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30 March 2020

Mr Tyson Self
Economic Regulation Authority
Level 4, Albert Facey House
490 Wellington St, Perth WA 6000

Via website submission

Dear Tyson,

Dampier to Bunbury Natural Gas Pipeline Access Arrangement 2021–25, Issues Paper

Thank you for the opportunity to provide this response to the ERA Issues Paper on the Proposed revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline for 2021 to 2025.

ABOUT GASTRADING

Gas Trading Australia Pty Limited ("**gasTrading**") has operated in the Western Australian market for over 10 years and is regarded as the premier gas supply manager in Western Australia. The gasTrading team offers an unparalleled level of service, expertise and experience. gasTrading:

- employs 12 expert staff members to manage the gas supply of its clients;
- has a large Perth presence and an established Melbourne office;
- has over 300 TJ/d of gas under management each day;
- provides Gas Supply Management Services to 30 clients across multiple States and Territories and across various industries including mining, power generation, manufacturing and gas production;
- manages gas supply on all Western Australian pipelines, the Amadeus Gas Pipeline, Northern Gas Pipeline and the Carpentaria Gas Pipeline;
- broad and diverse transport position in own right; and
- is the operator of the gasTrading Spot Market:

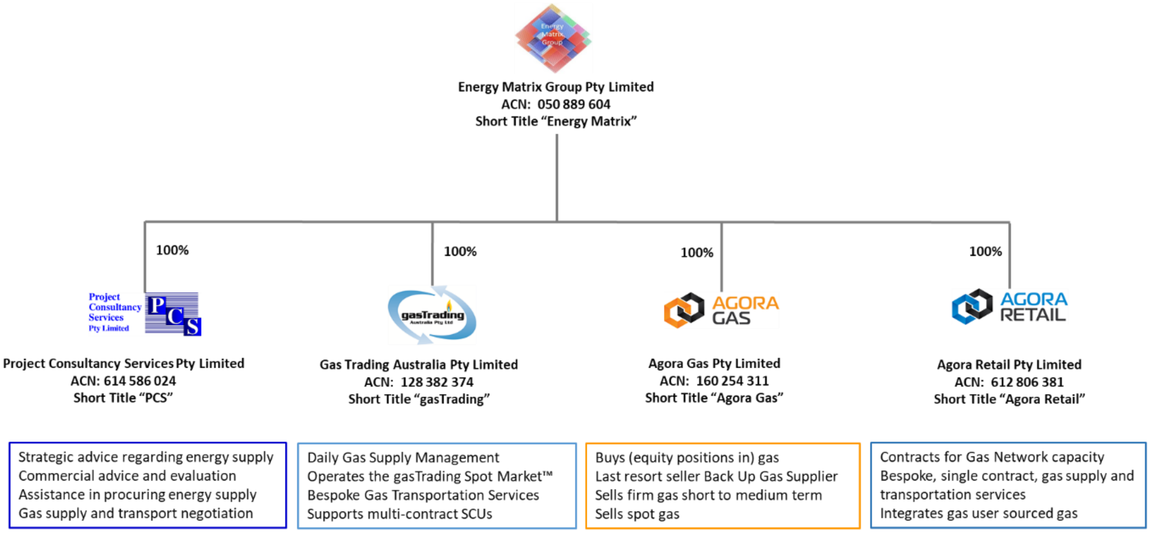
  http://www.gastrading.com.au/spot-market.

gasTrading is a member of the Energy matrix group.

ENERGY MATRIX

The ERA is probably familiar with the activities of some of our group members and the information in the diagram below, describing the focus or each entity, will allow you to complete the picture.

The diagram below sets out the structure of the Energy Matrix Group Pty Limited ("**Energy Matrix**") group of companies. In this structure, Energy Matrix holds all the shares in each of gasTrading, Agora Gas Pty Limited ("**Agora Gas**"), Agora Retail Pty Limited ("**Agora Retail**"), and Project Consultancy Services Pty Limited ("**PCS**").



Thank you for the opportunity to make this submission.

Yours sincerely

[redacted]

Allan McDougall
GENERAL MANAGER
Gas Trading Australia Pty Ltd

Attached: Submission to the Issues Paper

Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline for 2021 to 2025

gasTrading's Opening Comments

The changing supply-demand dynamics with respect to climate change and its impacts on DBNGP

DBP in its submission has sought to address a number of concerns around the changing supply-demand dynamics in Western Australia driven by the need to respond to climate change. gasTrading is broadly supportive of the discussion in the submission. The gas value chain needs to understand the economic impact of changing supply and demand on all components of the value chain, so that the most efficient outcome is delivered to minimise the impacts of climate change.

We must plan for alternative energy sources including intermittent renewables and battery storage systems but also consider the impact of new technologies, including hydrogen derived from electrolysis, carbon capture and storage, electrification of demand and demand side and distributed energy management such as virtual power plants.

The work undertaken by ACIL Allen in support of DBP's submission though was woefully out of step with the current Western Australian gas market. For example, the 3 gas price scenarios used by ACIL Allen are well in excess of current prices, with the spot market trading near $2/GJ and contract prices below $5/GJ depending on the key terms (Refer Attachment 1).

DBP provided a response to our comments on 30 March after Shipper Roundtable #10. The comments stated that "ACIL Allen used forecasts produced by the international Energy Agency and the Australian Energy Market Operator (AEMO) for WA gas prices". gasTrading does not dispute that, though equally valid prices are the published spot price, or any number of prices considering the analysis is based on future scenarios and predictions of alternate energy sources. For example, ACIL Allen used carbon price curves that range from $100/TCO2e to $250/TCO2e in 2085 yet gas prices varied from $6.86/GJ to $8.38/GJ in 2085.

In gasTrading's view, DBP tended to use scenarios that placed natural gas at a significant cost disadvantage to drive AGIG's corporate agenda. ACIL Allen did not consider more broadly the possible impacts of electrification on gas demand, especially when the time frame stakeholders are being asked to consider is sufficiently long that any number of plausible futures exist. Futures where our passenger vehicle fleet runs almost exclusively on stored electrical energy. This could include passenger vehicles that are no longer owned by individuals, but self-driven vehicles hired only for the purposes of trips. One where carbon capture and storage is economic such that large industrial user of natural gas can viably capture carbon dioxide emissions.

These scenarios above could increase demand for natural gas, they may also lower it. The principal concern being that we are being asked to guess a future where the possibility is much broader than those presented by DBP and ACIL Allen. Indeed, just 5 years ago gasTrading believes no person was predicting gas prices to be sitting where they are now. How do we expect ACIL Allen to be so confident of gas prices in over 60 years' time!

North West Shelf Backfill and impacts on the DBNGP

DBP has not addressed the much-rumoured export of onshore gas to the North West Shelf Project for "back fill" or export as LNG.

gasTrading raised this issue at DBP's most recent Shipper Forum on 25 March and it was clear from the lack of response by DBP that this had not been given much thought on how it would impact the reference service contracts.

DBP responded on 30 March that the DBP already has bi-directional capabilities and not proposed any forecast capex in AA5. DBP also noted that the tariffs for bi-directional flows are based on a per kilometre tariff and assumed this is fair and equitable. In part gasTrading agrees the tariff is likely to be fair and reasonable but points out a number of issues with this assumption and legal issues with the drafting of the transportation contracts.

gasTrading considers that there are probably a good number of reasons why this discussion did not enter the Access Arrangement submission, but the concept is clearly the elephant in the room. gasTrading has attached (**Attachment 2**) a discussion on the proposal to its submission.

Full Haul versus Part Haul delivered south of Compressor Station 9

The **Standard Shipper Contract** has defined any delivery of gas south of Compressor Station 9 as Full Haul. This definition has been standard for much of the life of the DBNGP, especially as all shippers had a standard shipper contract prior to 2014.

