

# Application of the proposed Domestic Supply Obligation policy framework to the East Coast 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 East Coast Gas Market (ECGM) if implemented as currently designed. Key elements of the framework include the opportunity for LNG exporters to propose 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 to the domestic market.

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’.

***A 20% DSO applied to Queensland would compel the sale of significant volumes of gas into an already balanced market, causing a large, sustained oversupply that eliminates price and investment signals.***

***When applied to the NT, the proposed DSO would make no difference to the forecast balance of the ECGM. Without significant and sustained variations, the DSO volumes supplied into the NT market would be stranded without an addressable market.***

***Across the ECGM, the resulting lack of investment in new supply would leave the market reliant on existing production that is already declining.***

***In the long-term, without new supply the market becomes structurally short, heavily reliant on imports and directly linked to LNG import parity pricing.***

***This is an outcome that undermines the policy's own stated objectives of security of supply, downward pressure on long-run prices, and an orderly energy transition.***

## East Coast Gas Market

The ECGM was historically underpinned by supply of conventional gas from southern gas fields offshore Victoria, as well as gas production from the Cooper-Eromanga Basin. Conventional production has been falling as late-life fields in the southern states have depleted and are not being sufficiently replaced with new supply. Restrictions on onshore exploration and development of gas resources in New South Wales, Victoria and Tasmania have contributed to this lack of new supply, which has since been offset by the success of Coal Seam Gas (CSG) production in Queensland. Queensland also has an existing domestic gas reservation – since 2017, Queensland has released over 20,000 square kilometres of land for gas exploration and production reserved exclusively for Australian domestic supply via the Australian Market Supply Condition imposed on specific exploration and development acreage in the state.

With the recent investment in increased north-south pipeline capacity<sup>1</sup>, the southern market is adequately supplied on an average annual basis until 2033 by a combination of southern supply and piped gas supply. From 2034 onwards, southern supply declines to the point that piped gas supply can no longer fill the remaining supply-demand gap. At this point, the southern market becomes structurally short of gas. To continue to balance the southern market, new supply and new infrastructure to deliver it to demand centers is needed. The investment that would deliver this new supply needs to occur between now and the early 2030s.

<sup>1</sup> Stage 3A of the East Coast Gas Grid (ECGG) expansion

## Domestic Supply Obligation applied to Queensland and the NT

### Direct impacts

- A significantly and structurally oversupplied market with supply being more than 200 PJ/a higher than demand in the short-term, requiring significant and sustained DSO variations or substantial LNG export curtailments.
- Compelled selling by LNG exporters potentially displacing the majority of other domestic gas supply in the market in the short-term, resulting in price and investment signal destruction.
- Prices below the marginal cost of production halt exploration and appraisal, render pre-FID projects uninvestable, reduce sustaining capital, and ultimately force domestic-only producers to exit the market. New supply is not brought to market when it is needed as a result.
- The resulting structural shortfall of gas in the ECGM would cause prices to quickly rebound above current levels and rise towards LNG import parity over time as a result of the necessary reliance on significant energy imports.
- Physical constraints and a lack of addressable markets for NT LNG export DSO volumes make meeting the requirements of the framework difficult without significant and sustained DSO variation approvals.
- The application of a DSO in the NT would put at risk a connection of the Beetaloo Basin to the ECGM – significantly lower prices put at risk the commercial development of Australia's largest prospective resource.

### Indirect impacts

- The ability for LNG exporters to purchase existing gas from Domestic-only producers does not acquit their DSO obligations as existing Domestic-only production is not additional new supply and so does not qualify as DSO supply. Further, underwriting or developing new supply takes many years and significant risk capital.
- With the loss of investment and price signals in the short-term due to structural market oversupply, these investments would likely be uneconomic and could not proceed to development. Supporting additional domestic gas production should be available as an option for LNG exporters, however it is unlikely to be a major contributor to meeting DSO obligations, particularly in the near-term.
- Even in the unlikely scenario of these projects being sanctioned as loss-making investments, this would effectively concentrate all new supply projects entirely on LNG exporters, reducing market competitive tension and directly linking security of domestic gas supply to the global LNG cycle.
- The DSO does not address the more urgent issue of peak-day shortfalls in southern gas markets, and in fact is likely to make peak-day exposure worse over the medium term by suppressing the domestic price signal through compelled-seller economics, removing any incentive to invest in infrastructure and peak-day deliverability.
- Despite being labelled a prospective supply obligation, the protection nominally afforded to existing contracts is limited in practice. This is particularly acute for NT and some Queensland projects that are feed-gas limited.
- The policy introduces change-in-law and delivery risk into export offtake, which counterparties are likely to price through shorter contract durations, discounts, or procurement diversification to other suppliers outside Australia. This compounds the material sovereign risk introduced into the market by the framework.
- 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.

### Supply-demand

Applying the framework as designed to Queensland LNG exporters, with minimal variations or RVM approvals, results in the southern market experiencing a sustained, structural and large oversupply from 2027 to 2035 as compelled LNG exporter DSO volumes are far in excess of domestic market demand. Between 2027 and 2032, total DSO variation and RVM volumes are over 150 PJ/a, only falling below 50 PJ/a from 2035 through a combination of declining Queensland exporter upstream production, and lower southern production creating greater capacity to absorb Queensland volumes.

This excessive structural oversupply would remove any price signals in the ECGM that would have underpinned investment in future supply, transportation infrastructure to bring this new supply to market and demand moderating programs that would reduce gas usage. Essentially, the ECGM would become so oversupplied that prices would collapse to below the marginal cost of domestic-only producers and any future investment in gas supply would become uneconomic. As a result, it is likely that no new supply would be brought to market during this period.

The challenge in the medium to long-term is that the market flips from being structurally oversupplied to structurally

undersupplied as existing Queensland LNG exporter reserves are exhausted, no new supply has been invested in, southern market supply has fallen to less than 20 PJ/a, and southern market demand remains above 200 PJ/a. The loss of investment signals in the market, and the risk premium applied to investments under a DSO regime, mean that there would be a reduction or complete loss of the continued investment required to maintain production over the longer term. The implications from the lack of investment in new supply would take a decade or more to rectify given the long-lead-time nature of gas developments.

At this point, the southern market has no ready source of gas supply beyond Cooper Basin tail production and (potentially) LNG imports. The result would potentially be a near-complete reliance on LNG imports to meet ECGM demand, stranded gas pipeline infrastructure with no supply of gas and domestic gas prices set by international LNG markets directly (spot or contract LNG supply delivered into the ECGM, plus regasification costs).

This outcome is one that undermines the policy's own stated objectives of security of supply, downward pressure on long-run prices, and an orderly energy transition.

### **Worsening peak-day exposure**

The DSO also does not address the more urgent challenge in the southern markets, which is peak-day shortage risks. Peak-day shortfalls require investment in southbound pipeline and compression capacity, storage injection and withdrawal capability, and firm peaking supply close to load. The DSO, by contrast, simply directs more northern CSG into a market that is already long in the north, where it cannot physically reach southern peak-day demand through corridors that are already close to full on those same peak days.

More damagingly, the DSO is likely to make peak-day exposure worse rather than better over the medium term. By suppressing the domestic price signal through compelled-seller economics and replacing long-dated contracting visibility with an annual ministerial determination of deliverable volume, it erodes the bankability of precisely the long-tenure offtakes that underwrite new southern supply, storage and transport firming, which is the investment the Australian Energy Market Operator (AEMO)'s outlook says is needed from around 2030 to manage the tightening.

It also crowds out the domestic-only producers in both the northern and southern markets (Surat-Bowen, Cooper, Otway, Gippsland third parties) whose marginal molecules and flexibility help cover winter peaks. The net effect is that the policy converts a manageable, investment-contingent tightening into a deeper structural southern deficit from the mid-2030s, with peak-day shortfall risk higher, not lower, than the un-intervened baseline.

### **Indirect impacts and costs**

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. 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 those located proximate to southern demand centers in the Otway, Gippsland and Bass Basins, 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 spend, and ultimately force exit. ECGM domestic supply would therefore become concentrated on a handful of Queensland LNG exporters, reducing competitive tension and supply diversity. The loss of nearer southern supply would raise delivered prices into the southern markets given the transport distance from the north.

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 Queensland's LNG exports would fall from 23 mmtpa under current market conditions to less than 10 mmtpa under the announced DSO framework. In that one year alone, this could see a reduction in Queensland state petroleum royalties paid on gas production by as much as A\$838 million.

In total, the curtailment of LNG exports could result in the loss of approximately A\$44 billion in export revenue<sup>2</sup> between 2027 and 2040, and would likely negatively impact employment, economic activity, Government income from taxes,

royalties, and broader investment across the sector in Queensland. 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.

Purchasing gas from domestic gas producers to avoid curtailment offers LNG exporters limited opportunity to acquit their DSO. The framework's additionality test requires that for any LNG exporter that meets its obligation through a third party, the arrangement must deliver gas to the domestic market 'that would not otherwise have been made available'. Contracting the existing output of a Cooper, Otway, Gippsland or Surat-Bowen domestic-only producer fails this test, because those molecules are already supplied domestically.

To contribute to the acquittal of an exporter's DSO volumes the supply must be incremental, which means the LNG exporter must underwrite new production. New upstream developments, whether frontier unconventional acreage, offshore backfill, or incremental onshore appraisal, require a domestic price that recovers full-cycle costs including discovery, development and sustaining capital, and they require it under long-dated, bankable contracts to reach FID. Compounding this, new supply cannot be developed in accordance with the framework's near-term compliance timetable. Appraisal, approvals, FID, drilling and midstream connection run over multiple years, whereas the DSO commences in less than one year and thereafter operates on an annual reset basis. While supporting additional domestic gas production should be available as an option for LNG exporters, it is unlikely to be a major contributor to meeting DSO obligations, particularly in the near-term.

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 contract durations, discounts, or procurement diversification to other suppliers outside Australia. 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.

Applying the DSO to existing projects developed over two decades under existing regulatory regimes (and State-based regimes in the case of Queensland) changes terms after capital is sunk and raises Australia's sovereign risk. The limited practical effect of the existing contract protection via variation approvals means the change will impact contracts already in place. This in turn raises hurdle rates for the new investment (Beetaloo, Taroom) that future supply requires.

## Introduction

The Australian government has released its draft design framework for the proposed 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 ECGM, 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:  $DSO = 20\% \times LNG\ Exports$ , 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 participant – this distinction could have material consequences and has not been addressed in the draft policy. The analysis presented in this report is based on an application at the project level, and not at the JV equity or corporate level. The application of the DSO at the JV participant level creates a number of issues for LNG exporters in the Northern Territory (NT) and Queensland (QLD), which are discussed further as part of the second-order impacts assessment in this report.

### Ability to vary DSO volume

LNG exporters will have the opportunity 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.

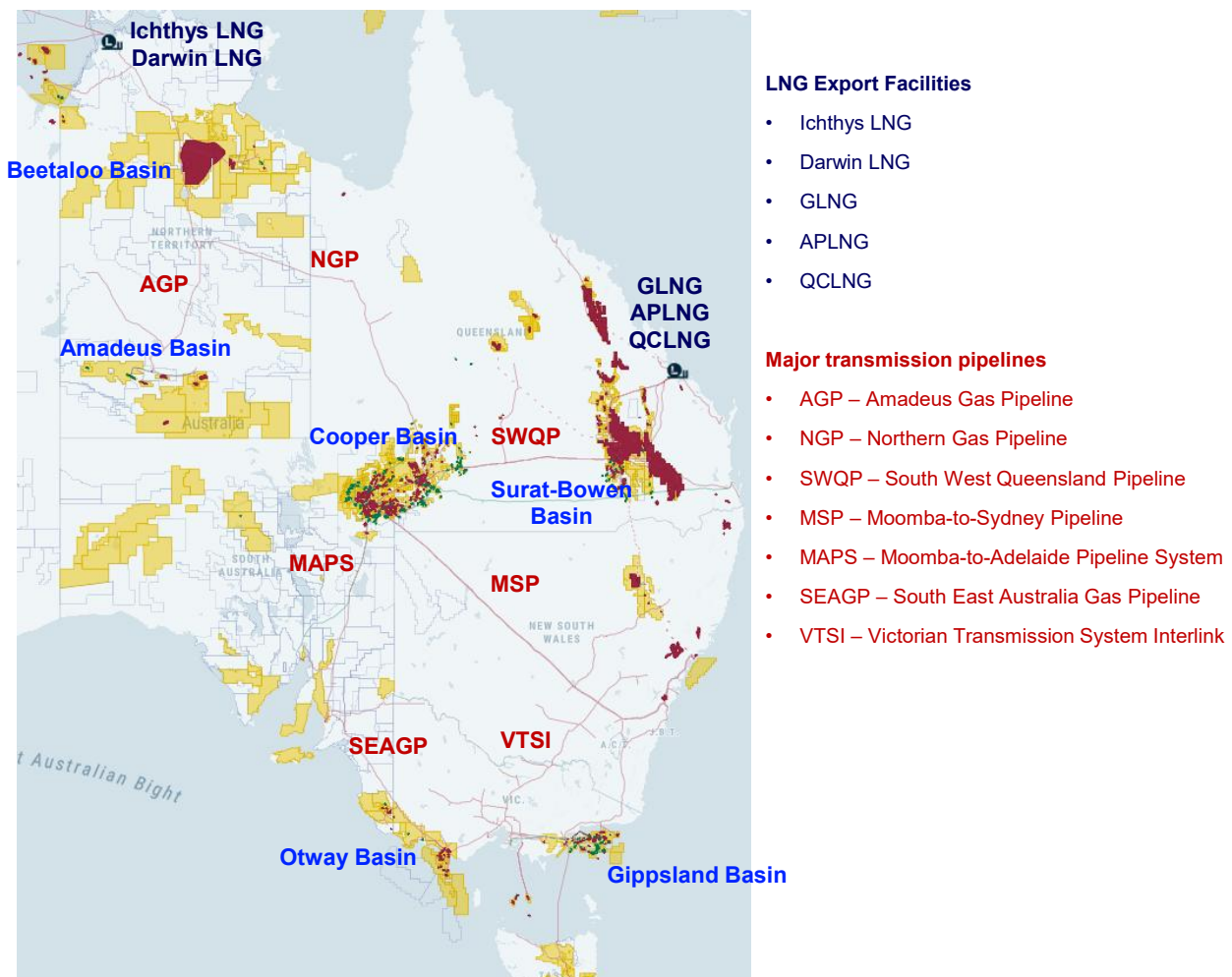
As with for variations, any DSO volumes that are exported through the RVM will be accrued into subsequent periods, adding to the DSO 'debt' being carried by the LNG exporters. The framework highlights that these volumes would be called on to support resilience of the (domestic) market during any anticipated 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.

## Overview of the East Coast Gas Market

An interconnected gas grid connects all of Australia's eastern and southern states and the NT. The gas basins that supply this market contain around one third of Australia's gas reserves. The ECGM encompasses Queensland (QLD), New South Wales (NSW), Victoria (VIC), South Australia (SA), Tasmania (TAS) and the Australian Capital Territory (ACT). This market is interconnected by transmission pipelines, which source gas from basins and deliver it to large industrial customers and major population centers. The main production basins are the Surat-Bowen Basin in Queensland, the Cooper-Eromanga Basin in northeast South Australia, and three basins off coastal Victoria, the largest being the Gippsland Basin.

The ECGM was historically underpinned by supply of conventional gas from southern gas fields offshore Victoria as well as gas production from the Cooper-Eromanga Basin. Conventional production has been falling as late-life fields in the southern states have depleted and are not being sufficiently replaced with new supply. Restrictions on onshore exploration and development of gas resources in New South Wales, Victoria and Tasmania have contributed to this lack of new supply, but it has also been offset by the success of Coal Seam Gas (CSG) production in Queensland. As a result, CSG now accounts for 90% of the east coast's known remaining gas reserves, and Queensland has become the dominant source of gas supply and demand (considering both domestic demand and feed-gas into the LNG export projects).

Figure 1 – Overview of ECGM



Whilst the ECGM is nominally an interconnected grid that covers all eastern states and the NT, in practice this interconnection is limited by a number of physical constraints. These include the limited connections between the NT and the eastern states, which currently only consists of a single 90 TJ/d gas transmission pipeline from Tennant Creek to Mt Isa.

Both Queensland and the NT are self-sufficient in gas production, and both export gas as LNG to global markets. The supply-demand challenge in the ECGM is focused on southern states, where legacy production is declining and supply-demand gaps are forecast to emerge in the early 2030s without significant near-term investment in new supply.

## Supply and demand in the southern ECGM

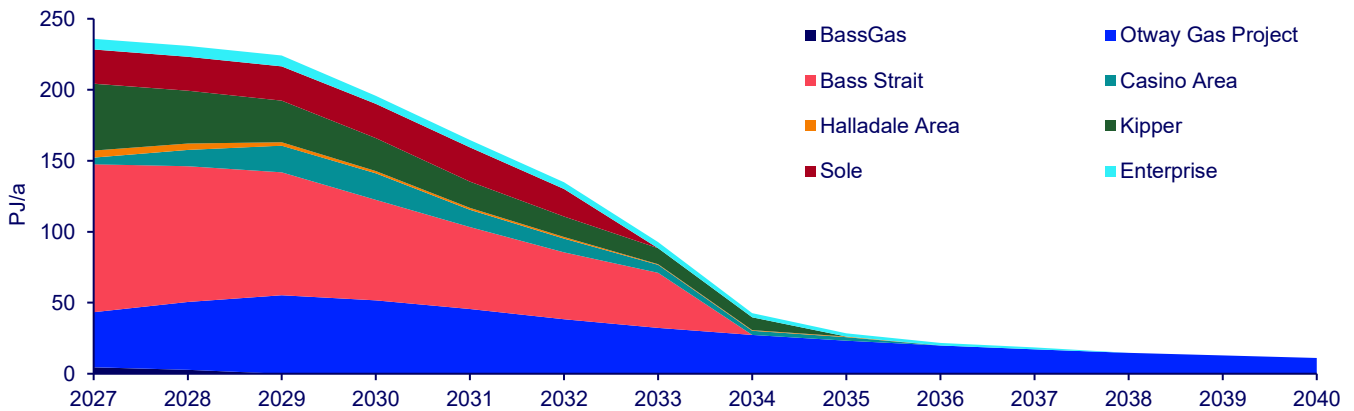
The southern market consists of supply and demand centers in New South Wales, Victoria, South Australia, Tasmania and the ACT. The southern market is supplied predominantly by two main sources:

1. Southern supply – mature offshore basins that are in structural decline.
2. Piped gas supply – gas sourced from the Cooper Basin and Queensland.

### Southern supply

The Gippsland Basin in Bass Strait has been the mainstay of southern supply for six decades. Production is processed principally at the Longford gas plant in eastern Victoria, which has historically supplied a large share of Victorian and wider southern demand. The Longford plant is scheduled for retirement at the end of 2033, which represents the single most consequential discrete event in the southern supply outlook. Supply from existing and committed projects is forecast to decline without near-term investment to develop new resources and maximise the utilisation of existing processing and transportation infrastructure.

Figure 2 – Southern supply outlook – existing and committed supply



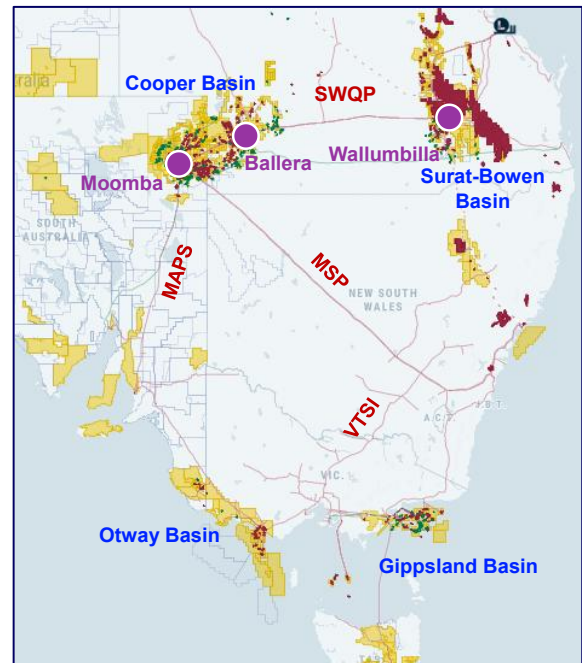
Source: Wood Mackenzie

### Piped gas supply

Piped gas supply is principally sourced from two main gas basins – the Cooper Basin that straddles the SA / QLD border, and the Surat-Bowen Basin, which produces CSG for both the domestic market and LNG export via Gladstone.

The supply of piped gas to southern states is via four main transmission systems:

- South-West Queensland Pipeline (SWQP) – connects Queensland producers in the Surat-Bowen Basin at Wallumbilla with the Cooper Basin at Moomba, for onward gas transmission to southern states.
- Moomba-Adelaide Pipeline System (MAPS) – connects the Cooper Basin at Moomba to Adelaide and supplies the majority of SA demand.
- Moomba to Sydney Pipeline – connects the Cooper Basin at Moomba to Sydney and supplies NSW, ACT and some VIC demand.
- The Victorian Transmission System (VTS) Interlink – connects NSW and Victoria and allows flow between the two markets.



### SWQP

The SWQP is a bidirectional pipeline that supplies Queensland CSG western-haul towards Moomba. It has a western-haul capacity of 512 TJ/d. The pipeline’s owner, APA Group, has taken Final Investment Decision (FID) on Stage 3A of its East Coast Gas Grid (ECGG) expansion, which includes an increase of SWQP capacity from 2028. As a result, western-haul capacity will rise from 512 TJ/d to 570 TJ/d.

**MAPS**

MAPS is the principal source of supply for SA’s gas demand. It supplies Cooper Basin gas to Adelaide and has a capacity well in excess of actual SA demand. MAPS capacity is nominally 300 TJ/d when operating with full compression (currently MAPS operates with four of seven compressors due to actual SA gas demand). Generally, SA is able to be fully supplied by Cooper Basin gas transported via MAPS.

**MSP**

From Moomba, the Moomba-to-Sydney Pipeline (MSP) is the primary outlet for Cooper Basin gas and the principal route by which gas reaching Moomba from Queensland or the NT continues into the New South Wales market. It is also connected to the Victorian Transmission System at Young, where gas can be supplied between Victoria and NSW. The current MSP capacity is 590 TJ/d when incorporating the conversion of the Moomba to Sydney Ethane Pipeline to transport gas, however as part of Stage 3A of the ECGG expansion the capacity of MSP will increase to 600 TJ/d from 2028.

