mpta of backfill gas. Woodside has said that piping gas from Browse for processing through the Karratha Gas Plant is 60% cheaper than the onshore development originally envisaged.



Source: Woodside presentation

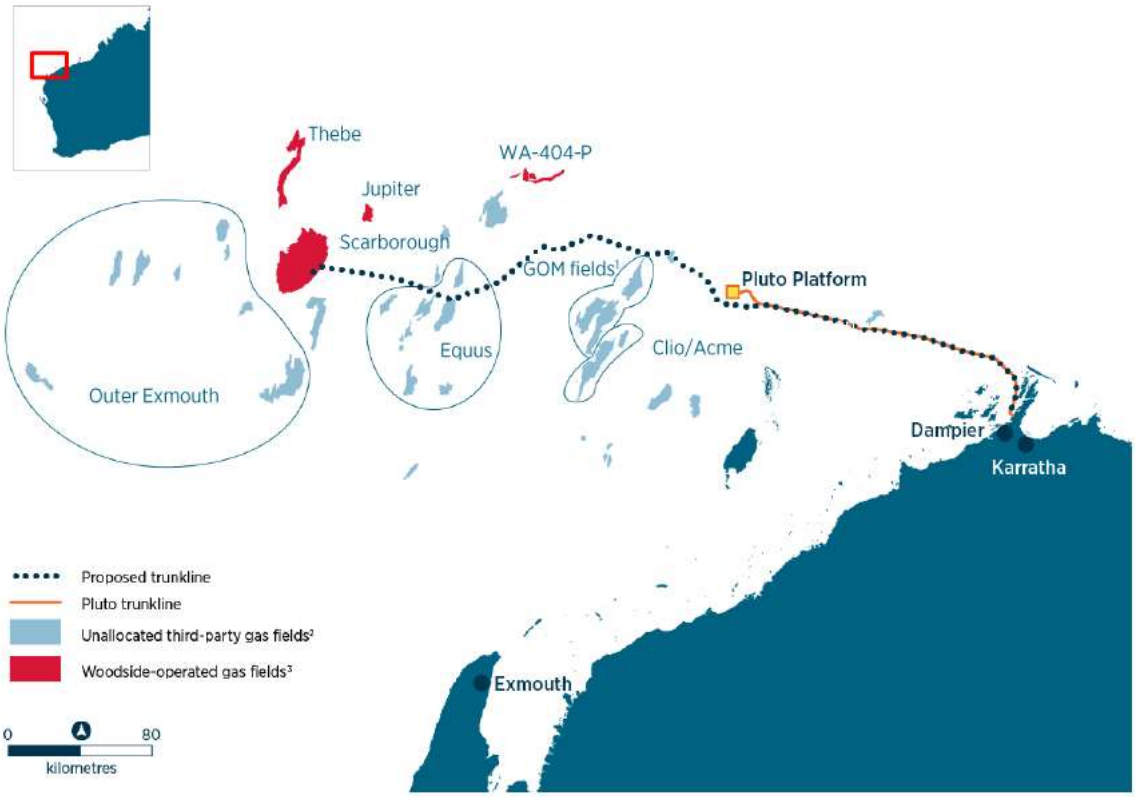
Western Gas is planning to take FID on the development of the 2Tcf Equus field in late 2019 with first gas planned in 2023/24 at a rate of 250mmcf/d. It will be a phased FPSO development with an initial 3 wells and 220km pipeline to shore.

Pluto

Pluto's performance has been very strong, producing consistently well over name plate capacity and the economics are favourable to develop the giant Scarborough field as a tie-back to a new build second train at Pluto.

Pluto is another plant which has consistently shown the ability to produce with high reliability and above nameplate capacity. The current single train at Pluto has capacity of 4.9mtpa, which is 14% higher than the name plate capacity when FID was taken on the plant in 2007 on the back of process optimisation and improved technology. In 2018 we expect the plant to produce 5mt (excluding turnarounds, capacity is actually 5.2mtpa). For example, in Q4'17, reliability was 100% and annualised production was 5.1mtpa, 19% higher than the original 4.3mpta name plate capacity for the plant. Pluto has the potential to produce at even higher rates and excess gas is planned to be sent through an interconnector built to the NWS LNG facilities. Although there is the potential to debottleneck Pluto further, it seems highly likely that a 2nd LNG train of close to 5mpta will be built to take gas from the planned Scarborough development. Woodside is also targeting costs below US$650/tonne for Pluto expansion compared with Train 1 liquefaction costs of around US$2,000/tonne. FID is expected to be taken in 2020 with first gas in 2023 and the 2nd LNG facility starting up in 2024. There are further fields that could tie-in (e.g. Equus, Jupiter, Thebe etc.).