The **Reference Contract** has defined Part Haul differently:

> *"a service to provide Forward Haul on the DBNGP which is not a full haul service and which includes, without limitation, Services where the Inlet Point is upstream of main line valve 31 on the DBNGP and the Outlet Point is upstream of Compressor Station 9 on the DBNGP, Services where the Inlet Point is downstream of main line valve 31 on the DBNGP and the Outlet Point is downstream of Compressor Station 9 on the DBNGP, and Services where the Inlet Point is downstream of main line valve 31 on the DBNGP and the Outlet Point is upstream of Compressor Station 9 on the DBNGP*".

In other words, **<u>a Part Haul can be delivered south of Compressor Station 9</u>**.

DBP has argued in the past that the Full Haul capacity of the DBNGP is the capacity of all compressor stations to deliver gas to Perth (or down stream of Compressor Station (CS) 9) assuming certain qualities of gas. gasTrading agrees with that definition, the capacity of any pipeline system is limited by the capacity of the last point on the pipeline where the pressure can reach the Maximum Allowable Operating Pressure. For the DBNGP this is Compressor Station 9.

If a shipper were to apply for Access for gas supply from the Perth Basin to Perth (e.g. Mondarra to Perth), the shipper should receive a firm, Part Haul reference service with a tariff of approximately A$0.35/GJ (2020 Reference Tariffs). That shipper would be utilising the capacity of CS8 and CS9 to deliver the gas to Perth. In effect it would be using “Full Haul Capacity” to deliver a Part Haul service. That is, capacity DBP could have sold for ~$1.35/GJ but must provide the service for ~$0.35/GJ (using 2020 Reference Tariffs).

In gasTrading’s view this is completely reasonable, as the shipper is not utilising any of the installed capacity upstream of the Inlet and there is potentially a competing service (being the Parmelia Gas Pipeline). Finally, encouraging gas users to contract for gas supply from the Perth Basin has the added benefit of increasing the supply diversity to the WA market (both suppliers and geographically) which increases the robustness of the supply chain.

gasTrading’s concern is that if a customer makes an Access Request under a Reference Part Haul service, DBP is not incentivised to accept the Access Request, especially in the case of an existing Shipper re-contracting existing Full Haul volume to Part Haul. In this case, DBP has previously argued that this is sterilising their Full Haul capacity. In gasTrading’s view, it needs to be very clear to the market that a Reference Part Haul gas transportation service from south of MLV31 to south of CS9 is a Part Haul service, and that AGIG must accept any valid request, where there is available capacity.

This is particularly important for the gas projects in the Perth Basin which have the potential to supply in excess of 200TJ/d to the WA market, with a gas transmission tariff advantage of approximately $1/GJ. And where, as we see in DBNGP’s forecast demand, there is ample spare firm capacity at CS9.

Change of location of I1-02

DBNGP states Attachment 8.5 – Capex Business Cases (p.432):

“***Between 2010 and 2015, changing pipeline hydraulics has resulted in CS1’s gas flow being below its design capacity. Further reductions have been experienced with the Varanus Island inlet gas bypassing CS1 – a request by the Producer to inject into the downstream side of CS1. The flow of gas has reduced over time to approximately half of the design flow***.”

From this statement it appears the Varanus Island (I1-02) moved from upstream (north) of CS1 to downstream (south) of CS1 during the period 2010-2015.

Therefore, is I1-02 upstream of CS1 or downstream of CS1?

DBP responded to this issue on 30 March 2020, after Shipper Roundtable #10, and stated that "the proposed works at CS1 will not change the custody transfer point for the Varanus Island Inlet". From the Access Arrangement Information Appendix 8.5, gasTrading is led to believe Varanus Island changed location between 2010 and 2015.

This change of location has a serious impact on gas transport from I1-02. I1-02 would become a "Back Haul" service to the GGP and FRGP slashing the tariff from $0.13/GJ to less than $0.001/GJ and would put gas from I1-02 on the same tariff as I2-01, Gorgon. For a typical small mining customer (2.5TJ/d), this change would save them $118,000pa.

DBP's pipeline description has not changed the location of I1-02 over this period.

If this change occurred, DBP failed to make this change public and notify shippers.

Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline for 2021 to 2025

ERA Issues Paper 17 March 2020

Note: gasTrading's comments are in Italics in this section of the submission.

Issue 1 DBP stakeholder consultation process

1. Does DBP's submission align with stakeholder expectations following the engagement program?
2. Was DBP's engagement program a useful approach for stakeholders to be actively involved in the development of the access arrangement submission?

DBP's stakeholder engagement was very informative and helpful process from our perspective. DBP was open to receiving comments and offer responses. However, it is only from detailed review of the submission that it appears DBP may not fully considered all market perspectives.

Reference	DBP Position	gasTrading Comments	Recommendation / Conclusion
Attachment 5.2 Stage 1 Stakeholder Engagement Report p14	*DBNGP's customers raised "The future of gas trading was an issue for consideration"*	*This claim has been made in several DBNGP's documents. DBNGP has not reflected how this impacts the Access Arrangement, if at all.* *gasTrading, as the only gas spot market operating in WA which provides public data on the gas market at no charge, would value DBNGP continuing to support the development of gasTrading's aspiration for a transparent, liquid spot gas market.* *For example, the regulation of the Pilbara Service would improve transparent pipeline access which supports flexible gas purchasing arrangements*	*DBNGP should support the existing gas trading spot markets on offer in WA, the gasTrading Spot Market and Energy Access Services. DBNGP services such as spot gas transport for Part Haul, Back Haul or the Pilbara Service should continue to be offered by DBNGP.* *Any modifications to CRS, DBP's customer facing system, should focus on quality consultation with all stakeholders and not hinder market development.*

Issue 2 Depreciation

3. Should a service provider be allowed to increase revenue to reduce the risk that it will not recover the cost of its existing assets?
4. Given the uncertainty associated with future demand, should the economic lives of new investments be reduced?
5. Should a mechanism be added to the Access Arrangement to provide for the redundancy of assets in the future if demand falls away?
6. Are DBP's three new proposed asset categories appropriately defined to include assets with the same economic life? In undertaking the recategorisation process, should DBP have proposed that it review all assets to ensure that these assets are in the correct asset category?

Refer Attachment 1.

gasTrading is concerned by the lack of robust modelling undertaken by AGIG and ACIL Allen. In fact, the modelling appears to be promoting the use of hydrogen rather than natural gas which is surely not consistent for a natural gas monopoly asset owner that is critical to the state's economy and household's energy needs. The natural gas pricing scenarios conducted by ACIL Allen should consider a significantly broader range of prices, at least at current gas prices!

The issues raised in the Issues Paper could lead to questioning why CKI would purchase the DBNGP, if just two years later, CKI is seeking to devalue the asset by reducing the asset life. The rate of return calculation already reflects the underlying risk for the asset class. The Access Arrangement, through the rate of return mechanism, already considers the market's view of the risk of similar assets to the DBNGP being displaced by new energy business models by comparing the cost of equity.

Issue 3 Incentive mechanism (E Factor scheme)

7. Whether the proposed E Factor scheme promotes efficient use of DBP's pipeline assets, and efficient investment in and provision of pipeline services.
8. Whether the efficient provision of pipeline services can be achieved without an efficiency carryover mechanism such as the E Factor scheme.
9. Whether the E Factor exclusions proposed by DBP to calculate the E Factor benchmarks are reasonable.
10. Whether the length of the proposed carryover period and proportional allocation of benefits (or costs) between DBP and customers is reasonable.
11. Whether contractual obligations and operating licence conditions, including financial penalties, are sufficient to ensure that efficiency gains achieved under the E Factor scheme would not lead to a decline in service reliability.
12. Whether additional mechanisms or provisions are required to offset DBP's incentives to incur or defer capital expenditure, or allow service performance to decline under the E Factor scheme.

gasTrading has no comment on the Incentive Mechanism, other than any Incentive should be applied to savings that are directly a result of DBP's management, rather than savings that result from lower than forecast utilisation which leads to savings in maintenance, System Use Gas or overhauls. Incentives should benefit the Pipeline Owner due to the Pipeline Owner's use of technology, ingenuity and skill.

