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We acknowledge that, wherever we work, we do so on Aboriginal and Torres Strait Islander lands. We pay respect to the world's oldest continuing culture and First Nations peoples' deep and continuing connection to Country; and hope that our work can benefit both people and Country.

'Journey of unity: AEMO's Reconciliation Path' by Lani Balzan

AEMO Group is proud to have launched its first [Reconciliation Action Plan](#) in May 2024. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate our ongoing journey towards reconciliation - a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

Important notice

Purpose

AEMO publishes this New South Wales Gas Infrastructure Review to complete Recommendation 34 of the New South Wales Electricity Supply and Reliability Check Up as requested by the Minister for Energy pursuant to section 91C of the National Gas Law, in accordance with the Terms of Reference for Recommendation 34 as outlined by the Department of Climate Change, Energy, the Environment and Water. This publication is generally based on information available to AEMO as at 1 April 2025, unless otherwise indicated.

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Executive summary

The New South Wales Electricity Supply and Reliability Check Up, performed by Marsden Jacob Associates and released in September 2023, contained several recommendations. One relates specifically to the gas supply infrastructure and its ability to supply gas-powered generation (GPG) in New South Wales. Specifically, recommendation 34 states:

That given New South Wales will have seven gas plants by the end of 2024, AEMO be commissioned to undertake a New South Wales gas infrastructure review to advise whether additional storage will be required for those generators given an impending supply gap in the east coast gas markets.

The New South Wales Gas Infrastructure Review (NGIR) assesses the adequacy of gas production, storage, and pipeline infrastructure to meet forecast gas demand and consumption in New South Wales over a 10-year outlook period.

Modelling performed for the NGIR focused on the capability of the gas system to support National Electricity Market (NEM) connected GPG facilities in New South Wales while maintaining gas supply to residential, commercial, and industrial gas consumers. Modelling also explored storage facilities in New South Wales, including both dedicated storage facilities and pipeline linepack as a form of gas storage. The options and pathways analysed to improve GPG supportability can also help to address the overall gas availability and supply adequacy in the long term.

Gas consumption forecasts

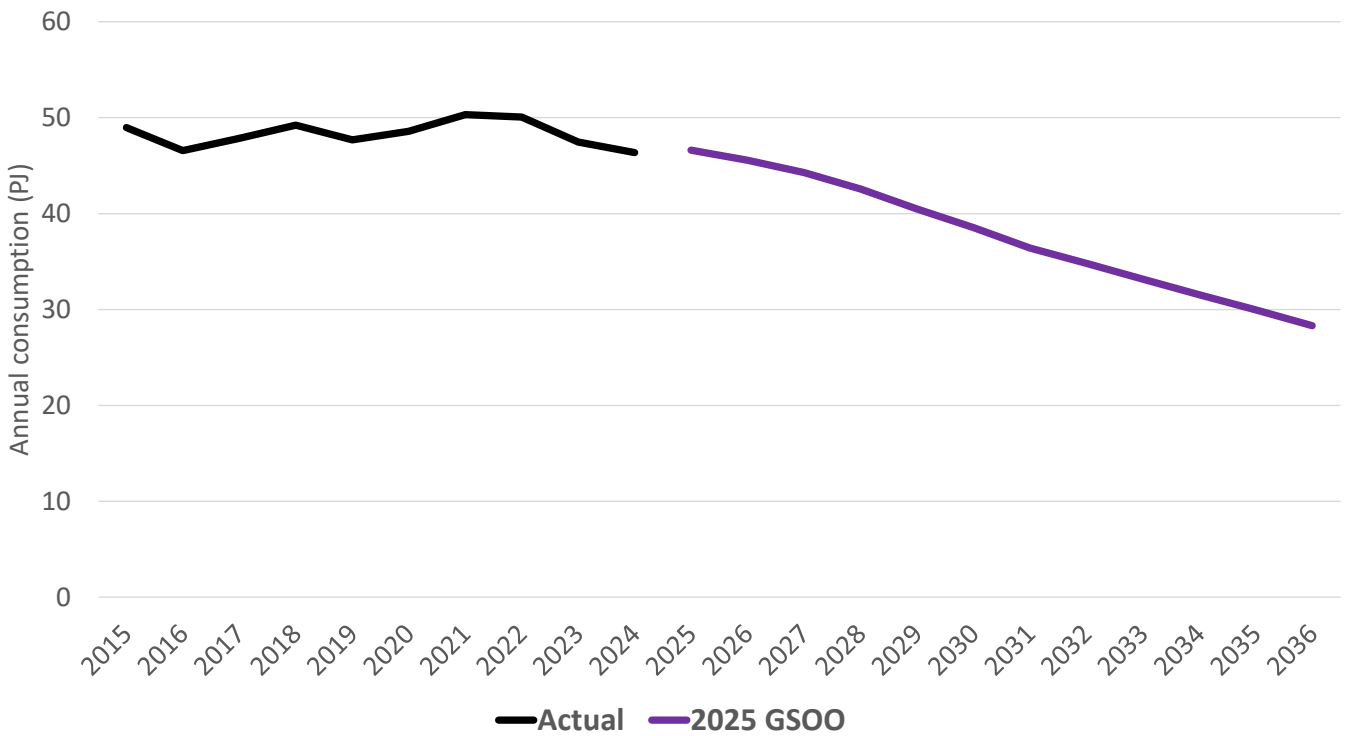
The forecasts for the NGIR report align with the 2025 *Gas Statement of Opportunities* (GSOO) focus on the *Step Change* scenario outlined in AEMO's Draft 2025 *Inputs, Assumptions and Scenarios Report* (IASR)¹.

Figure 1 shows the gas consumption forecast for residential and small commercial sectors in New South Wales and the Australian Capital Territory under the 2025 GSOO **Step Change** scenario.

AEMO forecasts a continued decline in gas use, with residential and small commercial customer consumption dropping to 28 petajoules (PJ) by 2035, 40% lower than in 2024. Electrification is the primary driver of this decline.

¹ At <https://aemo.com.au/-/media/files/major-publications/isp/2025/draft-2025-inputs-assumptions-and-scenarios-report-stage-1.pdf?la=en>.

Figure 1 Actual and forecast residential and small commercial annual consumption in New South Wales and Australian Capital Territory, 2015-36 (PJ)



The total industrial and commercial demand averages 120-160 terajoules per day (TJ/d) throughout the year in New South Wales, with higher demand on weekdays and dips during the Christmas and New Year period showing minimal seasonal variation. This gas usage in New South Wales is mainly driven by 25 large industrial loads (LILs) which account for over 60% of industrial and commercial consumption, with 19 LIL facilities located in Sydney, Gosford, or Newcastle. These facilities include chemical processing, iron smelting, steel manufacturing, and other industrial processes. Notable sites include Orica’s Kooragang Island plant and Manildra’s Shoalhaven Starches facility. LIL demand remains constant unless there is a major shutdown.

The remaining 40% of industrial and commercial gas usage comes from smaller facilities involved in food and beverage manufacturing, heating ventilation and air conditioning (HVAC) systems, water heating, and laundry services.

Figure 2 shows actual demand from 2019-24, highlighting that demand for the industrial and large commercial demand sector has minimal seasonal variation compared to residential gas, with only some industrial and large commercial consumers using more gas in colder weather. Industrial and large commercial gas demand averages between 120 TJ/d and 160 TJ/d year-round, is 18% higher on weekdays than weekends, and is lowest during Christmas and New Year. Demand for LILs remains constant all year, except during major shutdowns at LIL sites.

Figure 2 Industrial and large commercial gas demand in New South Wales and Australian Capital Territory, 2019-24 (TJ/d)



The industrial and large commercial gas consumption forecast for New South Wales and Australian Capital Territory is flat for the outlook period. AEMO forecasts consumption for each LIL individually, informed by surveys and interviews with facility operators that are conducted as part of the annual GSOO data collection process. The decarbonisation pathway chosen by each LIL will greatly influence the outcome of future gas consumption in New South Wales; this is discussed further in Section 2.3.3.

It is difficult for LIL facility operators to provide advanced notice of expected closure, which adds complexity to demand forecasting for this sector. A recent LIL closure example is the Qenos plastics manufacturing facility in Port Botany².

Gas-powered generation forecasts

The GPG usage forecasts are consistent with the optimal development path (ODP) outlined in AEMO’s 2024 *Integrated System Plan (ISP)*. AEMO’s GPG forecast for New South Wales varies by sector aligning with the 2025 GSOO forecast, as shown in **Figure 3**.