Tie-in opportunities to Pluto and NWS



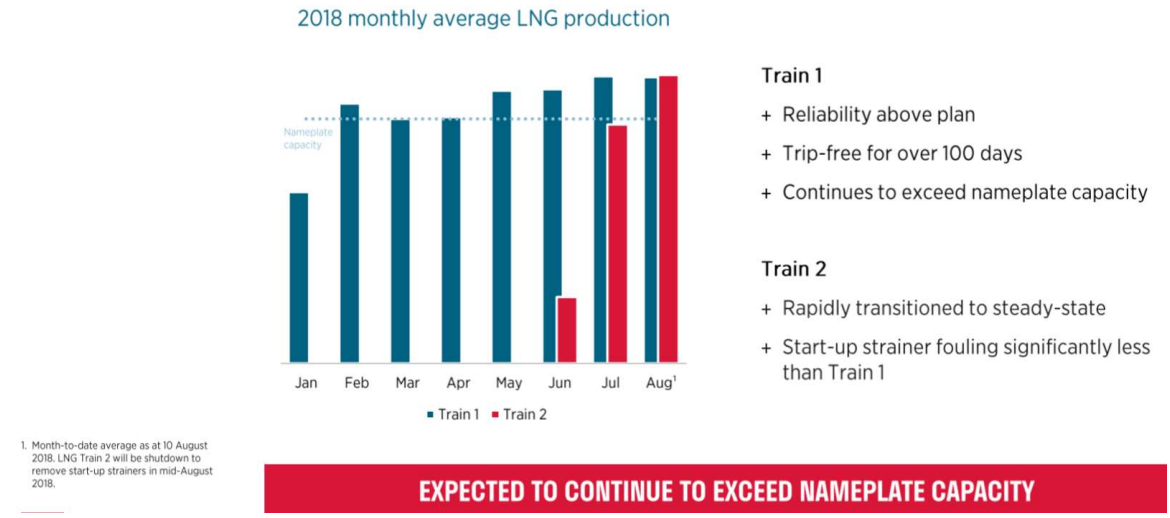
Source: Woodside presentation

Gorgon

Gorgon is an infamous LNG project, most often the poster child for delayed and over budget LNG projects not only in Australia but globally. Despite all the issues in the past, the plant appears to have got over the teething problems and in Q3'18 produced around 8% above nameplate capacity of 15.6mpta, demonstrating the ability to produce at >10% above nameplate in October. Chevron said that Train 1, since its "pit stop", has run more than 285 days without a day of downtime and the knowledge gained from the Gorgon Train 1 has been applied to Train 2 and 3. There is plenty of gas and the well deliverability has been very good so if the facilities allow it, there is scope to run the plant above nameplate capacity. Chevron has flagged debottlenecking opportunities, so we think that in the 2020s the plant will start continuously running at nameplate capacity or beyond. There is room for further trains at Gorgon but given the cost, we think it is unlikely to be looked at for a few years.

Wheatstone

We expect Wheatstone to produce above nameplate capacity in 2019 and beyond. Although Wheatstone suffered from similar cost over-runs to Gorgon, the start-up and initial production from the plant has been much smoother as operator Chevron took the lessons leant from Gorgon. Wheatstone only started up in Q4'17 but has already achieved production rates above nameplate capacity of 8.9mtpa in mid-2018. Wheatstone Train 1 has been running well, having demonstrated nameplate capacity and has run 195 consecutive days without a day of downtime. Wheatstone Train 2 only achieved first production in mid-June but the ramp-up exceeded expectations as Train 2 reached nameplate capacity within weeks of start-up. Woodside talked about Wheatstone operating at >10% above nameplate capacity. T2 had some incremental capital put into it ahead of start-up to increase the capacity of the compression and liquefaction trains which appears to have increased the capacity by well over 10%.