Issue 4 Reference tariffs

13. The ERA invites submissions on DBP's proposed reference tariffs and the overrun charge of 1.15 times the reference tariff. The ERA is inviting submissions on the appropriateness of DBP's tariff structure and alternatives, including:
    - The fixed and variable components of the reference tariff.
    - Whether any revenue from the overrun charge should be considered in calculating reference tariffs.

Fixed and Variable components

gasTrading broadly supports the fixed and variable components of the reference tariff, being broadly reflective of DBP's actual costs but does note that rotating equipment overhauls are predominantly driven by run hours. The changing gas supply picture (in particular Perth Basin gas production) will likely significantly reduce run hours on compressors north of CS8, whilst the decline in production at North West Shelf will reduce run hours on CS1. This does not appear to have been considered by DBP.

Overrun

If the Overrun Charge is imposed to encourage good shipper behaviour, then there is no need for it to be brought into revenue calculations. If, however, DBP engages in systemic behaviour to promote, manipulate or maximise these charges the charges should be brough to account in reference tariff calculations.

Issue 5 Operating expenditure

14. DBP's proposed conforming operating expenditure for AA5, including whether the proposed activities align with good industry practice and whether the associated expenditure is reasonable.

Reference	***DBP Position***	***gasTrading Comments***	***Recommendation / Conclusion***
Attachment 7.1 Opex Forecast Model Public. System Use Gas cost forecast	*DBNGP has forecast an increasing SUG cost.*	*Without knowing further data behind this assumption, the SUG price is forecast to grow roughly with CPI until 2024 where it jumps 4.5% and then back aligned with CPI.* *Gas prices are currently low and gas contracts over the period of the Access Arrangement can be obtained currently with prices escalating only at CPI. Furthermore, forecast full haul volumes are expected to decline which will result in a reduction in SUG volume.*	*Without being able to see the data behind the calculation, the SUG annual spend does not seem consistent with contract gas prices or the volumes claims made by DBNGP.*

Issue 6 Conforming capital expenditure for AA4

15. DBP's proposed conforming capital expenditure for AA4, including whether the projects and work activities align with good industry practice and whether the associated expenditure is reasonable.

Issue 7 Forecast conforming capital expenditure for AA5

16. DBP's proposed forecast of conforming capital expenditure for AA5, including whether the proposed projects and work activities align with good industry practice and whether the associated expenditure is reasonable.

IT related expenditure

gasTrading is supporting of the IT improvements.

Reference	DBP Position	Comments	Recommendation / Conclusion
Attachment 8.4 DBP IT Investment Plan 2021-25	*IT Investment*	*gasTrading is broadly in support of the IT Investment Plan, provided DBNGP engages with its customers and stakeholders to efficiently manage the transition of systems and interface with other parties' systems.* *However, the costs to upgrade systems to enable AGIG to manage its portfolio of businesses on a common system should not be included in the Access Arrangement. AGIG acquired DBNGP and the costs related to integrating the DBNGP with their other assets are not costs customers should contribute to unless there is a business case for the customer.*	*gasTrading is broadly in support of the IT Investment Plan.*
Attachment 8.5 – Capex Business Cases p297	*CRS Business Case*		*gasTrading is broadly in support of the CRS business case, provided DBNGP engages with its customers and stakeholders to efficiently manage the transition of systems and interface with other parties' systems.*

Issue 8 Demand

17. Do stakeholders require further explanation of how DBP's forecasts are derived for the reference services forecasts?
18. The ERA is seeking views on the comparability of growth rates of the Australian Energy Market Operator's Gas Statement of Opportunities used to validate DBP's forecasts and DBP's forecasts.
19. The ERA is seeking views on whether the proposed step change in DBP's demand forecast is due to growth in renewable electricity. In particular, whether the current and ongoing growth of renewable electricity (wind and solar) in the SWIS is displacing electricity generated from natural gas from the DBNGP.

20. The ERA is seeking views on the adequacy of the stakeholder consultation undertaken by to derive DBP's bottom-up demand forecasts.

gasTrading is of the view that getting transparency on the forecast is very difficult given the confidential nature of information received by DBP. However, gasTrading would like to see more clear comparisons to rolled up data, for example comparing AEMO's GSOO and ESOO with DBP's forecasts. gasTrading also notes DBP often makes data confidential which is available from public sources (such as historical gas demand) which can frustrate the process. Forecasts could be aggregated in categories aligning with existing GBB data and transitions from actual to forecast could demonstrate these trends without breaching confidentiality (where forecasts are not available for loads included in historical data they could be identified and held constant).

Confidentiality Claims

Reference	**DBP Position**	**Comments**	**Recommendation / Conclusion**
Attachment 1.4 Confidentiality Claims Claim 12	*Demand forecast by commodity is claimed as confidential*	*Demand data for 2019 is publicly available via the AEMO Gas Bulletin Board (and prior years)*	*Data for current years or historical is not confidential. Only forecast gas data should be redacted.*

Issue 9 Pipeline and reference services

21. DBP's proposal to keep the T1 Service, P1 Service and B1 Service as reference services under the access arrangement.
22. DBP's amendments to the descriptions of the proposed reference services to be offered under the access arrangement.
23. Whether any other pipeline services should be specified as reference services.

Refer Attachment 2.

gasTrading is noticing an increasing preference for the Pilbara Service. DBP has argued that the service has low revenues and customer numbers and is easily substituted with an alternate Reference Service (being a Part or Back haul).

gasTrading's engagement with gas suppliers has shown that, since the end of joint marketing, a number of gas sellers, with equity in different gas projects, are requiring buyers to accept flexible delivery locations for gas, at the gas seller's discretion. Whilst this market development is often welcomed by gas buyers, as it provides greater supply security, the difficulty is that the gas buyer may have a point to point transportation service and no capacity to ship the gas, especially where it would be supplied under an alternate gas transport arrangement.

An example, for the purpose of illustration, being a gas supply from an NWS Gas Producer where the gas is normally supplied from Karratha Gas Plant (I1-01) being a Part Haul say to the Goldfields Gas Pipeline. If Karratha Gas Plant was then unable to supply the gas, the Producer could elect to supply the gas at other Delivery Points and the customer may require a Back Haul from the Delivery Point. This scenario could occur for one day or a period (for example a prolonged unplanned shut down). This example could apply to Chevron, Woodside, Shell, BHP, Mitsui, Santos and any number of customers in the Pilbara or on the Goldfields Gas Pipeline.

DBP has shown a reasonable approach in allowing some flexibility where a shipper would have to relocate their service to meet their obligation to take the gas from an alternative Delivery Point. However, there is some uncertainty and potential additional cost if the Producer supplied the gas at certain Delivery Points, the customer would be paying a significant premium over a point to point backhaul to the GGP (as an example). Hence more Part Haul Shippers will be increasing their reliance on the Pilbara Service going forward.

Obviously, the exact arrangement will impact the cost for the Shipper, but the DBP never loses as they will receive the higher tariff (the original part haul, or the cost of the new shipper contract). Typically, the gas seller does not incur any of the cost as the gas buyer would have otherwise not received any gas. So, in the gas seller's opinion the added delivery point is a value add for the gas buyer.

The Pilbara Service provides a valuable option for gas shippers to purchase gas from sellers with diverse supply portfolios and leverage the supply security offered by gas sellers who have access to multiple production locations whilst avoiding being locked into a long-term arrangement. With the move to equity marketing shippers are being pushed to consider the use of the Pilbara Service.