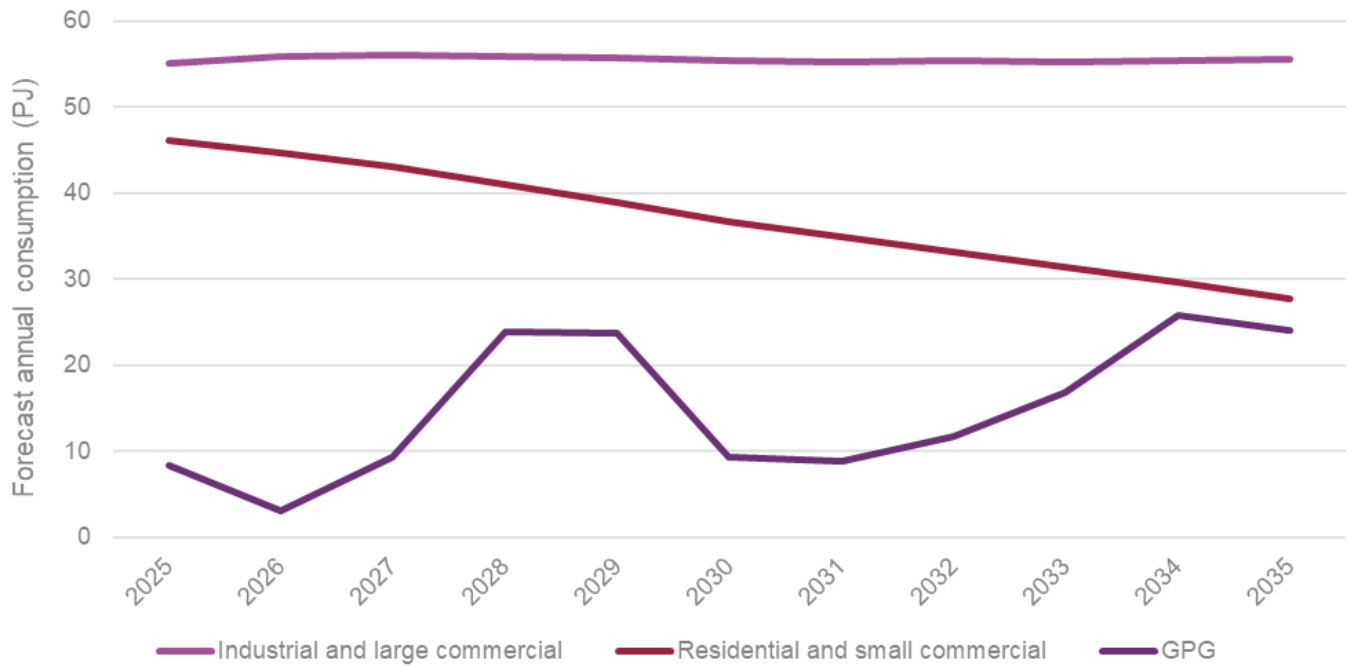
The forecasts fluctuate over time, with three key periods expecting:

- Near-term – reliance on GPG during peak demand and maintenance periods.

² “Qenos in VA, Botany plant shutdown confirmed”, 17 April 2024, at <https://www.packagingnews.com.au/latest/qenos-in-va-botany-plant-shutdown-confirmed>.

- Post-Eraring retirement – increased reliance on GPG after the Eraring coal power station retires in August 2027 until energy storage technologies are more widely deployed.
- Early 2030s – reduced reliance on GPG as renewable energy and storage technologies grow, but potential for increased GPG if coal generation withdraws from the NEM.

Figure 3 2025 Step Change – Coal retirement delay annual consumption forecast for all gas use sectors in New South Wales and Australian Capital Territory by year, 2025-35 (PJ)



Winter peak day GPG demand is forecast to rise from the early 2030s when flexible GPG capacity is expected to be crucial during periods of lower renewable generation, with approximately 15 gigawatts (GW) of GPG forecast to be needed in the NEM by 2050.

Limited decarbonisation pathways for high-heat industrial gas users

While residential and small commercial gas consumption is forecast to decrease as consumers electrify and appliances become more efficient, industrial gas consumption is forecast to remain steady.

In New South Wales, industrial and large commercial users typically make up 48% of total gas consumption, and this proportion will grow as residential consumption declines. For some large industrial businesses, continuing to use gas remains the most economic or only technical choice. The opportunity to electrify processes is only applicable for scenarios where gas is used to produce heat up to around 200°C³. Switching from gas to electric can involve significant costs and potential disruptions, such as downtime for upgrading electrical infrastructure at a hospital.

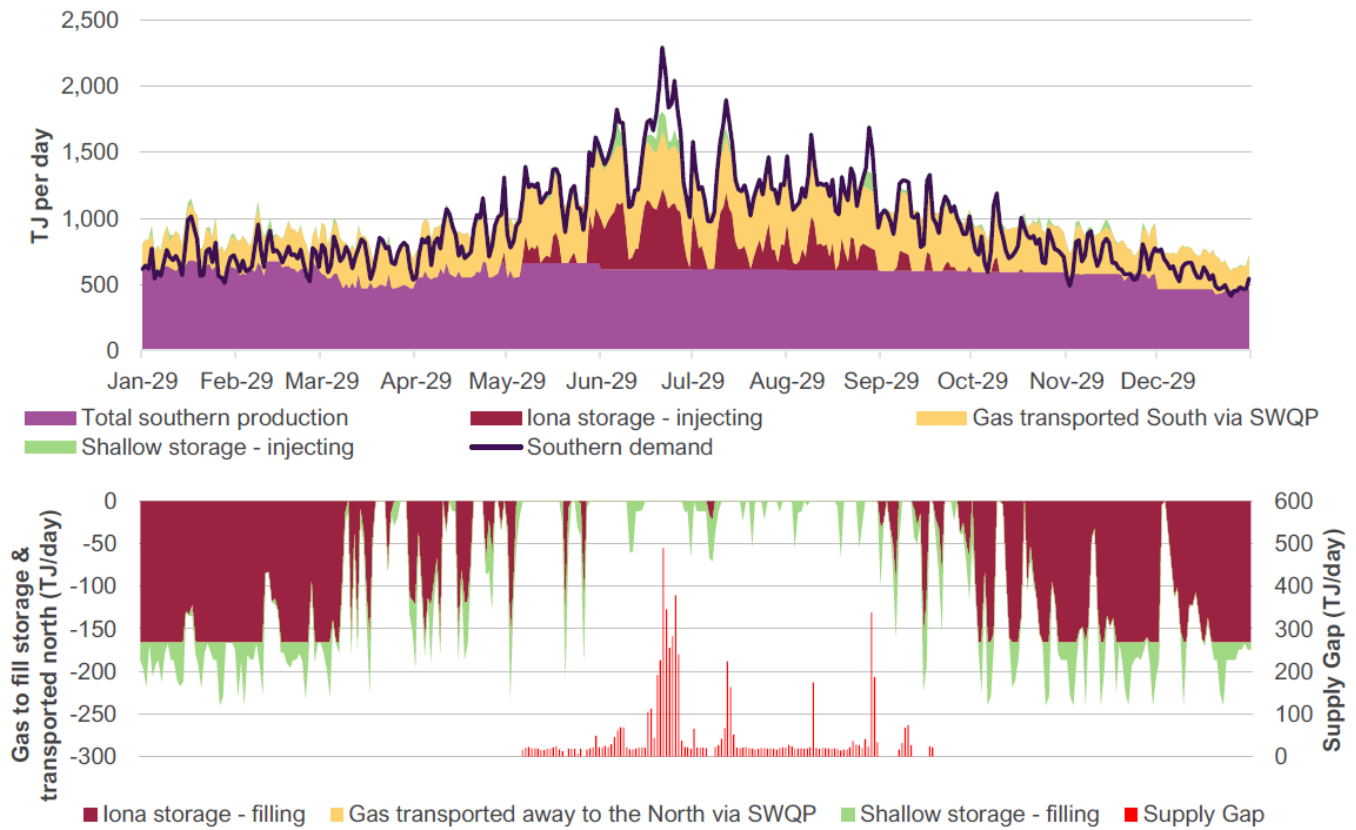
³ Victorian Government, *Victorian gas substitution roadmap 2024*, at <https://www.energy.vic.gov.au/renewable-energy/victorias-gas-substitution-roadmap/gas-substitution-roadmap-update-2024.pdf>.

Many of the industrial facilities in New South Wales currently do not have access to viable decarbonisation or electrification options, including for processes that require high temperatures or require natural gas as a feedstock. The ability of these large users to electrify or fuel-switch to hydrogen or biomethane and decarbonise their energy use, and the time in which they can make these changes, will have an impact on long-term gas consumption in New South Wales.

Forecast supply adequacy

The 2025 GSOO forecast risks of peak day shortfalls from 2028, and structural supply gaps emerging from 2029 in southern Australia. Seasonal supply gaps may occur from 2028 if conditions lead to sustained high gas usage. These supply gaps are forecast to occur during winter when gas demand in southern Australia is the highest, and could exceed the combined capacity of southern production, gas storage, and the pipeline supply from Queensland, as shown in **Figure 4**.

