Application of the proposed Domestic Supply Obligation policy framework to the Western Australia domestic gas market

Executive Summary

The Australian government has released its draft design framework for the proposed Domestic Supply Obligation (DSO), requiring LNG projects to supply gas equivalent to 20% of their export volumes to the domestic market from 1 July 2027 (Domestic Gas Reservation Scheme Draft Design Framework released in May 2026 – herein referred to as "the framework" or "framework"). The nationwide policy will be administered by Government Ministers and enforced by the Australian Energy Regulator (AER).

This analysis reviews the framework and analyses the impact it would have on the Western Australia gas market if implemented as currently designed. Key elements of the framework include the opportunity for LNG exporters to seek Ministerial approval for an individual variation in their annual DSO volume. In the case that a variation is granted, the volume of DSO not supplied under the variation would be carried forward as a DSO obligation applied to future years of production. The framework also requires that LNG exporters must sell and deliver gas into the domestic market to acquit their obligations, which is different to an obligation to market or offer gas.

A 20% DSO applied to Western Australia results in a market with almost twice as much supply as demand in the immediate term (2028-2030).

The resulting collapse in prices to below Domestic-only producers' marginal costs would remove any incentive to invest in new domestic gas supply outside of LNG export projects.

A rigid variation structure and material infrastructure constraints that are difficult to overcome mean that the WA market could face severe LNG export restrictions under the proposed policy framework.

The policy as currently designed assigns a high level of broad Ministerial discretion over annual DSO volumes, the use of various market balancing mechanisms and export approvals. The policy is also designed around an annual cadence of year-ahead and in-year volume commitments that introduce significant and ongoing uncertainty and risk, which will deter investment in the new supply that is required to maintain a well-supplied domestic market over the long-term.

Taking the policy at face value, applying a blanket 20% obligation across all export volumes would result in a significantly oversupplied domestic market. The framework does include two avenues to manage periods of significant oversupply and improve liquidity and transparency in the domestic market: varying the DSO percentage for the following year, or enacting a 'release valve' mechanism (RVM) during a given year. While variations and the RVM are incorporated into the framework to attempt to maintain supply and demand with a 'modest oversupply', the ability to utilise these mechanisms is explicitly framed as an option of last resort. The current language in the framework outlines the expected 'high threshold' for approving variations, and the fact that the RVM is only expected to be activated in 'rare occurrences'.

Western Australia gas market

If applied to the Western Australia (WA) gas market, the proposed 20% Domestic Supply Obligation (DSO) framework would replace a reservation system that currently balances the WA domestic market with a system that would remove any incentive to invest in domestic gas supply, increase reliance on Liquified Natural Gas (LNG) export projects for domestic gas security and cause a large and sustained structural oversupply that would either require the accrual of 'domestic gas debts' that are unrecoverable, or reduce WA's LNG exports over the next decade by 40%. Several second-order effects also form feedback loops that undermine the policy's own stated objectives of security of supply, downward pressure on long-run prices, and an orderly energy transition. The key direct and indirect impacts of the proposed DSO if applied in WA include:

Direct impacts

- A significantly and structurally oversupplied market with supply being nearly double demand in the short term.
- The need for unrealistic infrastructure investment to significantly expand capacity to accept supply with no market.
- A collapse in gas prices that could force the exit of domestic-focused gas producers from the market.
- Accrued DSO 'debts' of more than 2,600 PJ, with resultant write-downs in reserves that cannot be monetised.
- The loss of up to A$142 billion in export revenue if LNG export volumes are curtailed to meet DSO requirements.

Indirect impacts

- Despite being labelled a prospective supply obligation, the protection nominally afforded to existing contracts is limited in practice.
- The policy introduces change-in-law and delivery risk into export offtake, which counterparties are likely to price through shorter durations, discounts, or procurement diversification to other suppliers outside Australia.

- The proposed breadth of Ministerial discretion will be priced as a risk premium as parameters set by annual judgment rather than transparent rules cannot be modelled with confidence.
- The cadence of annual approval cycles introduces further costs and risk , as deliverable volumes set annually by Ministerial decision precludes the ability to offer the firm long-dated volumes required by the market.

A 20% DSO applied to the WA market would result in an oversupplied market just considering DSO volumes alone. The addition of domestic-only production results in a market with almost twice as much supply as demand in the immediate term (2028-2030). In order to balance the WA domestic gas market, the Carnarvon Basin LNG exporters would need a collective DSO variation and Release Valve Mechanism (RVM) allowance of ~290 PJ in 2028, and continuous annual variations of more than 200 PJ/a through to 2035. By 2040, the accumulated carried-forward DSO 'debt' volume would reach 2,600 PJ (~620% of domestic demand in 2040).

This is a debt that is unlikely to be fully repaid – by the time gas supplies fall below domestic gas demand in 2043, LNG exporters would have accumulated more than 2,675 PJ of DSO variation and RVM 'debt'. This will sit on investors' balance sheets, reducing investment appetite and incentive, and could lead to large amounts of stranded reserves that will never be produced from these fields.

While variations and the RVM are incorporated into the framework to attempt to maintain supply and demand with a 'modest oversupply', the ability to utilise these mechanisms is explicitly framed as an option of last resort. The current language in the framework outlines the expected 'high threshold' for approving variations, and the fact that the RVM is only expected to be activated in 'rare occurrences'. The framework vests wide discretion in Ministers over the base DSO percentage, variation approvals, activation and direction of the RVM, and the determination of whether the market is 'adequately supplied' before export approval (the targeted 'modest oversupply' is itself undefined). Discretion of this breadth is a cost independent of how it is exercised, because parameters set by annual judgment rather than transparent rules cannot be modelled with confidence and are priced as a risk premium.

As a result of the structural oversupply of the market, prices could be driven below the marginal costs of Domestic-only producers. Prices below such costs would halt exploration and appraisal, render pre-FID projects uninvestable, reduce sustaining capital, and ultimately force Domestic-only producers to exit the market. WA domestic supply would therefore become concentrated on a handful of Carnarvon Basin exporters, reducing competitive tension and supply diversity. The loss of nearer Perth Basin supply would, over the long run, raise delivered prices into the southwest / Perth region given the transport distance from the Carnarvon Basin.

Significantly, despite being labelled a prospective supply obligation, the protection nominally afforded to existing contracts is limited in practice. A variation to honour a pre-existing LNG offtake agreement requires demonstrating that there is 'no viable alternative' to fulfilling the contract commitments, including sourcing spot LNG. The nature of the spot market, including its size, liquidity and diversity, means that spot cargoes are effectively always available at a price and thus this test is difficult to satisfy.

The alternative, when considering the policy language as it stands, is the extreme outcome of curtailment of LNG exports such that domestic market sales equate to 20% of actual exported LNG. Forcing the option of curtailment of LNG output to meet the regulatory requirements of domestic supply (in a market that currently supplies sufficient domestic gas to meet demand) would mean that in 2028 WA's LNG exports would fall from 45 mmtpa under the current State-based Domestic Gas Policy (DGP) system to less than 20 mmtpa under the announced DSO framework. By 2031, LNG exports would have to fall to just 16 mmtpa and would thereafter never return above 32 mmtpa. In total, this would result in the loss of approximately A$142 billion in export revenue between 2027 and 2040, and would likely negatively impact employment, economic activity, Government income from taxes, royalties, and broader investment across the sector in WA. It would also damage Australia's position as the supplier-of-choice to our Asian trading partners, could put our own liquid fuel security at serious risk, and reduce Australia's ability to attract future foreign investment.

LNG volumes that can still be exported would also suffer from the effects of the DSO policy. The policy would introduce change-in-law and delivery risk into export offtake, which counterparties are likely to price through shorter durations, discounts, or procurement diversification to other suppliers outside of Australia. A federal scheme that overrides, or is perceived to override, ratified State Agreements signals that even legislated, project-specific certainty is not durable. By making LNG offtake contracts harder to sign, the DSO risks undermining the new supply on which domestic balance depends.

The annual approval cycle introduces further costs and risk – a supplier whose deliverable volume is set annually by Ministerial decision cannot readily offer firm long-dated volumes, pushing the market toward short-term and spot contracting, reducing the bankability of demand-side investment and increasing price volatility.

In WA, the proposed DSO policy framework as the discretionary language reads is unworkable – it would replace an existing regulatory structure that is currently forecast to maintain a balanced domestic gas market in the State through the late-2040s (assuming Browse-to-NWS is approved) with one that would provide the choice of structurally oversupplying the market and crowding-out Domestic-only producers, or reducing WA's LNG export volumes by 40%.

For Wood Mackenzie's base case LNG export forecast, the actual DSO that would balance the WA domestic market over the period 2027 to 2040 would average 11% of total LNG exports, a level that would avoid the issues associated with curtailed exports, infrastructure constraints, accumulated domestic gas 'debts' and domestic market crowding. This is much more closely aligned to the existing WA DGP commitment structure and well below the proposed 20% outlined in the draft DSO policy framework, making the application of the DSO policy to WA unnecessary.

Introduction

The Australian government has released its draft design framework for the proposed Domestic Supply Obligation (DSO), requiring LNG projects to supply gas equivalent to 20% of their export volumes to the domestic market from July 2027 (Domestic Gas Reservation Scheme Draft Design Framework released in May 2026 – herein referred to as "the framework" or "framework"). The policy aims to consolidate a fragmented set of existing east coast gas regulations into a single, definitive framework.

The proposed DSO policy targets Australia's LNG exporters and mandates that from 1 July 2027 gas equivalent to 20% of LNG exports is supplied to the local domestic market. The nationwide policy will be administered by Government Ministers and enforced by the Australian Energy Regulator (AER).

Whilst the specific details of the proposed policy and its implementation remain uncertain, consultation is currently underway and inputs are being sought from industry, the public and other stakeholders.

The objective of this study is to:

- Identify the possible volumes of gas that could be supplied under a 20% DSO with and without strict variation approvals processes.
- Analyse the direct impacts on the West Australian domestic gas market, including the impact on overall supply versus domestic gas demand, supply from non-LNG exporters, gas market pricing and permitted LNG exports.
- Analyse the second-order impacts on the industry, including changes to price signals, investment returns, sovereign risk and investment in future new gas supply.

Key elements of the proposed Domestic Supply Obligation framework

Key details of the framework include:

Timing

The DSO would come into effect from 1 July 2027 and will apply annually on a calendar year basis, or a financial year basis, subject to consultation. This analysis assumes application on a calendar year basis, with 2027 pro-rata.

DSO volume

The DSO calculation will be calculated as: *DSO = 20% x LNG Exports*, calculated based on the thermal energy content of the volume of LNG exported (i.e. net of liquefaction losses).

Application

It remains unclear whether the DSO applies at the project level or to each individual Joint Venture (JV) participant – this distinction could have material consequences for Queensland and Northern Territory exporters and has not been addressed in the draft policy framework. The analysis presented in this report is based on an application at the project level, and not at the JV equity or corporate level.

Ability to vary DSO volume

LNG exporters will have the opportunity to seek Ministerial approval for an individual variation in their annual DSO (from the 2027 regulatory period onwards) to account for pre-existing LNG contracts signed on or before 22 December 2025, or other relevant matters such as existing regulatory schemes or infrastructure constraints. Volumes committed to export under new or extended contracts executed after 22 December 2025 would not be considered acceptable reasons for not meeting a DSO.