**VTS Interlink**

The Victorian Transmission System (VTS) serves Victorian load and connects northward to New South Wales via the interconnect at Culcairn. The VTS is also the gateway to Iona storage and the Otway and Gippsland receipt points.

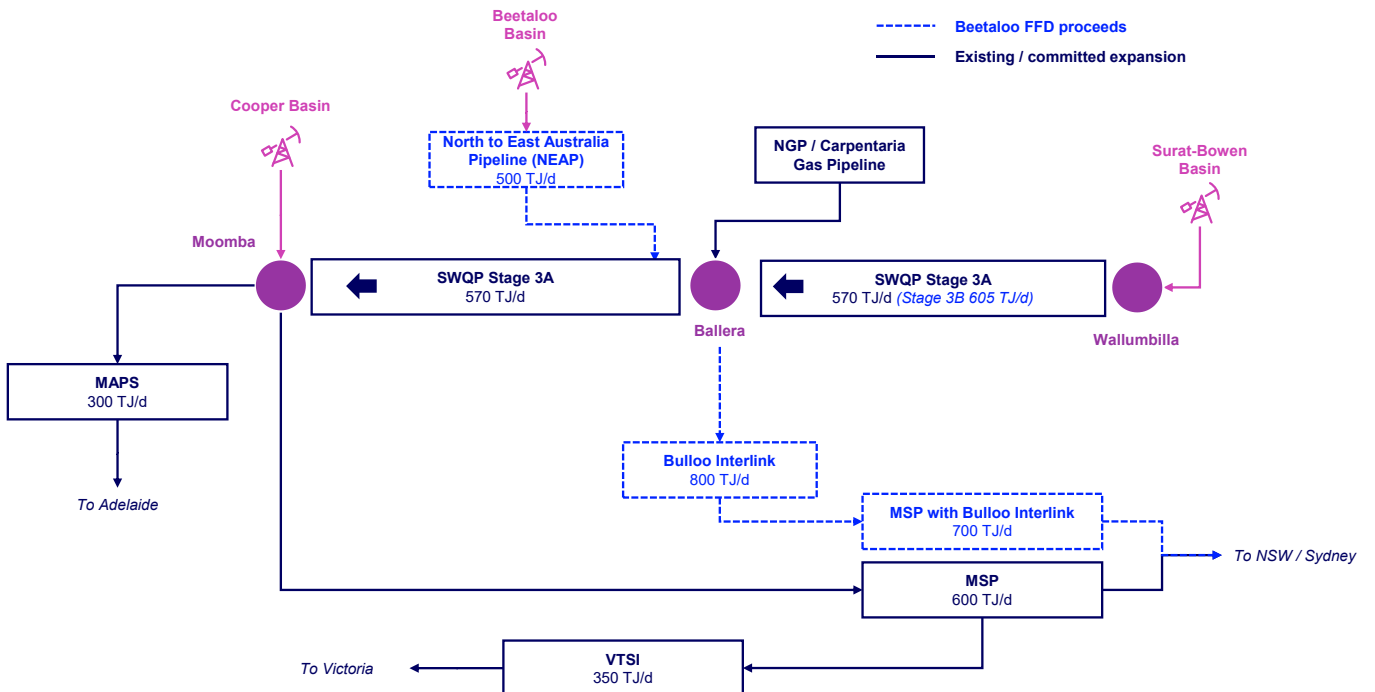
The VTSI connects NSW and Victoria, and allows gas supplied via MSP to be transported into Victoria for use. The current capacity of VTSI is 200 TJ/d, however a phased expansion plan is underway with capacity to rise to 229 TJ/d in 2028 and 350 TJ/d from 2029.

**Planned expansion – Bulloo Interlink**

APA has a planned interlink that would connect the SWQP (near Ballera) to the MSP (in north-west NSW) enabling delivery of greater volumes of Queensland and/or NT gas into the MSP. The Bulloo Interlink would increase the total capacity of the MSP system to 700 TJ/d and increase the SWQP western-haul capacity to 605 TJ/d if it is constructed. The investment in this Bulloo Interlink is subject to customers committing to transmission capacity contracts (with the customers also needing contracted supply certainty from the north).

For the purposes of this analysis, we assume that the NEAP and Bulloo Interlink are both constructed if the Beetaloo Basin Full Field Development (FFD) proceeds. The capacity of the transmission system to supply piped gas into the southern markets is outlined below. The MSP is the constraint that governs gas delivery to NSW and the VTSI is the constraint that governs gas delivery from the north into Victoria (via NSW).

Figure 3 – Pipeline network capacity overview



Source: Wood Mackenzie analysis of AEMO, AER and company data

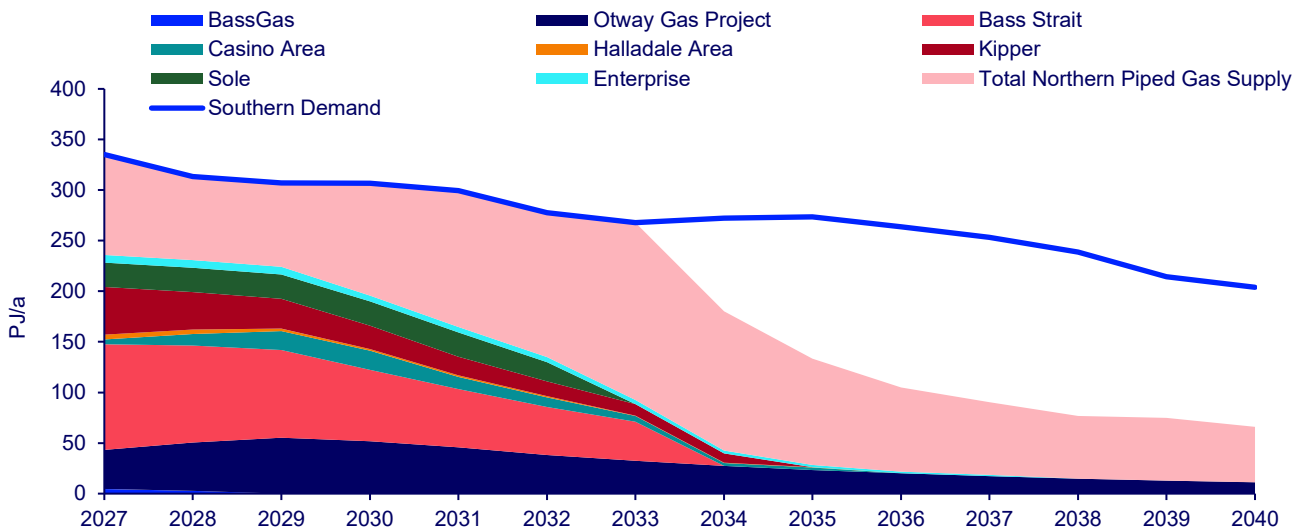
## Southern market balance on annual supply-demand

### Balance on existing supply

With the investment in Stage 3A of the ECCG expansion, the southern market is adequately supplied on an average annual basis until 2033 by a combination of southern supply and piped gas supply. From 2034 onwards, southern supply declines to the point that piped gas supply can no longer fill the remaining supply-demand gap without additional investment to discover, appraise and convert new resource into produceable reserves. At this point, the southern market becomes structurally short of gas.

It is worth noting that without investment in new production, piped gas supply is constrained by the availability of upstream gas supply post-2034, and not by transportation capacity (on an annual average basis). This is due to the decline in production from the current Queensland CSG fields from the mid-2030s and the need to develop new supply to ensure the ECGM remains balanced. There are a number of current investments in both southern and northern markets to develop this needed supply. This includes active exploration in the Otway Basin to develop and tie-back new resources to existing processing infrastructure, ongoing drilling in the Surat Basin CSG fields, and appraisal activities focused on oil and gas production in the Taroom Trough. These investments are key to extending supply further into the future and keeping the south market balanced beyond 2034.

Figure 4 – Southern state annual supply-demand balance – existing and committed supply



Source: Supply – Wood Mackenzie, Southern Demand – AEMO 2026 GSOO

### Impact of the proposed DSO (annual adequacy)

The DSO does address a dimension of the post-2033 risk of an annual energy supply gap. In a year when the current market may forecast an annual PJ deficit, holding more gas onshore narrows that gap in aggregate volume terms. The challenge is that structural deficits are forecast to occur in the future, and not immediately. The gas supply that would be held onshore to address these deficits has not yet been developed – existing supply is not sufficient over the long-term, and new supply needs to be brought to market via investment to close these forecast future supply-demand gaps.

Additionally, the DSO increases northern gas supply, but this will require pipeline capacity expansions (Stage 3B onwards) to be able to deliver this gas to markets in the south where the deficit exists. Effectively, the volume benefit is contingent on the same infrastructure the DSO makes harder to build. Second, and more fundamentally, by undermining the investment case for new supply, the volume the DSO can deliver is a fixed percentage of an export base that is declining, meaning the DSO delivers lower amounts of gas precisely when the shortfall is deepest, and it cannot backfill the gap that the DSO itself exacerbates by chilling new supply.

### Southern market balance on peak day supply-demand

The annual balance understates southern vulnerability because peak winter day demand substantially exceeds average daily demand, and it is peak-day deliverability – the rate at which gas can be delivered on the single coldest, stillest day – not annual volume, that is the more urgent constraint. The southern market can hold enough gas across a full year yet still be unable to physically deliver enough on an extreme winter day. AEMO assesses the annual supply gap (insufficient gas across the year) separately from the peak-day shortfall (sufficient gas in aggregate, but insufficient instantaneous deliverability from production, storage send-out and pipeline imports combined to meet an extreme day). The 2026 AEMO Gas Statement of Opportunities (GSOO) forecasts peak-day shortfall risks in the southern states from 2029 under sustained high-usage conditions.

### Drivers of peak day shortfalls

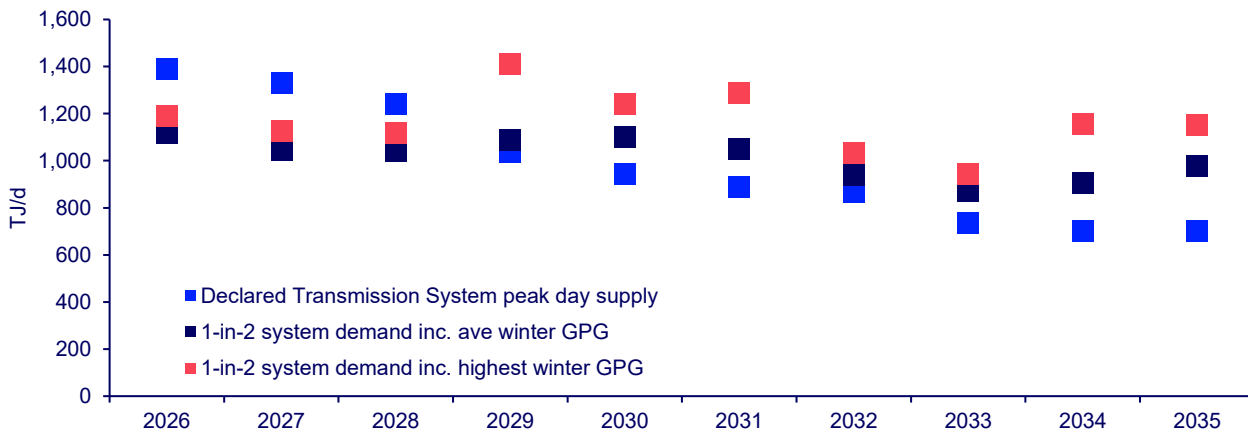
On a southern winter peak day, demand spikes due to residential and commercial space heating across Victoria and New South Wales, lifting daily demand well above the annual average. This can be worsened if gas-powered generation (GPG) is called on to support National Electricity Market (NEM) reliability during cold, dark, still conditions. This is worsening in shape even as annual gas volumes fall – as GPG shifts from regular mid-merit operation to a flexible back-up role, its output is increasingly concentrated into short periods of high need, making the system peakier as it decarbonises.

What determines whether that demand spike can be met is not how much gas exists, but the capability of three physical asset classes, none of which a volumetric obligation creates. The first is pipeline capacity into the southern load, principally the southbound corridor. Pipelines have a firm maximum daily throughput, and on a peak day the southbound corridor has limited headroom above its existing committed flows to carry incremental northern gas to where the spike is. The second is storage, specifically the injection and, more importantly, withdrawal deliverability of facilities such as Iona, plus pipeline linepack. Storage exists precisely to decouple supply from peak demand. Gas is injected in shoulder seasons and withdrawn at high hourly rates on peak days. Peak-day security depends on the maximum withdrawal rate (TJ/d) and the working-gas inventory available at the moment of the spike, both of which are physical, sited capabilities. The third is local peaking supply, meaning firm, swing-capable production or flexible offtake positioned close to southern load that can ramp on demand, rather than gas that has to be hauled hundreds of kilometres from Queensland.

Peak day gas demand is actually falling as electrification progresses – the 2026 Victorian Gas Planning Report (VGPR) shows the 1-in-2 year system demand declines from 958 TJ/d in 2026 to 836 TJ/d in 2030, and the 1-in-20 year (extreme) demand from 1,032 to 900 TJ/d, both a 12.8% reduction. The 2026 1-in-20 forecast of 1,032 TJ/d is itself well below the 1,157 TJ/d the 2025 VGPR had projected, and the 2025 actual maximum day was 933 TJ/d.

The problem is that peak day supply capacity is falling faster than peak day demand. Expected Victorian Declared Transmission System (DTS) peak-day supply capacity drops from 1,389 TJ/d in 2026 to 945 TJ/d in 2030, barely clearing the 900 TJ/d 1-in-20 demand by the end of the period, and that is before gas-powered generation is added. From 2026 to 2028, forecast DTS supply is sufficient to meet peak GPG demand occurring alongside a 1-in-2 and 1-in-20 year system demand day. However, from 2029 onward peak GPG demand is forecast to increase (due to the closure of the Yallourn and Eraring coal-fired power stations) and exceed the forecast DTS supply. As shown below, the coincidence of a cold peak day with high GPG demand pushes peak day demand above peak day supply capacity from 2029.

Figure 5 – Peak-day demand and peak-day supply – Victorian DTS



Source: Wood Mackenzie analysis of AEMO VGPR data

The fall in peak day supply capacity is driven by declining local gas production. Gippsland producers have advised that maximum available production capacity will decline by 60.5%, from 766 TJ/d in 2026 to 302 TJ/d in 2030, and to zero in 2034 onward. The reduction is primarily driven by declining output from the Gippsland Basin Joint Venture and Kipper Unit Joint Venture fields that supply the Longford Gas Plant, followed by its expected retirement at the end of 2033.

When local production cannot meet the peak, the south must lean on storage send-out and on gas transported from the north. Capacity increases due to ECGG expansion Stage 3A do help, particularly the increase in capacity of the VTSTI to Culcairn.

### Impact of the proposed DSO (peak-day adequacy)

Peak-day risk in the ECGM is overwhelmingly a southern phenomenon, driven by VIC/NSW winter heating and gas-powered generation load coinciding with Longford's decline (retirement end-2033) and limited southern storage and peaking deliverability. The DSO does nothing to add the things that resolve that risk, namely southbound pipeline and compression capacity (e.g. ECGG expansion Stage 3B), storage injection and withdrawal capability (e.g. at Iona), and firm peaking supply close to load. It simply directs more northern CSG into a market that is already long in the north, where it cannot physically reach southern peak-day demand through corridors that are already close to full on those same peak days.

More damagingly, the DSO is likely to make peak-day exposure worse rather than better over the medium term. By suppressing the domestic price signal through compelled-seller economics and replacing long-dated contracting visibility with an annual ministerial determination of deliverable volume, it erodes the bankability of precisely the long-tenure offtakes that underwrite new southern supply, storage and transport firming, which is the investment AEMO's outlook says is needed from around 2030 to manage the tightening.

It also crowds out the domestic-only producers (Cooper, Otway, Gippsland third parties) whose marginal molecules and flexibility help cover winter peaks. The net effect is that the policy converts a manageable, investment-contingent tightening into a deeper structural southern deficit from the mid-2030s, with peak-day shortfall risk higher, not lower, than the un-intervened baseline.

## Queensland

### Key conclusions

The Queensland market is the one region in Australia that could feasibly supply large aggregate volumes of domestic gas without physical constraints imposed by processing capacity or gas transportation infrastructure. The challenges instead are related to upstream supply and actual demand, with both featuring as the predominant constraint over the short and long terms:

- **Short-term** – a lack of addressable market demand in southern states that would result in the need for substantial and sustained DSO variations and RVM exports, as well as curtailment of base LNG exports from Gladstone.
- **Long-term** – a lack of upstream gas supply from existing sources, and destruction of price and investment signals which halt the development of new supply and leave the ECGM structurally short of gas.

Applying the framework as designed to Queensland LNG exporters, with minimal variations or RVM being approved, results in the southern market experiencing a sustained, structural and large oversupply from 2027 to 2035 as compelled LNG exporter DSO volumes are far in excess of domestic market demand. Between 2027 and 2032, total DSO variations and RVM volumes are over 150 PJ/a, only falling below 50 PJ/a from 2035 through a combination of declining Queensland exporter upstream production, and lower southern production creating a greater capacity to absorb Queensland volumes.

This excessive structural oversupply would remove any price signal in the southern market that would have underpinned investment in new upstream production for future supply, transportation infrastructure to bring this new supply to market and demand moderating programs that would reduce gas usage. Essentially, the ECGM would become so oversupplied that prices would collapse to below the marginal cost of domestic-only producers and any future investment in gas supply would become uneconomic. As a result, it is likely that no new supply would be brought to market during this period.

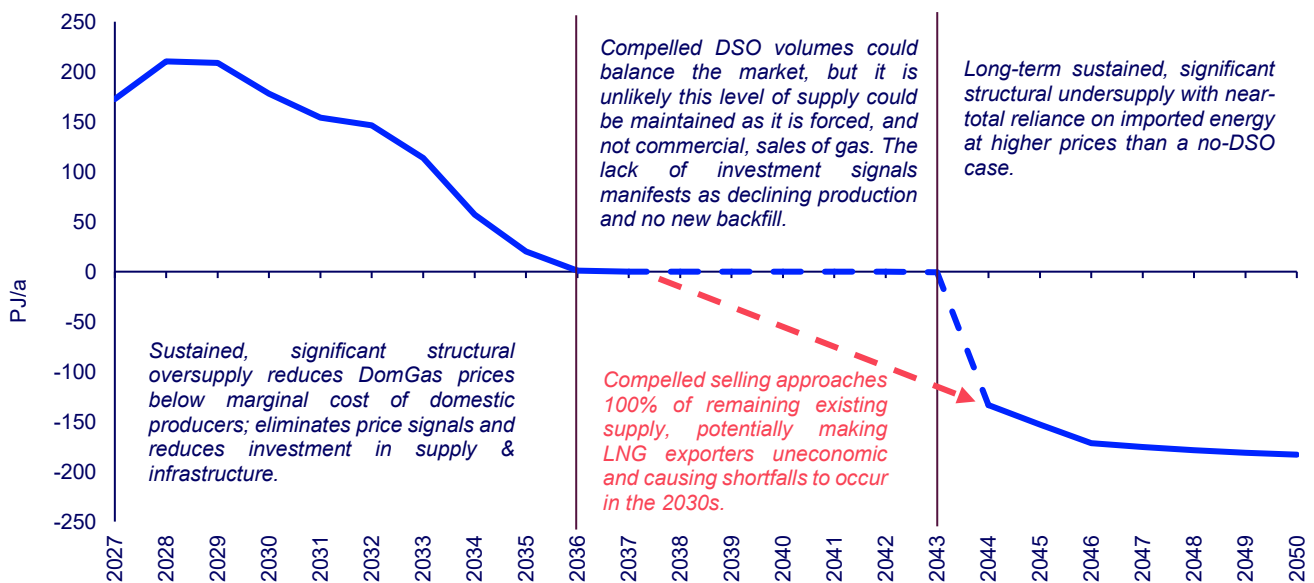
The challenge in the longer-term is that the market flips from being structurally oversupplied to structurally undersupplied as the current Queensland LNG exporter reserves are exhausted, no new supply has been invested in, southern market supply has fallen to less than 20 PJ/a, and southern market demand remains above 200 PJ/a.

By 2043, assuming no investment in new supply, the Queensland LNG exporters will have produced all of their remaining produceable reserves – the carried forward DSO ‘debt’ reaches more than 100% of remaining produceable reserves, and thereafter no upstream gas remains to supply any market (domestic or LNG, Queensland or southern states).

At this point, the southern market has no ready source of gas supply beyond Cooper Basin tail production and (potentially) LNG imports, whilst demand remains close to 200 PJ/a. This is the result of the DSO’s intervention in the market removing all investment and pricing signals in the period 2027 to 2035. The result would potentially be a near-complete reliance on LNG imports to meet ECGM demand, stranded gas pipeline infrastructure with no supply of gas and domestic gas prices set by international LNG markets directly (spot and contract LNG supply delivered into the ECGM, plus regasification costs).

This outcome is one that undermines the policy’s own stated objectives of security of supply, downward pressure on long-run prices, and an orderly energy transition.

Figure 6 – Southern markets supply-demand balance with 20% Queensland DSO



Source: Supply – Wood Mackenzie, Demand – AEMO 2026 GSOO

## Overview of QLD gas market

Queensland is a net exporter of gas to other states in the ECGM, including southern states as well as the NT when required (via reverse-flow in the NGP).

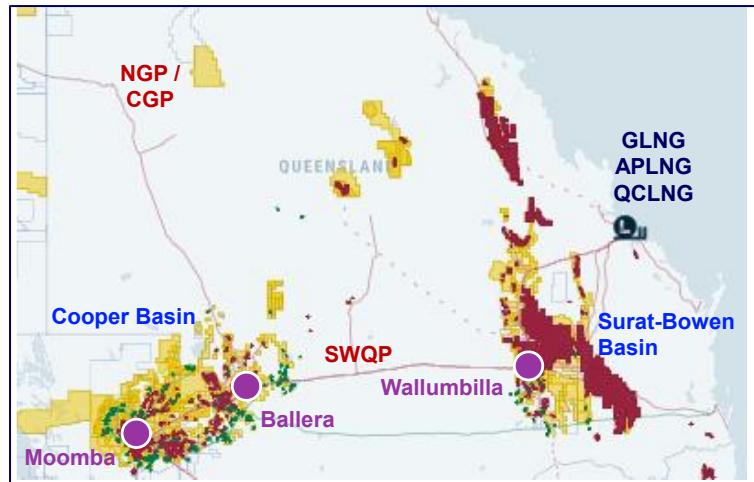
Queensland’s major producing region is the Surat-Bowen Basin in southern Queensland. The Coal Seam Gas (CSG) projects underpin supply to three LNG export facilities at Gladstone – QCLNG, APLNG and GLNG – as well as significant domestic gas volumes that are transported south via the ECGM pipeline network.