Source: Woodside presentation

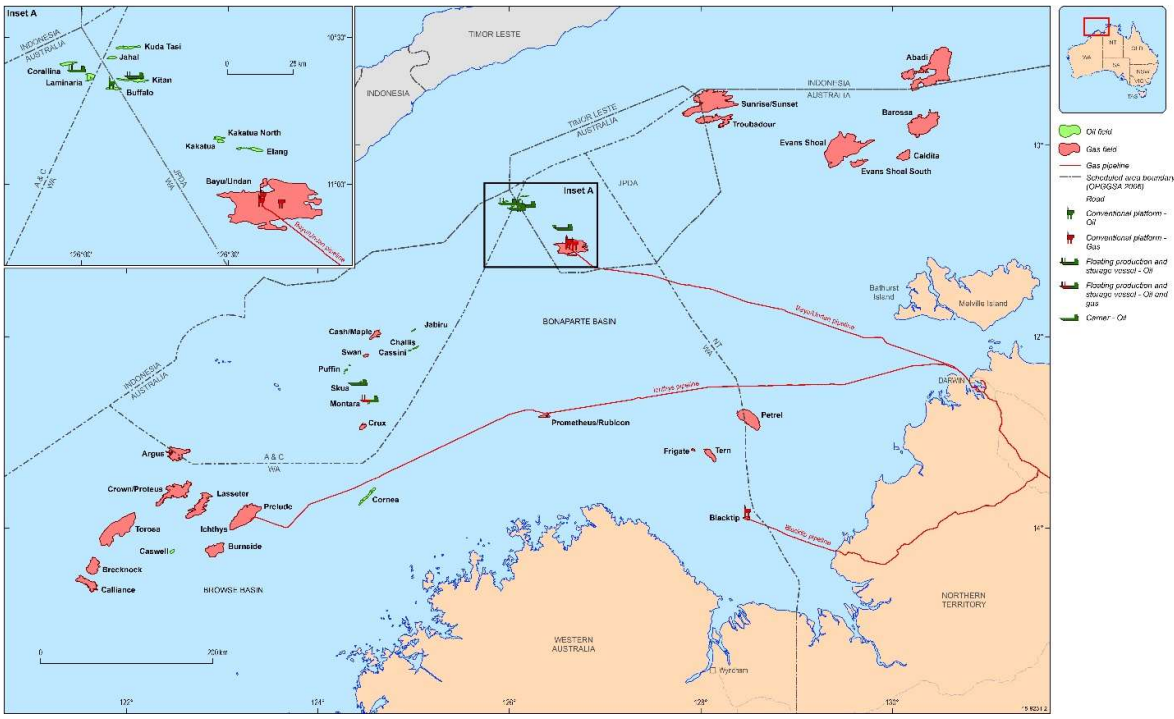
Browse and Bonaparte basin developments

As two key projects came on line in 2018, Ichthys and Prelude, the focus will shift to the development of fields to backfill Darwin and feed new LNG trains. There several ~2-3Tcf appraised discoveries looking for monetization options, with new trains at Darwin and/or Ichthys the most likely outlet.

There has been a lot of gas discovered in the Browse and Bonaparte basins, some of these fields are supplying the LNG plants at Darwin, Ichthys and Prelude FLNG but there is plenty of stranded gas too. First this means that there should be no problem keeping the facilities full out to 2030 and beyond. Darwin's existing supply from Bayu Undan will most likely be replaced with volumes from Barossa from late 2023 onwards (FID expected in Q3'19). There is the potential to expand Darwin to up to 10mtpa with a feasibility study funded by resource owners in the area being carried out by Conoco. Inpex has recently talked about exploring for more gas in the vicinity to Ichthys for future tie-ins. Inpex believes that the offshore pipeline capacity can be expanded by 50% and there is room for 4 more LNG trains at Ichthys. Even before Shell's Prelude facility comes on line it is looking at tying back the Crux discovery to back fill the FLNG vessel.