Figure 4 Forecast gas supply to meet southern daily demand, Step change scenario, 2029 (TJ/d)



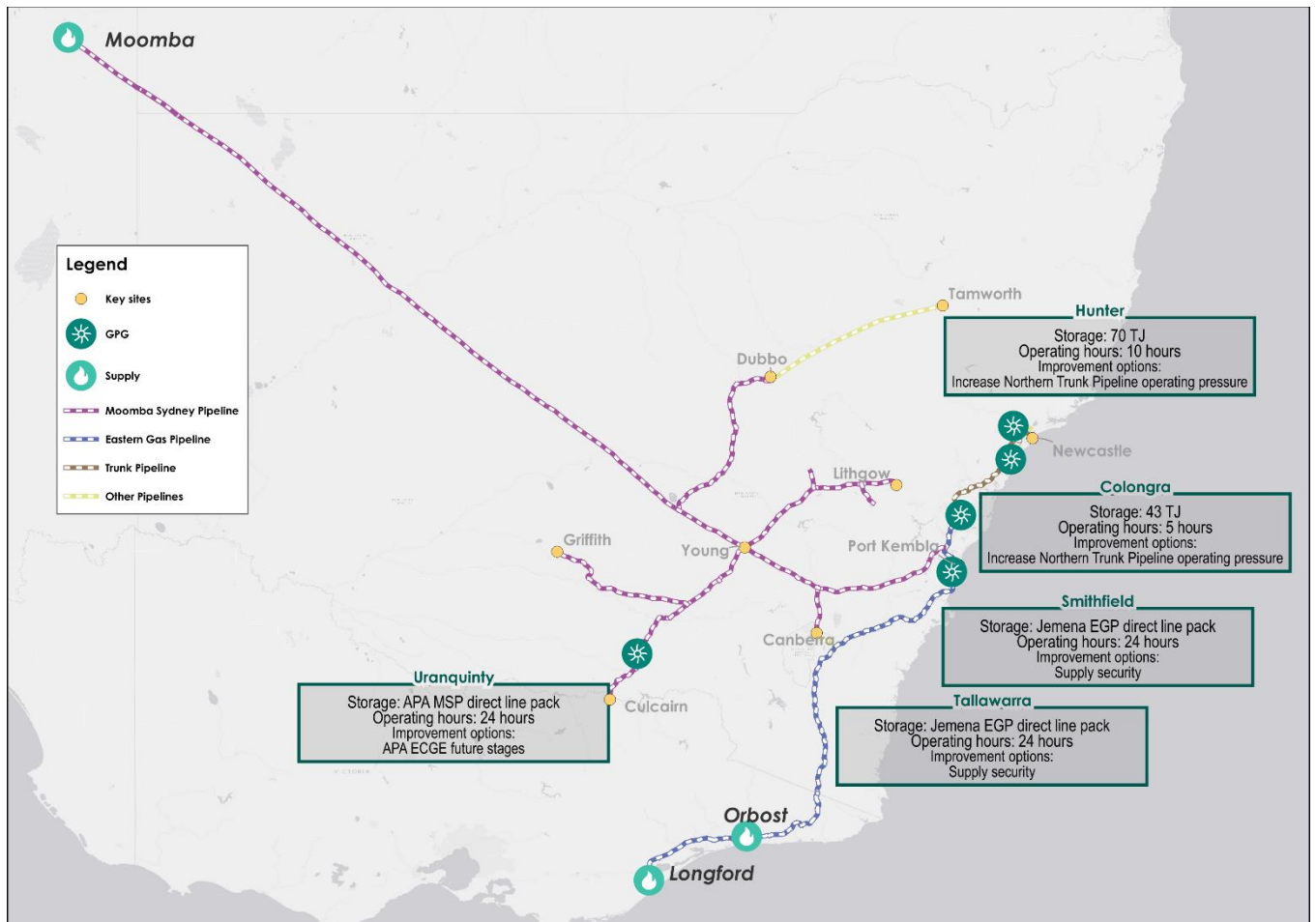
SWQP: South West Queensland Pipeline.

New South Wales currently has no local gas production, with demand in the state being met by gas transported from Victoria, South Australia and Queensland, and from the Newcastle Gas Storage Facility (NGSF). Supply from the Longford Gas Plant in Victoria to New South Wales has historically been steady throughout the year. Since 2022, Longford supply has been decreasing due to the depletion of the large legacy Gippsland Basin fields. This decline is forecast to continue.

Existing gas infrastructure limitations

Figure 5 shows the existing gas infrastructure adequacy modelling analysis in New South Wales to support existing GPG and storage, and assumes gas supply is available at all sources to meet the required demand. The modelling results show the number of operating hours and available linepack that the existing gas infrastructure can adequately support during the theoretical peak load conditions indicated in the ISP modelling results.

Figure 5 Existing gas infrastructure adequacy modelling analysis in New South Wales



The NGIR identifies key limitations of the existing New South Wales gas infrastructure and supply adequacy:

- Interactions between major loads on the Northern Trunk Pipeline (from Wilton to Newcastle) are forecast to increase with the connection of the Kurri Kurri Lateral Pipeline (KKLP), which supplies the new Hunter Power Station, in 2025.
- NGSF refilling may be limited, particularly in the event of extended periods of high GPG consumption, such as in the event of coal generation outages or prolonged low renewable generation.
- Utilisation of NGSF, the only large gas storage facility in New South Wales, is subject to commercial decisions made by owner and operator AGL.

- Operation of the Colongra and Hunter power stations is limited to stored gas available in their supply lateral pipelines, and they can operate at maximum rate for a total of five hours and 10 hours, respectively, per day using gas as a fuel. These power stations can operate for longer periods when operating at lower generation output or when using liquid fuel (diesel).
- Aging infrastructure is restricting transportation capacity on some pipelines and reduces operational capability.
- Demand solely supplied by connection points off the Eastern Gas Pipeline (EGP) is susceptible to supply issues in Victoria or pipeline issues south of these demand centres. The Tallawarra and Smithfield power stations are particularly vulnerable to an EGP supply disruption.
- Supply gaps forecast in the 2025 GSOO will impact the southern states⁴, including New South Wales. If supply from other states is reduced, forecast shortfalls would occur in New South Wales. If new supply sources are not developed, one option to reduce the impact of gas supply shortfalls is to operate GPG using liquid fuel, however not all GPG units in New South Wales have this capability, and this would result in higher emissions.
- New GPG units in New South Wales should be located where there is good gas pipeline supply and sufficient electricity transmission capacity. Based on reliability benefits for the electricity network, existing gas infrastructure and current gas supply sources:
 - A good location for a new GPG unit to connect would be the south-west of Sydney.
 - Areas north of Sydney and in Newcastle show high reliability benefits for the electricity network but are limited by gas infrastructure options.
 - Southern and south-western regions of New South Wales have strong existing gas infrastructure links and access to gas supply but low reliability benefits for the electricity network.

Options for improving gas supply adequacy and gas-powered generation supportability

The NGIR explored options to improve gas supply adequacy utilising existing infrastructure, including:

- increasing the operational pressure of the Northern Trunk Pipeline – this would decrease the interactions between major loads north of Sydney, including the Colongra and Hunter power stations, and NGSF, and
- managing storage inventories to support forecast increases in peak GPG demand – this would ensure storage inventory is available when the supply demand balance in New South Wales is the tightest or to mitigate issues with production or pipelines.

Beyond those limited options, the NGIR considered proposed projects in New South Wales and projected that supply from Squadron Energy's Port Kembla Energy Terminal (PKET) via the EGP would:

- provide sufficient supply capacity in New South Wales to delay the forecast supply gap to the mid-2030s
- provide an alternative supply source for south-east New South Wales demand that is supplied solely by the EGP

⁴ 'Southern states' in the NGIR are New South Wales, Australian Capital Territory, South Australia, Tasmania and Victoria.

- significantly reduce winter storage depletion risk in the southern states, including with the EGP reversal project, supporting future storage options potentially connecting to the EGP in Gippsland
- improve gas supply capacity to support future GPG south of Sydney, and
- act as a shallow storage facility, although with operational limitations.

The Queensland Hunter Gas Pipeline (HGP) with additional supply from Narrabri or the Wallumbilla gas supply hub would:

- provide additional supply in New South Wales to offset the forecast supply gaps
- reduce the dependency on supply to New South Wales from the declining fields in the Gippsland Basin and supply via the Moomba to Sydney Pipeline (MSP)
- enable direct connections from the HGP to the KKLP and NGSF at Newcastle, bypassing the Northern Trunk Pipeline, and
- improve gas supply and system operability for future GPG in the Hunter region and north of Sydney where there is existing electrical infrastructure.

APA's East Coast Grid Expansion future stages would:

- increase the transportation capacity for supply from Queensland or the Northern Territory into New South Wales, and
- add a new shallow storage facility providing storage inventory to support Uranquinty GPG demand or other demand on the MSP.