All of Queensland’s gas production is onshore, and falls under State jurisdiction as a result.

### Domestic gas supply

In addition to domestic gas volumes provided by the LNG exporters, a number of third-party projects produce gas in Queensland. These include projects in the Surat-Bowen Basin that produce CSG, developments in the North Bowen Basin that supply Moranbah and Townsville (and are not connected to the ECGM), as well as production from the Queensland-side of the Cooper Basin in the south-west.

Figure 7 – Overview of QLD gas market



### Domestic demand

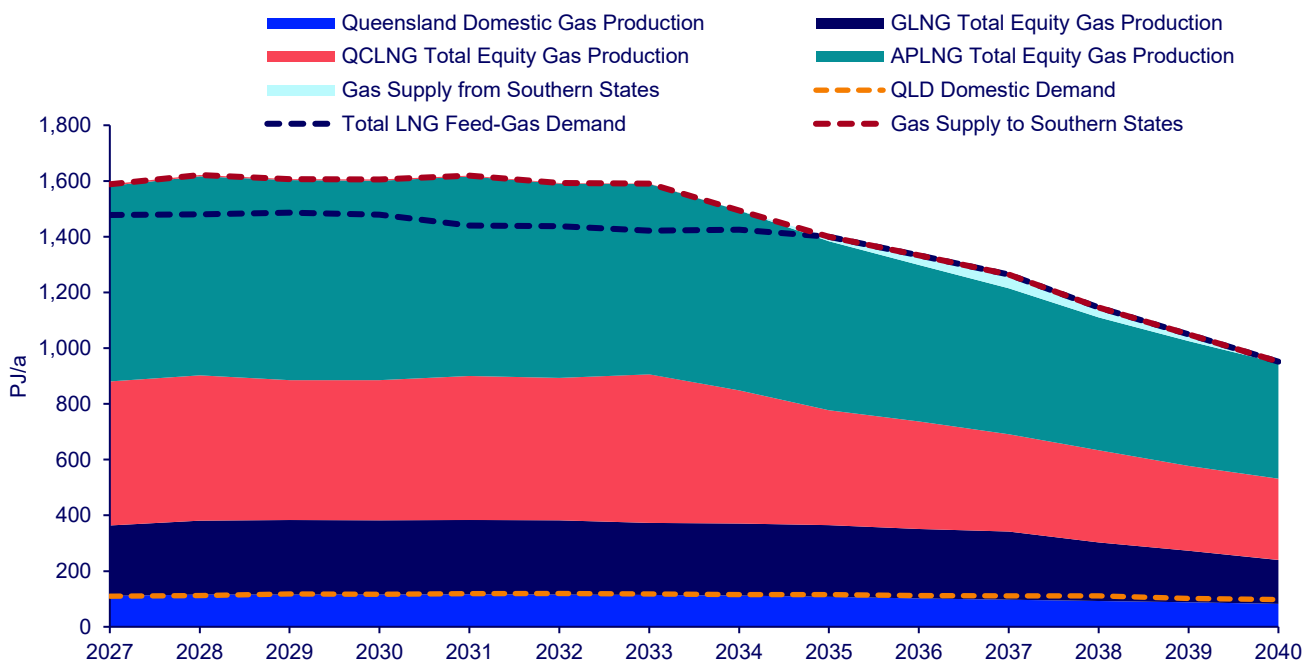
Queensland domestic demand is similar in size to NSW, though it primarily services the industrial sector and GPG, and is much less seasonal than demand in the southern states. Queensland’s current domestic demand is approximately 115 PJ/a, falling slightly to approximately 100 PJ/a by 2040.

The three LNG facilities consume approximately 1,300 PJ/a of feed-gas to produce approximately 23 mmtpa of LNG for export to predominantly Asian buyers. These LNG buyers are in many cases also participants in the LNG project JVs, and helped to underwrite the development of the CSG fields and LNG facilities that are the main supply of gas in Queensland.

### Supply-demand balance

Queensland is a net exporter of gas, with surplus gas transported to southern markets to support balance in those markets as southern supply declines. Surplus gas is transported to southern states for use via the existing pipeline network. Gas can also flow in the reverse direction if required, with Cooper Basin acting as the swing producer between the northern and southern states.

Figure 8 - Queensland gas market supply-demand balance on existing supply (excluding Cooper Basin production)



Source: Supply – Wood Mackenzie, Domestic Demand – AEMO 2026 GSOO

## Queensland LNG exports

### QCLNG

Queensland Curtis LNG (QCLNG) is a Shell-operated CSG to LNG project in Queensland. QCLNG was the first of the CSG-LNG projects to take FID in October 2010. It was also the first to produce an LNG cargo, in January 2015, four years and three months after FID. QCLNG was operated by BG throughout the construction phase, with Shell becoming operator through its February 2016 BG takeover. The Joint Venture of the project includes Shell, CNOOC and MidOcean Energy.

The project sources gas from over 35,000 square kilometers of permits in the Surat Basin. Early development work focused on developing the CSG acreage at the Undulla Nose first, with additional areas developed later. A series of large central processing plants have been constructed, which are supplied with gas from field compressor stations located in each producing area. More than 4,000 wells will be drilled to supply the project and over 180 mega-liters of water-processing capacity installed. A 474 km, 42-inch export pipeline transports gas from the upstream production facilities to the LNG plant, which is located on Curtis Island in Gladstone and features two 4.25 mmtpa (nameplate capacity) LNG trains.

QCLNG is a net contributor to the domestic gas market from its equity production (including Arrow Surat Gas Project volumes).

### APLNG

Australia Pacific LNG (APLNG) is an integrated CSG to LNG project in Queensland. The joint venture operating the project is comprised of Origin Energy, ConocoPhillips and Sinopec. FID on a one-train development was taken in July 2011 and on the second train in July 2012. First LNG was shipped in January 2016.

We expect the project to produce at a plateau rate of 9.0 million tonnes per annum (mmtpa) of LNG over its 30-year life. Gas is supplied from APLNG's CSG fields in the Surat and Bowen Basins, around APLNG's key Spring Gully (Comet Ridge), Condabri (Undulla Nose) and Combabula (Northern Walloons) acreage.

A 42-inch, 530 km export pipeline links the upstream development to a greenfield LNG plant located at Laird Point on Curtis Island. We assume over 5,000 CSG development wells will have to be drilled across the life of the project to meet the gas requirements.

APLNG is a large net contributor to the domestic gas market from its equity production, with more than 150 PJ/a of domestic gas supplied into the market by the project.

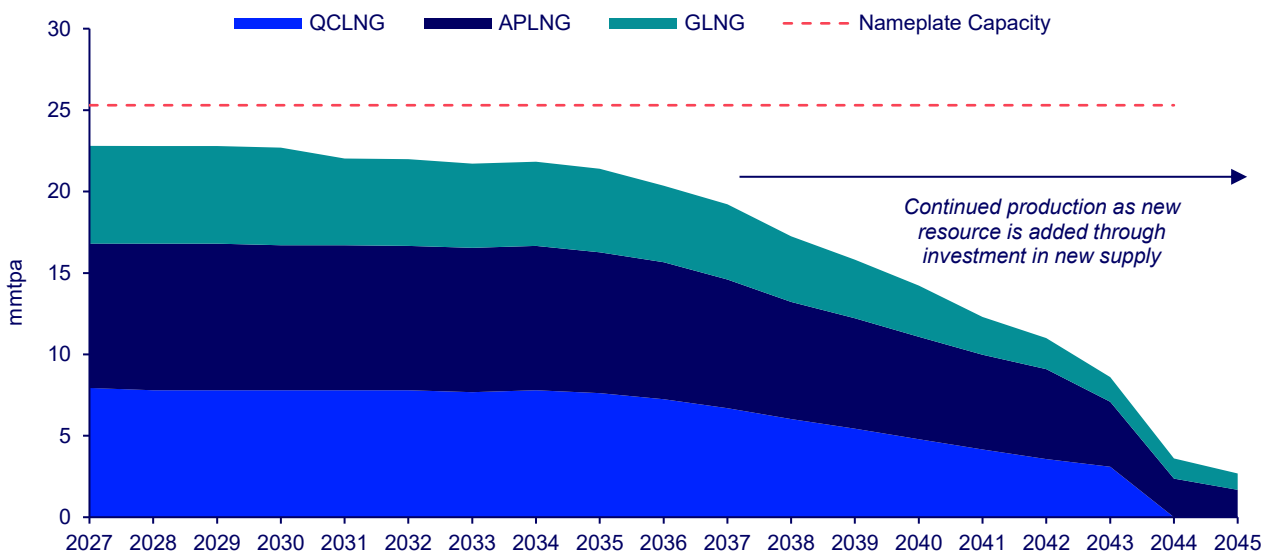
### GLNG

GLNG is an integrated CSG to LNG project located on Curtis Island, near Gladstone, Queensland. The project was first announced in 2007, with FID on the project taken in January 2011 and first LNG shipped to South Korea on 16 October 2015.

Equity CSG feedstock is primarily supplied from the Fairview, Arcadia, Roma and Scotia areas. The project is also supplied by conventional gas from the Cooper Basin fields, and additional volumes of gas are purchased from third parties. The two-train LNG plant has a nameplate capacity of 7.8 mmtpa and a maximum plant capacity of 8.6 mmtpa. We expect the project to deliver approximately 6.0 mmtpa equivalent of feed-gas to the plant through the end of the decade.

A 435 km export pipeline links Fairview and the other upstream supply areas to the LNG plant at Gladstone. We assume over 4,000 CSG development wells will be drilled across the life of the project to meet the gas requirements.

Figure 9 – Wood Mackenzie forecast – Queensland LNG exports based on existing reserves



Source: Wood Mackenzie

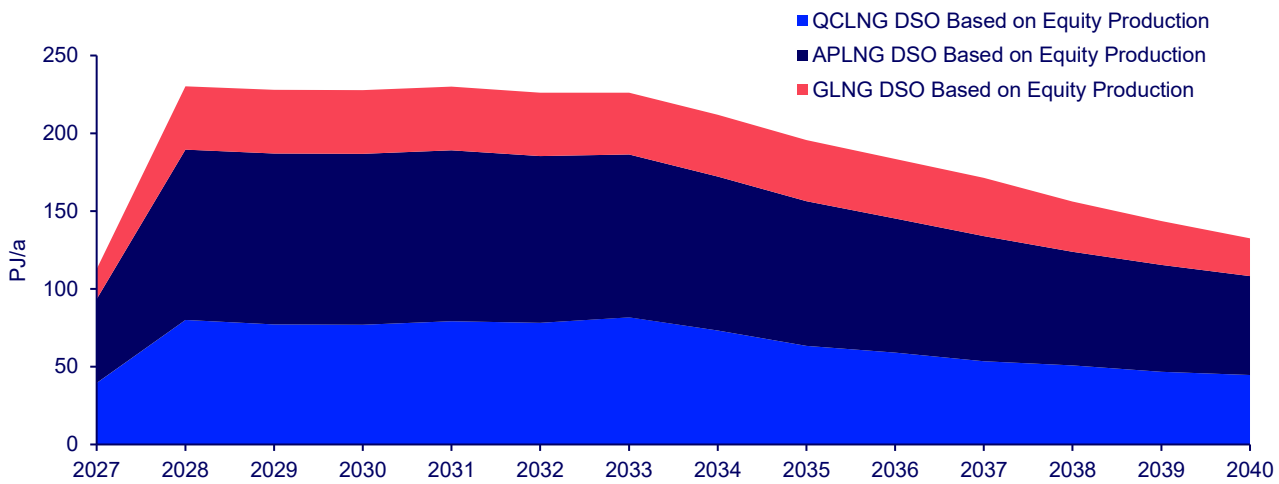
The LNG export forecast shown in the figure above is based on the production of existing 2P and 3P reserves. Additional production from the conversion of 2C resource into reserves, and the addition of new resource over time, will likely extend the production of LNG beyond the current forecast. The nature of CSG production is that it requires continuous capital investment to maintain production. Hundreds of wells are drilled each year, with expansion of associated pipeline networks and water and gas processing facilities. While supply from existing CSG fields is forecast to decline over time, as shown in the figure above, it is continued investment in new supply that will enable continued operation of these facilities over the longer term.

## Effect of a 20% DSO on Queensland domestic gas volumes

### Unconstrained DSO

Based on the calculation methodology outlined in the framework, the nominal DSO volumes in the Queensland market are outlined below. This is calculated on an ‘unconstrained’ basis – i.e. assuming no DSO variations are applied for or granted, and on LNG export volumes from the project proponents’ own JV equity production only.

Figure 10 – Unconstrained Queensland DSO volumes



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

### 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. They are important to consider in the context of the announced policy given the high thresholds expected to be applied to variation approvals.

The ability to deliver DSO volumes from Queensland is constrained by two different market limitations, each impacting different time horizons:

- Short-term (2027 to 2035) – lack of addressable market demand in the ECGM.
- Long-term (2036 to 2040+) – lack of upstream gas supply in Queensland.

Transportation infrastructure does also play a part in constraining DSO volumes from Queensland into southern states. Constraints from transportation infrastructure, as well as current and planned projects to overcome these constraints, are outlined in the southern market section earlier in this report.

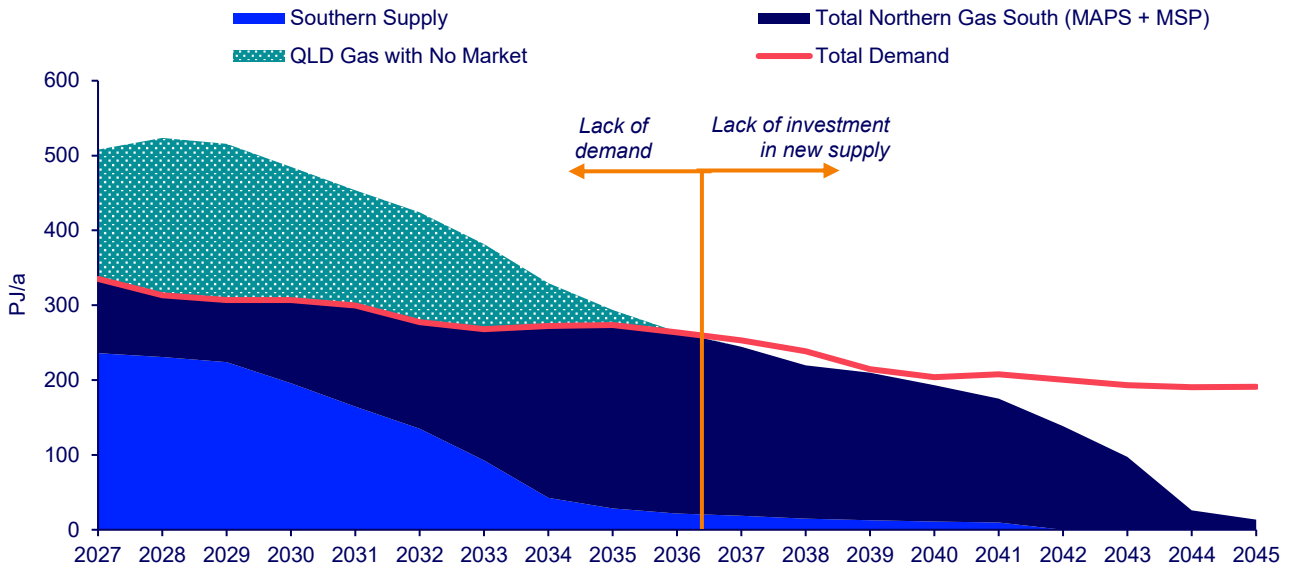
#### Constrained DSO – Short-term

In the short-term, Queensland unconstrained DSO volumes are greater than market demand by a significant margin. The combination of southern supply, Queensland and South Australia domestic gas production, and supply from the NT via the NGP are sufficient to keep the southern market balanced until 2035. As a result, the Queensland LNG exporters will require significant and sustained variations to their DSO levels to keep the market balanced with ‘a small surplus’.

#### Constrained DSO – Long-term

Over the long term, the constraint shifts from a lack of addressable demand to a lack of upstream gas production from Queensland as a result of the loss of investment in new supply. Southern supply begins to decline from 2029, increasing reliance on northern piped gas. From 2036 onwards, there is insufficient gas supply in the north, based on existing production, that could be brought south to satisfy this demand, and thus an annual average supply-demand gap begins to open. The investment in new supply that would have provided greater production over the long term would be unlikely to occur as a result of the DSO.

Figure 11 – Southern market supply-demand balance with 20% QLD DSO



Source: Supply – Wood Mackenzie, Demand – AEMO 2026 GSOO

### 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-discretion based 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.

### Short-term DSO Variations

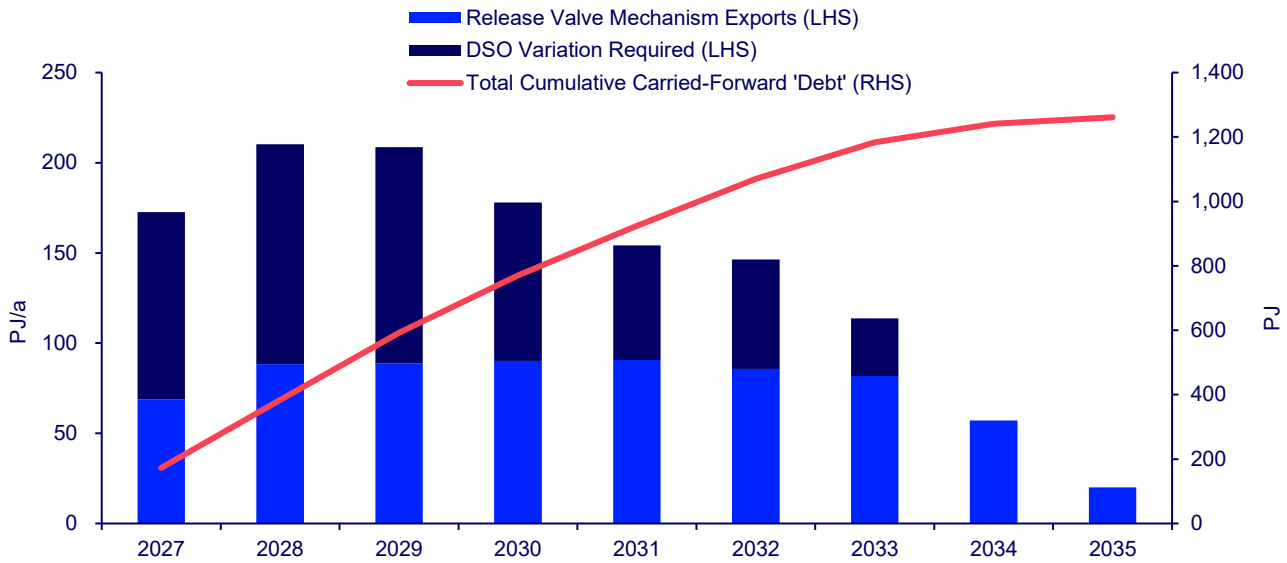
In the short term, supply is significantly greater than demand. As a result, Queensland LNG exporters will require sustained and material variations to the DSO volumes in order to maintain balance in the ECGM.

Between 2027 and 2032, total DSO variations and RVM volumes are over 150 PJ/a, only falling below 50 PJ/a from 2035 through a combination of declining Queensland exporter upstream production, and lower southern production meaning greater capacity to absorb Queensland volumes. This excessive structural oversupply would remove any price signal in the southern market that would have underpinned investment in new upstream production for future supply, transportation infrastructure to bring this new supply to market and demand moderating programs that would reduce gas usage. Essentially, the ECGM would become so oversupplied that prices would collapse to below the marginal cost of domestic-only producers and any future investment in gas supply would become uneconomic. As a result, it is likely that no new supply would be brought to market during this period.

The challenge in the longer term is that the market flips from being structurally oversupplied to structurally undersupplied as existing Queensland LNG exporter reserves are exhausted, no new supply has been invested in, southern market supply has fallen to less than 20 PJ/a, and southern market demand remains above 200 PJ/a. The implications from the lack of investment in new supply would take a decade or more to rectify given the long-lead-time nature of gas developments.

The balancing mechanisms in the framework consider this scenario, however even with greater southern reliance on Queensland gas supply, cumulative DSO variations and RVM volumes reach 1,260 PJ by 2035 – enough to supply the entire ECGM domestic demand for almost three years.

Figure 12 – Annual and cumulative DSO variations and RVM exports to balance ECGM – 2027 to 2035



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

### Long-term DSO variations and RVM

The challenge in the longer term is that the market flips from being structurally oversupplied to structurally undersupplied. By 2035, Queensland LNG exporters have developed a cumulative domestic market ‘debt’ of 1,260 PJ. From 2036 onwards, the southern domestic market needs these volumes – southern supply is less than 20 PJ/a at this point. This may seem like the DSO system has achieved its objective – reserving Queensland gas for future periods of supply shortfalls (ignoring the fact that this is only achieved if LNG exports are severely curtailed and existing LNG contracts broken to keep this gas in the ground).

The reality, however, is that over the same period of accumulation of this ‘debt’, the Queensland LNG exporters have started to deplete their existing upstream reserves. This is a result of production continuing to supply both some LNG exports, and the domestic market itself, over the period 2027 to 2035, coupled with the loss of investment signals and risk capital to develop new resources that would have otherwise supplied this gas over the longer-term.