In gasTrading's opinion, the fact that 8 customers[1] have a Pilbara Service (we estimate DBNGP has 30 unique shippers) which represents approximately 27% of customers is a reasonable basis for considering coverage, especially given that the move to equity marketing is a relatively new phenomenon.

The Pilbara Service also provides flexibility to participate more actively in short term or spot opportunities, a necessary precursor for the growth in a liquid spot and/or secondary market. With the continued development of spot gas markets, gas transport arrangements that are flexible, increase the ability of shippers to trade gas at different Inlet Points, knowing they have in place gas transport. DBP has numerous times stated that customers raised that "the future of gas trading was an issue for consideration". This would further indicate that there is likely to be increased demand for a flexible service.

Finally, the Pilbara Service includes gas supply from the Perth Basin. With increasing production from the Perth Basin, and much of the growth in gas demand being in the Pilbara

[1] Final Plan 2021-25 Attachment 6.1 p. 2, Pilbara Service

region, it is likely that customers will be seeking gas supply from the Perth Basin and gas producers in the Perth Basin, such as Mitsui, may like to provide gas from their portfolio of gas projects.

In gasTrading's view it is likely we will see increased demand for this service. Indeed, this service could become more common than point to point Part Haul or Back Haul services over the Access Period.

Issue 10 Terms and conditions for reference services

24. DBP's proposed amendments to the terms and conditions for each reference service – the T1 Service, P1 Service and B1 Service.
25. Whether any further consultation on DBP's proposed terms and conditions has taken place, between DBP and shippers, since DBP's submission to the ERA on 2 January 2020 and if so, the outcome(s) of the further consultation.
26. Whether any further amendments should be made to the terms and conditions for each reference service.

Refer Attachment 2

Issue 11 Access and queuing requirements

27. DBP's proposed amendments to the procedures for making access requests and queuing requirements.
28. Whether the queuing requirements need to be amended to give prospective shippers the ability to determine their actual position in the queue for access.
29. Whether any further amendments to the procedures for making access requests and queuing requirements should be made.

gasTrading is concerned that DBP could deny a request for Access to a Part Haul from south of MLV31 to Perth on the basis that the this would quarantine their Full Haul capacity. DBP needs to ensure that a customer is made aware that any part haul or full haul would be treated fairly, and not on the basis that the full haul contract for the same "capacity" is given priority due to the higher tariff. The capacity should be available on a first come first served basis and not be prioritised based on tariff or contract value (for example a longer contract).

Issue 12 Capacity trading

30. DBP's proposal to leave the capacity trading requirements unchanged from the current AA4 access arrangement.
31. Whether any amendments to the capacity trading requirements should be made.

Issue 13 Extension and expansion requirements

32. Make direct reference to "incremental services", as that term is defined in the NGR.
33. State whether the access arrangement will apply to incremental services to be provided as a result of a particular extension to the pipeline, and if so and where required, deal with the effect of the extension on the opening capital base, description of reference services and tariffs.

34. State that the access arrangement will apply to incremental services to be provided as a result of any expansion to the capacity of the pipeline during the access arrangement period and deal with the effect of the expansion on tariffs.
35. Delete all references to the term “enhancement”.

Issue 14 Receipt and delivery points

36. DBP’s proposal to leave the terms and conditions for changing receipt (inlet) and delivery (outlet) points substantively unchanged from the current AA4 access arrangement.
37. Whether any further amendments to the terms and conditions for changing receipt (inlet) and delivery (outlet) points should be made.

Issue 15 Review and commencement dates

38. DBP’s proposed review submission date of 1 January 2025.
39. DBP’s proposed revision commencement date of 1 January 2026.

gasTrading has not comments on Issues 12 to 15

Attachment 1: Issue 2 Depreciation Discussion

DBP has sought to shorten asset lives in response to changes in the energy market that may impact the DBNGP by reducing volume or making it redundant before the end of the current asset's life.

Whilst gasTrading recognises the challenges faced by man-made climate change, the modelling used in support of the argument has some flaws and was not tested over a significantly wide range of assumptions, given the uncertainties or time scale being considered. Indeed, the rapid uptake of battery electric vehicles could increase electricity demand in the SWIS in the near term, increasing gas demand. This outcome is entirely plausible, yet assumptions which increase gas or electricity demand were not considered.

gasTrading summarises our concerns below:

1. The gas price assumptions are narrow and **at least** 20% above today's gas price long term contract prices. There has been no testing of the scenarios at today's gas price or lower gas prices, such as the current spot market gas price of approximately \$2/GJ or anticipated break-even gas prices for some domestic gas developments proposed at above an estimated \$3/GJ (depending on capital costs, exchange rate and oil price assumptions).
2. DBP attempts to influence the reader's perception that renewables are cheaper than gas by comparing intermittent renewables and forecast intermittent renewable prices against dispatchable fossil fuel prices. This is not comparing like with like. To counter this argument, DBP has used data for a 2hr battery and pumped hydro storage. Pump hydro storage is unlikely to be viable on a large scale in the SWIS due to geography and water availability. A 2hr battery is not comparable, when intermittent renewables, like solar, are only producing energy for 10-14 hours per day.
3. CKI Group purchased DUET Group in 2017 and formed AGIG. CKI paid \$7.4B for a predominantly gas businesses, the DBNGP being the largest asset. CKI would have purchased the asset based upon their estimate of future cash flows and knew the asset life at the time. DBP is now arguing, only 2 years later the economic life of the DBNGP is now shorter than the asset life, which was on the public record at the time of acquisition. It appears that despite the absence of any climate change policy in the interim DBP is looking to impair the assets, when the certainty gas will be displaced by hydrogen is not well understood.

Reference	DBP Position	gasTrading Comments	Recommendation / Conclusion
ACIL Allen Report Attachment 9.3 p14 and 15	ACIL Allen used 3 gas price scenarios derived from LNG export prices to test the transition from a natural gas energy source to zero carbon energy sources.	The pricing used by ACIL Allen is well in excess of current gas prices and sets out a forward price curve that is well above the forward prices expected by AEMO, above the prices expected by gasTrading and are not relevant to the WA market where a domestic gas reservation policy partially decouples domestic gas from LNG netback pricing. DBP then uses this assumption in their economic life modelling. Gas prices in 2020 are available well below $6 (ACIL Allen's Low Case).	The modelling by ACIL Allen is strongly influenced by gas pricing. The model should more robustly test the gas price, given the inherent uncertainty in a range of assumptions used by ACIL Allen and use gas prices over a much broader range. For example, $4/GJ, $6/GJ and $8/GJ. The modelling also fails to recognise the impact of hydrogen uptake on the natural gas price. As natural gas demand falls, the natural gas price will also fall. The two markets are connected.
ACIL Allen Report Attachment 9.3 p19 and 20	ACIL Allen used 3 hydrogen price curves to estimate the future price of hydrogen	Whilst ACIL Allen has been very conservative on pricing natural gas where the costs in the natural gas supply chain are well known, ACIL Allen has proposed very aggressive reductions in the hydrogen prices to well below the natural gas price. Here we have great uncertainty over the future cost and ACIL Allen has demonstrated a cost that is currently unachievable.	The hydrogen price curves vary wildly compared to natural gas. This would appear to favour AGIG's corporate agenda in driving hydrogen. If these price curves are to be used, then a similar range of future energy prices should be applied to natural gas.
ACIL Allen Report Attachment 9.3 p27	ACIL Allen has forecast renewable energy prices and gas price equivalents	The renewable energy price under the "High" Case is approximately $50/MWh in 2085. The modelled Gas Equivalent price would be $5/GJ using a Heat Rate of 10GJ/MWh. Meaning that gas could well be competitive in the future, even allowing for a carbon price or other carbon mechanism.	The hydrogen assumptions are too aggressive to support AGIG's arguments. Gas is currently below $5/GJ and so could continue to be a viable fuel for electricity generation under the scenarios modelled by ACIL Allen