In the case that a variation is granted, the volume of DSO not supplied under the variation would be carried forward as a DSO obligation applied to future years of production. This is effectively a DSO debt that will need to be repaid later, and would sit on producers' balance sheets as a liability. LNG exporters that exceed their obligation in a given year may apply to supply a reduced volume in subsequent years, though LNG exporters will be required to demonstrate that the market is adequately supplied before export approval is granted – a provision that comes with considerable administrative burden and creates operational uncertainty for project participants.

Beyond prospectivity considerations, DSOs can only be varied due to unforeseen and unavoidable circumstances, such as unplanned outages with existing infrastructure.

Existing contracts are not protected

LNG exporters seeking a variation to their DSO to protect existing LNG export contracts must demonstrate to Ministers that there is no viable alternative to meeting their DSOs without a variation, having regard to a range of factors. These include meeting their existing LNG contract volumes via purchase and supply of spot LNG cargos to their LNG customers. The nature of the spot market is that cargos are always available for purchase at a price, meaning it would be near impossible to obtain a variation in DSO on this basis.

Obligation to sell, and managing supply vs. demand

LNG exporters must sell and deliver gas into the domestic market to acquit their obligations under the framework. This is different to an obligation to market or offer gas to the domestic market – this obligation to sell effectively means that, without an approved variation from the Government, an LNG exporter may only be permitted to export five times their domestic market sales in a given year.

Taking the policy at face value, applying a blanket 20% obligation across all export volumes would result in a significantly oversupplied domestic market. The framework does include two avenues to manage periods of significant oversupply and improve liquidity and transparency in the domestic market: varying the DSO percentage for the following year, or enacting a 'release valve' mechanism (RVM) during a given year.

As with for variations, any DSO volumes that are exported through the RVM will be accrued into subsequent periods, adding to the DSO 'debt' being carried by the LNG exporters. The framework highlights that these volumes would be called on to support resilience of the (domestic) market during any anticipated supply tightness or shortfall, meaning that during such a period an LNG exporter may not be permitted to export at their usual level and would effectively be directed by Ministers where, when and how to commercialise these volumes.

Western Australia

Western Australia (WA) operates as a self-contained gas market. It has no pipeline link to eastern Australia and must balance its own supply and demand. Domestic gas supply comes from two sources, both of which respond to different commercial drivers – Domestic-only producers, and LNG exporters with Domestic Gas Policy (DGP) commitments. At face value, the ability to implement a 20% DSO in WA would be limited by domestic gas demand. After accounting for Domestic-only production, WA exports almost ten times its domestic gas demand per year. Under the current WA domestic gas reservation policy, producers must reserve gas equivalent to 15% of LNG exports. However, they are not required to deliver this volume each year, as supply depends on demand. Therefore, the fact that LNG exports are, on average, ten times higher than domestic gas sales does not indicate that producers are failing to meet their obligations under the State policy. The current framework for a federal DSO would require a doubling of LNG exporter domestic gas supplies, without any increase in domestic gas demand.

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Domestic-only producers

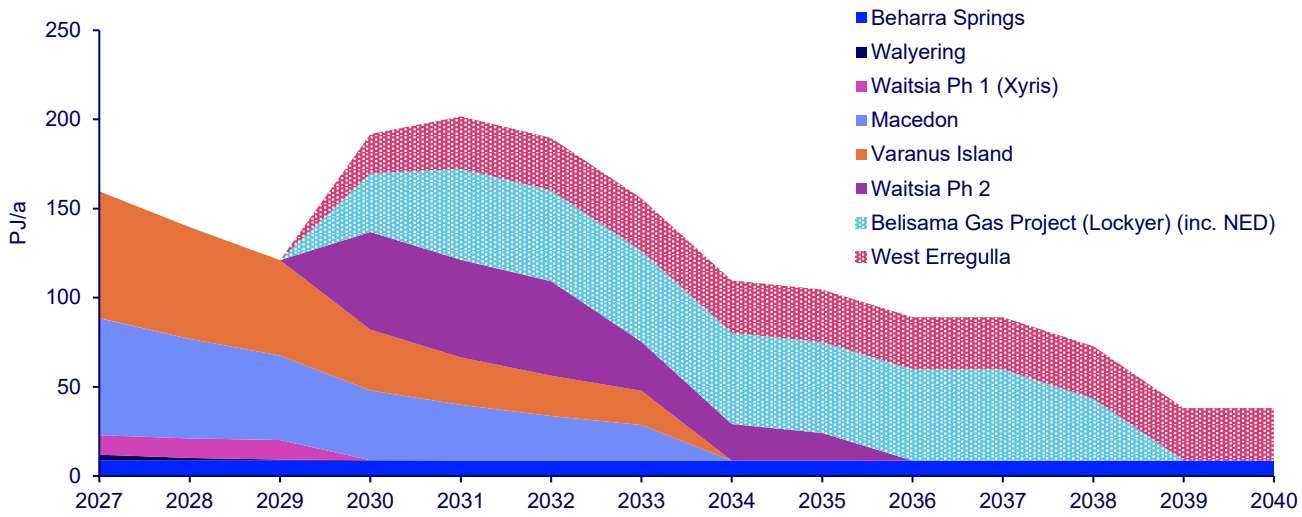
Domestic-only producers solely market volumes into the WA domestic market, from projects in both the Carnarvon Basin (offshore) and the Perth Basin (onshore). Domestic-only production in the Carnarvon Basin is anchored by the Varanus Island hub, which sources gas from John Brookes and nearby fields. The Macedon project near Onslow adds further dedicated domestic volumes.

The onshore Perth Basin is currently a more active frontier, with both existing production and planned future projects that would add material supply to the domestic market. Existing production is sourced from the Beharra Springs development, Walyering and Phase 1 of the Waitsia development (also known as Xyris). Waitsia Phase 2 is a dedicated domestic gas project, but was granted approvals to export up to 7.5 mmt of LNG via the North West Shelf facility, before redirecting all produced volumes to the domestic market after 2029.

Total domestic-only production in Western Australia is approximately 175 PJ/a currently, though by 2034 this falls to approximately 110 PJ/a as Macedon and Varanus Island cease production. This production comes from five existing projects, and two pre-FID projects in the Perth Basin (Belisama and West Erregulla).

Domestic-only production provides an important contribution to the WA domestic market, with Perth Basin supply located proximate to the largest region of demand in the State (Perth region). Development of the Perth Basin has resulted in direct capital investment totalling A$2.8 billion to date, with more than A$2.4 billion in capital investment expected to occur between now and 2050 as further fields are developed to provide domestic gas where it is most needed in the state. Perth Basin production is material to WA's domestic gas market and is forecast to provide as much as 30% of WA's total gas demand in 2030. This improves competitive tension in the market whilst also contributing economic value, employment and investment in the region between Perth and Geraldton.

Figure 1 – WA Domestic-only forecast gas production



Source: Wood Mackenzie Lens

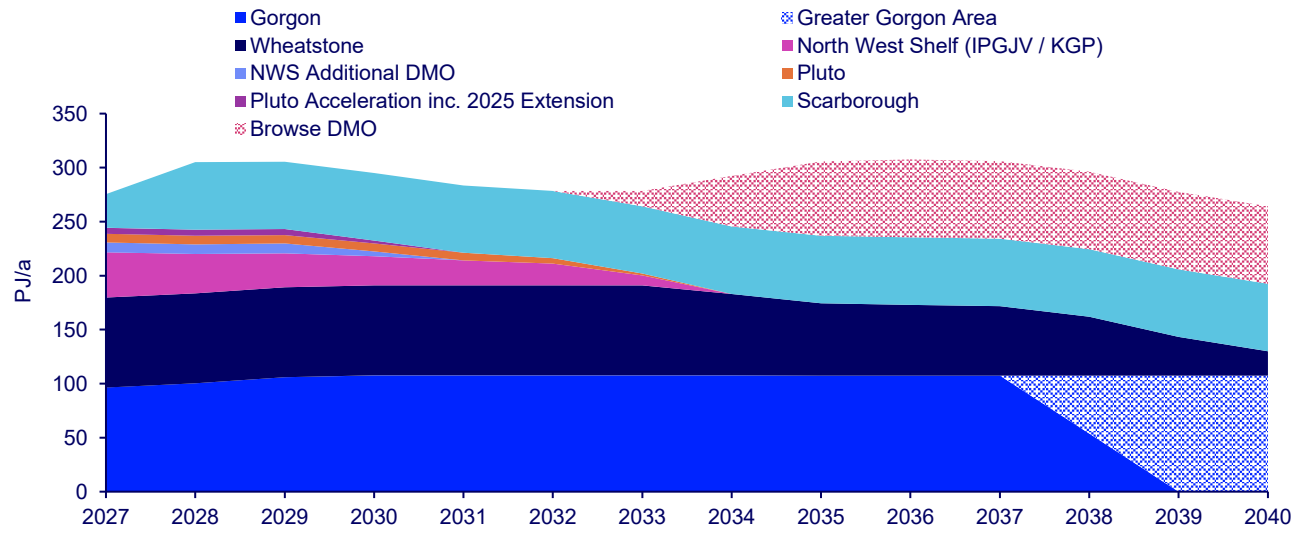
LNG export with DGP commitments

Since 2006, WA LNG projects have been expected to reserve the equivalent of 15% of their gas reserves used for LNG production for the domestic market, plus build the supporting infrastructure and market the gas in good faith. This is governed by Domestic Gas Policy commitments and currently operates through eight individually negotiated project agreements rather than one uniform rule. These project agreements outline the long-term expected domestic gas reservation volumes over the life of the project, providing certainty prior to taking FID on these projects. This element is important, as in contrast with the annual, highly discretionary Ministerial approvals proposed by the DSO framework, the current WA domestic gas policy agreements are long-term, are well understood prior to FID, and allow the necessary flexibility such that the market is not structurally over or under supplied year to year. Details of these agreements are provided in Appendix A. The suppliers are the large Carnarvon Basin LNG projects: North West Shelf (Karratha Gas Plant), Pluto, Gorgon (Barrow Island) and Wheatstone (Onslow), each running a dedicated domestic gas plant alongside their export trains.

WA's existing domestic gas reservation policy

A detailed description of the existing WA domestic gas reservation policy is provided in Appendix A. The scheme has broadly operated well since its introduction, and the WA market retains the lowest price domestic gas in Australia as a result. Supply from seven of the eight DGP commitment agreements totals approximately 300 PJ/a, summarised in Figure 2 below (Waitsia Phase 2 is excluded as it is a different form of agreement) based on Wood Mackenzie's understanding of existing agreements and expected average supply volumes year-to-year. This includes the assumption that future development of the Greater Gorgon Area and Browse-to-NWS would be subject to a similar DGP commitment as existing projects.