Previously there were standalone FLNG facilities planned at some fields such as Bonaparte and Cash Maple but these have been scrapped. There are several projects vying for supply to either a second train at Darwin or Ichthys in the future including: 2.7Tcf Bonaparte (Petrel, Tern and Frigate), 2Tcf Cash Maple, 2Tcf Crown & Lasseter, 3Tcf Evans Shoal and 3Tcf Greater Poseidon. Given the number of projects, it seems likely that a second train would go ahead.

Bonaparte and Browse Basin discoveries and gas infrastructure



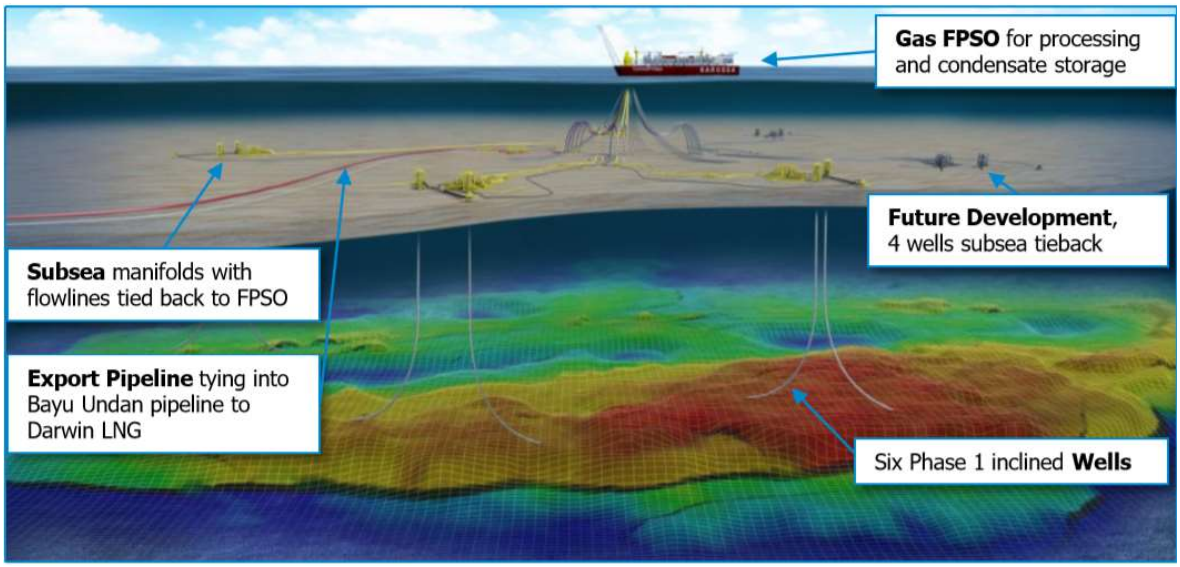
Source: Australian Department of Industry, Innovation and Science

Darwin

Darwin is another of the legacy West Coast LNG projects. Although the facility produced at nameplate capacity of 3.7mpta in 2016, it produced at lower levels in 2017 and year to date in 2018. However, the Bayu Undan infill drilling program is has been completed ahead of schedule with the first well producing at 150mmcf/d and two more wells that followed, which should see production return to around 3.7mpta in 2019 (Darwin produced at nameplate in Q3'18) and extend the plateau to 2022.

Bayu Undan is expected to cease production around 2023 but there are plenty of undeveloped discoveries in the vicinity that could provide backfill volumes and the lead candidate is Barossa, which is highly likely to take FID next year in our view, leading to first gas in 2023 and keeping Darwin at full capacity for years beyond. Barossa is to be developed using subsea wells tied back to an 800mmcf/d FPSO for gas processing and condensate export. A 260 km export pipeline will transport gas to existing Bayu Undan pipeline. ConocoPhillips said it expects to award a major contract for the Barossa gas project's subsea production system in early 2019.