Pathways for New South Wales to improve gas supply adequacy

AEMO recommends the following pathways for New South Wales to improve gas supply adequacy:

- Enabling the Northern Trunk Pipeline to operate at higher maximum receipt pressures, while also ensuring safe operation of the pipeline is prioritised.
- Supporting the ongoing operation of NGSF, KKLP and the development of gas storage opportunities outside of New South Wales that would be able to directly supply the state such as the proposed Golden Beach gas storage facility. Ongoing operation includes both the availability of the facility and sufficient stored gas ahead of the winter season and other periods of high gas demand.
- Supporting the development of new gas supply sources in New South Wales or projects that increase the transportation capacity or available supply of gas into New South Wales. The NGIR discusses the individual benefits of several proposed projects.
- If new GPG units are required in New South Wales, considering the location of new generators from a whole of energy perspective. Assessing locations from both a gas infrastructure and an electricity infrastructure perspective is important to minimise operational challenges.

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1 Introduction

The New South Wales Electricity Supply and Reliability Check Up⁵ performed by Marsden Jacob Associates and released in September 2023 contained several recommendations, one of which related specifically to the gas networks and the ability of these networks to supply the east coast gas markets. Recommendation 34 stated:

That given New South Wales will have seven gas plants by the end of 2024, AEMO be commissioned to undertake a New South Wales gas infrastructure review to advise whether additional storage will be required for those generators given an impending supply gap in the east coast gas markets.

The New South Wales Government accepted this recommendation in its response to the Electricity Supply and Reliability Check Up. The New South Wales Government developed a Terms of Reference outlining the scope of the NGIR, and in June 2024 the New South Wales Minister for Energy requested that AEMO complete the NGIR pursuant to section 91C of the National Gas Law.

1.1 Scope

The NGIR assessed the adequacy of gas production, storage, and pipeline infrastructure to meet forecast gas demand and consumption in New South Wales over a 10-year outlook period.

Modelling performed for the NGIR focused on supporting GPG for NEM-connected generators while maintaining supply to residential, commercial, and industrial gas consumers. Modelling also explored storage facilities in New South Wales, including both dedicated storage facilities and pipeline linepack as a form of gas storage.

The seven gas plants in New South Wales referenced in Recommendation 34 are the Colongra Power Station, Hunter Power Station, Smithfield Power Station, Tallawarra A and Tallawarra B power stations, Uranquinty Power Station, and Appin and Tower Gas. Appin and Tower Gas source gas locally from coal mine waste gas and therefore are not considered in the NGIR. For the purposes of modelling performed for the NGIR, Tallawarra A and Tallawarra B were treated as a single power station.

The NGIR considered the impact of proposed projects in New South Wales and the impact of projects outside of New South Wales that will impact gas supply adequacy in New South Wales. The projects that were modelled in the NGIR are those that may be completed within the outlook period and include projects that AEMO classifies as uncertain⁶. The NGIR also considered infrastructure that would be required to achieve outcomes beyond what is currently proposed by project proponents. None of the projects assessed represent a cost-benefit assessment and the viability of projects based on current market settings has not been considered.

⁵ See Electricity Supply and Reliability Check Up and New South Wales Government response, both at <https://www.energy.nsw.gov.au/nsw-plans-and-progress/regulation-and-policy/electricity-supply-and-reliability-check>.

⁶ 'Uncertain' projects are at earlier stages of development or face challenges in terms of commercial viability or approvals.

AEMO employed two modelling methodologies:

- Hydraulic pipeline modelling was used to investigate the gas network limitations that are a function of pipeline pressure, instantaneous flows, and the behaviour of equipment within the network. This modelling was limited to assessing behaviour within a day and for up to a week.
- Nodal network modelling was used to assess macro-level trends, risks, and shortfalls in the context of the wider east coast gas market. This modelling was used to assess the full outlook period.

1.1.1 Exclusions

The NGIR scope has the following exclusions:

- The NGIR did not consider contractual or commercial arrangements that may impact supply, storage, and transport of gas.
- The NGIR did not consider the price of gas or the economic viability of gas supply projects.
- The NGIR did not explore how renewable gases such as biomethane and hydrogen could act as alternatives to natural gas demand in New South Wales.

1.1.2 Australian Capital Territory

The Australian Capital Territory is physically located entirely within New South Wales and has no local gas supply or storage. Gas demand in the Australian Capital Territory is met by supply transported into the territory from the New South Wales gas transmission system. Modelling performed for the NGIR considered gas demand in the Australian Capital Territory as another load that must be met (unless otherwise stated).

While the assessment and outcomes of the NGIR primarily relate to New South Wales, it should be noted that developments that would improve gas system security in New South Wales would often also improve gas system security in the Australian Capital Territory.

1.1.3 Gas-powered generation fuel consumption

The NGIR included modelling of GPG fuel consumption, which is impacted by its design and operating configuration, operating capacity, temperature, and other operational factors.

For NGIR purposes, AEMO assumed a fixed heat rate which corresponded to the typical optimum heat rate of a given generator. Heat rates can only be confirmed when a GPG is commissioned and operational. For under construction and proposed generation, AEMO used an assumed heat rate, based on a similar existing generator.

1.2 Information and scenarios

AEMO gathered information and data from transmission pipeline owners, distribution network owners, storage facility owners, and GPG operators for the purposes of informing the NGIR. AEMO used information and assumptions from the 2024 GSOO⁷ to inform the modelling, forecasts, and analysis in the NGIR, and also used information provided for the development of the 2025 GSOO where possible.

⁷ At <https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo>.

The supply adequacy assessment in the 2025 GSOO focused on the **Step Change** scenario from the 2024 IASR⁸. The **Step Change** scenario achieves a scale of energy transformation that supports Australia's contribution to limiting global temperature rise to below 2°C compared to pre-industrial levels. The scenario assumed a coordinated economy-wide approach that efficiently and effectively tackles the challenge of rapidly lowering emissions (including electrification of gas heating load), driven by consumer-led change with a focus on energy efficiency, digitalisation and step change increases in global emissions policy above what is already committed.

The forecasts used in the NGIR are based on the **Step Change – Coal retirement delay** sensitivity defined in the 2025 GSOO. This is similar to the **Step Change** scenario but assessed the impact if the Eraring Power Station were to be closed in 2027 instead of 2025. The delay of the Eraring Power Station closure to 2027 was announced by Origin Energy and the New South Wales Government in May 2024⁹, after publication of the 2024 GSOO.

1.3 Overview of assets

The New South Wales gas network comprises three major interconnected pipeline systems:

- Moomba to Sydney Pipeline (MSP)
- Eastern Gas Pipeline (EGP), and
- Northern and Southern Trunk Pipelines, which are part of the Jemena NSW Gas Distribution Network.

Other key facilities in the New South Wales gas network include:

- Colongra Lateral Pipeline (CLP)
- Kurri Kurri Lateral Pipeline (KKLP), and
- Newcastle Gas Storage Facility (NGSF).

The following sections describe the major physical infrastructure components and facilities included within each of the pipeline systems above used for analysis.

1.3.1 Moomba to Sydney Pipeline

The MSP system is a transmission pipeline system owned and operated by APA Group¹⁰. The MSP consists of a 1,300 km mainline transporting natural gas bi-directionally between Moomba and Wilton, a lateral from Young to Culcairn transporting gas bi-directionally between New South Wales and Victoria, and various laterals supplying regional New South Wales. Laterals include Dalton to Canberra and from Young to Lithgow and Bathurst. Most of the MSP consists of single line pipelines, but the section from Young to Culcairn is looped between Young and Wagga Wagga before reverting to a single lateral from Wagga Wagga to Culcairn.

For the purposes of the NGIR, the MSP system also includes APA's Central West Pipeline, which connects to the MSP at Marsden and runs to Dubbo, and the Central Ranges Pipeline from Dubbo to Tamworth.

⁸ At <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios>.

⁹ Origin, "Origin and NSW Government agree to delay closure of Eraring Power Station", 23 May 2024, at <https://www.originenergy.com.au/about/investors-media/origin-and-nsw-government-agree-to-delay-closure-of-eraring-power-station/>.

¹⁰ Referred to as APA in the NGIR.

The existing MSP includes five compressor stations, with two recently commissioned in 2021 and 2023 as part of the delivery of Stage 1 and Stage 2 of APA's East Coast Grid Expansion (ECGE) project. These compressor stations are located between the existing mainline compressor stations at Bulla Park and Young. The remaining compressor station is located at the Marsden offtake to provide compression capability to the Central West Pipeline and Central Ranges Pipeline.

The MSP has three existing receipt locations at:

- Moomba, which includes supply from the Moomba Gas Plant and South West Queensland Pipeline (SWQP)
- Culcairn, which receives gas from the Victorian Transmission System (VTS), and
- Wilton, which receives gas from the EGP.

There are currently 44 delivery points along the MSP supplying transmission customers, distribution networks, and the Uranquinty Power Station. The Australian Capital Territory distribution network is also supplied by the MSP via the Dalton to Canberra lateral pipeline.

1.3.2 Eastern Gas Pipeline

The Jemena-owned and operated EGP, commissioned in August 2000, consists of a 797 km long mainline primarily transporting gas from the Gippsland Basin in Victoria to the Sydney Short Term Trading Market (STTM) hub and other locations along the route.