Figure 2 – Existing DGP commitment volumes by agreement (Western Australia)



Source: Wood Mackenzie

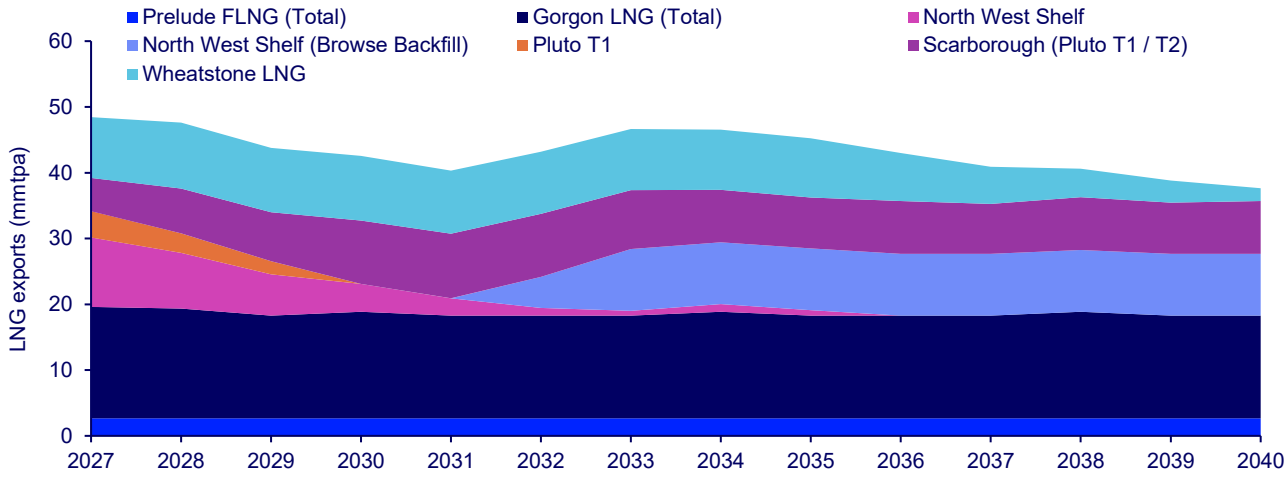
Effect of a 20% DSO on Western Australia domestic gas volumes

LNG export volumes

Western Australia is forecast to export between 40 and 50 million tonnes per annum (mmtpa) of LNG over the period to 2040. This is predicated on continued infield and nearfield development drilling (particularly within the Greater Gorgon Area) and new developments to sustain LNG output (particularly for North West Shelf and Wheatstone) as existing upstream gas production declines over time. Forecast new upstream developments include the Browse project as backfill to North West Shelf, and the potential Clio-Acme development as backfill to Wheatstone.

Wood Mackenzie's base case outlook for Western Australia LNG exports includes the Browse development, with first gas in 2033, but not the Clio-Acme development as the current development plan is not yet clear.

Figure 3 – Forecast LNG export volumes (Western Australia)



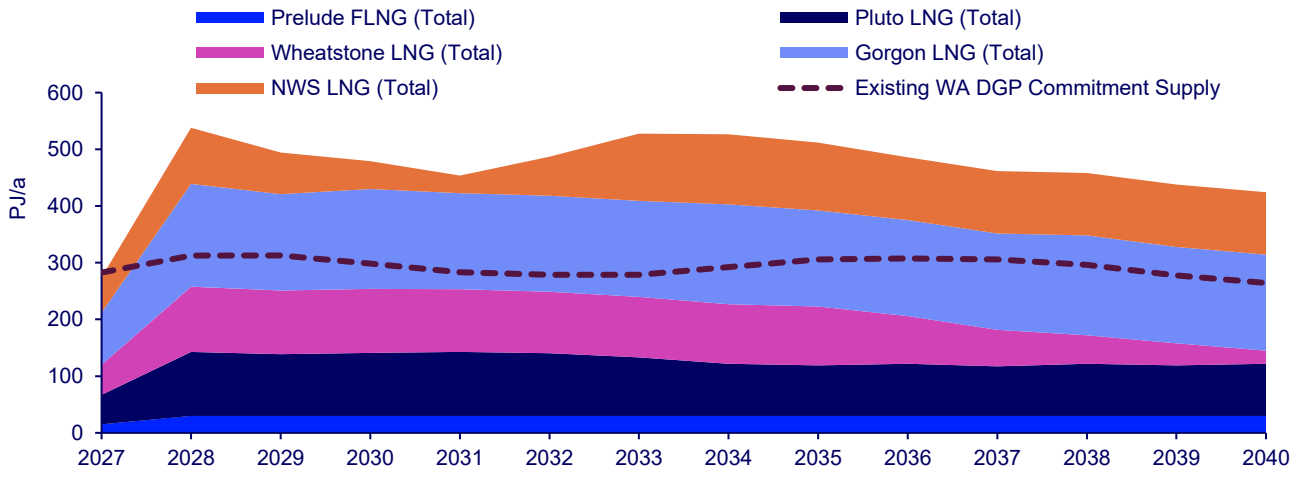
Source: Wood Mackenzie Lens

Unconstrained Domestic Supply Obligation (Baseline DSO)

Based on the calculation methodology outlined in the framework, the nominal DSO volumes in the WA market are outlined below. This is calculated on an 'unconstrained' basis – i.e. assuming no DSO variations are applied for or granted. The analysis methodology assumes that existing WA State LNG export DGP commitments are replaced with new DSOs in line with the released policy framework. If the WA DGP commitments, which are reservations based on long-term output and reserves, are retained and are credited towards the new 20% DSO, which is based on annual LNG output, the result would be a similar (but not necessarily exactly the same) outcome as replacing the existing WA State commitments with a wholly new 20% DSO. Because of the complex nature of the integration between the two regimes, and uncertainties around how this would be implemented in practice, we have modeled the more onerous obligation (the 20% DSO).

In 2028, the total DSO volume would be more than 530 PJ (for context, 2028 total WA domestic demand is forecast at approximately 387 PJ).

Figure 4 – Unconstrained DSO volumes (Western Australia)



Note: The DSO would be effective from 1 July 2027 – the DSO volumes in 2027 have been calculated on a pro-rata basis for calendar year 2027 (50% of full-year obligation).

Source: Wood Mackenzie

Overall Western Australia supply and demand

Capacity constraints in the WA system limit the ability to meet proposed 20% DSO volumes. However, a far more material issue is that WA domestic gas demand is not sufficient to absorb such an increase in supply even if it were physically deliverable. A 20% DSO applied to the WA market would result in an oversupplied market just considering DSO volumes alone. The addition of domestic-only production results in a market with almost twice as much supply as demand in the immediate term.

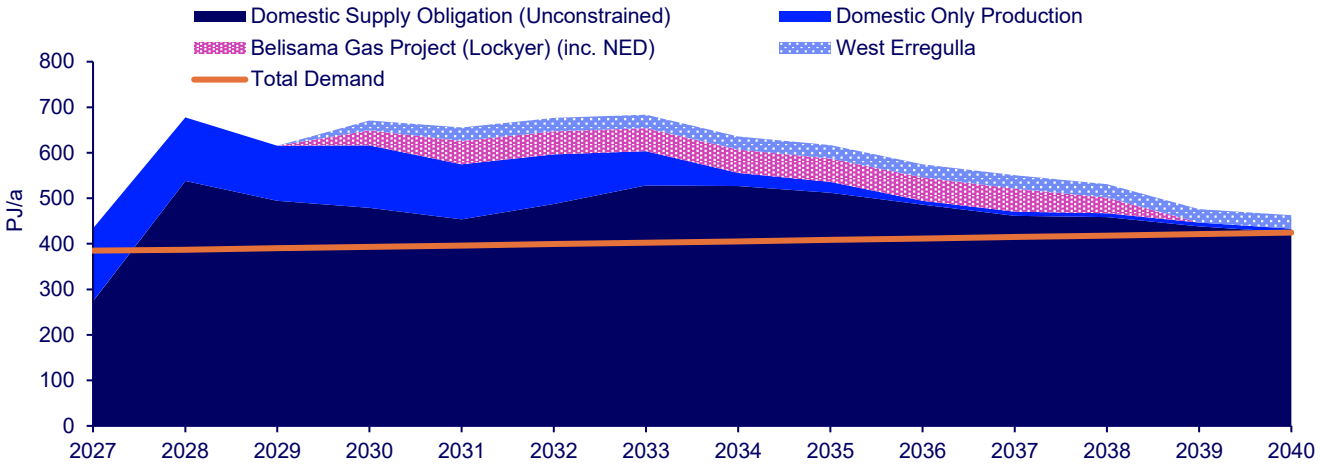
Domestic gas market demand

Overall domestic gas market demand in WA is expected to grow modestly through to 2040. Increased industrial demand from the Perdaman Urea project and increased diesel-displacement in the Pilbara will offset declining demand in the Alumina and Gas-Powered-Generation sectors. Overall domestic gas demand in WA is forecast to be ~385 PJ in 2027, reaching and maintaining ~420 PJ/a from 2038 through to the 2040s.

Supply-Demand balance – Baseline DSO

Baseline DSO volumes, combined with Domestic-only production from existing and Pre-FID projects, would result in a structurally oversupplied market with up to 300 PJ/a of gas supply not having a buyer.

Figure 5 – WA Domestic Gas Market supply-demand balance



Note: The DSO would be effective from 1 July 2027 – the DSO volumes in 2027 have been calculated on a pro-rata basis for calendar year 2027 (50% of full-year obligation).

Source: Wood Mackenzie

DSO Variations and Release Valve Mechanism (RVM)

The framework considers two avenues to manage periods of significant oversupply and improve liquidity and transparency in the domestic market:

- Year-ahead: the Ministers may vary the DSO following application by LNG exporters to reflect the forthcoming year's expected demand forecasts in line with the domestic market's expected demand for the forthcoming year plus a buffer. The framework also notes that *'any such variation would face a high assessment threshold'*.
- In-year: A Ministerial approval mechanism designed to facilitate exports when the domestic market cannot absorb DSO volumes, referred to as the 'release valve' mechanism. The framework specifically outlines that it expects the activation of the RVM to be *'rare occasions'*.

In both cases, any DSO volumes not supplied due to either a reduction in the DSO percentage below 20% or exported under the RVM will be accrued into subsequent periods, adding to the DSO 'debt' being carried by the LNG exporters. To limit this accrual, and to ensure that LNG exporters do not 'take advantage' of the RVM to reduce their DSO volumes over the long term, the ability to export excess gas that cannot be sold in the domestic market is limited to a nominal 30% of an individual exporter's DSO.