Barossa tie-back project



Source: Santos presentation

Ichthys

This is the latest project to come on-stream and like the other mega projects was significantly over budget (cost of >US$40B) and delayed. However post-start up things so far appear to have gone smoothly in the commissioning phase, with the plant producing at an annualised rate of >4mpta in November 2018 (based on the number of LNG cargos) and one of the partners expecting it to reach full commercial production by YE'18. Name plate capacity is 8.9mpta and as with the other plants we believe that there is upside to this. Operator Inpex expects to take two to three years to reach full production. Expansion is a top priority for Inpex: its strategy is to explore for more gas around Ichthys. The FEED process is underway for the US$1B phase 2 project: planned production from the initial phase of Ichthys will reach 1.2bcf/d but in phase two there is a suggestion the design rate will be increased to 2.4bcf/d. The 890km Ichthys export pipeline has five tie-in points, and at the onshore liquefaction plant near Darwin there is space for four more LNG trains. Inpex has stakes in a swathe of discoveries within tie-back distance to the Ichthys field including Burnside, Crown, Lasseter and Mimia.

Prelude

This FLNG project is possibly the most expensive (reportedly up to $20B) LNG project in the world, on a cost per tonne basis. At 3.6mtpa it won't be a huge contributor to production and until it is fully online, there may be some question marks over its reliability and utilisation rate. First LNG is expected at the end of 2018 and we expect it may take some time to ramp up to full capacity. We assume that once ramped up it will run at a lower utilisation rate of 90% compared to onshore projects. Despite Prelude having yet to come on-stream, Shell is already thinking about backfill options. It has finalised concept selection on the 2.2tcf Crux field and work plan is progressing towards FEED and first gas anticipated in 2024/25. Crux will be developed with a large fixed platform, 5 development wells and a 165km tie-back to Prelude

Transborders Energy – FLNG solution

Transborders (TBE) is in talks with resource owners as it looks to pursue a mini floating LNG development concept off Australia, that it hopes could be deployed by the mid-2020s and produce 1.2mtpa. TBE's FLNG Solution offers an accelerated development solution to owners of stranded resources, which can be converted into 2P reserves within 12 months and achieve FID within 24 months from project commencement. It had planned to select an undeveloped field in 2018, with a FID by 2020 and first gas by the mid-2020s. It is working with Add Energy, TechnipFMC and Modec to develop a low-cost FLNG development concept, and it is now trying to match that with an initial resource that can be developed with a EPC budget of around $1000/t of liquefaction capacity. Transborders has identified 16 appraised assets containing around 20Tcf in total, which it believes could support a development within the Bonaparte, Browse and Carnarvon basins, and it is about to open formal negotiations to secure at least a 50% operated position among its shortlisted assets. The company has set a breakeven point of US$6.5/MMbtu for LNG sold FOB.

.