The EGP compressor fleet includes a total of four compressor stations. Four units are located at the Longford Compressor Station (CS) and one unit at the Mila CS. The sixth and seventh units, the Michelago CS and the East Gippsland CS, were commissioned in 2015 as part of a further increase in pipeline capacity.

There are currently two receipt locations on the EGP, at:

- Longford, which includes supply from the Longford Gas Plant and could include flow from the VTS via VicHub, and
- Orbost, which includes supply from the Orbost Gas Plant.

An additional receipt point has been constructed at Port Kembla to connect the Squadron Energy owned PKET that could be used to import liquefied natural gas (LNG).

The EGP currently has 15 delivery points, each with its own metering station. Four of the delivery points – VicHub into the VTS, Tasmanian Gas Pipeline, Bairnsdale City Gate and Bairnsdale Power Station – are located in Victoria. The remaining delivery points supply demand in New South Wales including the Tallawarra Power Station. The Australian Capital Territory distribution network is also supplied by the EGP via the Hoskinstown delivery station.

1.3.3 Jemena New South Wales Gas Distribution Network

The Jemena New South Wales Gas Distribution Network includes over 26,000 km of pipelines and distribution mains of various sizes. Maximum Allowable Operating Pressures (MAOP) range from 6,895 kilopascals (kPa) to 7 kPa. The Jemena New South Wales Gas Distribution Network is owned and operated by Jemena Gas Networks (JGN).

The Wollongong to Newcastle section of the Jemena New South Wales Gas Distribution Network supplies natural gas from the transmission pipeline receipt points to gas customers via a series of trunk pipelines. The NGIR only considered these trunk pipelines and their delivery points in this analysis, and did not model the smaller, lower pressure pipelines in the distribution network or the regional sections of the Jemena New South Wales Gas Distribution Network. The trunk pipelines are grouped into two mainlines, the Northern Trunk Pipeline and the Southern Trunk Pipeline, that form an approximately 284 km gas supply backbone from Wollongong to Newcastle.

Northern and Southern Trunk Pipelines

The Northern Trunk Pipeline and Southern Trunk Pipeline are currently supplied via five receipt points including Wilton MSP and Wilton EGP at Wilton, Horsley Park EGP, Port Kembla EGP, and Hexham, which connects to AGL's NGSF.

The Northern Trunk Pipeline acts as the critical gas supply backbone for the Sydney metropolitan networks and extends north to Newcastle. The pipeline supplies 16 delivery points in total, including several major loads including the Colongra Power Station via the CLP, the Hunter Power Station via the KKLP, NGSF, and many large industrial loads including Orica's Kooragang Island facility.

The Southern Trunk Pipeline extends south to supply mostly residential networks in the Wollongong and Port Kembla areas.

1.3.4 Colongra Lateral Pipeline

The CLP is owned and operated by Jemena and is supplied from the Northern Trunk Pipeline at Munmorah. The CLP runs approximately 13 km to the Colongra Power Station and includes 3.5 km of 250 mm diameter feeder pipeline, the 1,050 mm diameter Colongra storage pipeline, and the Munmorah CS that compresses gas supplied from the Northern Trunk Pipeline into the storage pipeline to meet the required inlet pressure of the Colongra Power Station.

1.3.5 Kurri Kurri Lateral Pipeline

The KKLP has been constructed by APA and is expected to be available during winter 2025. The KKLP comprises a 21 km 350 mm diameter feeder pipeline, the 24 km 1,000 mm diameter Kurri Kurri storage pipeline, and the Kurri Kurri CS that compresses gas supplied from the Northern Trunk Pipeline into the storage pipeline to meet the required inlet pressure of the Hunter Power Station. The KKLP also includes a regulator facility that will enable flow from the storage pipeline back into the Northern Trunk Pipeline to supply the Sydney STTM.

1.3.6 Newcastle Gas Storage Facility

The NGSF is an LNG storage facility owned and operated by AGL. Gas is transported to and from NGSF via a 5.5 km pipeline that connects the gas storage facility to the receiving station at Hexham on the Northern Trunk Pipeline. Natural gas is converted to LNG at the facility and then stored in an LNG storage tank capable of containing equivalent of up to 1.5 PJ of natural gas.

1.3.7 New South Wales gas network capacities

Table 1 summarises the current New South Wales gas network capacities by pipeline systems and facilities.

Table 1 Summary of existing pipelines and facilities nameplate capacity

Infrastructure	Facility section	Nameplate capacity
Moomba Sydney Pipeline (MSP)	Moomba to Wilton ^A	565 TJ/d ^B
	Wilton to Moomba	193 TJ/d
	Young to Culcairn (south flow)	195 TJ/d
	Culcairn to Young (north flow)	200 TJ/d
Eastern Gas Pipeline (EGP)	Longford to Horsley Park	350 TJ/d
Colongra Lateral Pipeline (CLP)	Munmorah Compressor to Colongra Storage Pipeline	43 TJ/d
Kurri Kurri Lateral Pipeline (KKLP)	Kurri Kurri Compressor to Kurri Kurri Storage Pipeline	53 TJ/d
	KKLP storage capacity	72 TJ
Newcastle Gas Storage Facility (NGSF)	Liquefaction rate (refilling)	12.5 TJ/d
	Vaporisation rate	120 TJ/d
	NGSF storage inventory	1,500 TJ

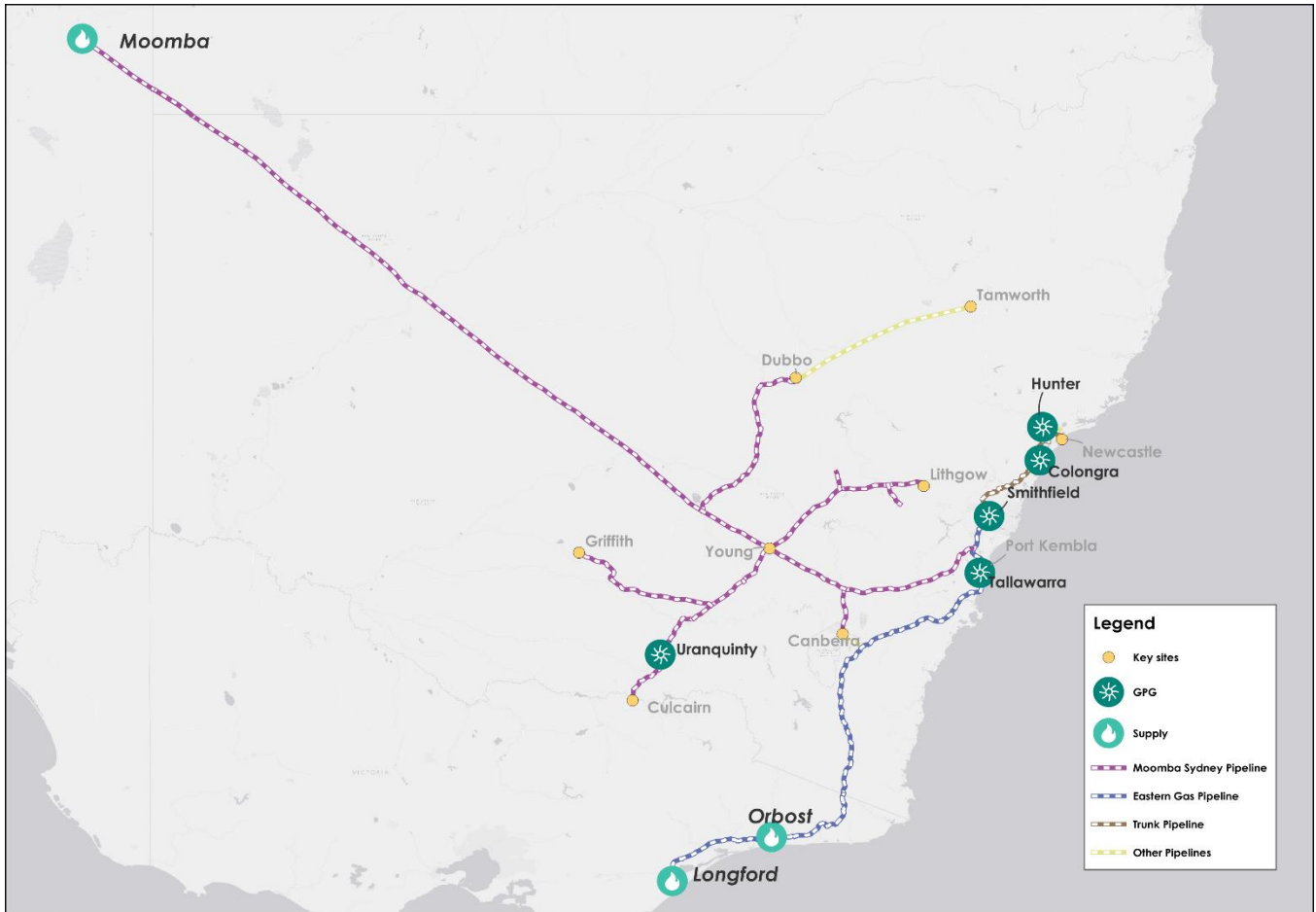
A. MSP nameplate capacity for this pipeline section is dependent on the flow split at Young.