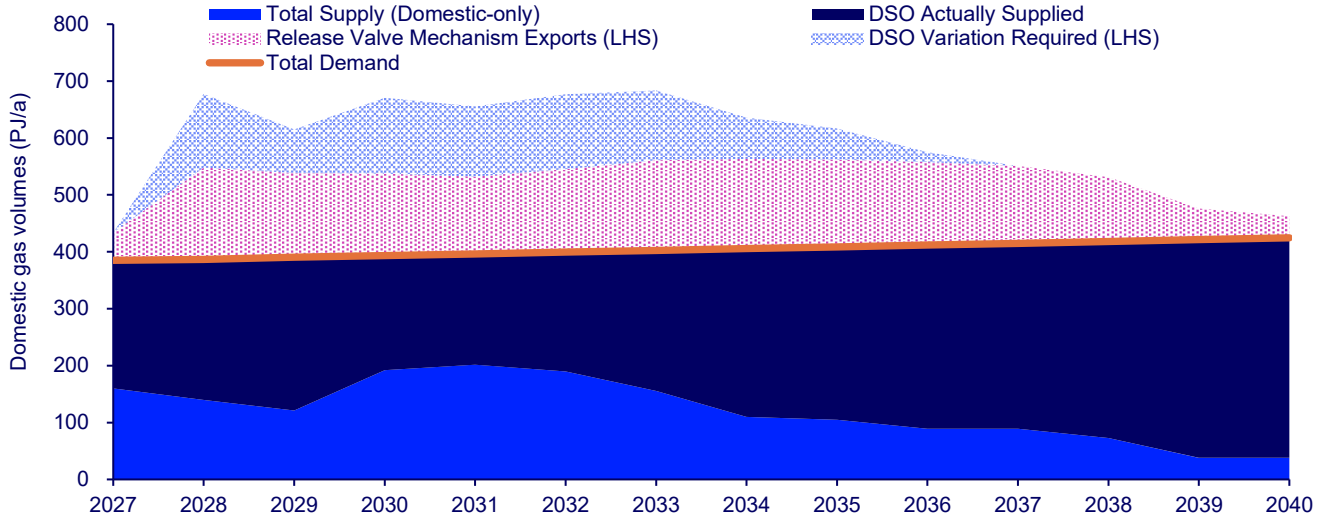
Outlined in Figure 6 below is an analysis of the WA domestic gas market with the RVM applied, following the structure proposed in the framework. The analysis assumes that attempts to balance the market first consider RVM volumes, and then variations to the baseline DSO. Similarly, carried-forward RVM volumes are 'repaid' first when the market is undersupplied. In reality the order in which these are applied does not matter to the overall outcome.

The findings of this analysis include:

- Rather than being a 'rare occurrence', the RVM would be required every year from 2027 to 2042 inclusive.

- With RVM volumes limited to 30% of total DSO, in addition to the annual activation of the mechanism, WA LNG exporters will still need variations to their DSOs to avoid structural oversupply of the market. DSO variations would be required in addition to the RVM every year from 2028 to 2037 inclusive.
- The market is structurally oversupplied every year until 2043, meaning both the RVM and DSO variation debts continue to accrue, reaching a peak of 2,675 PJ in 2042. This oversupply occurs regardless of whether Domestic-only Pre-FID projects proceed (the amount of oversupply changes, but remains structurally more than demand).
- The average annual RVM and DSO variation required to balance the market is 187 PJ/a between 2027 and 2040.

Figure 6 – WA Domestic Gas Market supply-demand balance



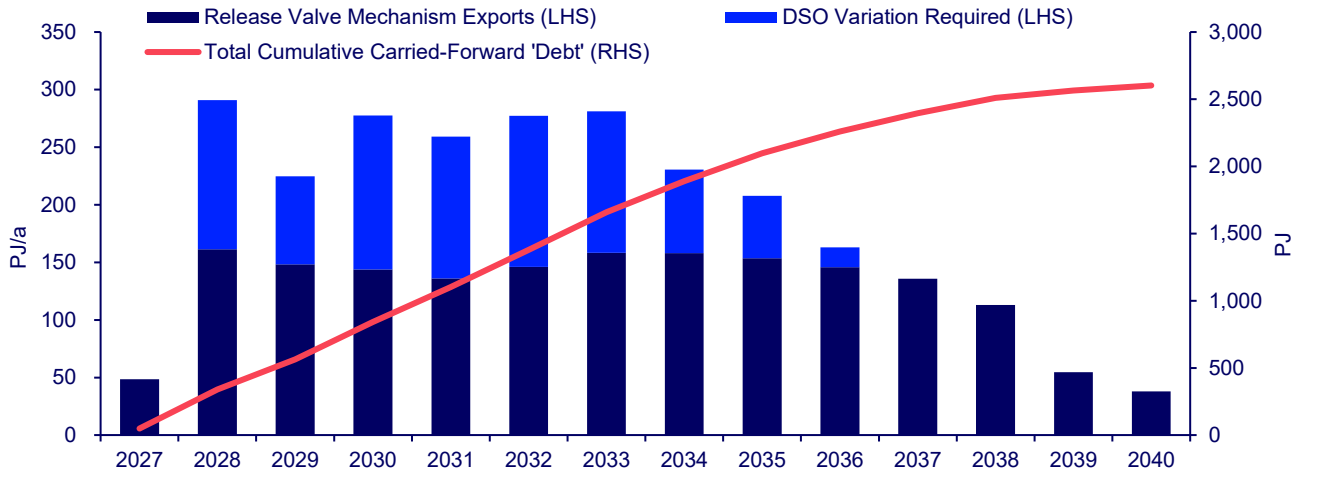
Note: The DSO would be effective from 1 July 2027 – the DSO volumes in 2027 have been calculated on a pro-rata basis for calendar year 2027 (50% of full-year obligation).

Source: Wood Mackenzie

Annual and cumulative DSO Variations / RVM

In order to balance the WA domestic gas market to actual demand, the Carnarvon Basin LNG exporters would need a collective DSO variation and RVM volume of ~290 PJ in 2028, and continuous annual variations of more than 200 PJ/a through to 2035. By 2042, the accumulated carried-forward DSO 'debt' volume would reach 2,675 PJ – a volume sufficient by itself to supply the WA domestic gas market at current demand for more than six years. As this gas cannot be exported under the DSO policy, these are reserves that would ultimately be stranded (i.e. left in the ground), resulting in the write-down of gas reserves potentially worth more than A$18.5 billion[1].

Figure 7 – Annual and cumulative DSO / RVM variations required to balance WA market



Note: The DSO would be effective from 1 July 2027 – the DSO volumes in 2027 have been calculated on a pro-rata basis for calendar year 2027 (50% of full-year obligation).

Source: Wood Mackenzie

[1] *Based on an average gas value of A$7 / GJ in the WA domestic market.*

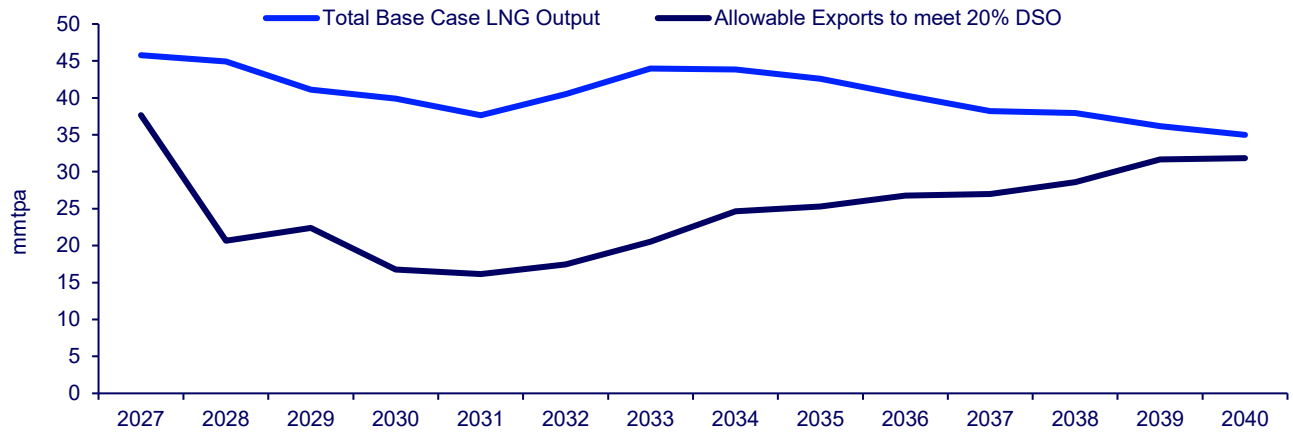
The actual DSO that would balance the WA domestic market over the period 2027 to 2040 would average 11% of total LNG exports. This is much more closely aligned with the existing WA DGP commitments agreed with the individual projects in WA and is significantly lower than the proposed 20% under the framework.

LNG export curtailment

If, as outlined in the framework, both DSO variations and RVM activations are expected to be 'rare occurrences' and subject to 'high thresholds' for approval, the only other way to balance the WA market under the proposed DSO policy is to curtail LNG exports to a point where the 20% DSO supplies enough domestic gas to balance the WA market plus a 'small surplus'. In order to achieve this, WA LNG exports would need to be reduced from the current forecast of ~40 to 45 mmtpa in the late 2020s and early 2030s, to as low as 16 mmtpa over the same period.

This would result in the cumulative loss of 226 million tonnes of LNG exports from WA between 2027 and 2040, equivalent to 40% of currently forecast LNG export volumes. This could cost the WA economy approximately A$142 billion in export revenue over that period.[2]

Figure 8 – Allowable LNG exports under existing and proposed DSO framework with no variations / RVM approvals

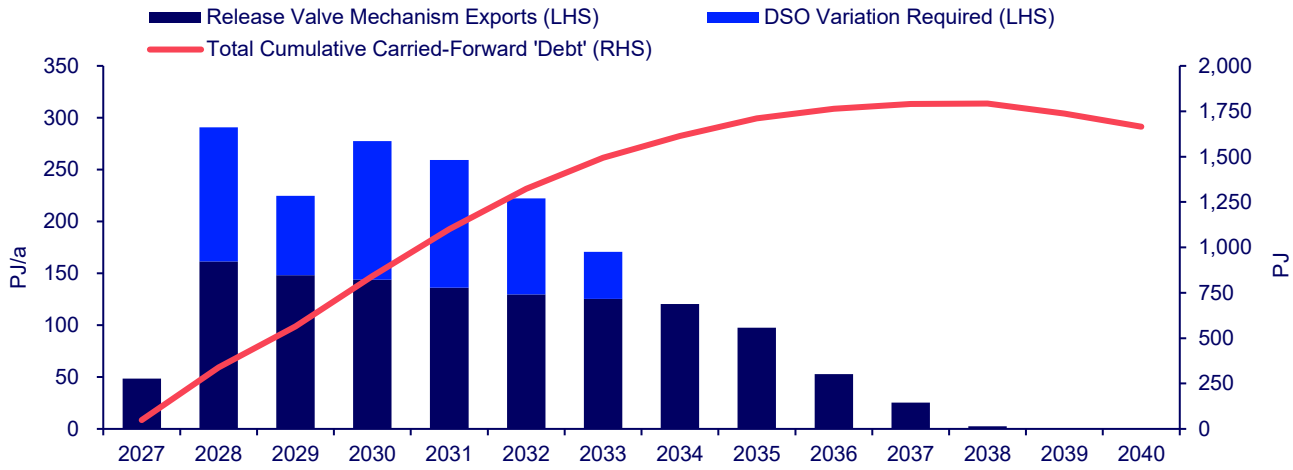


Source: Wood Mackenzie

Scenario analysis – Browse-to-NWS does not proceed

It is important to understand the case where the Browse-to-NWS project does not proceed, with the associated loss of domestic gas supply. Wood Mackenzie's base case LNG export forecast assumes Browse reaches first gas in 2032. Therefore, there is no change to the immediate structural oversupply in the domestic market from 2027 to 2032. Over the period to 2040, the DSO remains equally unworkable in the WA market. The market remains structurally oversupplied through to 2038, and LNG exporters still accrue a cumulative variation / RVM 'debt' of 1,800 PJ at this point.