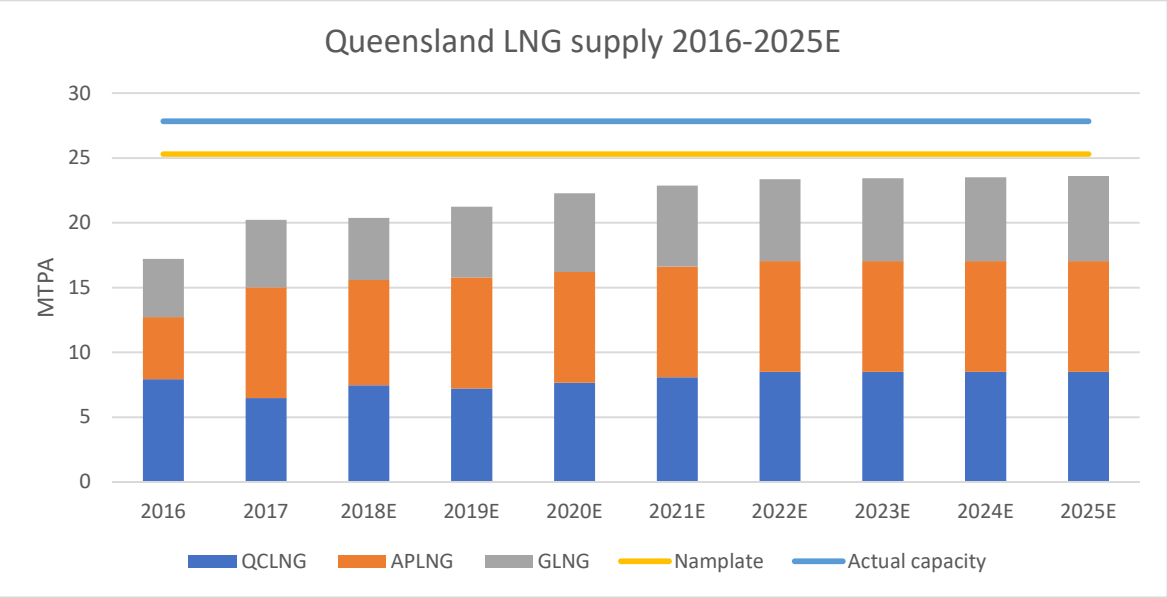
Queensland

The Queensland LNG projects have failed to live up to expectations with both reserves and investment write-downs. However, we see significant production upside potential as upstream investment returns on the back of improved economics and Arrow's deal to supply QCLNG providing further supplies.

The three Queensland CBM to LNG facilities are now fully online with a total nameplate capacity of 25mmtpa, however these plants have been producing at lower than this due to lower than expected supply from GLNG's upstream, QCLNG recently had a reserve write-down too and domestic demand has surprised to the upside. However, the actual plants, all built by Bechtel have shown the ability to produce at around 10% above nameplate capacity.

The upstream for these fields is different from a conventional project in that there needs to be continuous intensive drilling of wells, to offset the decline, from the high decline CBM wells. In the current higher LNG price environment, we would expect to see drilling ramp-up. CSG/CBM to LNG projects are somewhat akin to shale in their short cycle nature. To keep production going new wells need to be drilled so the marginal cost of these LNG projects is high (although Origin recently pointed to a <$3.5/MMBtu break-even on an FOB basis). So, if LNG prices are high then there is incentive to drill more and fill the facilities.

We estimate that the plants produced at 80% of capacity in 2017 – if you can get them to 110% of capacity that is the potential for an extra 7.6mmtpa of LNG. The announcement from Arrow that it will supply >600mmcf/d (~4.5mpta) to QCLNG starting from 2020 should facilitate closing this gap. According to a recent ACCC report, the East Coast gas facilities will have sufficient gas to meet 22mtpa of long-term LNG export contracts in 2019 plus will have excess gas of 1.7mpta to either export or supply into the domestic market. In fact, in November 2018 exports were 23.6mtpa on an annualised basis or 93% utilisation.