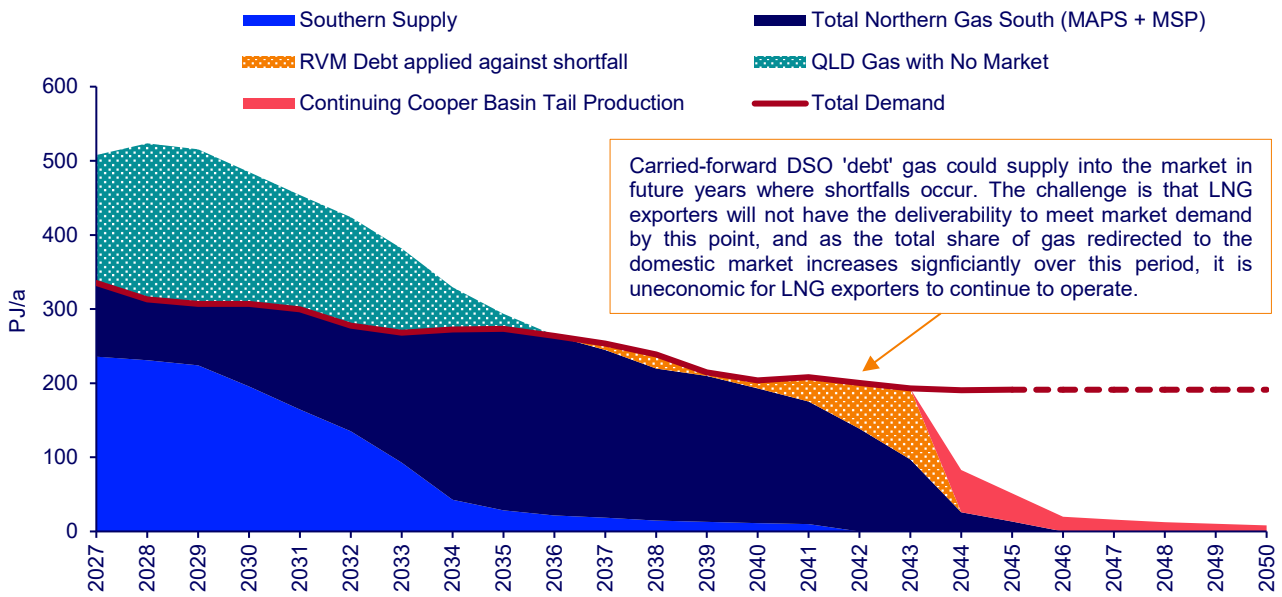
In theory, when the market becomes structurally short, Queensland LNG exporter DSO ‘debt’ volumes could be called upon to fill the gap. However, this ignores the second-order impacts of the DSO that would likely reduce upstream investment in the short-term and lower overall produceable reserves, as well as potentially remove domestic-only producers from the market in both Queensland and the southern markets. Gas is only classified as a Reserve if it can be commercially produced and sold for an economic return. Effectively the DSO policy would compel gas producers to continue to produce gas at a loss after the economic life of existing fields has been reached.

Theoretically, carried forward ‘debts’ could be called upon could keep the ECGM balanced until 2042 under a best-case scenario where ongoing investment in drilling, sustaining capital, maintenance and operations continues without detriment (highly unlikely in a post-DSO environment). This also assumes that the LNG exporters would continue to be commercially viable as they transition to compelled DSO debt repayment while no longer having sufficient gas to maintain production on a commercial basis.

In any case, even with compelled DSO debt repayment, by 2043 the Queensland LNG producers will have produced all of their existing reserves (assuming no major investment is made in new supply). The carried forward DSO ‘debt’ reaches more than 100% of remaining existing reserves, and thereafter no developed upstream gas remains to supply any market (domestic or LNG, Queensland or southern states).

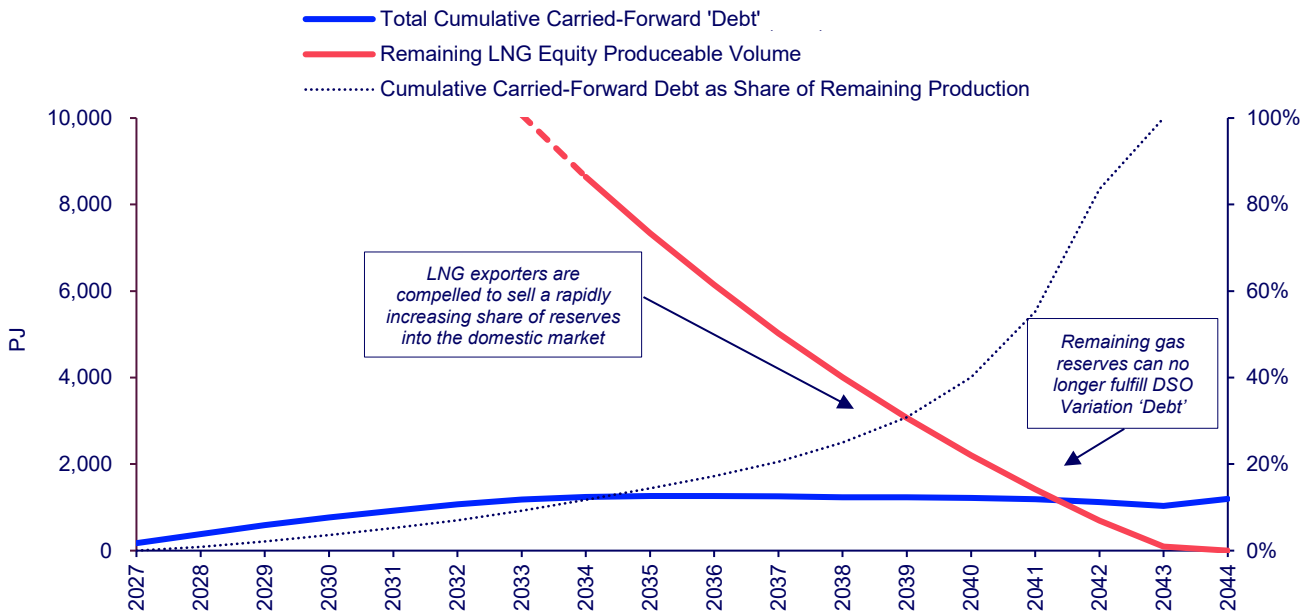
At this point, the southern markets lose all gas supply from every source with the exception of Cooper Basin tail production and (potentially) LNG imports, whilst demand remains close to 200 PJ/a. This is the result of the DSO’s intervention in the market removing all investment and pricing signals in the period 2027 to 2035 as the southern market is structurally oversupplied (by more than 200 PJ/a) through this period. The result would potentially be a near-complete reliance on LNG imports to meet ECGM demand, stranded gas pipeline infrastructure with no supply of gas and domestic gas prices set by international LNG markets directly (spot and contract LNG supply delivered into the ECGM, plus regasification costs).

Figure 13 – Southern market supply-demand balance – Unconstrained DSO



Source: Supply – Wood Mackenzie, Demand – AEMO 2026 GSOO

Figure 14 – QLD LNG exporters’ remaining produceable volumes against total DSO carried-forward ‘debt’



Source: Wood Mackenzie

### Use of domestic gas purchases to acquit DSO obligations

Purchasing gas from domestic gas producers offers LNG exporters limited opportunity to acquit the DSO. The framework’s additionality test requires that for any LNG exporter that meets its obligation through a third party, the arrangement must deliver gas to the domestic market ‘that would not otherwise have been made available’. Contracting the existing output of a Cooper, Otway, Gippsland or Surat-Bowen domestic-only producer fails this test, because those molecules are already supplied domestically. Redirecting them to an exporter’s DSO ledger simply reshuffles existing supply and displaces the independent producer’s own customers rather than adding to domestic supply.

To contribute to the acquittal of an exporter’s DSO volumes the supply must be incremental, which means the LNG exporter must underwrite new production. The economics of underwriting genuinely new supply are self-defeating for the same reasons that cause domestic-only producers to be crowded out of the market. New upstream developments, whether frontier unconventional acreage, offshore backfill, or incremental onshore appraisal, require a domestic price that recovers

full-cycle costs including discovery, development and sustaining capital, and they require it under long-dated, bankable contracts to reach FID. The price signal the DSO produces sits below that hurdle by design, so an exporter rationally underwriting third-party development to source additionality volumes would be committing capital to projects whose delivered gas cannot clear at a price that repays them.

Compounding this, new supply cannot be developed in accordance with the framework’s compliance timetable. Appraisal, approvals, FID, drilling and midstream connection run over multiple years, whereas the DSO commences in less than one year and thereafter operates on an annual reset basis. An LNG exporter facing curtailment in a given regulatory year cannot produce new supply in-year, and the annual cadence offers no credit for capital committed today against gas that flows late this decade or beyond.

The gross DSO on QLD and NT LNG exports runs to a very large annual volume (indicatively of the order of 250 to 280 PJ/a combined), and even the smaller incremental compelled component would require sustained new supply well beyond what the visible pre-FID pipeline and incremental new projects can collectively deliver. The Beetaloo is the only resource of a scale that could theoretically move the balance, but it remains transport-constrained to both northern and southern load and is years from material sustained production. Underwriting it at compelled-seller prices is neither economic nor timely.

The result is that exporters seeking additionality volumes would be bidding for a supply base that is too small in aggregate, too slow to develop, and uneconomic at the prices the policy itself creates. As a result, while supporting additional domestic gas production should be available as an option for exporters, it is unlikely to be a major contributor to meeting DSO obligations – particularly in the near-term.

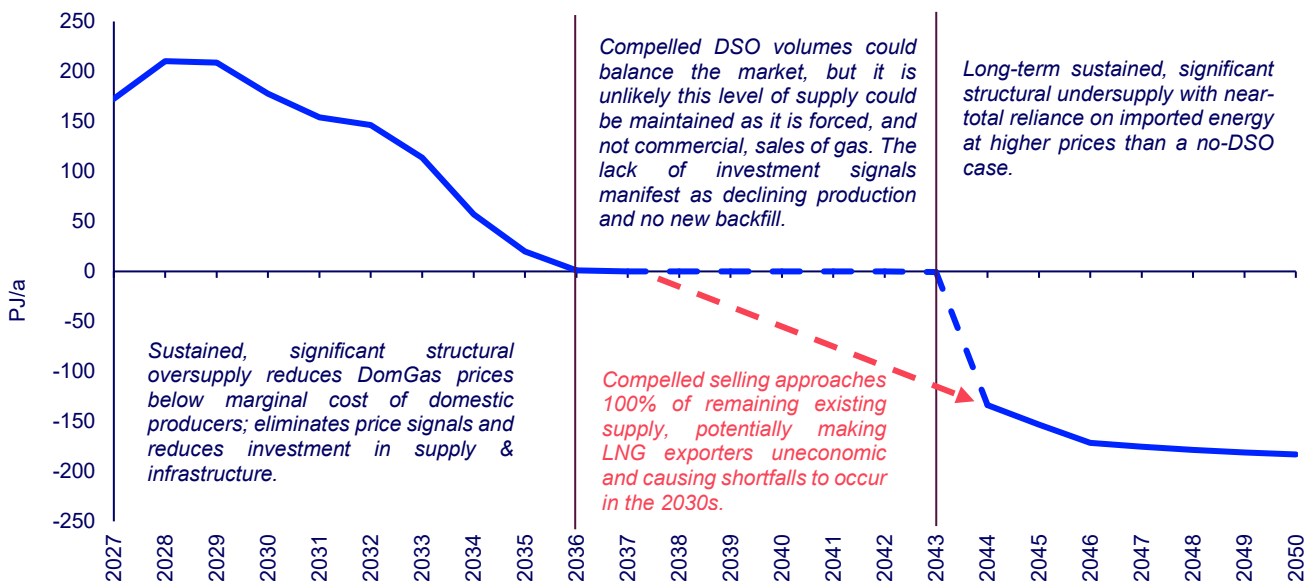
## Market balances on deliverable DSO

Applying the framework as designed, with minimal variations or RVM being approved, the southern market experiences a sustained, structural and large oversupply from 2027 to 2035 as compelled LNG exporter DSO volumes are far in excess of domestic market demand. From 2036 to 2043, the market could theoretically be balanced by high levels of compelled-selling as a result of southern supply declining, Queensland LNG exporter supply declining, and no investment in new supply occurring due to the elimination of price and investment signals in the market.

From 2043, the southern market experiences a sustained, structural and large undersupply. At this point, the majority of domestic gas production in eastern Australia has ceased, no new supply has entered the market to replace or backfill it, and the market becomes almost wholly reliant on imported energy to meet domestic needs. In such a situation, prices become directly linked to international LNG markets, with the added cost of shipping, regasification, storage and transport being added to the cost of LNG procurement so that the gas can be brought to the locations where demand exits.

This outcome stands in stark contrast to the policy’s own stated objectives of security of supply, downward pressure on long-run prices, and an orderly energy transition.

Figure 15 – Southern markets supply-demand balance with 20% Queensland DSO



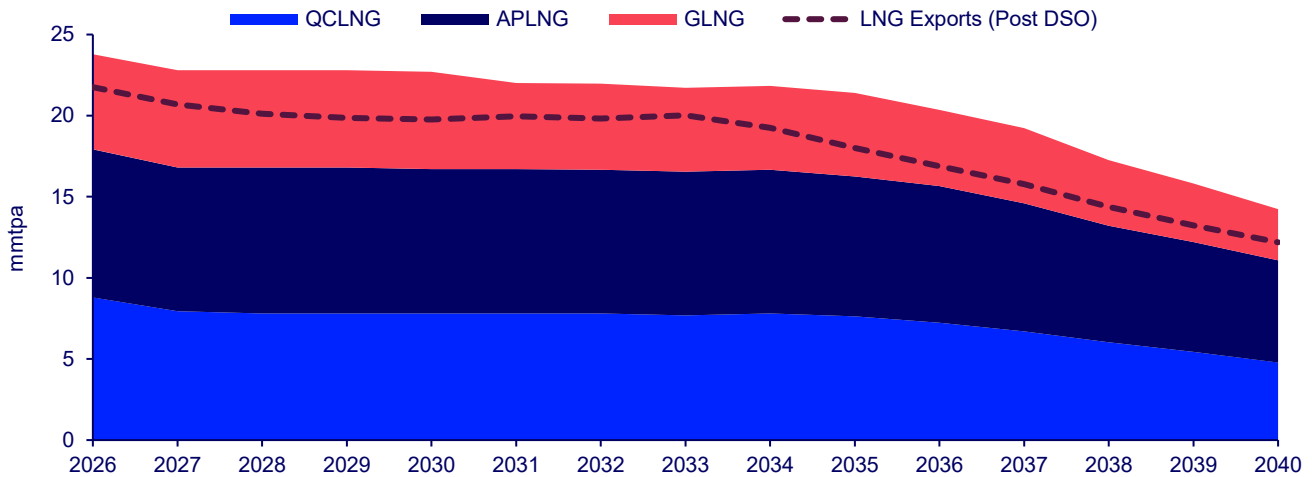
Source: Supply – Wood Mackenzie, Demand – AEMO 2026 GSOO

### LNG export curtailment

The Queensland LNG exporters are generally feed-gas limited in aggregate. The blunt instrument of a large, rigid, volume-based domestic gas obligation would result in the curtailment of LNG exports even if the DSO volumes were able to be physically supplied and had an addressable market demand to meet. Any amount of gas reserved for domestic use is an amount that cannot now be exported, and as the projects are feed-gas limited, this means a reduction in LNG output must result.

Assuming that there was sufficient domestic market demand to absorb DSO volumes from Gladstone LNG exporters, which is not the case as has been outlined above, Gladstone LNG exports would still be reduced by 37 mmt between 2027 and 2040 due to the diversion of feed-gas to the DSO. This loss of export volume could potentially cost Australia A\$16.8 billion in lost export revenue<sup>2</sup> over this period and would require the breaking of existing and foundation contracts that underpinned these developments.

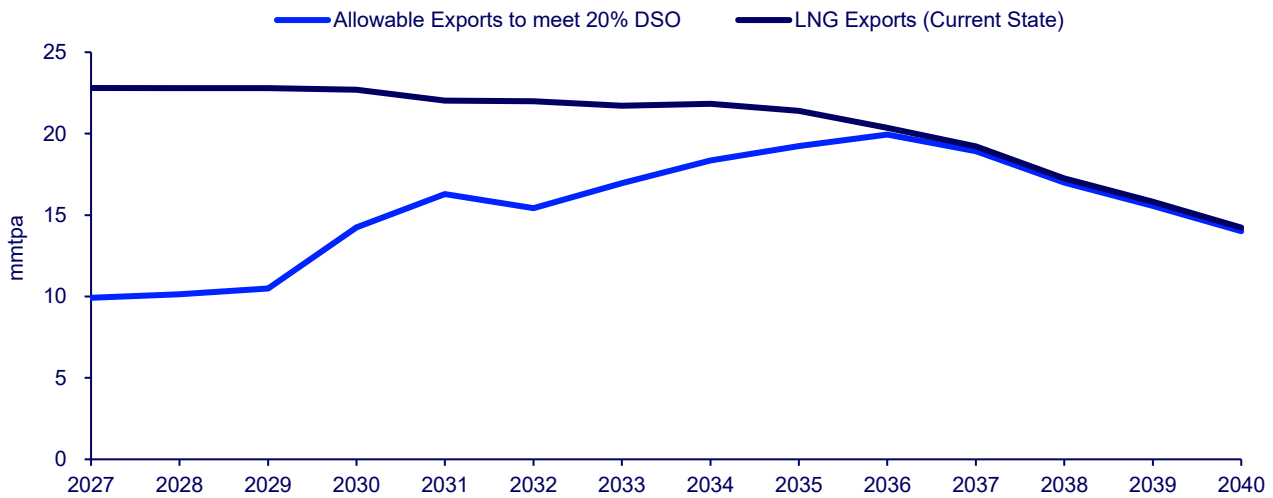
Figure 16 – Allowable LNG exports with 20% domestic gas diversion



Source: Wood Mackenzie

If, as outlined in the framework, DSO variations are expected to be ‘rare occurrences’ and subject to ‘high thresholds’ for approval, the only other way to balance the ECGM under the proposed DSO policy is to curtail LNG exports even further. As the lack of demand in southern states limits the amount of LNG exporter DSO supply in the short-term, the absence of sustained, significant variation approvals mean that LNG export volumes would have to be curtailed from approximately 23 mmt in 2028 to approximately 10 mmt. Over the forecast period from 2027 to 2040, the total export curtailment required to balance the ECGM would reach 70.5 mmt, putting as much as A\$32 billion in export revenue at risk.<sup>2</sup>

Figure 17 – Allowable LNG exports under existing and DSO framework with no variation approvals



Source: Wood Mackenzie

<sup>2</sup> 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.

## Impact on price, investment and Government revenue

### Price impacts

Gas in the domestic market is priced as a result of supply, demand and the cost to transport that supply to meet demand where it exists. Marginal cost serves as the absolute price floor for any competitive commodity market. Market prices are driven by supply and demand, but supply itself depends directly on production costs. In a rational market, a producer will only supply gas if the market price covers the additional cost of producing that final molecule of gas (the marginal cost). If the market price drops below this threshold, the producer loses money on every extra molecule supplied and would choose not to supply those molecules.

Therefore, to ensure that supply constantly meets total demand, the market price must remain high enough to cover the marginal cost of the single most expensive producer needed to satisfy that demand. If the price falls any lower, that critical high-cost supplier drops out, creating a market shortage that naturally forces prices back up.

In the ECGM, northern producers must also consider the netback of transportation costs from the end market in southern states to production fields in northern states. As a result, northern supply typically has a higher marginal cost of supply to the southern market than proximate southern fields.

#### Short-run marginal cost

Short-run marginal cost (SRMC) is the incremental cost of producing one more unit of gas from wells and facilities that already exist. For a producing field, this is essentially operating cost: the fuel, labour, maintenance, water handling and processing needed to lift and deliver the next gigajoule, with the large upfront capital already sunk and therefore irrelevant to the decision to flow another molecule.

While a price above SRMC allows a supplier to continue operating, it is insufficient to generate a return on investment or to underpin new investment. SRMC considers the cost of producing the next unit of gas from existing facilities. It does not consider the investment already made to enable that production – the capital required for exploration, appraisal, development drilling, processing facility and pipeline development – nor the return on that investment commensurate with the risk taken. As a result, SRMC is typically low in comparison to the delivered price of gas. The full-lifecycle cost that considers the large upfront capital investment required to develop gas supply is the Long Run Marginal Cost (LRMC), described below.

The SRMC concept is central to the DSO thesis because it explains why compelled-seller economics impact so substantially. An LNG exporter forced to sell and deliver domestically, whose only alternative is curtailing exports, faces a domestic opportunity cost that collapses toward its SRMC (or lower, once you net off the value of preserving export volumes). Because SRMC sits far below the full-cycle cost that a standalone domestic-only producer needs to recover, the exporter can rationally tolerate low domestic prices and still be better off than curtailing. That is the mechanism by which the clearing price gets reset downward. It does not, however, deliver a sustainable gas market.

#### Long-run marginal cost

Long-run marginal cost (LRMC) is the cost of bringing *new* supply to the market, and it includes everything SRMC excludes; exploration and appraisal, development drilling, processing and pipeline capital, and a return on that capital commensurate with the risk taken. LRMC is the price a project must expect to earn, on a full-cycle basis and over the life of a long-dated contract, to justify FID.

It is materially higher than SRMC for frontier and pre-FID plays (e.g. Narrabri, Beetaloo Basin, new Surat-Bowen Basin developments, and offshore Otway/Gippsland backfill). This is the concept that connects the near-term price collapse to the post-2035 shortage. New supply reaches FID only when developers can underwrite it with bankable, long-dated gas sales agreements priced at or above LRMC. If the DSO suppresses the domestic price signal toward SRMC and, through the annual compliance cadence, erodes the contract tenure that supply-side investment relies on, then expected returns fall below LRMC, hurdle rates rise, and the projects that the 2026 AEMO GSOO says are needed from 2030 to balance the market over the long-term do not proceed. The distinction matters analytically because the policy's early price reductions are based on a movement along the SRMC curve of existing supply, while the security of the market from the mid-2030s depends on prices clearing at LRMC to pull in new investment. A framework that optimises the former while undermining the latter is essentially self-defeating.