Figure 9 – Annual and cumulative DSO / RSV variations required to balance WA market – No Browse scenario



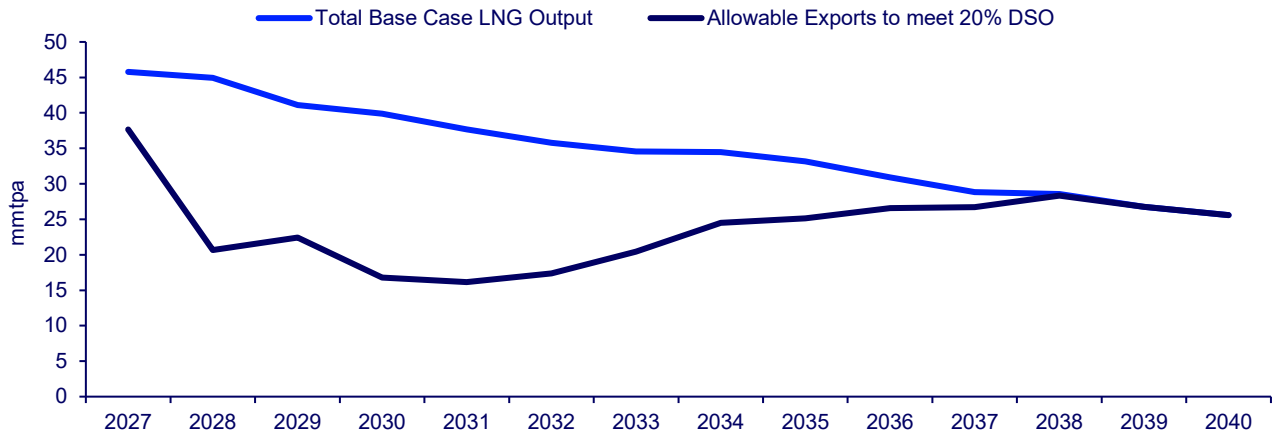
Note: The DSO would be effective from 1 July 2027 – the DSO volumes in 2027 have been calculated on a pro-rata basis for calendar year 2027 (50% of full-year obligation).

Source: Wood Mackenzie

[2] *Calculation based on FOB price equivalent of 12.5% Brent at US$70/bbl and energy content of 51.9 mmBtu per tonne of LNG.*

Similar to the base case, if it is assumed that both DSO variations and RVM activations are expected to be 'rare occurrences' and subject to 'high thresholds' for approval, the only other way to balance the WA market under the proposed DSO policy is to curtail LNG exports to a point where the 20% DSO supplies enough domestic gas to balance the WA market plus a 'small surplus'. In order to achieve this in a scenario where Browse does not proceed, WA LNG exports would still need to be reduced from the current forecast of ~40 to 45 mmtpa in the late 2020s and early 2030s, to as low as 16 mmtpa over the same period, as Browse does not enter the market in either scenario until 2032.

Figure 10 – No Browse scenario – allowable LNG exports under existing and proposed DSO framework with no variations / RVM approvals



Source: Wood Mackenzie

Constrained Domestic Supply Obligation Volumes

The unconstrained DSO volumes outlined above are what the current framework considers as the base level of DSO, to which variations would then be applied. Whilst not physically realistic, they are important to consider in the context of the announced policy given the high thresholds expected to be applied to variation approvals.

In reality, there are a number of constraints that currently exist that would prevent this total volume from being supplied to the domestic market in the immediate term, and would therefore need either DSO volume variations, or curtailed LNG exports. These include:

- Physical connection to the domestic market
- Domestic gas processing capacities
- Transport capacities

The WA market is constrained by all three of the above elements.

Physical connection

Prelude FLNG is a Floating LNG project. LNG is processed and exported offshore via a floating liquefaction facility approximately 475km offshore Broome, with no connections to land. As such, there is no physical connection that would allow domestic gas to be supplied to the WA market.

Under the DSO policy as currently written, Prelude would be required to direct 20% of their LNG export volumes to the domestic market. Two options appear to exist to achieve this:

- LNG export of gas equivalent to 20% of exports from Prelude and import into Australia.
- Purchasing gas equivalent to 20% of exports from other producers (either LNG or Domestic-only producers) to supply to the domestic market. The framework requires that these volumes must come from incremental (new) supply, meaning that Prelude would need to underwrite an expansion or development of approximately 30 PJ/a by 2028 (equivalent to the entire West Erregulla project).

Importing LNG from Prelude to meet the baseline DSO would equate to approximately 0.5 mmtpa of LNG supplied into Australia (30 PJ/a). It is unclear whether the DSO volume would include or exclude the liquefaction losses (i.e. calculated based on feed-gas into Prelude for domestic supply, or landed LNG into the regasification terminal). If calculated on landed LNG, this would effectively add an additional 8% to the DSO volume, as the feed-gas used to produce the domestic LNG is gas that would otherwise have been used for export.

Importing Prelude LNG volumes into Australia would require the development of import terminal infrastructure. No such infrastructure is operational in Australia, and none are planned in WA. Imported LNG volumes for use as domestic gas would also be the highest cost supply in the WA market due to the cost of liquefying, shipping and regasifying the volumes, meaning that it would be unlikely to find any buyers in an oversupplied market. This means that purchasing and reselling incremental new supply from other producers is the only current option to meet Prelude's DSO volume obligations.

Domestic gas processing capacity

Each LNG export project (excluding Prelude) has developed domestic gas processing trains alongside their export facilities. These processing plants treat, compress and supply gas to the WA domestic market under their existing WA DGP commitments. In total, these plants allow the injection of up to 1,435 TJ/d into the WA domestic pipeline network (at nameplate capacities). In comparison, a 20% DSO would require supply of approximately 1,474 TJ/d to the WA domestic market if exporting at current levels (~45 mmtpa). Whilst this seems relatively aligned at the highest level, at the individual project level the imbalances become material.

Table 1 – Domestic gas plant nameplate capacities

Project	20% DSO Volume (2028)	Domestic Gas Processing Plant Nameplate Capacity	Notes
Prelude	82 TJ/d	-	Constrained by market access
North West Shelf (KGP)	271 TJ/d	630 TJ/d	The KGP Interconnect allows the processing of Pluto T1 domestic gas at the NWS plant.
Pluto Train 1	151 TJ/d	25 TJ/d (pipeline) 25 TJ/d (trucking)	Additional Pluto T1 gas could be processed at NWS, but only until such time as Browse is developed.
Pluto Train 2 (Scarborough)	158 TJ/d	225 TJ/d	Under construction
Wheatstone	315 TJ/d	230 TJ/d	Constrained by DomGas plant capacity
Gorgon	497 TJ/d	300 TJ/d	Constrained by DomGas plant capacity
Total	**1,474 TJ/d**	**1,435 TJ/d**	

Source: Wood Mackenzie

When considered on a project-by-project basis, Wheatstone and Gorgon would be processing-capacity constrained and unable to meet their DSO volumes as a result. Pluto Train 1 would become constrained if Browse supply enters the market and utilises KGP ullage for domestic gas processing. In the immediate term, Prelude, Wheatstone and Gorgon would require variations to their DSO volumes. Over the medium term, towards the 2030s and later, the variation approval framework would require these projects to expand domestic gas processing capacity to meet DSO volume commitments as infrastructure constraints are not considered a valid reason not to meet DSO commitments over time.

Transportation infrastructure

All Carnarvon Basin gas production that is supplied to the WA domestic gas market is injected into the Dampier to Bunbury Natural Gas Pipeline (DBNGP). From there, it takes three main pathways – south to Perth and the southwest of the state via forward haul on the DBNGP, east to the Pilbara region via backhaul on the DBNGP to various laterals, and southeast to the Goldfields region via the Goldfields Gas Pipeline (GGP).

The DBNGP is sufficient to manage nameplate capacity flows from the LNG export domestic gas plants and the two Carnarvon Basin Domestic-only producers (Varanus Island and Macedon). Any additional gas supply from Gorgon and Wheatstone above their current nameplate capacities (which would be required to meet their baseline DSO) would meet capacity constraints on the DBNGP. This would also limit Prelude's ability to purchase, swap or toll gas from other LNG exporters through their respective domestic gas plants as this would also raise supply above DBNGP's nameplate capacity of 845 TJ/d (895 TJ/d peak). The only way to inject more volume from Gorgon and Wheatstone such that they can meet their DSO obligations would be to back-out production from Varanus Island and Macedon (therefore reducing domestic gas supply from Domestic-only production).

A detailed analysis of the transportation network limitations in WA is included in Appendix B of this report.

Deliverable Western Australia DSO volumes

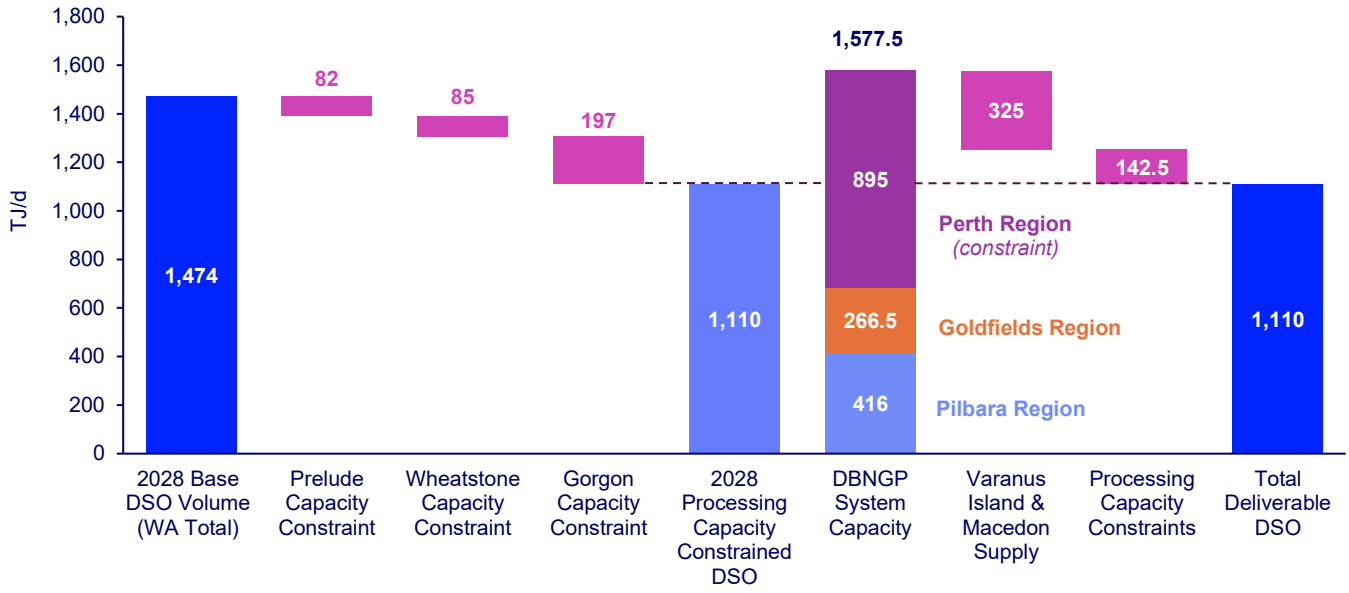
Outlined in Figure 11 below is an analysis of the constraints that would limit the total deliverable WA DSO volumes to approximately 1,110 TJ/d (405 PJ/a) in 2028. The main constraint is the domestic gas processing plant capacities, which reduce the deliverable DSO volumes from the baseline of 1,474 TJ/d to 1,110 TJ/d. However, this is only one part of the issue. Any increase in domestic gas processing capacities from the Carnarvon Basin exporters would quickly run into capacity constraints on the DBNGP, where no further gas could be transported southwest as capacity is limited to 845 TJ/d (895TJ/d peak). While the current capacity is sufficient to meet current supply from the Carnarvon Basin, there is limited headroom to process any further supply without capacity increases.