B. MSP nameplate capacity is expected to increase to 585 TJ/d with the completion of the Moomba Sydney Ethane Pipeline relicensing project in 2025.

1.4 Map

Figure 6 shows the locations of pipeline systems and facilities included in this analysis.

Figure 6 New South Wales pipeline systems and facilities locations



2 Gas supply and demand

This chapter provides context for the NGIR, with insights into the current status of gas usage in New South Wales, supply of gas to meet that demand, and AEMO's forecasts for gas consumption in the state.

Gas usage in New South Wales can be categorised into four sectors:

- **Residential and small commercial consumers** – these consumers use less than 10 terajoules per year (TJ/y) and make up the largest number of connections in New South Wales.
- **Industrial and large commercial consumers** – gas users in this category use more than 10 TJ/y but less than 500 TJ/y.
- **LILs** – these are large industrial sites that consume at least 500 TJ/y.
- **GPG** – in the NGIR, GPG refers to NEM-connected, gas-network-connected generation only, and does not consider GPG used to generate electricity for on-site use only (such as cogeneration units) or GPG powered by locally sourced gas.

AEMO refers to gas demand by residential, commercial, and industrial consumers as **system demand**. System demand does not include GPG demand.

2.1 Historical and forecast system demand by sector

2.1.1 Residential and small commercial gas usage

Residential and small commercial gas consumers in New South Wales use gas primarily for water heating, space heating, and cooking. The use of gas for heating leads to a seasonal demand profile, with daily residential and small commercial gas demand in winter averaging 148 TJ/d, while summer gas demand is 56% of this at 82 TJ/d.

As a proportion of total gas consumption, residential and small commercial gas usage makes up 45% of total gas demand in winter, compared to 35% in summer.

Figure 7 shows the seasonality profile for gas demand in this sector.

Gas is used by residential and commercial consumers throughout southern and eastern New South Wales, although demand is concentrated in metropolitan areas. The Northern and Southern Trunk Pipelines support 85% of the residential and commercial gas demand in New South Wales, which includes supplying the cities of Sydney, Gosford, Newcastle, and Wollongong. Regional cities including Wagga Wagga, Orange, Bathurst, Bowral, and Goulburn each account for 1% to 2.5% of residential and small commercial gas demand.

Figure 7 Residential and small commercial gas demand in New South Wales and Australian Capital Territory, 2019-24 (TJ/d)

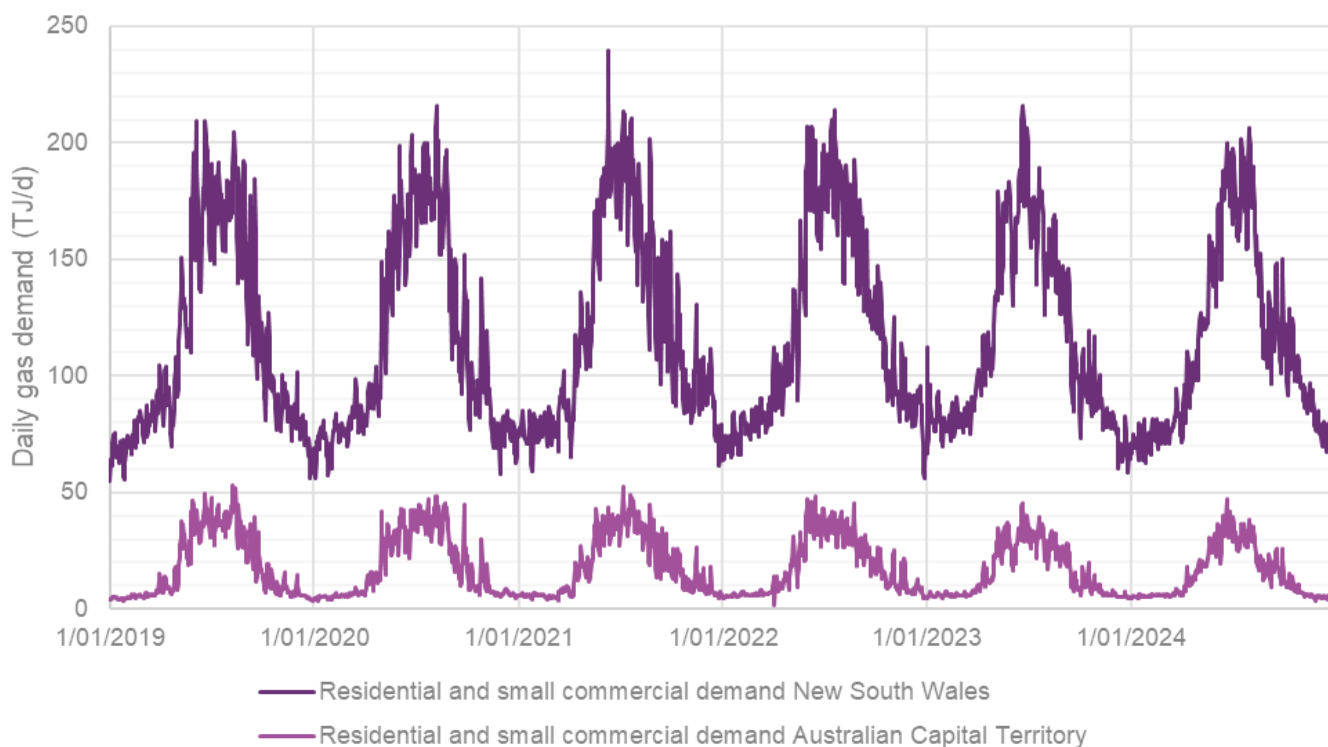


Table 2 shows that residential and small commercial gas consumption gradually increased from 2019 to 2022, but since 2022 consumption has been in decline. Winter 2023 was an especially warm winter¹¹, which partly accounted for the lower gas consumption, as well as changes in consumer behaviour as people returned to workplaces following the COVID-19 pandemic. Winter 2024 was colder than 2023 but remained warmer than average compared to historical winters.

In addition to warmer weather, reduced gas consumption is driven by a combination of factors including electrification of gas appliances, consumer response to higher retail gas prices, and to a lesser extent energy efficiency savings. It is difficult to identify the individual contribution of each factor as consumer choices may not be visible, such as a consumer choosing to run their reverse-cycle air conditioning instead of their gas heating.

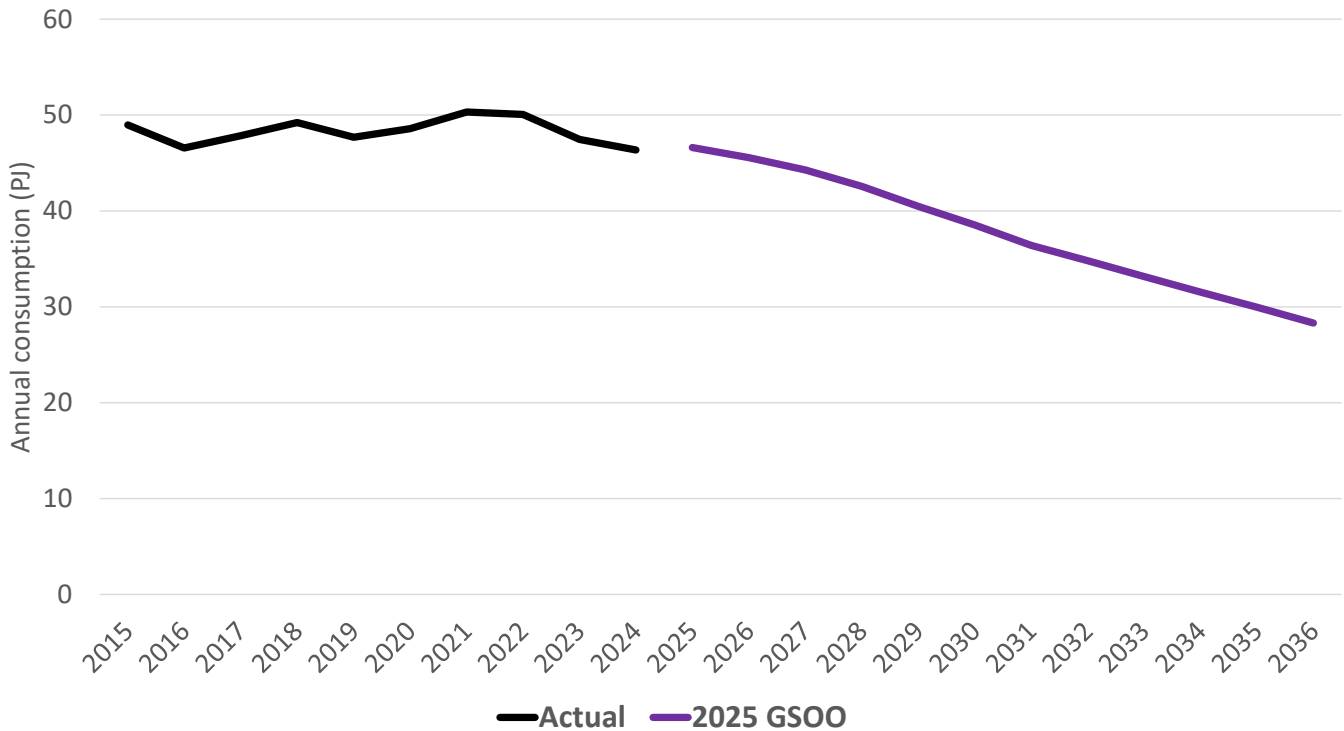
Table 2 Residential and small commercial gas consumption in New South Wales and Australian Capital Territory, 2019-24 (PJ)

	2019	2020	2021	2022	2023	2024
Total consumption	47.7	48.6	50.3	50.0	47.4	46.4
New South Wales	41.1	41.8	43.4	43.5	41.7	40.9
Australian Capital Territory	6.6	6.7	6.9	6.6	5.7	5.4

¹¹ New South Wales seasonal climate summaries are available from the Bureau of Meteorology at http://www.bom.gov.au/climate/current/statement_archives.shtml?region=nsw&period=season.