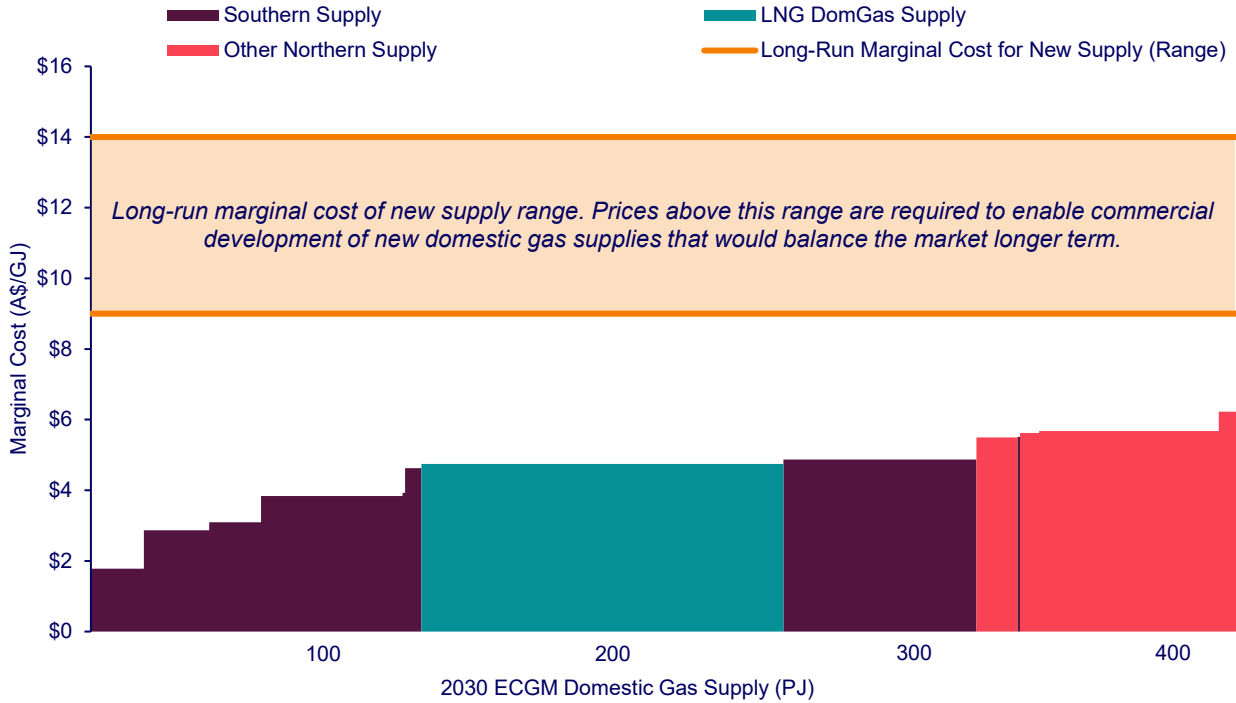
The Australian Competition and Consumer Commission (ACCC)'s Gas Inquiry 2017-2030 Interim update on the east coast gas market published in December 2025 highlights that the LRMC of new supply that could be brought to market in the ECGM is between A\$9/GJ and A\$14/GJ over the period 2030 to 2035. Gas market prices below this range would result in this new supply no longer being developed, as it is not possible to achieve an economic return on investment.

#### Short-term – oversupply and significant price suppression

In 2030, with the addition of a 20% DSO, LNG exporters would have to increase their domestic gas supply by 160 PJ of additional volume into a market that is already balanced on an annual basis. The economics of being a compelled seller means that the LNG exporters will sell this gas into the domestic market at a price that is competitive with the lowest cost alternative supplier of gas (the marginal supplier). This displaces other volumes of supply from domestic producers who are not compelled sellers and do not have alternative monetisation options to subsidise the uneconomic sale of domestic gas (i.e. selling gas below their marginal cost of supply).

Below is a representation of the supply cost curve for existing production in the ECGM delivered into southern markets. As this is existing supply it is based on short-run marginal cost, which does not consider the cost of capital already sunk. Note that short-run marginal cost does not imply the market price for that gas, rather it describes the minimum floor price that would cover the short-term cost of supply without any return on invested capital. It is a metric used to determine which sources of supply would be displaced first in a market with compelled DSO volumes that effectively have no floor price (due to the nature of compelled seller economics).

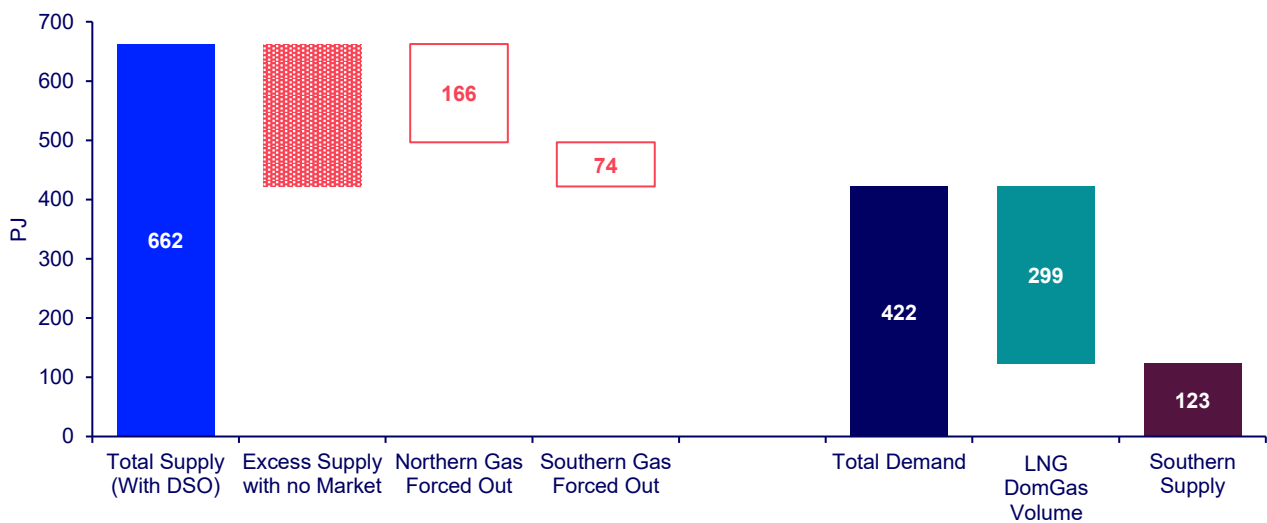
Figure 18 – Gas supply short-run marginal cost curve – 2030



Source: Wood Mackenzie

In 2030, the DSO results in an oversupply of 240 PJ compared to ECGM demand. In order to balance the market, all northern gas supply other than LNG exporter volumes would be displaced (given their higher marginal cost of supply). Additionally, another 74 PJ of southern production would need to be displaced – reducing southern market supply by 38% and potentially exacerbating peak-day shortfall risks.

Figure 19 – ECGM gas supply-demand balance with DSO volumes – 2030



Source: Wood Mackenzie

Due to the LNG exporters’ compelled selling, they would supply more than 70% of demand in the ECGM (including Queensland and southern states). Only the most cost competitive southern suppliers could continue to sell domestic gas at a price that would recover their short-run marginal cost (effectively covering ongoing OPEX with no return on investment).

This collapse in price is what drives domestic market suppliers with higher cost production to withdraw from the market – it is not commercially viable to sell gas at a price lower than the marginal cost of producing that gas.

Further, low prices as a result of compelled selling by LNG exporters would make any new supply projects uneconomic. Even for low cost producers, a price close to their short-run marginal cost is not sufficient to underpin the investment of new capital. An inability to earn a return on capital that is not yet sunk would prevent any new supply from coming to market, as domestic producers would focus on producing remaining developed reserves at the lowest possible cost, before exiting the market instead of investing in new backfill supply (exploration, appraisal, tie-back of new wells etc.).

The incentive to connect the Beetaloo Basin to the ECGM would be removed and could potentially put the development itself at risk, as it would be uneconomic to develop the field and construct a large transmission pipeline to connect the NT with the ECGM to sell gas at loss-making prices.

### **Mid-term – balanced, at a higher price**

With prices at uneconomic levels through the end of this decade and into the early 2030s, the lack of investment in new or incremental supply manifests as an accelerated decline in production from northern domestic gas producers and southern market producers. In Queensland, where CSG production requires continuous drilling, de-watering and pipeline network expansions to maintain existing production, the lack of investment support would likely accelerate production decline.

Projects with no ability to monetise gas through LNG export would need to halt any further drilling or development to extend existing production, and prospective supply from projects in the Surat-Bowen Basin, Cooper Basin and Taroom Trough would be unlikely to proceed.

The impact of this is a near-complete reliance on LNG export DSO volumes and ongoing Cooper Basin production to supply the ECGM. By 2036, demand in the ECGM is forecast to fall by approximately 50 PJ/a to 375 PJ (though this assumes no increases in demand due to price signals). At this point, Queensland could supply up to 95% of total ECGM demand, and with the loss of southern production there may be an increased need to import LNG cargoes to meet peak-day winter demand in southern states, creating a two-tier market during peak winter months.

While the market may remain balanced on an annual average basis, this balance would now be almost exclusively reliant on the supply of Queensland and northern gas. With reduced sellers in the market and large compelled DSO volumes that erode LNG output from existing reserves further, there is a risk that the market becomes undersupplied and LNG netback pricing returns.

### **Long-term – structurally short with no new supply**

As northern gas also begins to decline, from 2037 annual supply-demand gaps begin to emerge. This widens rapidly after 2040 as the need for new sources of supply becomes greater. With the loss of investment in new supply, the sources for this supply become limited. Rising prices would signal the need for more gas and greater investment to discover, develop and bring new supply to market, as well as underwriting the economics of new developments. However, the loss of domestic gas production due to the oversupply and collapse of prices over the decade to 2036 would result in a lack of risk capital available to fund these developments.

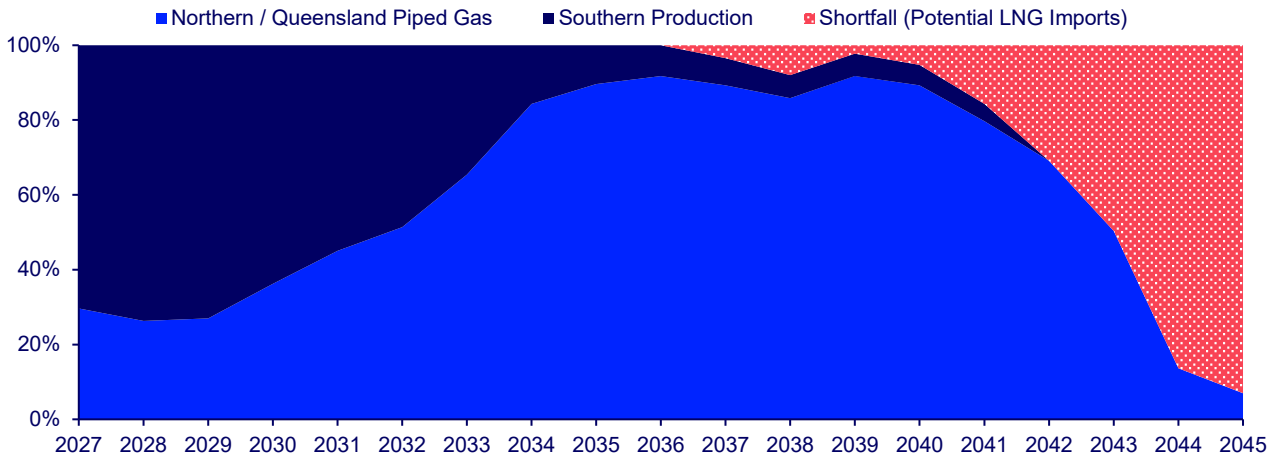
The global nature of oil and gas resources means that the period of suppressed prices and LNG export restrictions, as well as the burdens associated with wide, annual and uncertain Ministerial discretion over the market, would cause risk capital to be invested in other jurisdictions. The lack of project developments in Australia during periods of depressed prices would also cause the loss of drilling and gas-field service providers, whose specialist knowledge, technology and equipment is then difficult to rebuild and would take many years.

Even if risk capital were made available in Australia, the timeframe to discover, appraise, develop and extract new gas resources is measured in decades. Coupled with heightened sovereign risk, low confidence in existing and potential future regulatory environments, and the comparatively long and burdensome project approval processes in Australia, the development of new domestic supply is unlikely to be realized in time to meet growing and material supply-demand gaps. The investment that would fill these gaps is needed now, and in the immediate future. Pushing this investment out beyond the mid-2030s would result in a high probability of shortfalls and reliance on LNG imports.

In the event that LNG import terminal(s) enter the market, the southern domestic gas market will become even more strongly linked to LNG pricing. Marginal price setting supply in peak winter months will be linked to LNG import parity, which presents structurally different contracting options to the existing fixed-price agreements for domestic gas buyers. The delivered price of gas from LNG imports (delivered to Sydney) needs to consider the cost to purchase LNG at global market prices, shipping to Port Kembla, the cost of regasification, and transport from Port Kembla to Sydney.

Based on Wood Mackenzie's global shipping database, we estimate shipping costs to Port Kembla to be A\$0.33/GJ. Regasification costs depend on the utilisation of the regasification facility but could be between A\$1.00 and A\$2.50/GJ. Pipeline transport to Sydney via a lateral and Eastern Gas Pipeline north-haul transport is estimated to be A\$0.77/GJ, effectively resulting in LNG import parity gas prices being equal to Asia Spot LNG plus A\$2.10 to A\$3.60/GJ. From 2040, Wood Mackenzie forecasts Asian Spot LNG prices to be above US\$11 / mmBtu (in real 2026 terms). This would equate to domestic gas prices at import parity of approximately A\$17 to A\$19/GJ.

Figure 20 – Share of gas supply by source – ECGM (Queensland and southern states)



Source: Wood Mackenzie

### Impact on Government Revenue

The Queensland LNG projects produce feed-gas from onshore CSG fields within Queensland State jurisdictions, meaning they are not subject to federal Petroleum Resource Rent Tax (PRRT). The projects are subject to Queensland state royalties, which have differing rates and price benchmarks for domestic gas and LNG project feed-gas.

The effects of the DSO on Queensland state royalty receipts would be two-fold; the royalty rates vary with gas price, and royalty rates are higher for LNG feed-gas than domestic gas. As a result of the diversion of LNG feed-gas to the domestic market, Queensland would lose royalty income due to the application of lower rates. The effect of significantly lower domestic gas prices would also further reduce royalty receipts as the rate is applied to a lower absolute price value.

This loss of royalty revenue at a state level is additional to the loss of corporate income tax and other secondary taxes paid by the LNG exporters and the domestic producers who may be crowded out of the market altogether.

Depending on how the policy is implemented and the ability to obtain DSO variations and RVM exports, Wood Mackenzie estimates that the potential reduction in Queensland royalties on upstream CSG production could be between A\$200m to A\$800m in 2028 alone.

Table 1 – Queensland state royalty rates

Royalty Regime	Average sales price	Royalty Rate	Reference Price
Domestic gas	Up to and including A\$3/GJ	2%	Wallumbilla pricing
	Over A\$3/GJ and up to and including A\$8/GJ	8%	
	More than A\$8/GJ	10%	
Supply gas (gas supplied by a third-party to LNG exporters as feed-gas)	Up to and including A\$3/GJ	5%	Oil linked (9% Brent)
	Over A\$3/GJ and up to and including \$8/GJ	10%	
	More than A\$8/GJ	12.5%	
LNG project (equity) gas	Up to and including A\$9/GJ	3%	Oil linked (13.5% Brent)
	Over A\$9/GJ and up to and including A\$14/GJ	9%	
	More than A\$14/GJ	12.5%	

Two scenarios were considered to determine the impact on Queensland government royalty receipts over a single year in 2028:

1. LNG exporters divert 20% of LNG output to the domestic market (unconstrained DSO) despite any market limitations on deliverability.

2. LNG exports are curtailed such that LNG exporters are limited to exports equal to five times their domestic market gas sales (constrained DSO, limited by domestic market demand).

Table 2 – Case 1 – diversion of unconstrained DSO to domestic market in 2028

Diversion of unconstrained DSO to Domestic Market		
2028 Unconstrained DSO volume	220 PJ	Equal to 20% of 2028 exports under a DSO policy
Equity gas for LNG export		
Benchmark gas price (LNG project equity gas)	A\$13.04 / GJ	13.5% of US\$70 / bbl Brent oil price and 1.38 AUD / USD
Royalty	9%	
Royalty per GJ	A\$1.17 / GJ	
<b>Total Royalty payable</b>	<b>A\$258.2m</b>	
Domestic gas		
Benchmark gas price (Domestic Gas)	A\$3.20 / GJ	Short-term post-DSO Wallumbilla hub price
Royalty	8%	
Royalty per GJ	A\$0.26 / GJ	
<b>Total Royalty payable</b>	<b>A\$56.3m</b>	
<b>Net Royalty Loss (2028)</b>	<b>A\$201.9m</b>	

Table 3 – Case 2 – Export curtailment to meet constrained DSO based on actual deliverable volume

Export Curtailment based on actual deliverable DSO		
Current LNG Exports		
2028 LNG Export Volume	1,260 PJ	
Benchmark gas price (LNG project equity gas)	A\$13.04 / GJ	13.5% of US\$70 / bbl Brent oil price and 1.38 AUD / USD
Royalty	9%	
Royalty per GJ	A\$1.17 / GJ	
<b>Total Royalty payable</b>	<b>A\$1.48 billion</b>	
2028 LNG Export Volume	94 PJ	Actual deliverable volume (demand constrained)
Allowable RVM exports	76 PJ	30% of DSO
Permitted exports	546 PJ	Grossed up from 20% actual deliverable DSO plus RVM exports
Benchmark gas price (LNG project equity gas)	A\$13.04 / GJ	13.5% of US\$70 / bbl Brent oil price and 1.38 AUD / USD
Royalty	9%	
Royalty per GJ	A\$1.17 / GJ	
<b>Total Royalty payable</b>	<b>A\$0.64 billion</b>	
<b>Net Royalty Loss (2028)</b>	<b>A\$838 million</b>	

## Northern Territory

The application of the proposed DSO framework is only workable in the NT with significant and sustained DSO variation approvals. Physical constraints and a lack of addressable markets for NT LNG export DSO volumes make meeting the requirements of the framework difficult without these variations. With significant and sustained variations to maintain LNG export volumes, the application of the policy to the NT would result in no material change to domestic gas supplies in return for annual, highly discretionary and Government-centric approval cycles that would raise costs, undermine the ability to enter into and fulfil long-term LNG contracts, expose the projects to greater volatility and reduce Australia's attractiveness as both a supplier of energy and an investment destination.

### Impact on annual average supply-demand shortfalls

The proposed DSO when applied to the NT makes no difference to forecast average annual shortfalls in the southern ECGM from 2034. Without significant and sustained variations, the DSO volumes supplied into the NT market under the proposed DSO would be stranded in the NT without an addressable market.

### Impact of proposed DSO in the NT

This analysis has considered five theoretical pathways for the NT LNG exporters to discharge their DSO commitments without significant and sustained variation approvals if the policy is applied to the NT as currently designed. Each option is unlikely to be practical to implement – the time horizon is too short, and the investment too large, to be achievable – and would likely have negative impacts on the market.

#### 1. Develop and expand infrastructure to supply DSO volumes to the ECGM via Queensland

The NT LNG exporters could invest in significant infrastructure upgrades at both plants to process domestic gas, combined with large pipeline investments to deliver that gas from Darwin to South Australia or Queensland and into the ECGM. Given the lead times for development of this infrastructure, significant and sustained variations would still be required in the short-term. This pathway would also require the LNG exporters to invest significant capital to connect to the ECGM such that they can provide gas into a structurally oversupplied market where there is no demand to contract it, for prices that are not commercially viable.

- The NT LNG exporters are not physically connected to the NT domestic gas market in a way that would allow continuous, baseline and commercial supply of gas to domestic users.
- NT LNG exporters' deliverable volumes are constrained by the downstream capacity of the Wickham Point Pipeline (100 TJ/d) and the Amadeus Gas Pipeline (165 TJ/d).
- Without any further backfill, NT LNG exporter DSO volumes would average 90 PJ/a (247 TJ/d) between 2028 and 2040, almost 2.5 times the capacity of existing infrastructure.
- NT domestic market demand is forecast to average 25 PJ/a over the same period and will be fully supplied by existing producers in the Amadeus Basin and Beetaloo Basin Pilot Project gas from late 2026.
- The only addressable market for NT LNG exporter DSO volumes is therefore the broader ECGM. This would require the development of new pipeline(s) from Darwin to as far as Moomba with a capacity of more than 250 TJ/d just to deliver gas between 2027 and 2040, following which output from the LNG export projects begins to decline.

#### 2. Invest in and develop Beetaloo Basin acreage to meet DSO obligations

The addition of a Beetaloo Basin full field development with delivery of a new pipeline that connects to the ECGM at or near Ballera in Queensland increases the ability of the NT to supply DSO volumes to the ECGM. However, it could also add between 1,500 TJ/d and 2,000 TJ/d of new production into the market from the Beetaloo Basin itself. This supply would have to directly compete with NT LNG exporter DSO volumes to secure customer offtake. Given the lead time for development of this new Basin and pipeline connections, significant and sustained variations to DSO volumes would still be required in the short-term.

- Even with a new 500 TJ/d pipeline from the Beetaloo to Ballera, there would be no improvement in the ability to deliver NT LNG exporter DSO volumes to market.
- This is caused by both the limits on pipeline capacity, the ability to absorb Beetaloo volumes in the ECGM and the need to backout either NT LNG exporter DSO volumes or Beetaloo Basin volumes, as well as the additional DSO volume that would be required as a result of exporting Beetaloo gas via the existing LNG facilities.
- Both the Ichthys JV and the Barossa / Darwin JVs may be forced to acquire Beetaloo Basin acreage and develop it, and a pipeline to the ECGM, in order to be allowed to export LNG from their existing projects. This removes any competitive tension in the NT gas market, concentrates domestic gas supply solely on LNG exporters and forces the development of the Beetaloo for policy rather than economic reasons. Whilst swaps could be utilised to avoid direct participation in the development, the requirement for this gas to be new incremental supply means

that the LNG exporters must underwrite a development and take on development risk either physically or commercially regardless of the structure.

- Additionally, the timeline for a full field development of the Beetaloo Basin is unlikely to deliver meaningful volumes of gas to the market until the early to mid-2030s, whilst the DSO policy is expected to commence from 1 July 2027. As a result, significant and sustained variations to DSO volumes would still be required in the short-term.
- Forcing the LNG exporters to develop Beetaloo Basin acreage to meet a policy directive may result in a suboptimal development pathway for Australia's largest prospective resource – one that would otherwise have supplied the ECGM with sufficient volumes of gas even if the policy was not applied to the NT.

### 3. Invest in and develop new supply in other regions of the ECGM to meet DSO obligations

In order to avoid the physical and commercial limitations of directly supplying domestic gas from the NT to the broader ECGM, the NT LNG exporters could acquire and develop, or underwrite the development of, new supply elsewhere in the ECGM. Given the lead times for development of these projects, significant and sustained variations would still be required in the short-term. Whilst swaps could be utilised to avoid direct participation in the developments, the requirement for this gas to be new incremental supply means that the LNG exporters must underwrite multiple new developments and take on development risk either physically or commercially regardless of the structure. There are significant issues with this as it would be a forced decision required by Government intervention and is not a commercial decision on behalf of the JVs or their participants.