For all LNG exporters to meet their baseline DSO volumes, their increased supply into DBNGP would have to backout (i.e. replace) Varanus Island and Macedon production, which would have the perverse outcome of reducing domestic market focused supply in favour of LNG export DSO supply.

Expanding the capacity of the DBNGP to accept additional volume would face significant hurdles, including:

- Lead time to bring additional capacity to market is measured in years and would incur significant CAPEX that would need to be recovered by increases in delivered domestic gas prices (the opposite of the policy's intent).
- The constrained section is downstream of Compressor Station 2 and the length of the pipeline that would need to be expanded (via looping, compression, twinning etc.) is several hundred kilometres.
- Investment in any expansion will not occur without firm commercial offtakes underwriting the project. This is unlikely to materialise in a market where there is a large oversupply and no additional demand that would contract this gas.
- The WA pipeline network would become significantly oversized compared to actual demand.
- All of the above infrastructure spending would be required to expand capacity to accept supply that is not needed and has no market (i.e. volumes that are excess to demand).

Figure 11 – Deliverable WA DSO volumes (based on 2028 supply forecast)



Source: Wood Mackenzie

Impact on the WA market

The direct effects of applying a 20%-of-LNG-exports DSO to Western Australia are a structural oversupply of the small WA domestic market, binding infrastructure constraints, the accrual of unrepayable 'DSO debt' and (absent generous variation) the curtailment of LNG exports.

The second-order effects are harder to quantify but potentially more significant, as they alter the willingness to commit long-term capital and to sign the long-dated contracts that underpin both the domestic market and the LNG export industry.

The indirect effects of the policy when applied to WA include:

- Production curtailment and loss of Government income
- Annual approval cycles
- RVM and long-term LNG SPAs
- Ministerial discretion
- Domestic-only producers and market concentration
- Sovereign risk

Several of these second-order effects also form feedback loops that undermine the policy's own stated objectives of security of supply, downward pressure on long-run prices, and an orderly energy transition. In addition, the framework specifies that the AER will have broad involvement with the administration of the scheme, though the AER does not have any functions in relation to energy regulation in Western Australia.

Production curtailment and loss of Government income

If the DSO policy were applied to the WA market as currently proposed, the reduction in both upstream production and LNG exports to meet the requirements of the DSO could result in the loss of 40% of WA forecast LNG export volumes over the period 2027 to 2040. This would put at risk as much as A$142 billion in export revenue from curtailment of exports to meet the requirements of the DSO policy. The impact to Government income would be substantial – Australia's existing

fiscal terms allow government to capture a material share of profits from Australian oil and gas projects, with a current effective tax rate of approximately 53.5% to 57.5% over the lifecycle of a project. In addition to the loss of Corporate Income Tax, Petroleum Resource Rent Tax and other energy sector levies as a result of the reduction in output, Government income would also be impacted by the resulting material reduction in economic activity – both directly from reduced upstream and LNG operations and capital investment, as well as indirectly via reductions in activity for contractors and service providers, reduced employment, and lower regional investment.

Annual approval cycles

The framework operates on an annual cycle: the DSO for the forward twelve months is set at 20% of export volumes, year-ahead variations are adjudicated against a 'high assessment threshold', the RVM operates in-year, and unmet DSO volumes are carried forward. The visibility of available gas supply therefore resets each year. WA domestic buyers, however, contract over much longer horizons as gas supply for industrial, gas-powered generation, alumina and minerals-processing offtakes typically run five to ten, or even fifteen years and underwrite the buyer's own capital. A supplier whose deliverable volume is set annually by Ministerial decision cannot readily offer firm long-dated volumes, pushing the market toward short-term and spot contracting, reducing the bankability of demand-side investment and increasing price volatility.

It can be argued that annual adjustment is more responsive to actual demand than a fixed reservation, and the variation process and RVM are designed to smooth imbalances. Whilst this is valid, the design of the framework trades this ability to be responsive at the regulatory level, with uncertainty for both gas suppliers and buyers. The existing WA DGP operates through long-dated project agreements that give both sides a stable reference framework; the DSO would replace this with annual determination, working against the security of supply it is intended to provide.

RVM and long-term LNG SPAs

Long-term LNG SPAs underpin LNG project financing, with new trains and backfill developments reaching FID on the strength of ten-to-twenty-year offtake commitments. The current framework provides that RVM volumes may be called on to support the domestic market during periods of tightness, such that an exporter may not be permitted to export at their usual level and could be directed where, when and how to commercialise the volumes. This introduces change-in-law and delivery risk into export offtake, which counterparties are likely to price through shorter durations, discounts, or procurement diversification to other suppliers outside Australia.

The protection nominally afforded to existing contracts is also limited in practice. A variation to honour a pre-existing SPA requires demonstrating that there is 'no viable alternative' to fulfilling the SPA commitments, including sourcing spot LNG. The nature of the spot market, including its size, liquidity and diversity, means that spot cargoes are effectively always available at a price and thus this test is difficult to satisfy.

WA's forecast balanced market to the late 2040s depends on new LNG-driven developments (Browse, potentially Clio-Acme, Dorado, Equus) proceeding, and those developments require new long-term SPAs to reach FID. By making those SPAs harder to sign, the DSO risks undermining the new supply on which domestic balance depends. While most existing WA SPAs are long-established and unaffected in the near term, this directly impacts new and extended contracts, which is precisely where future supply is sourced.

Ministerial discretion

The framework vests wide discretion in Ministers over the base DSO percentage, variation approvals, activation and direction of the RVM, and the determination of whether the market is 'adequately supplied' before export approval (the targeted 'modest oversupply' is itself undefined). Discretion of this breadth is a cost independent of how it is exercised, because parameters set by annual judgment rather than transparent rules cannot be modelled with confidence and are priced as a risk premium. Notably, the WA parliamentary inquiry criticised the *existing* State policy for inadequate transparency, compliance and enforcement. A federal scheme built on broad discretion risks reproducing those governance gaps at national scale, over assets developed under State Agreements designed to provide certainty insulated from administrative intervention.

The proposed process for obtaining LNG export approval each year requires four separate administrative approval steps in consultation with the Ministers, as well as additional submissions to the AER. In-year compliance requires performance reporting on an undefined basis, and an additional complex administrative process to manage in-year banking and borrowing of gas volumes under the RVM, including the potential for audited performance reporting on a discretionary basis.

The process for managing the RVM requires the AER to undertake analysis of an LNG exporter’s domestic gas contracting process, near-term supply adequacy assessments, analysis of storage levels, pipeline constraints and NEM conditions (and presumably NWIS / SWIS conditions in WA, though this is not mentioned in the framework). This would need to be performed for each of the ten LNG export projects on an ad-hoc basis throughout the year. If the policy is applied at the JV participant or equity level, this process would be required for each equity participant, significantly increasing the already large and complex regulatory burden being placed on both industry and Government. The nature of gas production, liquefaction and export means that the timeframe for these broad and uncertain Ministerial decisions is unlikely to meet the needs of domestic gas buyers and sellers, and LNG buyers and exporters. The process introduces significant uncertainty, ongoing in-year risk, reduces the ability to contract gas and LNG volumes and undermines investor confidence further.

Gas markets are lumpy and rigid rules cannot anticipate every contingency, and so some discretion is necessary to avoid

perverse outcomes. But predictable rules with narrow, well-defined discretion are preferable to broad discretion for long-lived, capital-intensive assets.

Domestic-only producers and market concentration

An LNG exporter can monetise gas via export or domestically. Because the export option exists and the alternative under a binding DSO may be curtailed exports, the exporter's effective cost of domestic supply can fall close to zero. This makes exporters ‘compelled sellers’ that are forced to accept very low domestic gas prices in order to continue exporting LNG volumes at market prices.

Domestic-only producers, including the Perth Basin independents (Beharra Springs, Walyering, Waitsia, and pre-FID Belisama and West Erregulla) and the Carnarvon domestic projects (Varanus Island, Macedon), can only monetise gas domestically, and rely on domestic prices to cover full-cycle costs. Prices driven below those costs would halt exploration and appraisal, render pre-FID projects uninvestable, reduce sustaining capital, and ultimately force exit.

The second-order consequences are largely perverse relative to the policy's intent. WA domestic supply would concentrate on a handful of Carnarvon Basin exporters, reducing competitive tension and supply diversity. The loss of nearer Perth Basin supply would, over the long run, raise delivered prices into the southwest / Perth region given the transport distance from the Carnarvon Basin. And because exporter domestic supply is a by-product of export economics rather than a standalone merchant business, concentrating reliance on it ties domestic security to the global LNG cycle. Whilst the crowding-out of higher cost suppliers could be argued to represent efficient rationalisation of more efficient supply, this assumes that the near-zero price is a competitive equilibrium when it is in fact a result of compelled selling and asymmetric market access. This discounts the long-run delivered-cost, diversity and resilience effects that bear directly on security of supply.

Sovereign risk

Sovereign risk, that is risk that the state alters terms after capital is committed, is the cumulative expression of the effects above. Applying the DSO to existing projects developed over two decades, under State Agreements and the existing DGP, changes terms after capital is sunk. The limited practical effect of the existing contract protection via variation approvals means the change will impact contracts already in place. A federal scheme that overrides, or is perceived to override, ratified State Agreements signals that even legislated, project-specific certainty is not durable. This in turn raises hurdle rates for the new investment (Browse, Perth Basin) that future supply requires.

The material increase in sovereign risk would further erode investor and trading partner confidence in Australia as both an investment destination and a reliable supplier of energy. This in turn could put Australia’s energy security at risk, particularly for liquid fuels that are predominantly supplied by our trading partners who both buy and invest in Australian gas exports.

Governments may (and do) adjust resource policy in the national interest. Gas is a public resource and it is reasonable that the social licence to export LNG while domestic users face tight gas supply is contested. However, the majority of sovereign-risk harm flows from retrospectivity and discretion, not from reservation in principle. A truly prospective obligation applied to new projects would address the policy intent with a materially lower sovereign-risk cost.

Appendix A – Western Australia gas market regulation

WA's domestic gas market operates under a unique regulatory framework that reflects the state's significant natural gas resources and its strategic importance to both domestic energy security and export revenues. The regulatory landscape is characterised by a multi-tiered approach involving both state and federal authorities, with particular emphasis on ensuring adequate domestic supply through reservation policies while maintaining competitive market conditions.