Attachment 9.2 Assessment of the Economic Life of the DBNGP	The economic life of the DBNGP considering changes to the energy sector	In 2017 the owner of AGIG purchased Duet Group (DBP being the largest asset of the Group) for A$7.4B. At the time, AGIG would have valued Duet Group and its future cash flows based on presumably a long profitable life for the assets. If it now wishes to impair the life of the assets, then why did it value these assets so highly? Whilst there is significant uncertainty in the energy sector across all fuels, the situation was well known in 2017. AGIG's claims on hydrogen, supported by ACIL Allen's report shows a significant range of outcomes, and has not tested hydrogen against the CURRENT gas prices in WA, instead using significantly higher natural gas prices. gasTrading has serious concerns that the drivers around hydrogen are neglecting the likely costs of a hydrogen economy and particularly the impact on the cost to households. The increased cost of energy derived from hydrogen will result in increased costs to almost all materials, consumer goods and foods. Given this the transition may occur significantly differently to what economists predict. The arguments for shortening the asset life of the DBNGP are significantly uncertain that no justification for the change has clearly been made. For example, a rapid uptake on electric vehicles could increase demand for electricity fuelled by natural gas, supplied by DBNGP.	The modelling prepared by ACIL Allen to support DBP's arguments for reduced asset life has significant forecast risk and so no change should be undertaken until there is clear policy or economic drivers that support shortening the asset life. DBP has demonstrated the great uncertainty but also relied on data that is not consistent with pricing or costs relevant to WA.

Reference	DBP Position	gasTrading Comments	Recommendation / Conclusion
		AGIG has also ignored the fact that projects like Wheatstone, Gorgon, Scarborough and Browse are all investing in gas with a long project lifetime, typically over 30 years.	
Attachment 9.2 Assessment of the Economic Life of the DBNGP p6	The decreases in price have meant that renewables are now very close to traditional fossil fuels in cost and, in many cases, actually cheaper. This is shown in Figure 2, from a recent paper by the CSIRO for AEMO	This statement is not correct, as DBP is not comparing like for like electricity supply. For example, solar PV is not controllable or dispatchable and does not respond to load. Gas technologies is controllable, meaning it can be dispatched on demand. To compare like for like, storage costs need to be included in the renewable energy cost comparisons.	This section of the report is intended to sway arguments to support DBP which are not factually correct.
Attachment 9.2 Assessment of the Economic Life of the DBNGP p6	Note that renewables plus pumped hydro is already comparable to gas without a carbon price, whilst renewables plus batteries sit just above	In Western Australia we have little capacity for pumped hydro due to geography and available water in locations of benefit to the grid. 2 hours of battery storage is not sufficient for a solar system to provide firm energy overnight. DBP is once again not comparing like for like technologies. A gas power station can provide energy and network ancillary services indefinitely each day up to its capacity. In addition, the gas price scenario used by the CSIRO is $5.80/GJ in the low case and $11.30/GJ in the high case. Gas prices in WA are currently around $5-6/GJ delivered and below $3.50/GJ delivered spot. This is at or below the bottom of the range presented in the report. Indeed, if gas demand fell as aggressively as DBP expects, gasTrading expects the natural gas price would fall further.	DBP has selected data that overstates the value of intermittent renewables and understates the value of natural gas. For a gas pipeline company this data seems to go against the very reason why you would pay A$7.4B for a natural gas-based business

Attachment 2: Discussion on proposed "backfill" arrangements to export gas via the North West Shelf JV

Numerous media reports have been made proposing "back fill" of North West Shelf Gas with production from the Perth Basin or other fields in the Carnarvon Basin.

The proposals generally revolve around the concept of "back haul" on the DBNGP. The idea being that gas flows into North West Shelf from the DBNGP instead of the NWS being a domestic gas producing facility.

From gasTrading's perspective any development of gas projects in Western Australia is generally good for the availability of domestic gas. However, the proposal introduces a number of concerns in relation to the DBNGP Access Arrangement that we believe should be considered by the regulator ahead of any proposal. We have limited our discussion to the impacts on the DBNGP, relating to the Access Arrangement.

The issues are:

1. The Access Arrangement is based on a concept of forward haul from North West Shelf (I1-01) to Perth. This would no longer be valid.
2. The supply of gas from the DBNGP to North West Shelf Gas will involve physical reversal of capacity upstream of Compressor Station 1. This will change the commercial terms of a part haul and back haul contract from producers north of CS1 or for customer receiving gas north of CS1 including on the PEPL.
3. The Access regime may require significant review as assets funded by Shippers will no longer be required to deliver full haul transport.
4. Irrespective of NWS using domestic gas for backfill, the BEP lease and After Coolers at I1-01 are redundant and should not be included in the Asset Base.

Flows at CS1

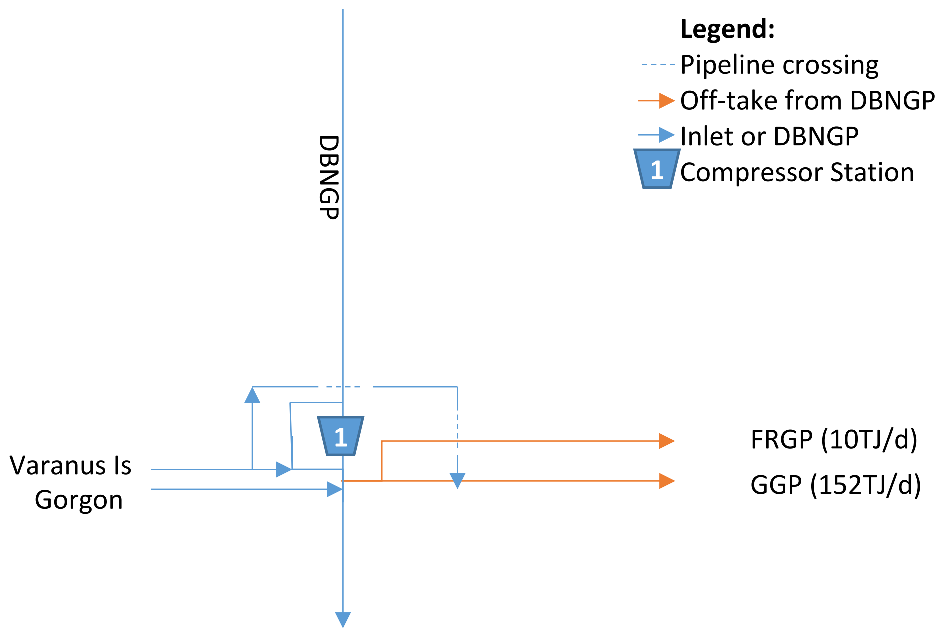
Before commencing it is worth highlighting the flows around Compressor Station 1 (Figure 1). The DBNGP typically has gas flowing south from Carnarvon Basin producers into CS1 where the gas pressure is increased to push the gas further south. The design of most compressor stations is such that one or both compressors can be operated, the gas flow bypasses one or both compressors or the gas bypasses the Compressor Station all together by going through the "Emergency Bypass" (Figure 1). Gas in the Emergency Bypass can flow in a northerly or southerly direction.

At Compressor Station 1, Varanus Island also joins the compressor station, though the exact location is unclear. In Figure 1 we have shown Varanus Island coming into the Emergency Bypass. It appears to be immediately south of CS1 based on DBP's Access Arrangement information (p.432), though the Pipeline Description has it at 136.9 pipeline kilometres (just north of CS1). Varanus Island also has its own connection directly to the GGP (shown).

Gorgon comes in immediately downstream of Compressor Station 1 also at 137.7 pipeline kilometres.

On the delivery side, both the Fortescue River Gas pipeline (FRGP) and Goldfields Gas Pipeline (GGP) outlet are at 137.2 pipeline kilometres. Note that in the image below we have shown them as one connection though we are not sure if this is technically correct.