- Without any further backfill, NT LNG exporter DSO volumes would average 90 PJ/a (247 TJ/d) between 2028 and 2040.
- In order to discharge this obligation under the DSO policy, the NT LNG exporters would have to underwrite or develop new supply equivalent to this volume.
- This would require the acquisition of a number of smaller projects, as no single prospective source of supply is large enough to produce an equivalent volume of gas to fulfil the NT DSO requirements (outside of the Beetaloo Basin).
- Additionally, none of these prospective developments would reach first gas before the commencement of the DSO policy, meaning that variations to maintain LNG output are inevitable in the short term.
- The lead time for the development of this new supply means that FID would have to be considered during the period that ECGM gas prices are below their LRMC of development. As a result, the projects would be uneconomic and it would not be possible for them to proceed. Investors cannot develop new supply that would be loss-making as a result of the structural oversupply during the period that FID would need to be taken.
- If the policy is applied nationally, the NT LNG exporters will be competing with WA and QLD LNG exporters for the same limited number of new supply projects.

### 4. Export LNG from existing facilities for importation into the ECGM

Under the DSO policy as currently written, NT LNG exporters could be expected to direct 20% of their LNG export volumes to the domestic market. Importing LNG from NT LNG exporters meet the baseline DSO would equate to approximately 1.6 mtpa of LNG supplied into Australia (90 PJ/a). Given the lead times for development of import infrastructure, significant and sustained variations would still be required in the short-term. This pathway would require the LNG exporters to invest significant capital to underwrite import infrastructure so that they can provide high-cost gas (LNG plus regasification) into a structurally oversupplied market where there is no demand to contract it, for prices that are not commercially viable.

- It is unclear whether the DSO volume would include or exclude the liquefaction losses (i.e. calculated based on feed-gas into the facilities 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 NT LNG exporter volumes into Australia would require the development of import terminal infrastructure. No such complete infrastructure exists in Australia – whilst the Port Kembla terminal has constructed the onshore infrastructure required to import LNG in NSW, it does not have a regasification vessel in place.
- Imported LNG volumes for use as domestic gas would be the highest cost supply in the 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 or even a balanced market.

### 5. Curtail LNG exports to meet DSO obligations

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 NT market under the proposed DSO policy is to curtail LNG exports.

**Existing production only**

- Considering only existing production and infrastructure in the NT, LNG exports would need to be curtailed to a point where the 20% DSO supplies enough domestic gas to balance the NT market and fully utilize the existing 90 TJ/d Northern Gas Pipeline (NGP).
- In order to achieve this, NT LNG exports would need to be reduced from the current forecast of ~11 mmtpa in the late 2020s and early 2030s, to as low as 3.1 mmtpa over the same period.

**Beetaloo Basin full field development**

- If the Beetaloo Basin is developed and supplies gas to the ECGM via a new pipeline and also contracts capacity on the NGP, there is no physical access to market for NT LNG export DSO volumes.
- As a result, LNG export volumes are reduced to RVM only from 2032 – this is equivalent to 0.4 mmtpa and only available on an annual Ministerial approval basis. If this were to occur, exports would effectively cease from the NT as it is not commercially or technically possible to export only RVM volumes.

Rather than fulfilling its stated aims of ensuring lower long term prices and security of supply, the policy if applied to the NT would significantly oversupply the domestic market, force large investments in gas processing and transportation infrastructure at Darwin that would otherwise not be required, or reduce LNG exports from the NT to potentially as low as zero, while doing nothing to address forecast east coast gas shortfalls. The Wood Mackenzie base case forecast for NT LNG exports determines the NT market (plus full utilization of the NGP) would only require a DSO of less than 6% of total LNG exports in order to be balanced over the forecast period.

**Overview of NT gas market**

Despite geographic proximity, the NT (NT) operates as an effectively separate market from the ECGM. Its only physical link to the east coast is the Northern Gas Pipeline (NGP) – a 620 km, 90 TJ/day pipeline from Tennant Creek (NT) to Mount Isa (QLD). The NT’s internal trunk, the Amadeus Gas Pipeline (AGP), runs from Alice Springs to Darwin and feeds the NGP near Tennant Creek; it does not itself reach Queensland.

Gas production in the Territory is from both onshore and offshore conventional gas fields. Onshore production is from three fields in the Amadeus Basin in central Australia (Mereenie, Palm Valley and Dingo). Offshore production is predominantly from Commonwealth waters with gas then being exported via two LNG facilities on the northern coast of the NT; Darwin LNG and Ichthys LNG (the NT LNG exporters).

**Domestic gas supply**

Onshore Amadeus Basin fields and the offshore Blacktip gas field have historically been the main sources of supply to the NT domestic gas market. However, production issues at Blacktip have resulted in supply shortfalls that have drawn on emergency gas supply (relatively small volumes provided on an intermittent basis) from NT LNG exporters.

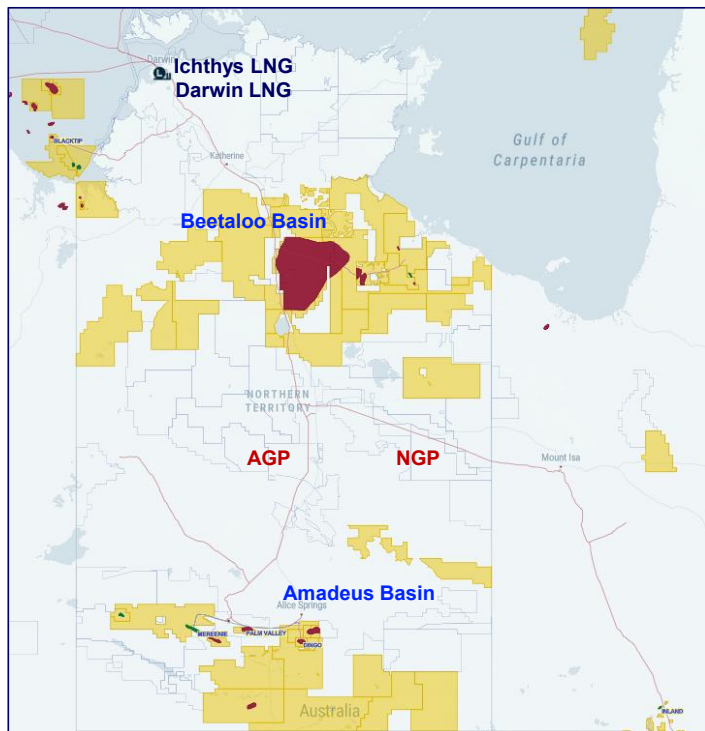
The Amadeus Basin producing fields (Mereenie, Palm Valley, Dingo) are located west-southwest of Alice Springs, and together supply approximately 40 TJ/d into the southernmost end of the AGP. This production predominantly supports power generation in the Territory.

**Beetaloo Basin**

The Beetaloo Basin is a large onshore gas field in central NT and is considered as a separate depocenter within the greater Georgina Basin. It spans an area of 35,600 km<sup>2</sup> (8.8 million acres) with license holders conducting recent exploration and appraisal activities focusing predominantly on the "B shale" in the Amungee Member of the Velkerri Formation.

The appraisal of Beetaloo Basin is still at an early stage. The announced development plans (which are still indicative at this stage) from the proponents total over 2,500 TJ/d to both backfill LNG export from Darwin and the provision of 500 TJ/d to 1,000 TJ/d into the ECGM for domestic use. Further upside could also be transported east into the ECGM for export from the Gladstone LNG plants.

Figure 21 – Overview of NT gas market



### Beetaloo Basin Pilot Projects

There are two pilot projects currently being developed in the Beetaloo Basin – the Carpentaria Gas Project, and the Shenandoah South Pilot Project.

The Carpentaria Gas Project is currently constructing the Carpentaria Gas Plant and aims to commence delivery of up to 15 TJ/d of gas in 2026. The project will transport gas via the existing McArthur River Gas Pipeline to Power and Water Corporation (PWC), who has fully contracted the pilot gas on a take-or-pay basis.

The Shenandoah South pilot project is constructing a gas plant and gas transmission pipeline to bring the gas to market. Wood Mackenzie expects first gas from the pilot project in Q3 2026 with an estimated pilot plateau in late 2028 / early 2029. As with the Carpentaria pilot gas, the Shenandoah South pilot gas is also fully contracted to PWC on a take-or-pay basis.

### Beetaloo Basin Full Field Development (FFD)

Existing infrastructure is insufficient to facilitate the full-scale development of the Beetaloo Basin at the volumes targeted by the proponents. To deliver meaningful volumes to the ECGM from a FFD of the Beetaloo, new transport infrastructure would be required. Wood Mackenzie’s assumption is a new build pipeline that connects the Beetaloo to near Ballera in QLD via a similar corridor to that used by the existing Northern and Carpentaria Gas Pipelines. This pipeline project is called the North to East Australia Pipeline (NEAP) by its proponent, APA Group.

### Domestic demand

PWC is a major buyer and supplier of gas in the NT. Most of that gas is used by PWC’s customers including the NT’s electricity generator Territory Generation to generate electricity for consumption by industrial, commercial and residential consumers in the NT. The NT electricity system is dependent on natural gas for essentially all power generation requirements, and the NT is not electrically connected to other grids in other states of Australia.

Security of gas supply is particularly important to the NT as a result of the dependence on natural gas for the provision of baseload power generation. The NT gas market historically sourced up to 90% of supply from the Blacktip field in the Bonaparte Basin, with the remaining 10% sourced from fields in the Amadeus Basin. Given the reliance on Blacktip production, PWC entered into commercial agreements with the NT LNG exporters for emergency back-up supply from the LNG export facilities at Darwin.

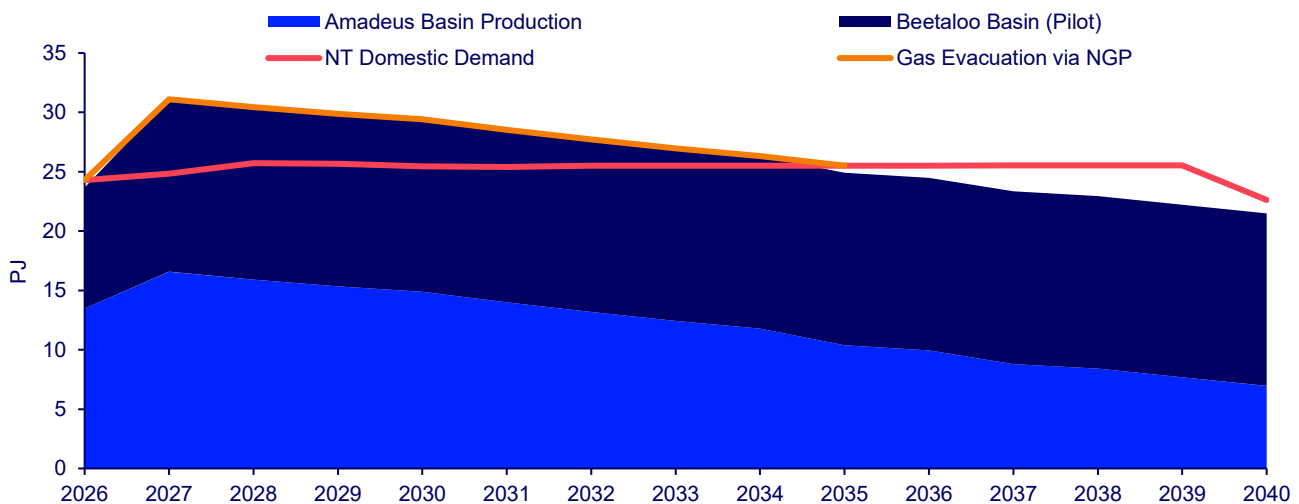
Notwithstanding their self-sufficiency and independence from the NT gas market, the two LNG projects do have physical connections to the NT gas market by way of emergency lateral pipelines that connect the plants. One lateral connects Darwin LNG and one lateral connects Ichthys LNG. PWC owns and operates both laterals. The emergency lateral pipelines are sized to meet the needs of the domestic market and to match the capacity of the downstream Wickham Point Pipeline (WPP), which can transport up to 100 TJ/d.

Overall domestic gas demand in the NT is small when compared to other states of Australia – total gas demand in 2025 was approximately 28 PJ.

### Supply-demand balance

The NT domestic gas market is broadly balanced as a result of Amadeus Basin production, with small contributions from Ichthys LNG emergency supply until the Beetaloo Basin pilot projects begin production in Q3 2026. Depending on the productivity of the Beetaloo pilot projects, excess supply in the NT may be exported to QLD via the NGP throughout the early 2030s. From 2034 onwards, NT supply adequacy depends on the broader FFD of the Beetaloo Basin.

Figure 22 – NT market supply-demand balance – existing and committed supply



Source: Supply – Wood Mackenzie, Demand – AEMO 2026 GSOO

## NT LNG exports

### Ichthys LNG

Ichthys is a giant gas-condensate field in the Browse Basin approximately 220 km off the coast of Western Australia (WA) and 820 km west of Darwin. The field was brought onstream in 2018 via an integrated LNG development comprising an offshore upstream section, an 890 km gas export pipeline and onshore processing facilities at Bladin Point in Darwin.

The onshore Bladin Point site has two LNG processing trains. The initial design LNG capacity was 8.9 mmtpa (2 x 4.45 mmtpa trains), later increasing to 9.3 mmtpa by the end of 2024 through debottlenecking. LNG output from Ichthys is forecast to decline from the mid-2030s as upstream reservoirs that supply feed-gas are depleted. Ichthys LNG will require the development of new supply to backfill this ullage from this period onwards. Potential sources of backfill gas include the offshore Cash-Maple field, as well as gas from any Beetaloo FFD project.

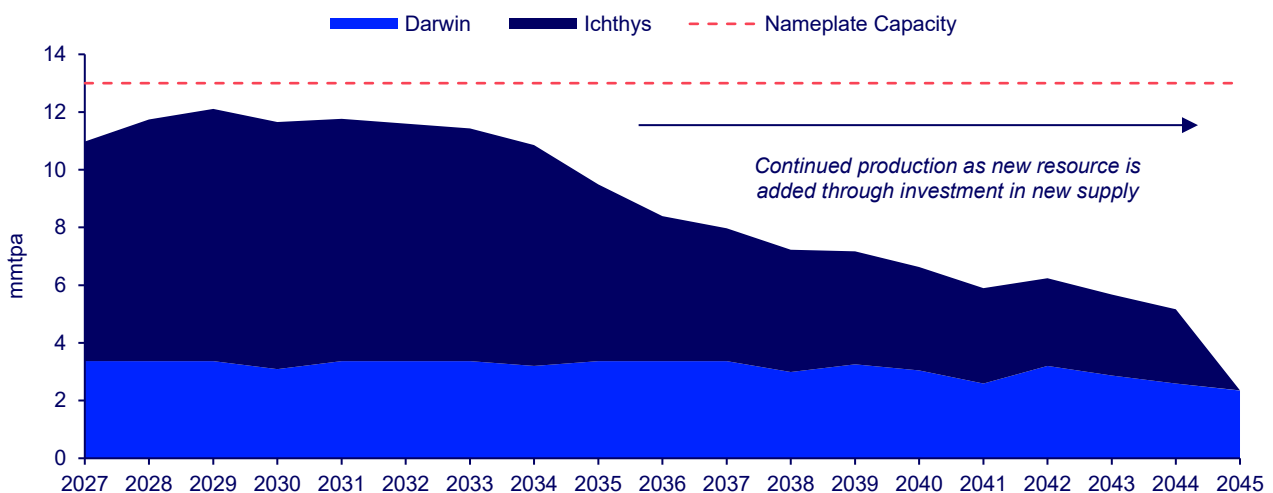
### Darwin LNG

The Darwin LNG plant is located at Wickham Point, Darwin with a nameplate capacity of 3.7 mmtpa LNG. The Bayu-Undan JV approved the Darwin LNG development in June 2003 after the Timor Sea Treaty was ratified between Timor-Leste and Australia. The first LNG cargo was shipped in February 2006.

The Barossa field was developed as backfill for Bayu-Undan and achieved first gas in late 2025. We assume that the Caldita field, nearby Barossa, will be brought onstream in the early 2040s to support and maintain output at DLNG until the early 2050s.

Both NT LNG export projects require investment in new upstream supply to backfill the existing LNG liquefaction facilities. Prospects include offshore fields in the Bonaparte Basin, onshore prospects in the Beetaloo and South Nicholson Basins and further exploration upside. The JV participants are already actively evaluating these prospects and investing significantly in their appraisal for future development to support continued exports and domestic gas supplies for the NT and Queensland.

Figure 23 – Wood Mackenzie forecast – NT LNG exports – existing and committed supply



Source: Wood Mackenzie

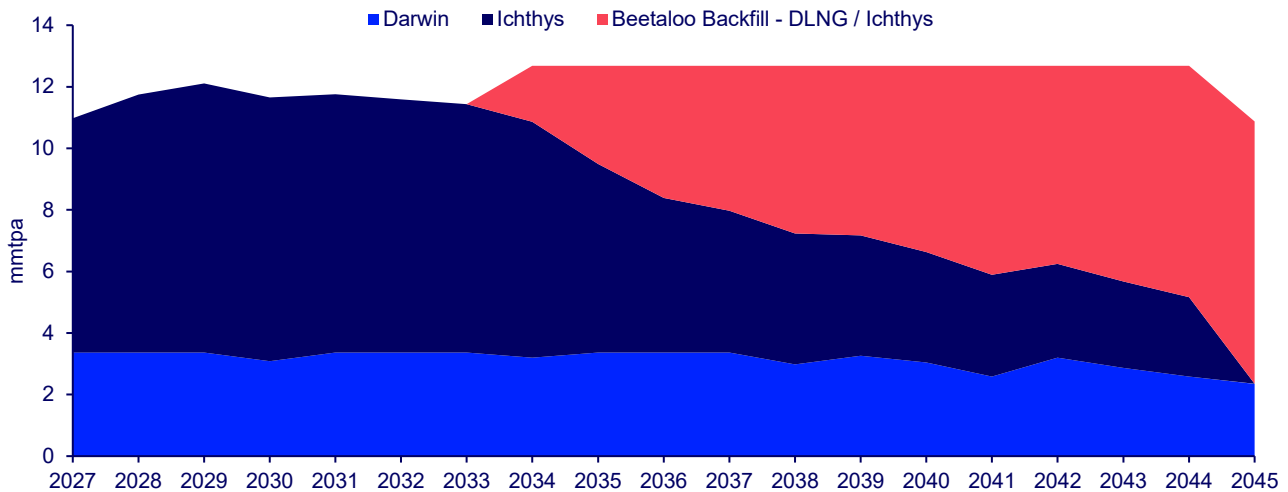
It is important to note that any gas supplied to the domestic market from Ichthys or Barossa-Caldita will reduce LNG exports directly – the projects were not designed to provide domestic gas, and all upstream production is directed to LNG export. Their contracted volumes reflect the existing upstream supply capacity. Whilst the reduction in liquefaction losses and fuel gas usage means that reductions in LNG export will not scale one-to-one with domestic gas supply, the result is that any DSO will cause a direct reduction in LNG exports, putting existing contracts at risk.

### Beetaloo Basin FFD Backfill

A successful FFD of the Beetaloo Basin could provide gas to both the domestic market and backfill the LNG facilities at Darwin. For the purposes of this analysis, Wood Mackenzie has assumed that Beetaloo Basin gas will be exported out of Darwin as backfill of existing facilities. This would result in between 100 and 500 PJ/a of Beetaloo gas being supplied into LNG export over the period 2034 to 2045.

This assumes the development of sufficient transportation infrastructure to connect the Beetaloo to Darwin, as the existing AGP is limited to approximately 165 TJ/d (60 PJ/a) and is not sufficient to deliver LNG backfill volumes to the plants.

Figure 24 – NT LNG exports with Beetaloo Basin FFD backfill



Source: Wood Mackenzie

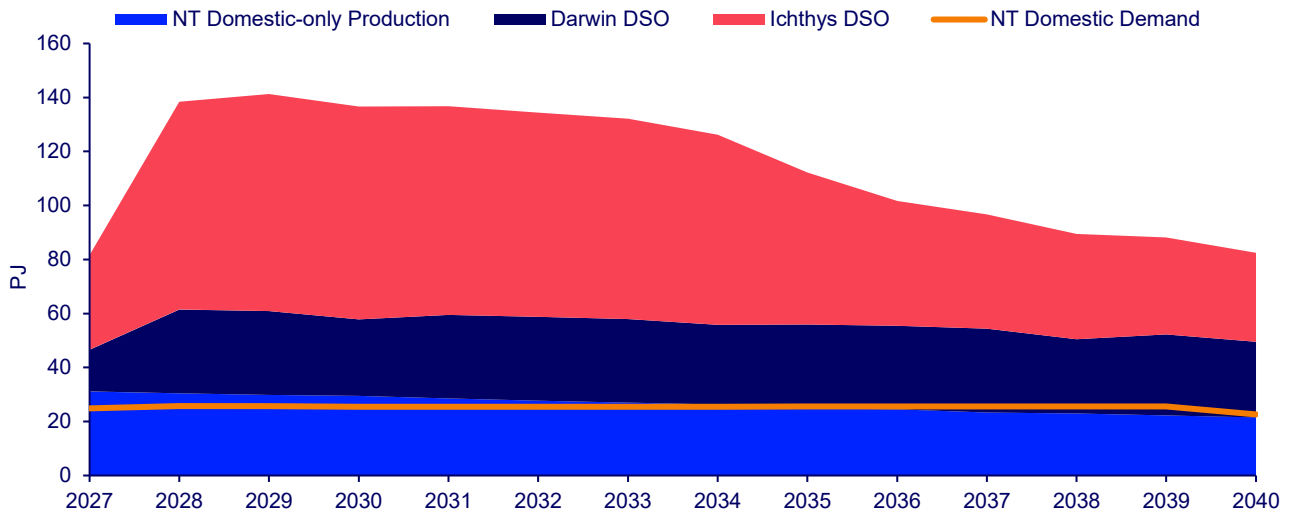
### Effect of a 20% DSO on NT domestic gas volumes

The analysis considers the NT DSO based on existing production from the NT LNG exporters, as well as a scenario where the Beetaloo Basin is successfully developed and provides backfill to the two LNG plants up to their existing nameplate capacities.

#### Unconstrained DSO – existing production only

Based on the calculation methodology outlined in the framework, the nominal DSO volumes in the NT market are outlined below. This is calculated on an ‘unconstrained’ basis – i.e. assuming no DSO variations are applied for or granted. Considering only existing production, and no contributions to LNG export volumes from the Beetaloo Basin, the total DSO volume in 2028 would be more than 100 PJ (for context, 2028 total NT domestic demand is forecast at approximately 26 PJ).