At the federal level, the ACCC maintains oversight of competition and consumer protection aspects of the gas market, as it does for the ECGM. Beyond this, though, the WA gas market differs substantially from the ECGM. The regulatory bodies that regulate the ECGM do not cover WA (i.e. AEMO, AER, AEMC) and National Gas Law and National Gas Rules do not apply in the State. WA operates as a largely isolated system with limited interconnection. This isolation has necessitated specific regulatory approaches to ensure supply security, price stability, and fair market access for both industrial and residential consumers.

The key regulatory bodies in the WA gas market are the Economic Regulation Authority (ERA), the Department of Mines, Petroleum and Exploration (DMPE) and the Department of Energy and Economic Diversification (DEED).

ERA

The ERA serves as WA's primary energy market regulator, established under the ERA Act 2003. The ERA's responsibilities in the gas sector include:

- **Licensing and Market Access.** The ERA administers the gas trading license regime under the Energy Coordination Act 1994, ensuring that gas trading participants meet financial, technical, and operational requirements. This includes oversight of gas retail and distribution licenses, which are essential for maintaining service standards and consumer protection.
- **Price Monitoring and Regulation.** While the WA gas market operates largely on commercial terms, the ERA monitors gas prices and market conduct to identify potential anti-competitive behaviour. The authority maintains oversight of regulated gas distribution networks, ensuring that network access charges are reasonable and non-discriminatory.
- **Market Development.** The ERA plays a crucial role in facilitating market development through policy advice to government and implementation of market reforms. This includes assessment of market structure changes and recommendations for improving market efficiency.

DMPE

DMPE is responsible for ensuring that resources are managed by industry in an effective, efficient, and sustainable way – maximising recovery in the public interest and delivering both immediate and long-term benefits to the Western Australian and Australian communities. This includes management of petroleum and energy titles, assessment of development proposals and monitoring of production performance against approved development plans.

DEED

DEED implements, assesses compliance and enforces the DGP on behalf of the WA Government. This includes implementing and monitoring the WA DGP, including negotiation of domestic gas commitments with LNG project proponents and ongoing compliance monitoring.

The regulatory approach in WA emphasises a combination of light-handed regulation with targeted intervention where market failures are identified. Key mechanisms include:

- **Licensing Regimes.** Comprehensive licensing requirements ensure that market participants maintain appropriate standards of service, financial capacity, and technical competence. The ERA employs risk-based compliance monitoring, with regular reporting requirements and periodic audits.
- **Information Disclosure.** Regulatory authorities require extensive information disclosure from market participants, including production data, reserve estimates, and pricing information. This transparency supports effective market monitoring and policy development.
- **Consultation Processes.** Major regulatory decisions involve extensive stakeholder consultation, ensuring that industry perspectives are considered while maintaining focus on consumer and public interest outcomes.

WA Domestic Gas Reservation Policy

The WA Domestic Gas Reservation Policy, implemented in 2006, represents one of the most significant interventions in the state's energy market. The policy requires LNG project proponents to demonstrate that they have made reasonable efforts to ensure that gas equivalent to 15% of LNG production is made available for domestic use at competitive prices.

The policy's primary objectives include:

- **Energy Security.** Ensuring adequate gas supply for WA's domestic market, supporting industrial development and residential needs.
- **Economic Development.** Maintaining competitive gas prices to support energy-intensive industries and broader economic growth.
- **Resource Optimisation.** Balancing export revenue generation with domestic value-adding opportunities.

Under DGP in WA, producers are expected to allocate a portion of gas reserves commercialised for export, for sale into the domestic market. In reality, the policy itself is guidance that sets a benchmark of expectations for negotiated arrangements between LNG exporters and the WA Government. During the approval process for exports, each project is expected to commit an appropriate tranche of its reserves (15%), as well as build sufficient infrastructure to deliver this gas into the domestic market in a timely manner. However, the gas price or actual production to be supplied in any given year from this commitment, does not form part of existing agreements.

Domestic gas commitments from the LNG export projects have delivered ~50 to 60% of WA's domestic gas supply over the last two decades and is expected to continue to do so at similar levels in the future. WA's DGP has sought to maintain some flexibility to ensure that security of energy supply in the WA economy is balanced with commercial considerations around specific projects. However, the WA Government has recently outlined that no further agreements to export will be made available from the onshore Perth Basin.

The DGP works by establishing a series of project-specific arrangements with LNG export producers to ensure a portion of gas earmarked for export is made available for WA domestic consumers by:

- Reserving domestic gas equivalent to 15% of LNG production from each LNG export project;
- Developing and ensuring access to the necessary infrastructure (including domestic gas processing, associated facilities and offshore pipelines) to meet domestic gas commitments as part of the approvals process; and
- Showing diligence and good faith in marketing gas to the domestic market.

The WA DGP was recently reviewed and updated in September 2024 in response to a parliamentary inquiry into gas market issues, with the latest update following an August 2025 update by the state government. The review was conducted by an independent panel comprising energy market experts, economists, and industry representatives.

The review scope encompassed:

- Assessment of policy effectiveness in achieving stated objectives.
- Analysis of market development and structural changes since 2006.
- Evaluation of alternative policy mechanisms.
- Consideration of emerging energy transition challenges.

The inquiry released an interim report that focused on the AEMO's forecast of a shortfall in domestic gas supply and stated that the current policy was not 'fit for purpose'. The interim findings took aim at LNG exporters, whom the committee suggested were not all honouring the 'spirit' of the domestic gas obligation. This specifically relates to the rate at which domestic gas is supplied compared to LNG export volumes. The interim report highlights that stakeholders have concerns that the Policy is unable to respond to the evolving market. Specifically, the Policy lacks consistency and clarity, transparency on compliance, and provides inadequate compliance and enforcement mechanisms.

The tabling to WA parliament of the inquiry's findings was conducted on 15 August 2024. The report found that based on current evidence, it is possible that the gas market in WA will stay tightly balanced until 2030, with a possibility of a shortfall materialising – reaching 330 mmcfd from 2032. Whilst Wood Mackenzie's analysis also expects shortfalls in the domestic market, these are later (2034 onwards) and smaller (~142 mmcfd). Note that these shortfall forecasts exclude the Browse-to-NWS DGP commitment volumes that would be expected to enter the market if the project proceeds. In this case, the market would remain well supplied through the 2040s.

The Committee's report noted that keeping the market in balance through 2030 and beyond will require action by industry and government. These recommended actions included:

- That the State Government commence negotiations with obligation holders to address the limitations of existing domestic gas agreements, including terms about transparency, the marketing of domestic gas, and the timeliness of gas delivery.
- That domestic gas agreements should be standardised and improved in the future.
- That the WA DGP as a whole is reviewed and updated, and that a new domestic gas security policy objective is developed that expands and clarifies the current objective of 'securing WA's … energy needs and ongoing economic development…'.

The Committee also addresses the topic of onshore gas projects being allowed to export LNG via existing pipeline infrastructure. Ultimately, the Committee has determined that until the domestic gas market is well-supplied, no onshore gas should be exported using this infrastructure. This finding does not expressly prohibit LNG exports, whilst not expressly permitting them. Wood Mackenzie's expectation is that the State Government may allow LNG exports using gas that is

firstly offered to the domestic market on competitive terms for a period of time, and if no buyers are found domestically during this time frame, the gas may then be exported. This has implications for the types of contracts and pricing onshore LNG exporters could expect to achieve.

Existing Domestic Gas Policy Agreements

Table A.1 – Existing Domestic Gas Policy Agreements

Agreement	Project	Initial DGP commitment Volume *(PJ)*	Estimated Remaining DGP volume[4] *(PJ)*	Status	Associated processing facility	Comments
Gorgon Gas Processing and Infrastructure Project Agreement	Gorgon LNG	2,000	1,241	Online	Gorgon	Rather than an ongoing 15% obligation, the Gorgon arrangement is a fixed delivery obligation of 2,000 PJ
Wheatstone State Development Agreement	Wheatstone LNG	1,600	1,132	Online	Wheatstone	
Pluto Domestic Gas Arrangements	Pluto 1 – DomGas	450	399	Online	Pluto	
	Pluto 1 - LNG trucking			Online	Pluto mini-LNG truck loading facility	
Scarborough Domestic Gas Commitment Agreement	Pluto 1 (backfill) and Pluto 2 (expansion)	1,400	1,400	Under construction	Scarborough	
North West Gas Development (Woodside) Agreement	NWS DGP commitment (additional)[1]	660	228	Online	North West Shelf	NWS equity producers have flexibility from year to year
	Additional NWS DGP commitment (Woodside)[2]	45.6	34.2	Online		2025 to 2029 – 45.6 PJ commitment
Pluto Acceleration Domestic Gas Commitment Agreement; and Additional Domestic Gas Commitment Agreement	Pluto Acceleration (NWS)[3]	48 (25 plus 23)	23	Online		2022 to 2025 – 25 PJ commitment processed through NWS facilities 2026 to 2029 – 23 PJ commitment processed through NWS facilities
Waitsia Domestic Gas Commitment Agreement	Waitsia Phase 2	Exports capped at 7.5 mt LNG to 2028		Tolling via NWS		Although Perth Basin onshore gas, Waitsia is treated as an LNG project for these purposes because it was the first onshore field permitted a partial LNG export entitlement (processed via the North West Shelf) in exchange for committing the bulk of its gas to the domestic market

Notes:

1. *The NWS fulfilled its original DGP commitment in 2014. An additional volume of domestic supply (660 PJ) was agreed between the WA Government and the NWSJV (State Agreement Variation) from 2015.*
2. *Pluto Train 1 Acceleration DomGas (24.7 PJ) is additional domestic gas supply associated with the acceleration of 3 Mt of LNG exports tolled and processed through the NWS (2022-2025).*
3. *Woodside also committed 45.6 PJ to the domestic gas market from its share of NWS production from 2025 - the WA Government will treat gas supplied by Woodside under this extra NWS DomGas supply (45.6 PJ) against the existing Pluto Train 1 domestic gas commitment. This was extended in December 2025 to allow further LNG export volumes, adding another 23 PJ to the commitment (also applied against the Pluto Train 1 DGP commitment).*
4. *Remaining DGP commitment reserves are an estimate based on the total obligation minus WM understanding of what has been supplied under the commitment to Q1 2026.*

Appendix B – Western Australia gas transportation network capacity

The main spine of the WA domestic gas grid is the Dampier to Bunbury Natural Gas Pipeline (DBNGP), with a firm capacity of 845 TJ/d. Most Carnarvon Basin gas, including all Onslow-area supply, must travel south on this spine to reach the dominant southwest load in the Perth region. The corridor south of the Wheatstone / Gorgon injection point is the binding constraint to delivering incremental DSO volumes.