Figure 1. Simplified Compressor Station 1 Flow Schematic



Gas flows between I1-01 and CS3

Current typical gas flows:

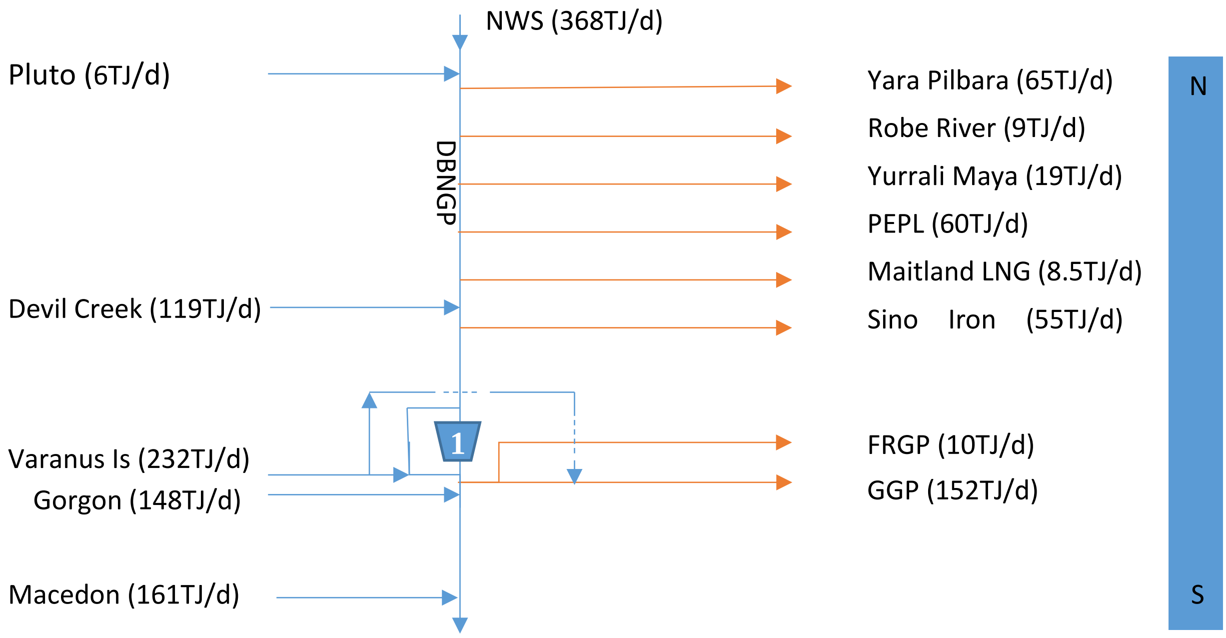
2019 (TJ/d)	Production[2]	Demand[3]
Between I1-01 and upstream of CS1 (incl NWS, Pluto and Devil Creek)	492	217
(includes North West Shelf Production)	(368)	
Around CS1 (Varanus and Gorgon)	380	161
Downstream of CS1 (All other producers)	266	761
Total*	**1139**	

[2] Total Production is based on data reported to the GBB for the relevant period from each gas production facility

[3] Demand is based on data reported to the GBB for the relevant period from loads on the GGP, FRGP and upstream of CS1 including PEPL.

Figure 2 shows the data in a diagram format. The bar on the right-hand side shows direction the gas is physically flowing in a southerly direction (blue colour).

Figure 2. Typical 2019 Gas Flows

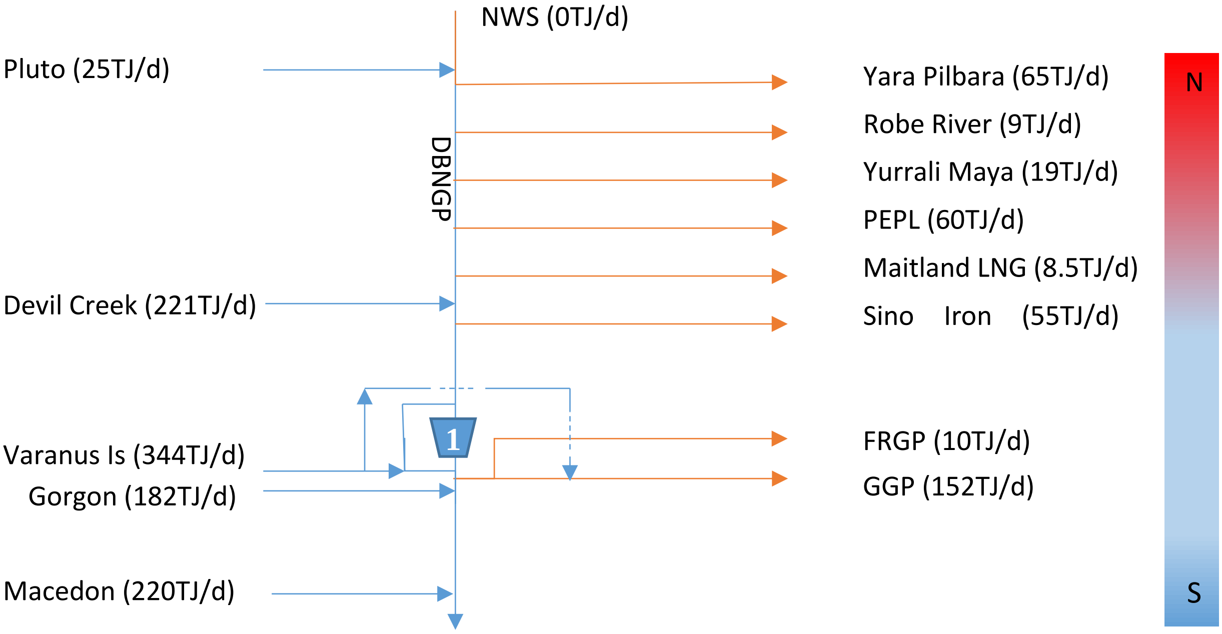


North West Shelf goes to zero flow

Now let's assume North West Shelf ceases producing any domestic gas. All other facilities produce at maximum (as we do not know who will replace the capacity (Figure 3)). The following occurs, the northern section of the pipeline reverses flow, exactly where is dependent on the balance of outflows and inflows, but assuming Devil Creek goes to nameplate capacity, then it would occur at Devil Creek. If Devil Creek did not ramp up then Varanus Island gas would flow north, presumably via the CS1 emergency bypass.

2019 (TJ/d)	Production	Demand
Between I1-01 and upstream of CS1 (incl NWS)	124	217
(includes North West Shelf Production)	-	
Around CS1	380	161
Downstream of CS1	266	761
Total	**1139**	

Figure 3. Gas flows under a North West Shelf zero (0) flow scenario



The bar on the right-hand side shows that for customers north of Devil Creek (KP = 58.66km) the gas is physically flowing in a northerly direction (red colour).

The operator of the DBNGP will be required to ensure sufficient pipeline pressure to supply all customers and the Pilbara Energy Pipeline (PEPL).