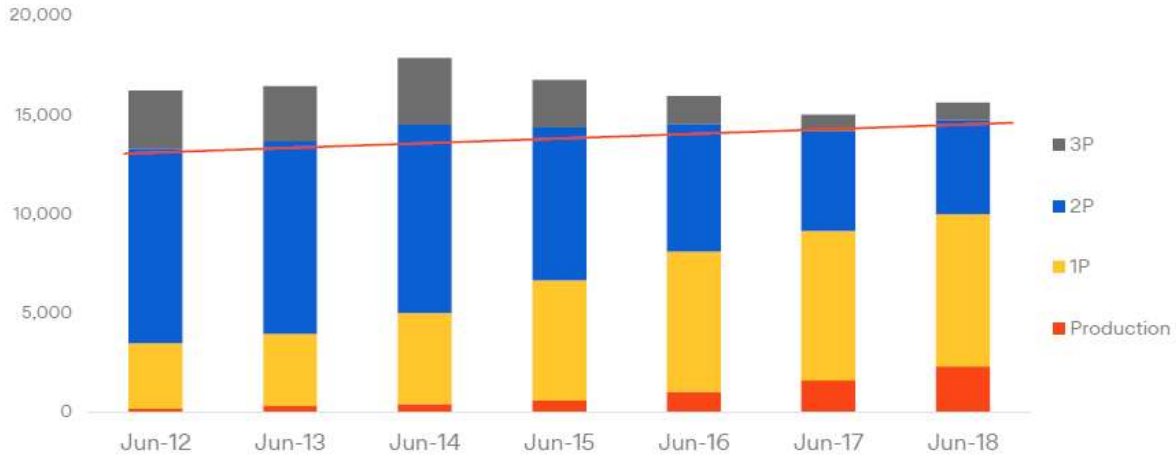


Source: Company Data; AKap Energy estimates

Australia Pacific LNG

The APLNG plant has consistently produced closer than nameplate capacity of 9mpta than the other two Eastern Australian LNG export projects. 98% uptime has been achieved over an extended period. APLNG successfully concluded a 90-day operational phase of the two-train project finance lenders' test, with the LNG plant operating at more than 10% above nameplate capacity on average during the test. It has the largest resource base of any of the projects, which supports high production without worries of depleting the reserves (see chart below). An agreement has been reached on long term infrastructure sharing arrangements between APLNG and the QCLNG project. APLNG has taken the opportunity to secure up to 350 PJ of gas from the QCLNG project for 10 years from 2024 (equivalent of 90mmcf/d or 0.7mtpa) on the back of QCLNG's deal to source gas from Arrow Energy.