Grid structure and injection / offtake points

WA operates as an isolated gas system anchored on the DBNGP, which runs approximately 1,600 km from the Burrup Peninsula near Karratha to Bunbury via ten compressor stations (CS1 to CS10). It has around 300 km of laterals serving Carnarvon, Geraldton, the Pilbara, Kalgoorlie, Kwinana, Pinjarra and Harvey. Gas enters the DBNGP at three main clusters in the north:

- **Burrup cluster.** The NWS Karratha Gas Plant and Pluto are the largest and northernmost injection points. This area also includes the Pilbara Energy Pipeline (PEP) offtake, taking gas eastward from Karratha.
- **CS1 cluster.** The Varanus Island and Gorgon projects inject supply near CS1, with two large pipeline offtakes at the same location – the Goldfields Gas Pipeline (GGP) from Yarraloola to Kalgoorlie carrying Carnarvon gas southeast to the Goldfields; and the Fortescue River Gas Pipeline (FRGP) to Fortescue's Solomon hub.
- **Onslow / Ashburton cluster.** The Macedon domestic-only plant injects supply between CS1 and CS2 at Ashburton North. Further south, Wheatstone supply is injected via the Ashburton West Pipeline as the southern-most major supply point.

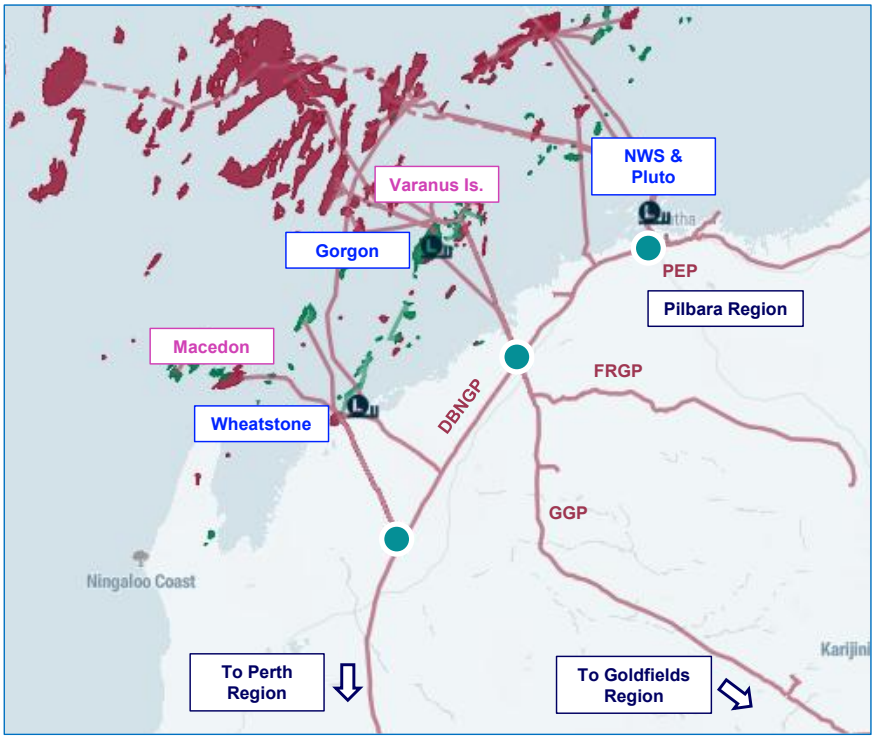
Figure B.1 – Northern WA gas pipeline network

DBNGP – Dampier to Bunbury Natural Gas Pipeline

PEP – Pilbara Energy Pipeline

FRGP – Fortescue River Gas Pipeline

GGP – Goldfields Gas Pipeline



Offtake points

Gas demand in WA relevant to this analysis falls into three areas:

- **Pilbara loads** – iron-ore mining and minerals processing, Burrup industrial users (urea and ammonia), regional power generation and growing diesel-displacement demand are met locally from the northern injection points and laterals.
- **Goldfields loads** – Kalgoorlie and mine-site generation served southeast via the GGP.
- **Southwest (Perth region) loads –** The largest group by far includes Kwinana industrial, the alumina refineries, gas-powered generation and urban demand around Perth.

The southwest (Perth region) sits at the southern end of the DBNGP and is reached only by full-haul transport south down

the pipeline. Two underground storage facilities (Mondarra and Tubridgi), as well as DBNGP linepack, provide limited within-day and seasonal flexibility.

Capacity constraints

The DBNGP's firm full-haul capacity is 845 TJ/d (895 TJ/d peak). This single figure governs how much gas can be moved south past the Onslow / Ashburton cluster to the southwest (Perth region) market, and it must carry all southbound volumes net of what the Pilbara and Goldfields draw off. South-haul volumes in the DBNGP include Burrup cluster gas injected further north *plus* Onslow-cluster gas. The constrained section is downstream of Compressor Station 2 and extends for several hundred kilometres toward Perth.

A 20% DSO would require Gorgon and Wheatstone to inject domestic volumes well above their current domestic gas processing plant nameplates (300 and 230 TJ/d respectively). Even if those plants were expanded, the incremental gas would have to travel south to reach demand, and the southbound corridor cannot accommodate it.

Burrup cluster

The Burrup cluster receives domestic gas from Pluto and NWS. Under a 20% DSO, this would total 555 TJ/d injected at the northern end of the DNBGP. This gas can flow in three directions which each have capacity limitations:

- To Burrup area offtake (~250 TJ/d) – including Yara Pilbara, Sino Iron Ore and various GPG power plants.
- To the Pilbara Energy Pipeline (PEP) (~166 TJd) – flowing gas to Pilbara area consumers, the downstream Telfer Gas Pipeline and other laterals.
- West towards the Onslow / Ashburton cluster.

Assuming maximum offtake by the Burrup-area demand centers and the PEP (i.e. at full capacity, which is more than actual current demand), the total flow westwards under a 20% DSO is ~305 TJ/d.

CS1 cluster

At the CS1 cluster, Varanus Island injects ~175 TJ/d of additional supply, meaning that ~480 TJ/d of forward-haul gas flow is now supplied into the DBNGP at this point. Gorgon then adds an additional 300 TJ/d at its current plant nameplate capacity limit. Offtake from the GPG and FRGP at this point total a maximum of 266.5 TJ/d (i.e. at full capacity, not actual demand), leaving a net supply of 513.5 TJ/d continuing forward-haul on the DBNGP.

Onslow / Ashburton cluster

At the final injection cluster, Macedon and Wheatstone (at its current 230 TJ/d plant capacity) inject a further 380 TJ/d into the DBNGP. At this point, there are no further major offtake points until the Carnarvon lateral. The total forward-haul flow at this point in the DBNGP would be 894 TJ/d – above the nameplate capacity but in line with peak-flow capacity of 895 TJ/d.

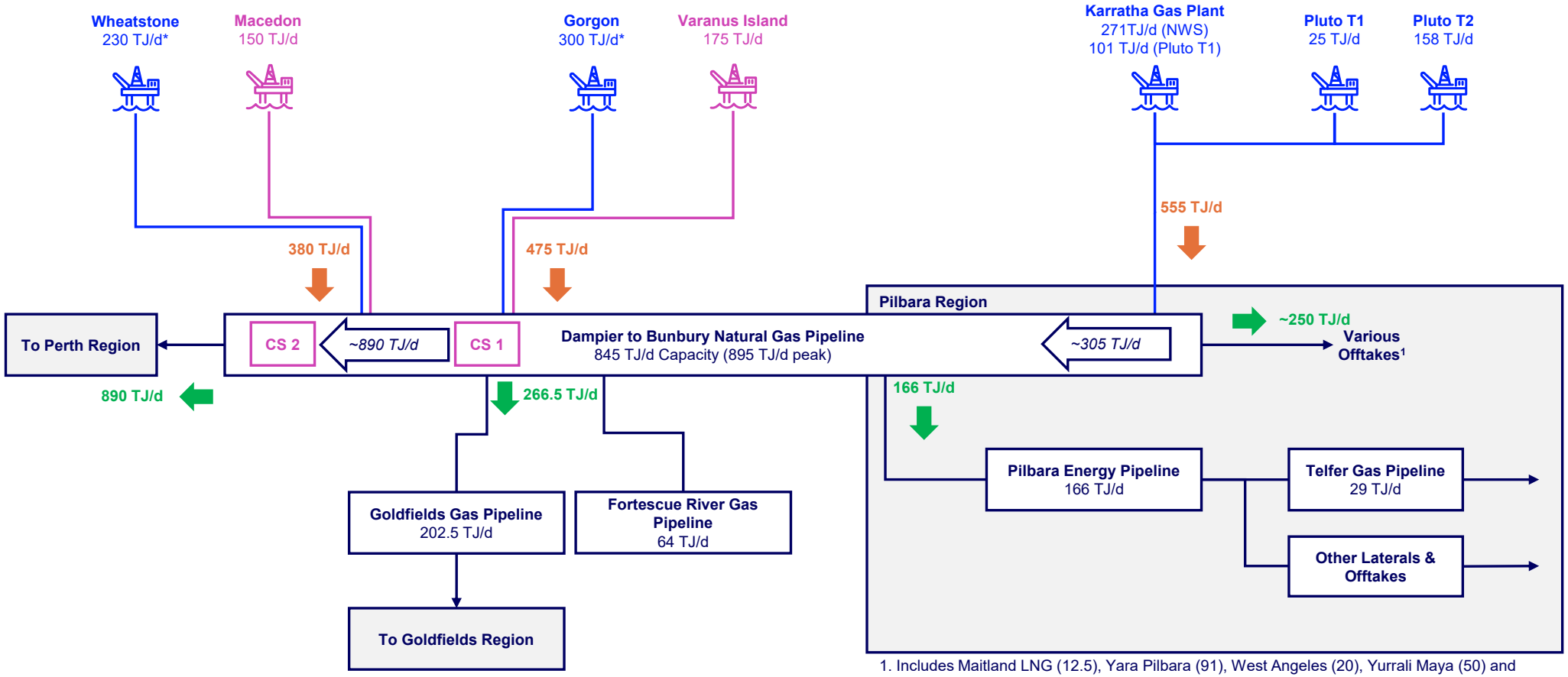
Ability to meet DSO volumes

If both Gorgon and Wheatstone were forced to supply 20% of the LNG export volumes into the domestic market, this would increase gas supply to over 1,110 TJ/d – well over the transport capacity of the existing pipeline network in the area. This is also before the potential addition of Prelude volumes via swaps with Carnarvon Basin producers. The only plausible option for LNG exporters to supply a 20% DSO without variations would be to back-out Macedon and Varanus Island supply to free up capacity in the DBNGP to accept these LNG-exporter volumes. This would create the perverse outcome of substituting compelled LNG-exporter supply for existing Domestic-only supply.

Expansion of the DBNGP would be slow, costly and un-bankable here. Looping and compression on the constrained section south of CS2 would take years, require significant capital recovered through higher delivered tariffs (contrary to the policy's price intent), and need firm offtake to underwrite it – commitments that will not materialise in a structurally oversupplied market with no incremental demand. The result would be an oversized network built to carry volumes the market does not need.

The geography of the WA domestic gas market concentrates demand at the southern end of a single capacity-limited pipeline, while the DSO would concentrate incremental obligation at the northern injection points. The mismatch is physical, not merely commercial, and the corridor south of the Wheatstone / Gorgon injection point is where it binds.

Figure B.2 – Constrained DSO volumes in 2028 (processing capacity limited)



1. Includes Maitland LNG (12.5), Yara Pilbara (91), West Angeles (20), Yurrali Maya (50) and Sino Iron Ore (80) (TJ/d)

** Constrained by DomGas plant processing capacity*

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