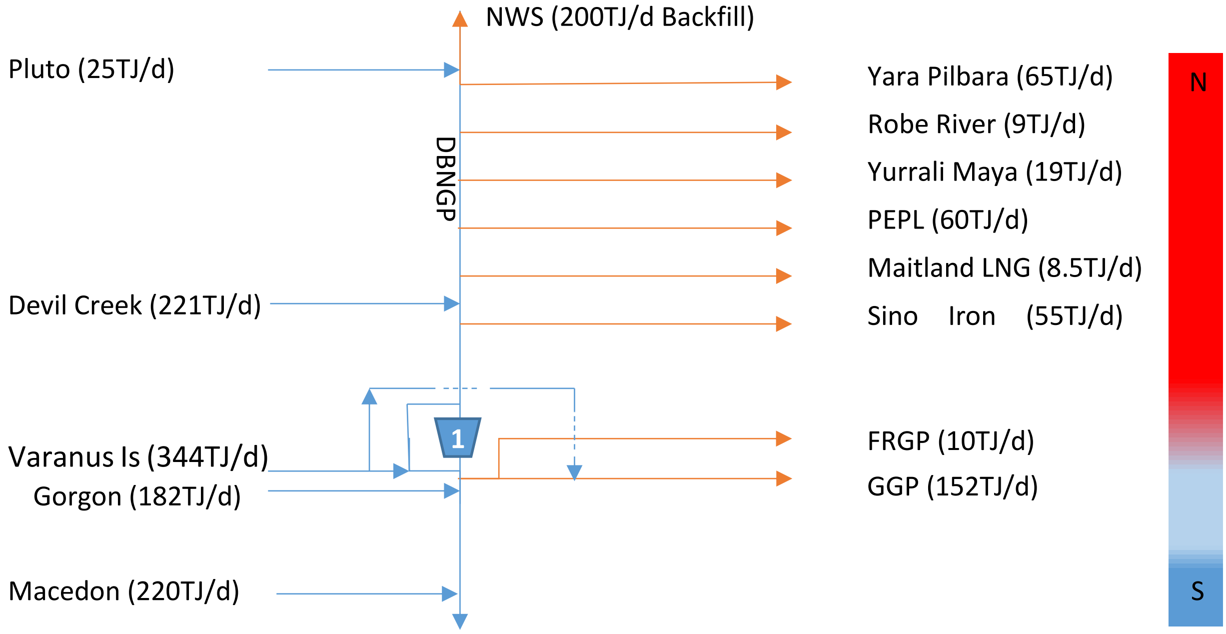
The Burrup Extension Pipeline (BEP) is a pipelined leased by DBP that connects Karratha Gas Plant to MLV7 (the point at which the PEPL meets the DBNGP). The BEP is not connected to any other customers or producers. The BEP lease will now not be required as no flow is needed through the BEP lease to deliver gas to any of the DBNGP customers.

The After Coolers at I1-01 are definitely not required as the purpose of the After Coolers is to cool the gas from North West Shelf when North West Shelf is producing at very high rates (name plate capacity or above) and no gas is being supplied from NWS.

North West Shelf becomes a gas consumer

If North West Shelf ceases production and becomes a "load" or gas consumer, that is taking domestic gas for conversion to LNG for export then, the flows change further. Let's assume NWS is now a 200TJ/d load on the domestic gas system (Figure 4)

Figure 4. Gas flows under an NWS 200TJ/d backfill scenario



Again, the bar on the right-hand side shows that all supply north of Varanus Island is a physical north flow (red colour). The balance point is now at CS1, assuming Pluto and Devil Creek ramp to maximum. If they did not, Varanus Island and potentially some Gorgon gas would likely flow north as some of Varanus Island's production will flow directly into the GGP and not all into the DBNGP.

In other words, Varanus Island becomes the swing producer, where, depending on which export pipeline is being used, gas will flow north from Varanus Island to supply customers. If production falls below NWS demand minus 216.5TJ/d (in the example, if Varanus Island delivered into the DBNGP less than 170.5TJ/d) then Gorgon gas would flow north.

Potential Impacts on the Pipeline and Shippers

Given the impacts, customers on adjoining pipelines and on the DBNGP typically require a minimum delivery pressure. Under the above scenario it is not clear that all customers will receive gas at their minimum required pressure. As a result, DBNGP may require compression facilities modifications (to piping) to push gas north to CS1 to provide sufficient gas pressures to meet all customers' requirements. However, DBP has noted in their Shipper Roundtable #10 Issues Response Paper that this is not required.

In additional, DBNGP has leased the Burrup Extension Pipeline to provide capacity from I1-01 to MLV7 (essentially the PEPL). Under the above conditions the BEP lease is not required for Shippers as:

1. All customers are connected to the DBNGP and not the BEP including Pluto. The BEP is only connected to Karratha Gas Plant and MLV7.

2. NWS is the only facility connected to the BEP lease and could use the BEP for its own needs including importing Domestic Gas for backfill

Furthermore, the After Coolers installed immediately south of Karratha Gas Plant (I1-01) were installed to cool gas coming from North West Shelf at high flow rates. The After Coolers are no longer required given there is no expectation that North West Shelf Gas will be selling or producing gas at or above its name plate capacity in the future. It is unclear if these are in the assets for the Reference Pipeline.

The impacts of the above flow scenarios demonstrate:

1. Depending on flows on a day, gas flows north of CS1 will physically flow north. Gorgon gas may also flow north
2. The capacity provided by the BEP Lease is not required
3. The After Coolers installed immediately downstream of I1-01 are not required
4. The Access Arrangement model, based upon forward haul from NWS is no longer valid
5. Compressor Station 1 may be required to provide pressure north to meet customer needs

Impacts to the Access Arrangement

The Access Arrangement is built upon a model which assumes gas flows from I1-01 to Perth (Bunbury). If NWS did take backfill gas, the pipeline section north of CS1 is not required to supply gas to Perth. As a result, customers to the north of CS1, who were previously back haul customers become "forward haul customers" and should pay for their share of the compression services at CS1 (if required) and also their share of the assets used to physically transport their gas. Customers south of CS1 who take gas from a production facility at CS1 or below are forward haul shippers from south of CS1. These shippers should not be required to pay for the compression provided by CS1 as compression appears not to be required.

Contractual Impacts

Here are some of the contractual impacts on the Reference Contracts that gasTrading considers requires review. Note that all Reference Service Contracts assume the same definition of Forward Haul:

Definitions

Back Haul means a Gas transportation service on the DBNGP where the Inlet Point is upstream of the Outlet Point

Forward Haul means a Gas transportation service on the DBNGP where the Inlet Point is downstream of the Outlet Point.

The effect being from CS1 north this means a northerly flow. From CS1 south this means a southerly flow under the scenarios above. Unless upstream was to be defined as north and downstream were to be defined as south.

P1 Service in respect of the Shipper's Capacity Service,.. , means a Forward Haul transportation service…

Part Haul means a pipelines service to provide Forward Haul on the DBNGP…

T1 Service has the meaning given in clause 3.3(a) means a Forward Haul transportation service…

Clause 3.2(c)
"Shipper acknowledges and agrees that, subject to clause 14, the P1 Service under this Contract is a Forward Haul service and cannot be:

(i) Back Haul; or
(ii) Full Haul."

Under the above definitions, assuming the definitions of forward haul and back haul are unchanged, a shipper who is located on the PEPL (for example) buying gas from a producer at Devil Creek or Varanus Island would likely be purchasing a Part Haul Service when NWS is at 0 or is a gas consumer. If they bought gas from a producer at Pluto, they would be buying a Back Haul Service. Note that the Back Haul contract has a similar clause.

Clause 3.3 Contracted Capacity

Subject to this Contract, the Shipper's Contracted Capacity for each Gas Day within a Period under this Contract:

(a) at an Inlet Point specified in the Access Request Form - is the amount for P1 Service set out (adjacent to that Inlet Point) in the Access Request Form for that Period; and
(b) at an Outlet Point specified in the Access Request Form - is the amount for P1 Service set out (adjacent to that Outlet Point) in the Access Request Form for that Period

The effect here being that a Shipper has contracted for a Forward Haul Part Haul Service when the direction of flow may actually mean the Shipper requires a Back Haul service. In an extreme example, the Shipper may have contracted for Capacity it cannot use!

Clause 6.5 Allocation of Gas at Outlet Points

Clause 6.5 (d) Gas Delivered by the Operator to an Outlet Point is deemed to be Received by the Shipper in the order specified generally or for a particular Gas Day by the Shipper, and if the Shipper fails to specify for any Gas Day in the following order:

(i) first, Gas for any available scheduled P1 Service (which shall include any available and Aggregated P1 Service);
(ii) second, Gas for any scheduled T1 Service and Aggregated T1 Service;

(iii) third, Gas for any scheduled B1 Service and Aggregated B1 Service;

The effect here being a Shipper does not know if they transported their gas under a Part Haul or a Back haul, it is dependent on the physical direction of flow. So, in an Allocation, a Shipper with a Part Haul contract may receive gas when the gas was not flowing Forward Haul. They were actually operating under a Back Haul.