Figure 8 shows the residential and small commercial gas consumption forecast for the 2025 GSOO **Step Change** scenario for New South Wales and Australian Capital Territory. AEMO forecasts that residential and small commercial gas consumption will continue to decline. Annual consumption for New South Wales and the Australian Capital Territory in 2035 is estimated to be 28 PJ, 40% lower than consumption in 2024. Electrification is the most significant driver of the forecast decline in consumption.

Figure 8 Actual and forecast residential and small commercial annual consumption in New South Wales and Australian Capital Territory, 2015-36 (PJ)



The rate of electrification is a key uncertainty in AEMO forecasts; this is discussed further in Section 2.3.1.

2.1.2 Industrial and large commercial gas usage

Industrial and large commercial gas usage in New South Wales is dominated by a small number of LIL customers which account for over 60% of industrial sector gas consumption. There are 25 LIL sites in New South Wales, 19 of which are in Sydney, Gosford, or Newcastle. There are no LIL facilities in the Australian Capital Territory. The LILs in New South Wales include industrial facilities ranging from chemical processing, iron smelting and steel manufacturing, cement, brick manufacturing, particle board manufacturing, dairy, starch processing, paper and glass, to other minerals processing.

The location of the largest gas users in New South Wales – including Orica’s ammonia and ammonium nitrate manufacturing plant at Kooragang Island and Manildra’s Shoalhaven Starches facility at Bomaderry – plays a critical role in the assessment of gas transmission and supply adequacy.

The remaining 40% of industrial and large commercial gas consumption in this sector is by smaller industrial and large commercial facilities such as food and beverage manufacturing, HVAC systems in offices, shopping centres

and supermarkets, water heating for pools and aquatic centres, and laundry services and sterilisation in hospitals and aged care facilities.

Figure 9 shows that demand for this sector has minimal seasonal influence compared to the residential gas sector, because only some of the gas demand used by industrial and large commercial consumers is in response to colder weather. Total industrial and large commercial gas demand averages between 120 TJ/d and 160 TJ/d throughout the year. Demand is 18% higher on weekdays in this sector compared to weekends, and typically is at its lowest for any given year over the Christmas and New Year period. Demand for the LILs is constant throughout the year and only materially decreases when one of the LIL sites has a major shutdown period.

Figure 9 Industrial and large commercial gas demand in New South Wales and Australian Capital Territory, 2019-23 (TJ/d)



Similar to the residential and small commercial sector, 83% of industrial and large commercial gas consumption is concentrated in Sydney, Gosford, Newcastle, and Wollongong. Regional cities with large industrial facilities such as Nowra, Wagga Wagga, Marulan, Tamworth, and Tumut account for 1.2% to 6.5% of industrial and commercial gas usage each.

Table 3 shows that industrial and large commercial demand in New South Wales and the Australian Capital Territory has been steady year-on-year. Changes from one year to another can be caused by LILs taking longer maintenance periods or otherwise changing their consumption behaviour.

Table 3 Industrial and large commercial gas consumption in New South Wales and Australian Capital Territory, 2019-24 (PJ)

	2019	2020	2021	2022	2023	2024
Total consumption	52.8	50.4	52.1	53.6	50.6	46.4
Total New South Wales consumption	51.5	49.2	50.8	52.3	49.4	45.3
LIL consumption	32.0	31.1	32.9	33.9	31.3	27.4
Australian Capital Territory consumption*	1.3	1.1	1.2	1.3	1.2	1.1

* There are no LIL sites in the Australian Capital Territory.

The industrial and large commercial gas consumption forecast for New South Wales and the Australian Capital Territory is flat for the outlook period. AEMO forecasts consumption for each LIL individually, informed by surveys and interviews with facility operators conducted as part of the annual GSOO process. The decarbonisation pathway chosen by each LIL will greatly influence the outcome of future gas consumption in New South Wales. This is discussed further in Section 2.3.3.

It is difficult for LIL facility operators to provide advance notice of expected closure, which adds complexity to forecasting this sector. A recent LIL closure example is the Qenos plastic manufacturing facility in Port Botany¹².

2.2 Gas-powered generation

2.2.1 The role of gas-powered generation

In New South Wales and other NEM regions, utility-scale and distributed renewable energy sources continue to be deployed at pace, but the existing GPG fleet is still required to support instances of peak consumer electricity demand and back up storage technologies during periods of low variable renewable energy (VRE) output.

New South Wales currently has approximately 3.1 GW of installed or committed GPG capacity, as 0 shows.

The New South Wales GPG fleet typically operates during periods of low regional reserve¹³ or high spot market prices due to their relatively fast ramp-up rate but relatively high fuel cost compared to other generation sources¹⁴. This behaviour is consistent with AEMO’s 2024 ISP, which indicated that as the energy transition continues, a typical NEM GPG facility may only utilise 5% of their annual capacity but are a critical back-up generation source for the grid.

¹² “Qenos in VA, Botany plant shutdown confirmed”, 17 April 2024, at <https://www.packagingnews.com.au/latest/qenos-in-va-botany-plant-shutdown-confirmed>.

¹³ The available generation supply relative to the demand within the NEM region; the larger the reserve, the larger the surplus of available generation relative to the expected demand.

¹⁴ Approximately 0.4 GW of the 3.1 GW of GPG capacity currently in service or committed in New South Wales is mid-merit generation. Tallawarra, Uranquinty, and Colongra operate as flexible GPG.

Table 4 In-service and committed GPG fleet information for New South Wales in scope of this report^{A,B,C}

Station	Owner	Nameplate capacity (MW)	Location	Gas supply	Planned retirement	Technology type ^D
In-service						
Colongra	Snowy Hydro Ltd	724 <i>Across 4 turbines</i>	Colongra <i>South of Newcastle</i>	Colongra Lateral Pipeline	2070	OCGT
Tallawarra	EnergyAustralia Tallawarra Pty Ltd	760 <i>440 Tallawarra A 320 Tallawarra B</i>	Yallah <i>South of Wollongong</i>	Eastern Gas Pipeline	2043 (A) 2053 (B)	CCGT (A) OCGT (B)
Smithfield	Smithfield Power Generation Pty Ltd	185 <i>Across 3 turbines</i>	Smithfield <i>Sydney</i>	Eastern Gas Pipeline	2044	OCGT
Uranquinty	Origin Energy Uranquinty Power Pty Ltd	692 <i>Across 4 turbines</i>	Uranquinty <i>Southern New South Wales</i>	Moomba to Sydney Pipeline	2044	OCGT
Committed (operational from winter 2025)						
Hunter Power Station	Snowy Hydro Ltd	750 <i>Across 2 turbines</i>	Kurri Kurri <i>West of Newcastle</i>	Kurri Kurri Lateral Pipeline	2064	OCGT

A. See NEM Generation Information, at <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information>.

B. See expected closure years, at <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information>.

C. See Pipeline Connection Point Mapping, at <https://www.aemo.com.au/energy-systems/gas/gas-bulletin-board-gbb/data-gbb/standing-data-and-notices/standing-data>.

D. The two types of NEM-connected GPG technology employed in New South Wales are open cycle gas turbines (OCGT) and combined cycle gas turbines (CCGT).

2.2.2 Recent gas-powered generation events

While the current role of GPG is typically to back up other sources of generation in the NEM, there are two recent examples which highlight the flexible nature of GPG:

- Coal generation outages and reduced fuel supply in winter 2022^{15,16}.
 - Planned and unplanned coal generation outages placed pressure on other generation sources in the NEM to meet demand.
 - The New South Wales coal generation fleet recorded record low average generation in Q2 of 2022, with a total average generation decrease of 836 megawatts (MW) across the fleet.
 - Gas consumption for GPG across the east coast increased in Q2 of 2022 by 28% from Q1 to 45.1 PJ, with a 210% quarterly increase in New South Wales alone.
 - Average NEM-wide GPG increased by 472 MW and 259 MW in Q2 and Q3 respectively.
 - Average GPG in New South Wales increased in Q2 by 340 MW, the highest Q2 rate since 2014.
 - Challenging gas supply conditions lead to the curtailment of some GPG units or the reliance on high-cost liquid fuel sources.