Figure 25 – Unconstrained NT DSO volumes (existing production only)



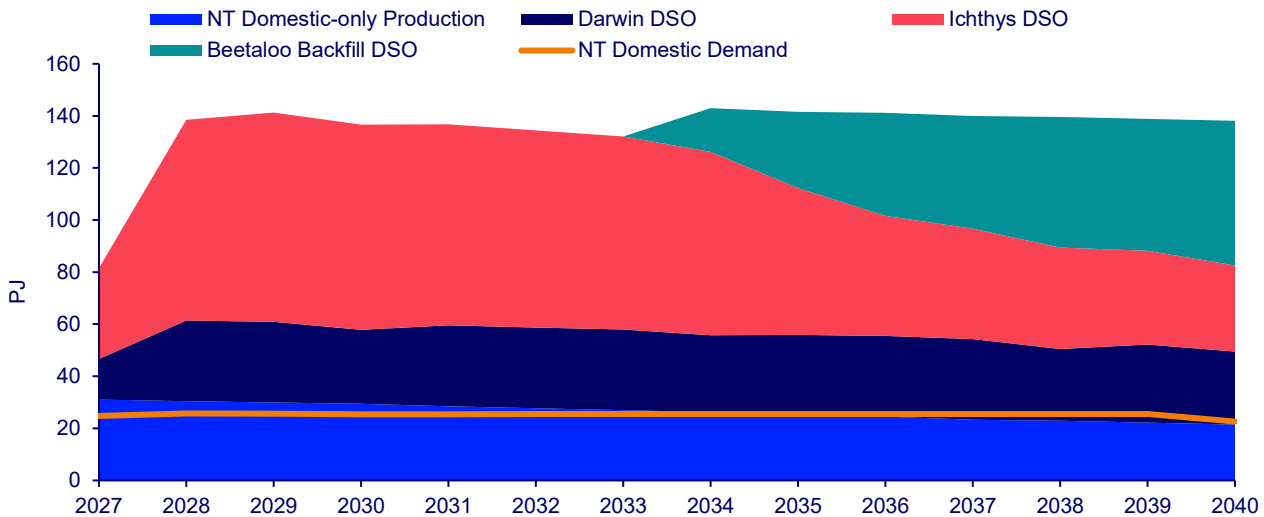
Note: The DSO would be effective from 1 July 2027 – the DSO volumes in 2027 have been calculated on a pro-rata basis for calendar year 2027 (50% of full-year obligation).

Source: Supply – Wood Mackenzie, Demand – AEMO 2026 GSOO

#### Unconstrained DSO – Beetaloo Basin backfill

The addition of Beetaloo Basin backfill volumes to the baseline LNG output figures adds material DSO volumes in the NT. With the LNG plants kept operating at nameplate capacity from 2034, the total DSO volume increases from ~61 PJ in 2040 to more than 115 PJ (for context, 2040 total NT domestic demand is forecast at approximately 23 PJ).

Figure 26 – Unconstrained NT DSO volumes (Beetaloo Basin backfill)



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: Supply – Wood Mackenzie, Demand – AEMO 2026 GSOO

### 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
- Domestic gas processing capacities
- Transport capacities

The NT market is constrained by a combination of all of the above elements.

#### Physical connection

While the NT LNG export facilities are physically connected to the NT domestic gas market, these connections are designed to act as small, bidirectional balancing connections that both support commissioning, start-up and emergency back-up for the LNG facilities themselves, as well as providing emergency market-balancing gas supply from the facilities to the NT during emergency periods to ensure sufficient power generation capacity in the Territory.

Both facilities lack dedicated commercial, baseline or continuous domestic gas supply facilities that would enable the physical delivery of domestic gas to the market in material volumes. Because these connections are not designed for continuous commercial baseline supply, their capacities are governed by strict technical constraints and emergency regulatory rules. The Australian Energy Market Commission (AEMC) enforces a "zero baseline" policy on the facilities, meaning continuous commercial transmission into the domestic grid is prohibited unless the projects forfeit their regulatory Bulletin Board exemptions.

Supplying DSO volumes into the NT would require the development of large-scale domestic gas processing facilities at the plants, as well as large capacity transmission pipelines to connect the plants to the NT domestic market. Even with these investments, downstream capacity in the network would still severely limit the total volumes of gas that both facilities could provide to the domestic market (discussed below).

#### Domestic gas processing capacities

Both facilities' emergency supply connections feed into the Wickham Point Pipeline (WPP). This pipeline connects both Wickham Point (Darwin LNG) and Bladin Point (Ichthys LNG) and has a bidirectional capacity of 100 TJ/d southern-haul (i.e. from the LNG facilities to the NT grid) and 70 TJ/d northern-haul (the reverse). As a result, the maximum volume that both facilities combined could supply into the domestic market is limited to 100 TJ/d. For context, the combined facilities' baseline DSO in 2028 would be nearly three times this capacity at 295 TJ/d.

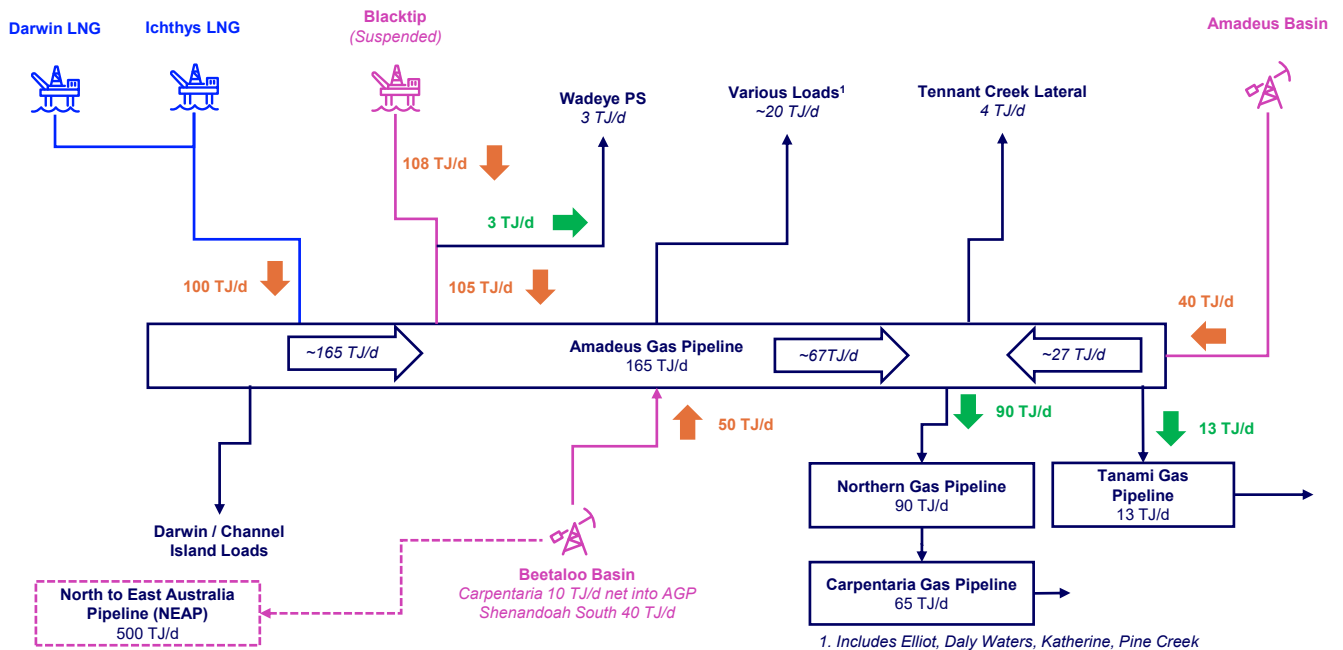
### Transportation infrastructure

All NT gas production that is supplied to the domestic gas market is injected into the Amadeus Gas Pipeline (AGP) via various laterals. The AGP runs north-south, from Darwin in the north to the Amadeus Basin in the south, and has a maximum capacity of 165 TJ/d.

The AGP is sufficient to manage nameplate capacity flows from the domestic gas producers in the Territory, including Mereenie, Palm Valley and Dingo at the southern end, Beetaloo Basin pilot projects in the center, and Blacktip via the Bonaparte Gas Pipeline in the north. Gas in the AGP is used to supply domestic loads along its length including Alice Springs, Tennant Creek, Tanami, Warrego, Daly Waters, Katherine and Darwin.

The AGP also supplies the NGP at Warrego, with a 90 TJ/d nameplate offtake capacity. The NGP is only open and exporting gas into QLD when sufficient domestic gas supplies exist to first satisfy NT demand, with the surplus then exported via the NGP to supply users in Mt Isa. With the production issues being experienced at Blacktip, the NGP has been closed since 2024 with some intermittent periods of re-opening, though it may be able to remain open from late 2026 or 2027 if Beetaloo Basin pilot volumes are sufficient to underpin a surplus of supply.

Figure 27 – NT gas transportation infrastructure overview



1. Includes Elliot, Daly Waters, Katherine, Pine Creek

Source: Wood Mackenzie analysis of AEMO, AER and company data

### Overall limitations

Currently, the supply of baseline DSO volumes from NT LNG exporters is not possible using existing infrastructure. They are primarily constrained by the capacity of the WPP (100 TJ/d) and secondarily constrained by the capacity of the AGP (165 TJ/d). A number of gas infrastructure projects are currently proposed to connect the NT to the ECGM with greater capacity, however these are contingent on the success of the Beetaloo Basin, the ability to supply material volumes over the longer-term from a successful FFD, and the demand for gas from ECGM users incremental to existing supply in the market.

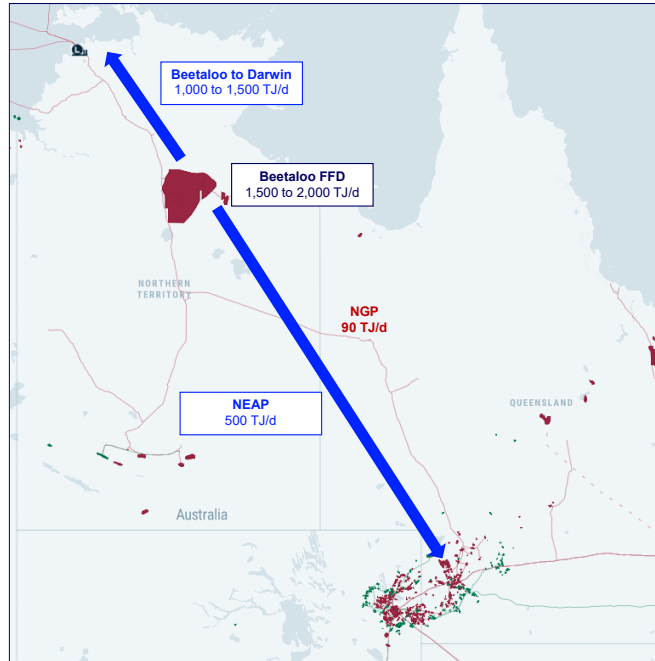
### The impact of a Beetaloo FFD

The FFD of the Beetaloo could add large volumes of gas supply into the Territory. In order to support access to market, a number of pipeline projects are currently being considered. These include large diameter transmission pipelines from the Beetaloo to Darwin (for LNG export) and Beetaloo to Ballera in Queensland to supply domestic users in the ECGM.

The proposed North to East Australia Pipeline (NEAP) would connect the Beetaloo to the ECGM near Ballera and provide the ability to monetise volumes of Beetaloo gas via the domestic market. The capacity of this pipeline has not yet been decided, however we model the following development as an analogue for a Beetaloo FFD:

- Beetaloo FFD upstream production of between 1,500 TJ/d and 2,000 TJ/d, ramping from 2030 onwards
- A new pipeline from Beetaloo to Ballera with a capacity of 500 TJ/d to supply the ECGM, with a start-up in 2030.
- Beetaloo to Darwin pipeline with a capacity of between 1,000 TJ/d and 1,500 TJ/d to provide backfill to NT LNG exporters, with backfill aligned to ullage from 2034 onwards.

Figure 28 – Beetaloo pipeline options



This increases the NT’s connection to the ECGM from the current 90 TJ/d (NGP) to 590 TJ/d (new pipeline, plus NGP).

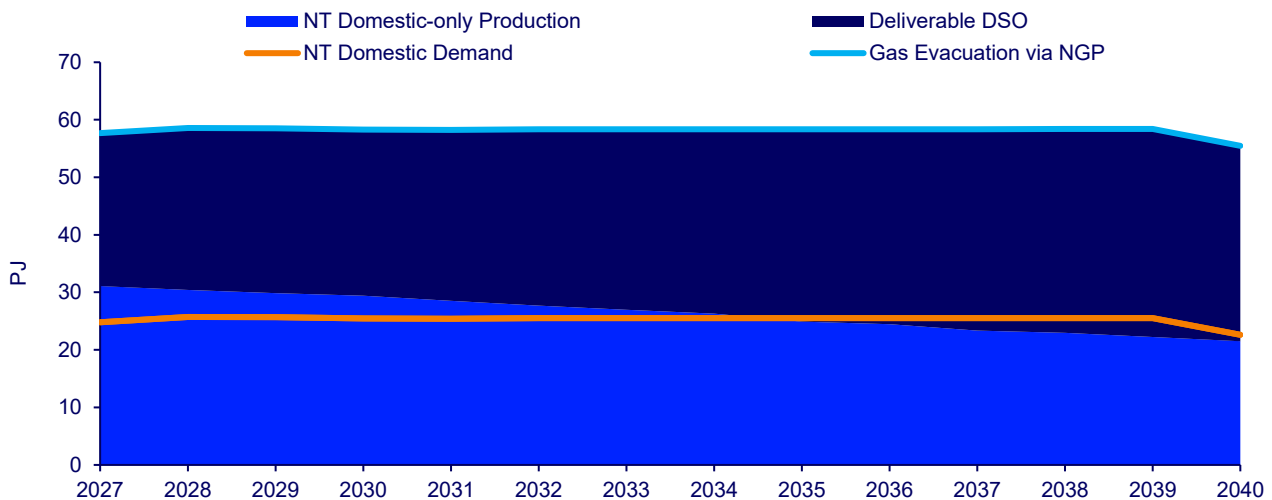
### Deliverable NT DSO volumes

#### Existing production only

Considering existing production and infrastructure, the maximum deliverable DSO from NT LNG exporters would be limited to total NT domestic market demand, plus 90 TJ/d via the existing NGP. Considering existing Amadeus Basin and Beetaloo pilot production, NT LNG exporters would be limited to a domestic market supply of between 28 and 36 PJ/a between 2028 and 2040. Even this volume would require significant investment in both domestic gas processing capacity at the LNG facilities, and an expansion of the WPP from 100 TJ/d to 150 TJ/d to transport these volumes. It would also need to back out any Blacktip production should it recover to ensure that sufficient capacity exists on the AGP to transport Ichthys and Darwin volumes to the NGP offtake.

Without any variations being applied, a deliverable DSO of just 28 PJ/a would limit LNG exports from the two plants combined to a maximum of just 3.1 mmtpa, compared to the current forecast of more than 11 mmtpa.

Figure 29 – Deliverable DSO – existing production



Source: Supply – Wood Mackenzie, Demand – AEMO 2026 GSOO

### Beetaloo Basin FFD

The addition of a Beetaloo Basin FFD with delivery of a new pipeline at 500 TJ/d increases the ability of the NT to supply DSO volumes to the ECGM. However, it also adds between 1,500 TJ/d and 2,000 TJ/d of new production into the market. As a result, while actual deliverable supply increases, the amount of new supply means that there is no improvement in the ability to deliver NT LNG exporter DSO volumes to market. This is caused by both the limits on pipeline capacity, the ability to absorb Beetaloo volumes in the ECGM and the need to backout either NT LNG exporter DSO volumes or Beetaloo Basin volumes, as well as the additional DSO volume that would be required as a result of exporting Beetaloo gas via the existing LNG facilities.

The Beetaloo FFD creates a unique outcome whereby the addressable market for NT gas is only expanded by the new pipeline connection that will rely on the Beetaloo upstream project in order to proceed. However, with this increased capacity to sell gas into the ECGM, and assuming that NT LNG exporters are forced to expand their capacity upstream of this to deliver their DSO (as required by the framework), the fact that the LNG exporters are compelled sellers means they will be forced to sell gas into the ECGM at any cost. As a result, LNG exporter gas can be sold at a price lower than the marginal cost of Beetaloo Basin gas. This will also be required well before Beetaloo FFD gas is able to enter the market – the DSO would apply from 2027, we forecast Beetaloo FFD first gas from 2030.

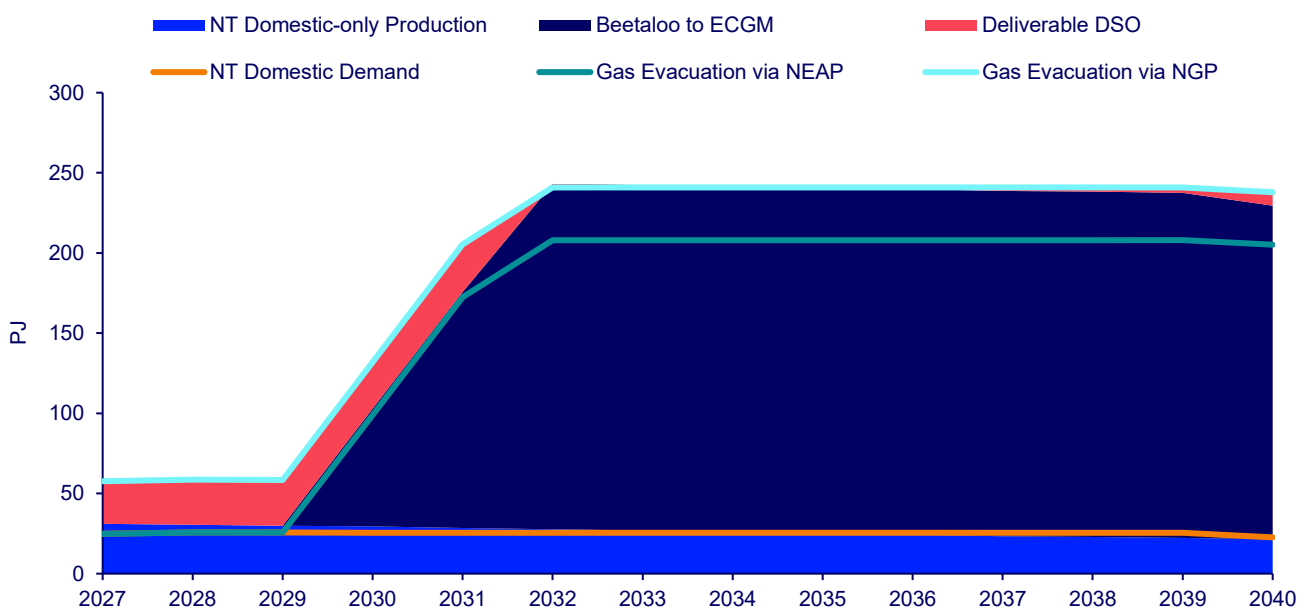
This places at risk the new pipeline connection to the ECGM that would enable greater supply. The outcome of this situation is that both the Ichthys JV and the Barossa / Darwin JVs may be forced to acquire Beetaloo Basin acreage and develop it, and the pipeline to the ECGM, in order to be allowed to export LNG from their existing projects. This removes any competitive tension in the NT gas market, concentrates domestic gas supply solely on LNG exporters and forces the development of the Beetaloo for policy rather than economic reasons.

The second-order consequences are largely perverse relative to the policy's intent. NT domestic supply would become wholly reliant on two LNG exporters, reducing competitive tension and supply diversity. As a result, 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.

Our analysis and market balances are determined based on the assumption that Beetaloo Basin domestic gas supply must take precedence over LNG exporter gas when considering available capacity on the new Beetaloo to Ballera pipeline. This is required in order for the Beetaloo FFD to be commercial and thus take FID, as Beetaloo is seeking market demand in order to drive an economic development. Pushing other supply into the market at this time could risk Beetaloo Basin proponents delaying development because of a lack of investment, demand and price signals in the market.

The argument may follow that simply increasing the capacity of the new ECGM connection (e.g. the NEAP) to accept both LNG export DSO volumes and new Beetaloo Basin volumes would address this unintended consequence of an NT DSO. However, in practice this does not solve the problem as downstream pipeline capacity in Queensland and southern states, combined with the limitations of actual ECGM demand, reduce the amount of NT gas that can practically reach the ECGM demand centers.

Figure 30 – Deliverable DSO – Beetaloo FFD scenario



Source: Supply – Wood Mackenzie, Demand – AEMO 2026 GSOO

## 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-discretion based 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 below is an analysis of the NT 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.

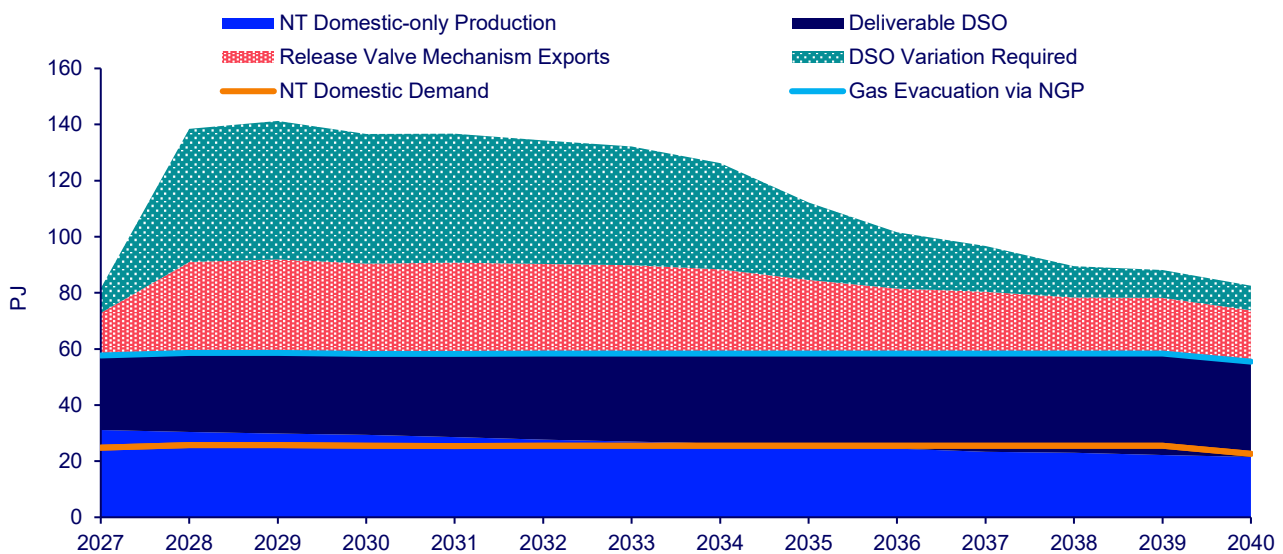
### Existing production only

In order to balance the NT domestic gas market to actual demand, including gas exported to Queensland via the NGP at full capacity, the NT LNG exporters would need a collective DSO variation and RVM volume of ~80 PJ in 2028, and continuous annual variations of more than 60 PJ/a through to 2034. By 2040, without one of the five unlikely pathways outlined to discharge DSO being realised, the accumulated carried-forward DSO ‘debt’ volume would reach 786 PJ – a volume sufficient by itself to supply the NT domestic gas market at current demand for more than 31 years.