Clause 8.16 Nominations at inlet points and outlet points where Shipper does not have sufficient Contracted Capacity

Subject to this clause 8, Shipper is entitled to nominate that Gas be Delivered under Shipper's P1 Service:

(a) at an inlet point or an outlet point at which Shipper does not have Contracted Capacity for P1 Services, provided that such outlet point is above CS9; and

(b) in excess of Shipper's Contracted Capacity for P1 Services at an Inlet Point or Outlet Point,

(being Aggregated P1 Service), provided that all of the following are satisfied:

(c) Aggregated P1 Service is a Forward Haul service and may not be used for Back Haul;

The effect here being the Shipper is not entitled to nominate for gas that is a Back Haul (i.e. for gas flowing north). Note that the Back Haul Contract has a similar clause.

Clause 11.2 Unavailability Notice

(a) The Operator may at any time, acting as a Reasonable and Prudent Person, give notice (an Unavailability Notice) to the Shipper that Overrun Gas is unavailable to the Shipper, or is only available to the Shipper to a limited extent, for one or more Gas Days, but only to the extent that the Shipper overrun will impact or is likely to impact on any other shipper's entitlement to its Daily Nomination for any Capacity Service including allocated Spot Capacity. The Operator must, at the same time, give an Unavailability Notice to all other shippers that are taking Overrun Gas, the taking of which, due to the location on the DBNGP at which the Overrun Gas is being taken, has an impact on the ability of the Operator to Deliver Gas to meet its obligations to shippers.

The effect here being that any Shipper on the DBNGP must stop taking Overrun gas. However, in the scenarios outlined by gasTrading, that may not be relevant where the pipeline is flowing bi-directionally, and the Notice should only be applied to those that are impacted.

Clause 14. Relocation

14.2 Assessment of Requested Relocation

(b) For the purposes of clause 14.2(a), a Requested Relocation of Contracted Capacity is not an Authorised Relocation if:

(iii) the Requested Relocation is such that the an Inlet Point at which there is Contracted Capacity under this Contract would be downstream of the an Outlet Point at which there is Contracted Capacity under this Contract and it would change the normal direction of Gas flow in the DBP

(c) For the purposes of clause 14.2(a), unless clause 14.2(b) provides that it is not an Authorised Relocation, a Requested Relocation of Contracted Capacity to a New Inlet Point is an Authorised Relocation under the Contract if:

(i) the Requested Relocation would result in the New Inlet Point being downstream of the Existing Inlet Points;

The effect here being, that if a Shipper Requested a Relocation of their Part Haul service because the DBNGP reversed flow (through no action of the Shipper as identified in the North West Shelf scenario) then the Relocation is not an Authorised Relocation. The Shipper would be acting reasonably to make Relocation request even though their Inlet and Outlets were not changing. The service is changed as the direction of gas flow has changed; one could presume "permanently".

Assuming DBP accepts the relocation then clause 14.7 applies

Clause 14.7 Charges for relocation

(a) Unless the Parties agree in writing to the contrary, no Charges payable under this Contract must will be reduced as a result of a relocation of Contracted Capacity under this clause 14, even if the relocation causes some or all Gas to be transported over a shorter distance or has the result that there is a shorter distance between the inlet point(s) and outlet point(s) at which the Shipper has Contracted Capacity, or reduces the "km" (as that term is otherwise used in the calculation of the P1 Tariff, P1 Commodity Tariff or P1 Capacity Reservation Tariff (as the case may be)), or the relocation causes a notional reversal of flow of Gas transported under this Contract for the Shipper from Forward Haul to Back Haul.

The practice by DBP is that the tariff is not changed. However, the distance travelled under the regulatory tariff model will change.

For example, a Part Haul, being a service for Forward Haul, is calculated with reference to I1-01 (0 pipeline kilometres). But the gas would not be flowing "Forward Haul" under the scenario where North West Shelf is at 0 or a consumer. The gas would be flowing in a northerly direction.

Under one definition it could be considered a Back Haul (even though the gas is flowing physically in the same direction) and the distance travelled is the distance from the Inlet to the Outlet, "upstream" (to the North) of the Inlet.

Under another definition it could be considered a Part Haul because the gas is physically flowing in the same direction as the service, even though it is flowing in a northerly direction. Here the tariff would make sense to be the distance travelled, from the Inlet to the Outlet, even though it is in a northerly direction.

Now thinking more broadly, what happens if a Shipper with an Outlet between CS1 and I1-01 was to purchase gas from a Wheatstone producer? The gas would be Back Haul to CS1 (as gas in the pipeline is physically flowing south) and then be a Part Haul from CS1 to the customers (where gas in the pipeline is physically flowing north).

This is particularly relevant under clause 17.2 of the Back Haul Contract:

Clause 17.2 Curtailment Generally:
The Operator may Curtail the provision of the Capacity Services to the Shipper from time to time to the extent the Operator as a Reasonable and Prudent Person believes it is necessary to Curtail:
(f) in circumstances where actual Forward Haul gas flow is less than the B1 Service demand across all shippers with a B1 Service.

The effect here being that Forward Haul under this clause is a northerly flow under the scenarios presented by gasTrading.

Implementation

To address the issues gasTrading has raised, the Draft Access Contracts need to be amended to reflect the changing nature of gas flows in the DBNGP. There are a number of ways this could be addressed, but these need to consider the structure of the Access Arrangement. For example, having a contractual arrangement for the purpose of calculating tariffs that presumes gas always flows "south" or "downstream" may be pragmatic, but the terms in the Transport Agreements need to allow Shippers to be confident of the Operator delivering their gas and of receiving a fair tariff for the actual costs of transporting their gas and not having other shippers subsidise gas transport.

If the concept was to ignore the physical flows and rely on a contractual interpretation (i.e. that gas flows south along the entire length of the DBNGP), then fewer clauses need changing in the Reference Contracts. Based on an initial review: the definitions of Part Haul, Back Haul and Forward Haul need to reflect the fact that downstream and upstream refer actually to north and south and clause 17.2 needs to reflect that physical flows in one direction are less than the volume of flows in the reverse direction. The challenge is then to ensure that the costs of those services reflect actual costs and some shipper are not subsidising others.

If the concept was to attempt to change the contractual arrangements such that they reflect physical flows a more thorough review is required, especially where the flow may change directions depending on the locations and volumes of gas supply and demand.

Conclusion

There has been little discussion about the changing flow dynamics on the DBNGP and these need to be considered in the next Access Arrangement as it is entirely foreseeable that the flows north of CS1 will become a northerly flow and this will impact the commercial terms under which gas is transported.

Historical Gas Flows annually

2018 (TJ/d)	Production	Demand
Between I1-01 and upstream of CS1 (incl NWS)	492	215
North West Shelf Production	372	
Around CS1	407	153
Downstream of CS1	197	699
Total*	1067	

2017 (TJ/d)	Production	Demand
Between I1-01 and upstream of CS1 (incl NWS)	463	222
North West Shelf Production	377	
Around CS1	352	155
Downstream of CS1	209	678
Total*	1055	

2016 (TJ/d)	Production	Demand
Between I1-01 and upstream of CS1 (incl NWS)	493	218
North West Shelf Production	481	
Around CS1	233	144
Downstream of CS1	229	673
Total*	1035	

2015 (TJ/d)	Production	Demand
Between I1-01 and upstream of CS1 (incl NWS)	572	197
North West Shelf Production	488	
Around CS1	243	120
Downstream of CS1	189	695
Total*	1012	