APLNG reserves net to Origin

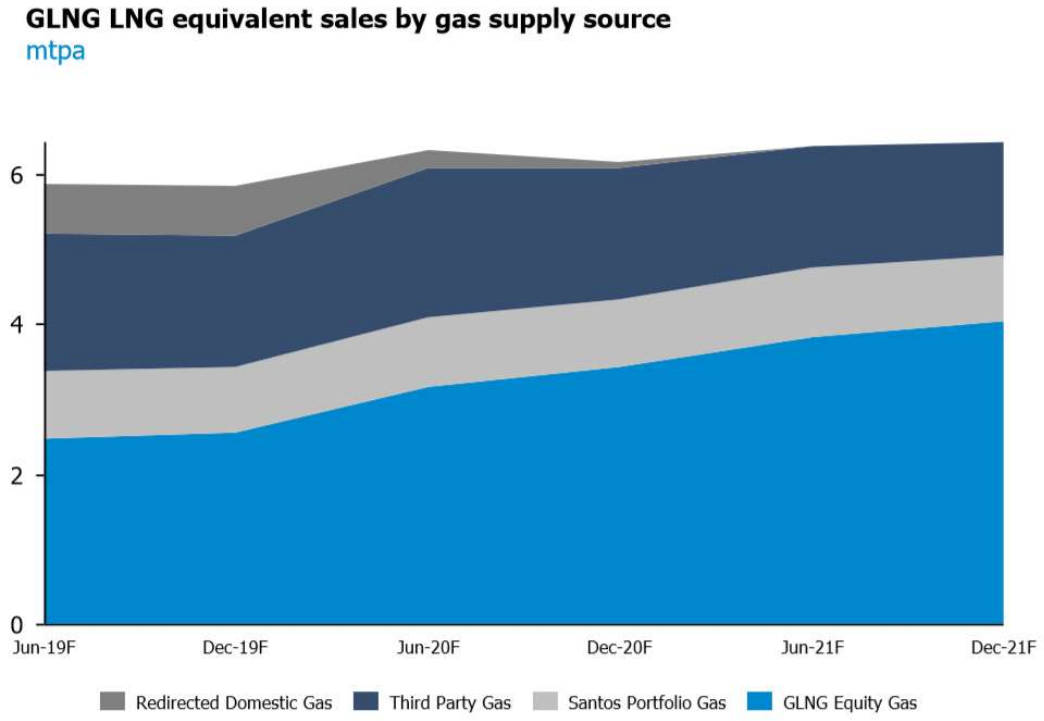


Source: Origin presentation

QCLNG

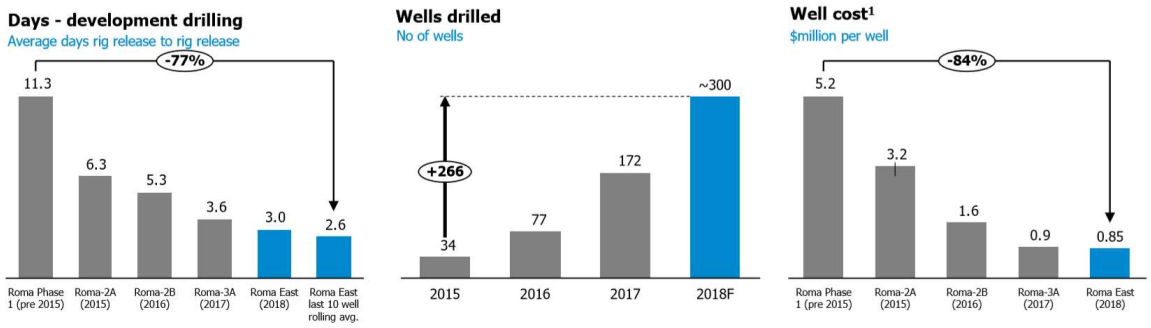
QCLNG is a plant that has struggled to produce at capacity due to weaker upstream production and diversions to the domestic market, however the plant has shown the ability to produce at 10% above name plate capacity. The project has also seen reserves write-downs. QCLNG's production fell sharply in 2017 to ~6.5mpta or just 76% of name plate capacity of 8.5mpta on the back of maintenance and also the legacy impact of a reduction in drilling through the oil downturn. Production has rebounded in 2018 and in fact in Q3'18 was at an annualised rate of 8.1mtpa. There have been several projects to sustain/grow production. The 2015 "Project Charlie" was completed in 2017 and involved 340 wells being drilled to produce ~230mmcf/d. In 2017 Shell announced "Project Ruby" that its QGC joint venture would drill up to 161 additional wells to sustain production. The wells are being drilled in the Chinchilla/Tara area in 2017 and 2018. During 2019 and 2020, Shell will progressively drill 250 new gas wells as part of the QGC venture in the Western Downs region of Queensland. Most significantly, QGC agreed a deal with Arrow, which has the largest uncontracted gas reserves on the east coast, to produce >600mmcf/d at peak starting in 2020.

Gladstone LNG



Source: Santos presentation

GLNG has suffered from poorer than expected upstream performance that has led to the facility having to rely heavily on third party gas and even so producing well below its potential. Initially when the first train came on line it was producing above nameplate capacity, shortly after start-up, in September 2015. Train 2 was expected to take 2-3 years to reach capacity. GLNG produced 4.5mtpa in ’16 and 5.2mpta in ’17 and YTD ’18 (9m annualized) is at 4.8mpta. The consequence of the lack of drilling through 2014-16 meant that the well stock wasn’t there to produce at capacity. The long-term contracted volumes from GLNG are 7.2mtpa and name plate capacity is 7.8mpta.



Source: Santos presentation

An improvement in drilling time and lower drilling costs means that the economics of ramping up production have improved. The current plans are for ~300 wells in 2018 increasing to 350-400 per annum in 2019 and 2020, which should lead to significant growth in GLNG equity gas. Well costs at its key Roma

development have been lowered by 85% from the pre-2015 levels. The project focus has been to get to 6mpta and now with visibility on this, we expect Santos to focus on finding ways to utilise the spare capacity: GLNG's ullage to 8.4mtpa potential capacity (assuming 10% upside to nameplate) provides opportunities for organic and inorganic growth. We expect production to hit 6mpta in 2020 and grow slightly after that. Santos/Shell recently won 400sqkm exploration rights, immediately south of the Wallumbilla hub, to target natural gas in deep sandstone reservoirs of the Bowen Basin, beneath the Surat Basin. If successful this could also go towards filling the plant in the future.

Disclaimer

The document is for the use of the recipient only and must not be reproduced or distributed in any forms, in parts or full without permission from Akap Energy Ltd. Any kind of reproduction, including scanning into an electronic retrieval system or copying to a database, without written permission by the publisher is strictly prohibited. Redistribution of the report or its content to persons other than legitimate recipients is strictly prohibited.

Errors and omissions excepted. Whilst every effort has been made to ensure that the information provided is accurate, it does not constitute legal, tax or other professional advice and should not be treated as such. This information is a market analysis service, it does not constitute a solicitation for the purchase or sale of any commodity or financial instrument. Any persons acting on information contained in this report do so solely at their own risk. The document is subject to revisions.

Akap Energy Ltd is not responsible for actions taken based on information in this document. Akap Energy Limited will not be liable to you in respect of any business losses, including without limitation loss of or damage to profits, income, revenue, use, production, anticipated savings, business, contracts, commercial opportunities or goodwill.

This disclaimer will be governed by and construed in accordance with English law, and any disputes relating to this disclaimer will be subject to the exclusive jurisdiction of the courts of England and Wales.