At a minimum, variations from 2027 to at least the early 2030s would be required regardless of any investment in infrastructure expansion, development of other new supply or producing LNG for import, as the lead times to realise these investments is years at best, at which point accumulated DSO debt has already been accrued.

- Rather than being a ‘rare occurrence’, the RVM would be required every year from 2027 to 2040 inclusive.
- With RVM volumes limited to 30% of total DSO, in addition to the annual activation of the mechanism, NT LNG exporters will still need variations to their DSOs to avoid significant oversupply of the market. DSO variations would be required in addition to the RVM every year from 2027 to 2040 inclusive.
- The market is structurally oversupplied every year from 2027 onwards, meaning both the RVM and DSO variation debts continue to accrue, reaching a peak of 786 PJ in 2040.
- The average annual RVM and DSO variation required to balance the market is 56 PJ/a between 2027 and 2040.

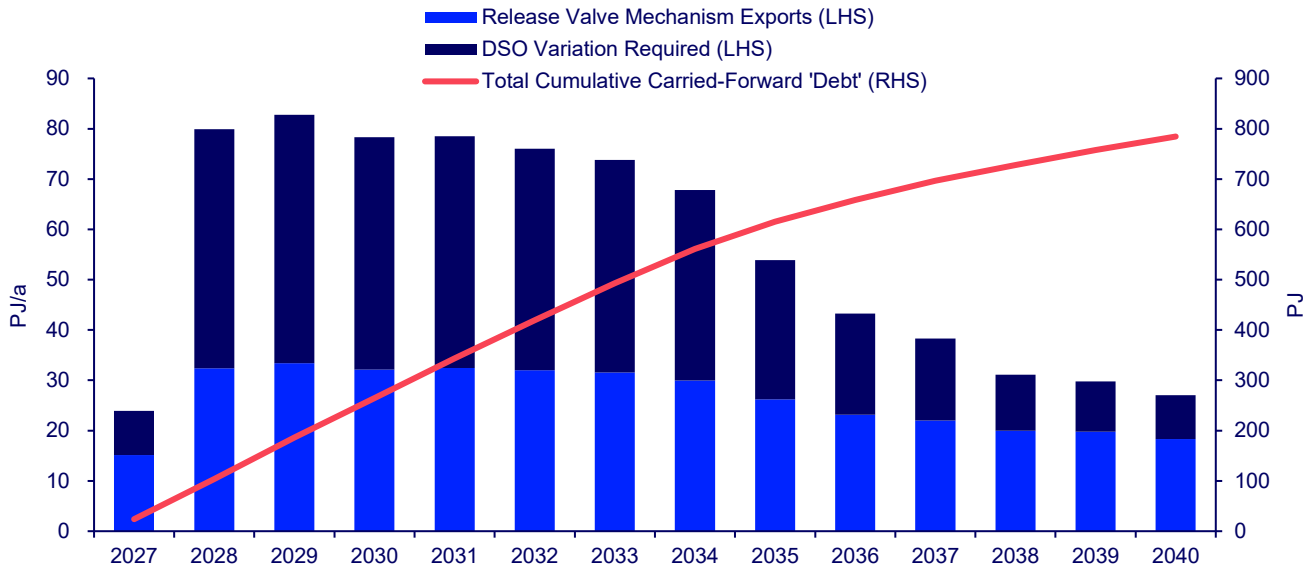
Figure 31 – Annual deliverable DSO and DSO / RVM variations required to balance market (existing production only)



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: Supply – Wood Mackenzie, Demand – AEMO 2026 GSOO

Figure 32 – Annual and cumulative DSO / RVM variations required to balance market (existing production only)



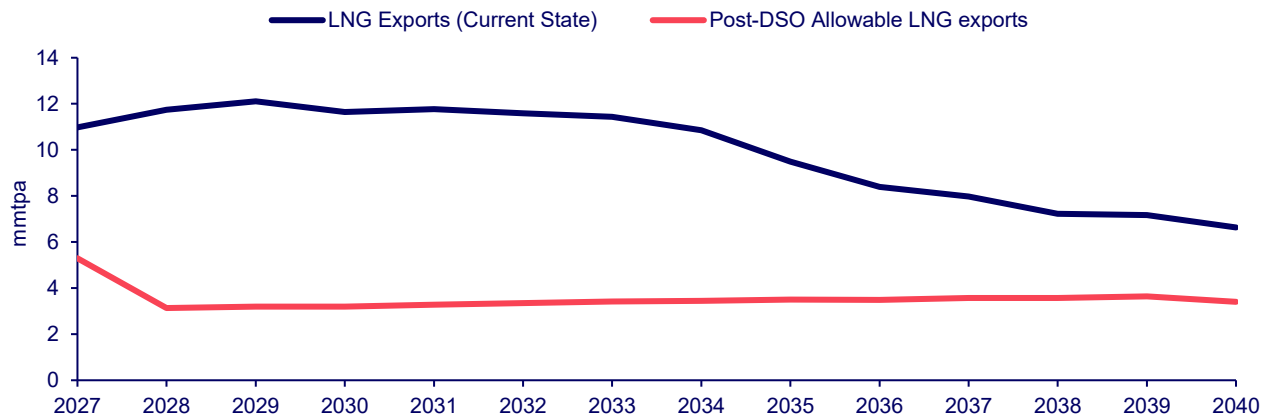
Note: The DSO would be effective from 1 July 2027 – the DSO volumes in 2027 have been calculated on a pro-rata basis for calendar year 2027 (50% of full-year obligation).

Source: Wood Mackenzie

### 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 NT 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 NT market, fully utilize the NGP and add 'a small surplus'. In order to achieve this, NT LNG exports would need to be reduced from the current forecast of ~11 mmtpa in the late 2020s and early 2030s, to as low as 3.1 mmtpa over the same period.

Figure 33 – Allowable LNG exports under existing and proposed DSO framework with no variations / RVM approvals (existing production)



Source: Wood Mackenzie

The Wood Mackenzie base case forecast for NT LNG exports determines the NT market (plus full utilization of the NGP) would only require a DSO of less than 6% of total LNG exports in order to be balanced over the forecast period.

### Beetaloo Basin FFD

The addition of Beetaloo FFD volumes at a nominal 1,500 TJ/d exacerbates the challenge. Even with a 500 TJ/d pipeline to the ECGM, the combination of new Beetaloo supply, increased DSO volumes as a result of LNG backfill by Beetaloo gas, and existing production in the Territory, only increases the need for variations, not reduces them.

As for the base case, at a minimum variations from 2027 to at least the early 2030s would be required regardless of any investment in infrastructure expansion, development of other new supply or producing LNG for import, as the lead times to realise these investments is years at best, at which point accumulated DSO debt has already been accrued.

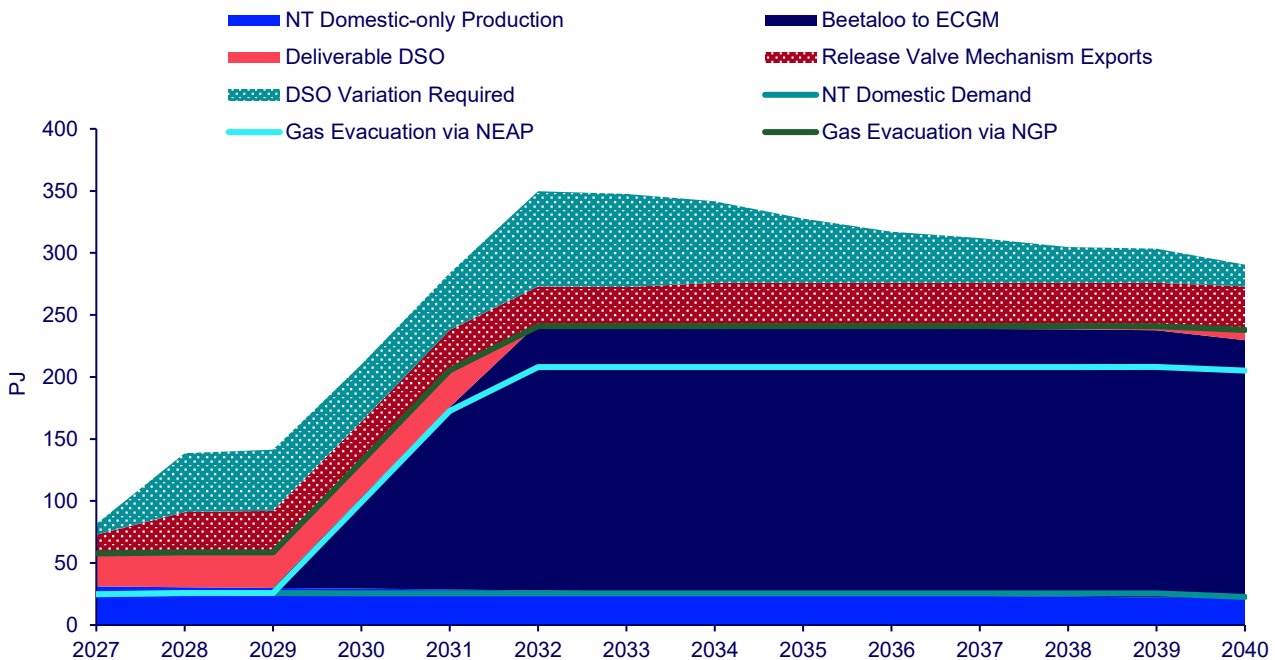
- As with for existing production only, rather than being a ‘rare occurrence’, the RVM would be required every year from 2027 to 2040 inclusive.
- With RVM volumes limited to 30% of total DSO, in addition to the annual activation of the mechanism, NT LNG exporters will still need variations to their DSOs to avoid significant oversupply of the market. DSO variations would be required in addition to the RVM every year from 2027 to 2040 inclusive.
- The market is structurally oversupplied every year from 2027 onwards, meaning both the RVM and DSO variation debts continue to accrue, reaching a peak of 1,072 PJ in 2040.
- The average annual RVM and DSO variation required to balance the market is 77PJ/a between 2027 and 2040.

The market would become so heavily oversupplied that either the NT LNG exporters must cease production, or the Beetaloo Basin development cannot proceed unless it is developed by the LNG exporters themselves to discharge their DSO requirements. There is no market for both sources of gas combined that is physically accessible, and as outlined in earlier in this report, there is not enough demand in the ECGM as a whole.

The only solution to this would be for the NT LNG exporters to enter into the Beetaloo upstream JVs or acquire an equity position in existing developers in order to produce their own equity gas from the Basin and use this supply to fulfill its DSO requirements. In this scenario, they would be forced to acquire equity in the Beetaloo aligned to their participation in the LNG JVs in order to continue exporting. Whilst swaps could be utilised to avoid direct participation in the development, the requirement for this gas to be new incremental supply means that the LNG exporters must underwrite its development and take on development risk either physically or commercially regardless of the structure. There are significant issues with this as it would be a forced decision required by Government intervention and is not a commercial decision on behalf of the JVs or their participants.

Our analysis and market balances are determined based on the assumption that Beetaloo Basin domestic gas supply must take precedence over LNG exporter gas when considering available capacity on the new Beetaloo to Ballera pipeline. This is required in order for the Beetaloo FFD to be commercial and thus take FID, as if Beetaloo Basin gas is expected to be backed-out in favour of LNG exporter DSO gas, the Basin becomes uneconomic and thus would not take FID. As a result of this, the LNG exporters lose the ability to supply any DSO into the NT or ECGM domestic markets from 2032 with the exception of their own equity production from Beetaloo, as Beetaloo gas utilises the full capacity of the new pipeline.

Figure 34 – Annual deliverable DSO and DSO / RVM variations required to balance market (Beetaloo Basin FFD)

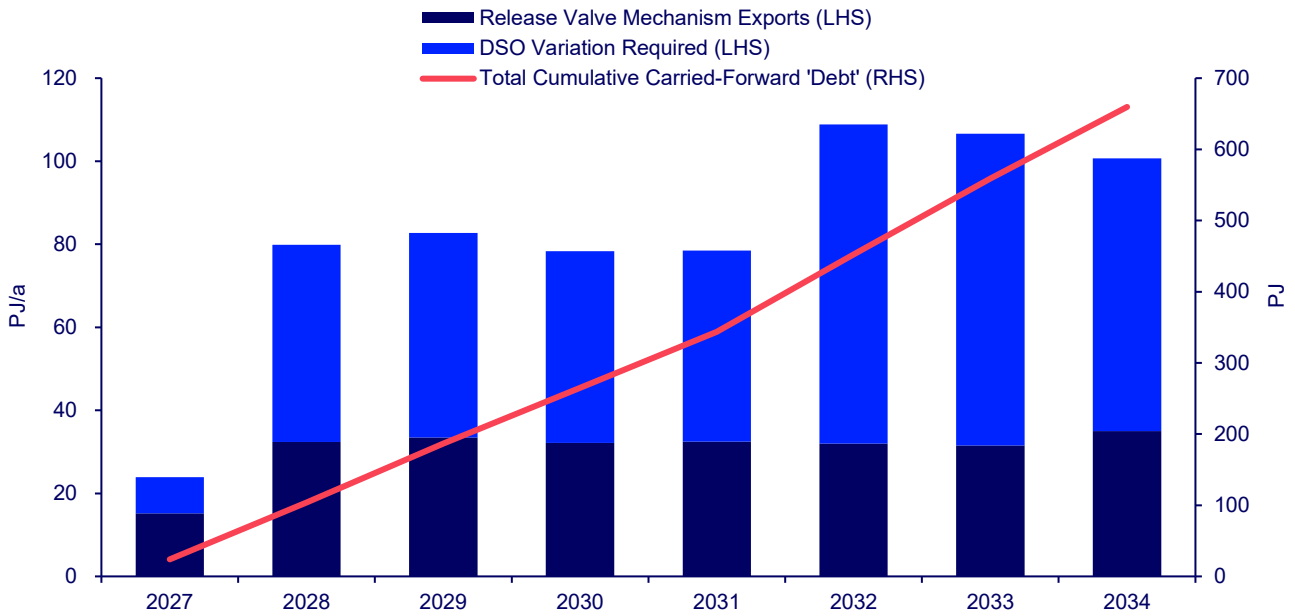


Note: The DSO would be effective from 1 July 2027 – the DSO volumes in 2027 have been calculated on a pro-rata basis for calendar year 2027 (50% of full-year obligation).

Source: Supply – Wood Mackenzie, Demand – AEMO 2026 GSOO

This scenario highlights how unworkable the current framework is within the NT market. Rather than fulfilling its stated aims of ensuring lower long-term prices and security of supply, it would likely force a suboptimal development of Australia’s largest prospective upstream resource, force significant investment in gas processing and transportation infrastructure at Darwin that would otherwise not be required, or reduce LNG exports from the NT potentially to zero.

Figure 35 – Annual and cumulative DSO / RVM variations required to balance NT market (Beetaloo Basin FFD)



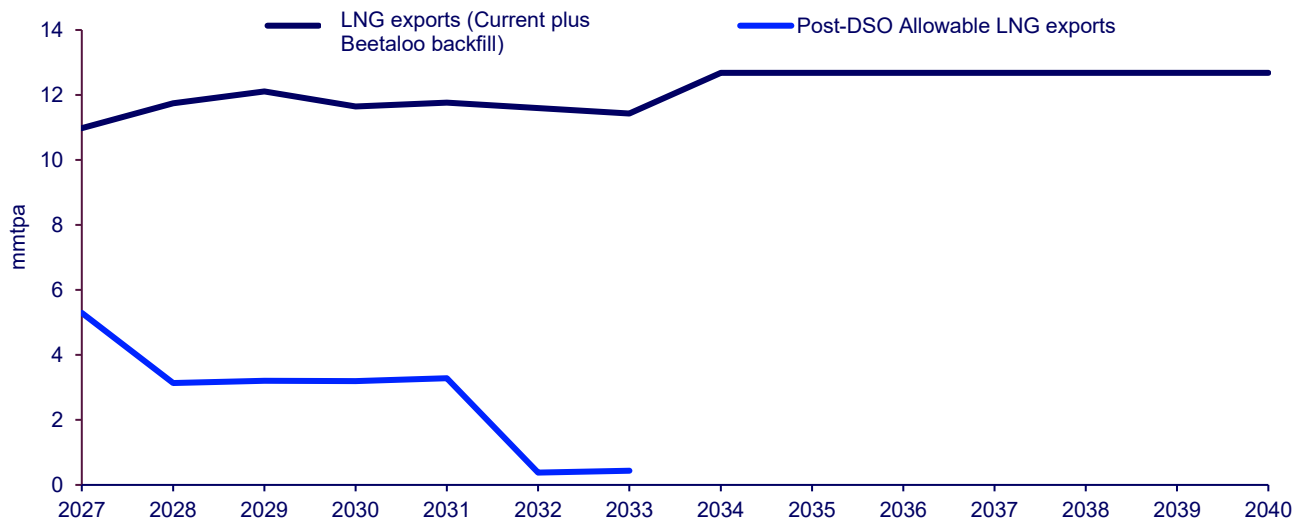
Note: The DSO would be effective from 1 July 2027 – the DSO volumes in 2027 have been calculated on a pro-rata basis for calendar year 2027 (50% of full-year obligation).

Source: Wood Mackenzie

### 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 NT market under the proposed DSO policy is to curtail LNG exports. With Beetaloo Basin gas supplying the ECGM via the NGP and the new Beetaloo to Ballera pipeline, there is no physical access to market for NT LNG export DSO volumes unless the LNG exporters themselves are the developers of the Beetaloo. If the LNG exporters do not participate in the Beetaloo development, LNG export volumes would be reduced to RVM only from 2032 – this is equivalent to 0.4 mmtpa and only available on an annual Ministerial approval basis. If this were to occur, exports would effectively cease from the NT as it is not commercially or technically possible to export only RVM volumes.

Figure 36 – Allowable LNG exports with Beetaloo backfill under DSO framework with no variations / RVM approvals (Beetaloo Basin FFD)



Source: Wood Mackenzie

## Indirect market impacts

The direct effects of applying a 20%-of-LNG-exports DSO to the ECGM are a structural oversupply of the domestic market, binding infrastructure constraints (in the NT), 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 the ECGM include:

- Annual approval cycles
- RVM and long-term GSAs and LNG SPAs
- Ministerial discretion
- Domestic-only producers and market concentration
- Equity marketing of DSO volumes
- 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.

### 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. ECGM domestic buyers, however, contract over much longer horizons as gas supply for industrial, gas-powered generation and retailer offtakes typically run five to ten, or even fifteen years and underwrite the buyer's own capital investments. 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 ECGM operates through long-dated contracts that give both sides a stable reference framework; the DSO would replace this with annual discretionary determinations, working against the security of supply it is intended to provide.

### RVM and long-term GSAs and 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 to fulfil the supply obligations of the existing contract. 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.

With the addition of significant new supply, such as that from the Beetaloo Basin, the ECGM is forecast to be a balanced market to the late 2040s without a DSO policy. However, this depends on the ability to invest in long-term, capital intensive developments with commercialization dependent on both domestic gas buyers and LNG offtakers to underwrite the economics of the project. A Beetaloo Basin development will need new long-term GSAs and LNG SPAs to reach FID. By making those GSAs and SPAs harder to sign, the DSO risks undermining the new supply on which domestic balance depends. 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* Western Australia State Domestic Gas 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 existing market regulations 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. This would need to be performed for each of the ten Australian 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 short-term 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 those located proximate to southern demand centers in the Otway, Gippsland and Bass Basins 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. ECGM domestic supply would concentrate on a handful of northern state LNG exporters, reducing competitive tension and supply diversity. The loss of nearer southern basin supply would, over the long run, raise delivered prices into the southern region given the transport distance from the north. And because exporter domestic supply is a by-product of export economics rather than a standalone merchant business, concentrating reliance on it ties domestic gas 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.

### **Equity marketing of DSO volumes**

The framework does not specify how domestic gas volumes are to be marketed and sold by LNG exporters. Queensland and NT LNG export projects are owned by JVs with multiple equity holders and have different equity holders and JV participants across the upstream, midstream and liquefaction elements of the projects. The potential requirement to market and sell domestic gas on an equity level comes with challenges. Several international JV partners, whose involvement helped underwrite LNG projects in both the NT and Queensland, do not have domestic gas positions in Australia. In some cases, they do not have Australian entities, do not have domestic gas trading capabilities and do not have experience or capability in contracting in Australian domestic gas markets.

The requirement to market on an equity basis would compel LNG buyers, trading partners and international investors who participate in these projects to invest considerable time, effort and capital to establish the required entities, offices, capabilities and licenses to actively participate in domestic gas sales that are effectively forced on them by Government intervention. It also forces the sale of smaller parcels of domestic gas, particularly where JV participants hold small amounts of equity in a project (e.g. the Ichthys JV includes five international participants with equity positions of less than 3% each).

In the short-term, this erodes investment returns for capital already spent in the country, whilst also adding a longer-term deterrent to future investment in gas and LNG projects in Australia. This compounds the erosion of investment attractiveness in Australia and puts new supply projects (that are needed to keep domestic markets balanced long-term) at further risk.

Conversely, the operators of these projects are generally Australian entities who already participate directly in the domestic markets. The operators of GLNG, DLNG, Ichthys LNG and QCLNG already participate in the market directly, as does the APLNG JV which is the operating entity of the APLNG project. Allowing projects to market and sell gas on a JV basis, with the operators engaging directly in the market on the JV's behalf, reduces investment friction and overall complexity for gas buyers, gas producers and their investors.

### **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 existing regulatory regimes (and State-

based regimes in the case of Queensland) 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 (Beetaloo, Taroom) that future supply requires.

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.

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