¹⁵ AEMO, *Quarterly Energy Dynamics Q2 2022*, at <https://aemo.com.au/en/energy-systems/major-publications/quarterly-energy-dynamics-qed>.

¹⁶ AEMO, *Quarterly Energy Dynamics Q3 2022*, at <https://aemo.com.au/en/energy-systems/major-publications/quarterly-energy-dynamics-qed>.

- Electricity and gas market prices and volatility rose, with New South Wales recording its second-highest NEM spot market price at the time (Q3, 2022), leading to periods of market administration or price caps in both the electricity and gas markets.
- Reduced hydro and wind generation in winter 2024¹⁷.
 - Low wind speed across the NEM led to a 657 MW (20%) year-on-year decrease in wind generation output.
 - Low seasonal rainfall and water release restrictions led to a 16% year-on-year decrease in hydro generation output.
 - NEM-wide GPG increased across all hours of the day, and generation averaged 1.7 GW, a 16% year-on-year increase.
 - On 20 July 2024, GPG in New South Wales peaked at approximately 1.8 GW (15% of New South Wales' electricity demand), or approximately three quarters of currently installed capacity, with a daily average gas-powered generation of 0.8 GW¹⁸.

2.2.3 AEMO's consumption and peak day forecasts for gas-powered generation

AEMO's gas consumption forecast for New South Wales varies considerably by sector, as seen in **Figure 10**.

The 2025 GSOO annual consumption forecast for GPG, including the seasonal peak day demand forecast (**Figure 11**), oscillates across the forecast horizon and can be broadly classified into three general periods:

- Near-term reliance on GPG.
 - GPG in New South Wales is typically associated with meeting peak demand periods and supporting the grid during generator or transmission maintenance periods.
- Supporting the grid after the Eraring coal power station retirement.
 - As discussed further in Section 2.3.4, when the Eraring coal power station retires in August 2027, there will likely be increased reliance on GPG until the deployment of utility and consumer-scale energy storage technologies ramps up in New South Wales and the NEM. This is reflected in the annual consumption and peak day demand forecasts.
- Backing up renewable energy generation and firming technologies.
 - As discussed further in Section 2.3.4, as the deployment of utility and consumer-scale energy storage technologies, transmission developments, and renewable electricity generation continues in the early 2030s, there could be less reliance on GPG to meet the generation and firming needs of the grid. However, as discussed in the 2024 ISP, if coal generation continues to withdraw from the NEM broadly, then peak-day and annual GPG usage may increase from the early 2030s. This flexible GPG capacity is critical to back up the grid and the 2024 ISP projects that approximately 15 GW of flexible capacity will be needed in the NEM by 2050.

¹⁷ AEMO, *Quarterly Energy Dynamics* Q2 2024, at <https://aemo.com.au/en/energy-systems/major-publications/quarterly-energy-dynamics-qed>.

¹⁸ For information regarding NEM price, demand and fuel mix, refer to the NEM data Dashboard and associated datasets, at <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/data-nem/data-dashboard-nem>.

- As **Figure 11** shows, firming in the winter season especially may become increasing crucial. Peak day GPG demand continues to increase from the early 2030s, particularly in winter when renewable generation is naturally lower.

Figure 10 2024 Step Change – Coal retirement delay annual consumption forecast for all gas use sectors in New South Wales and Australian Capital Territory by year, 2025-35 (PJ)

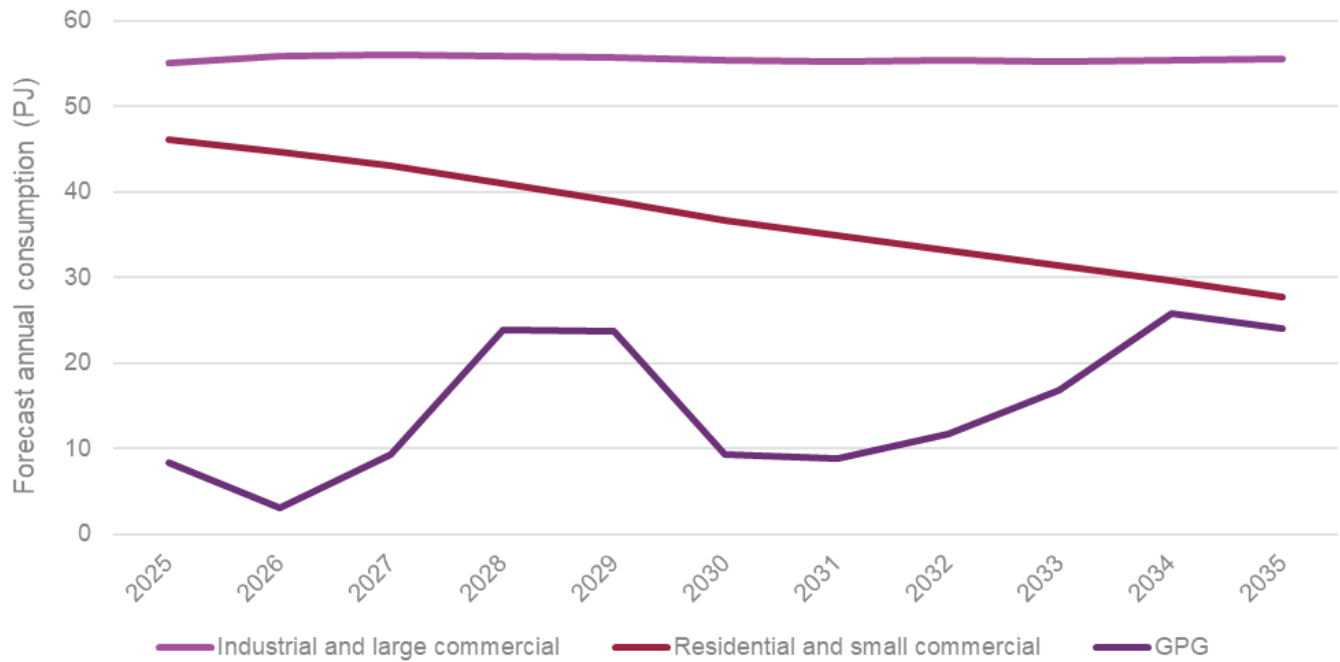
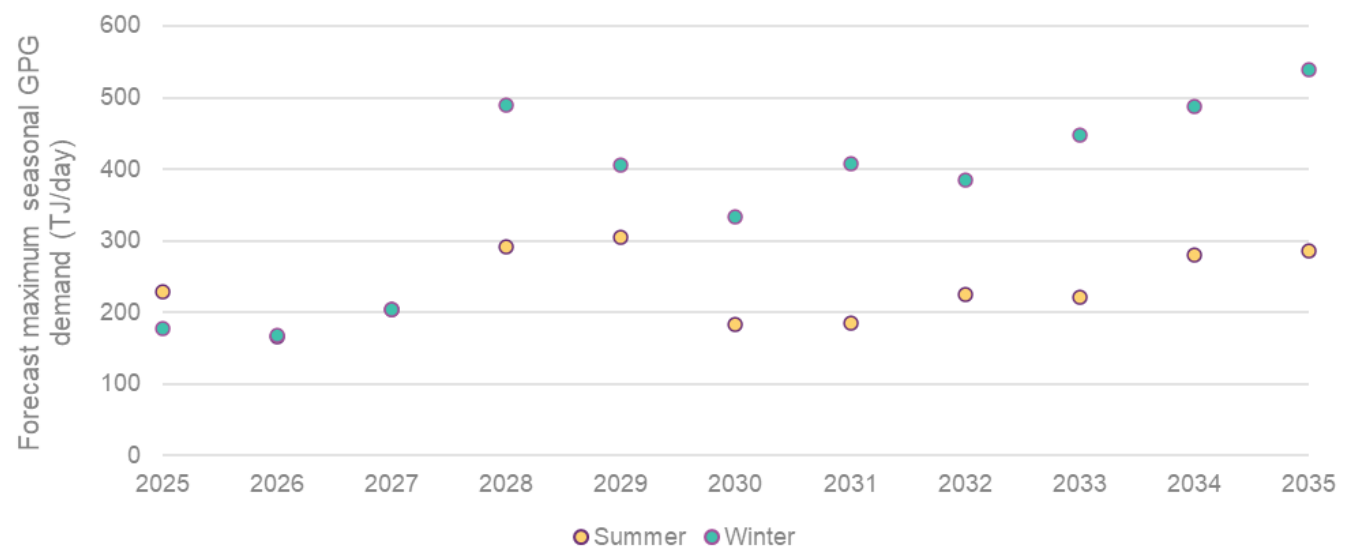


Figure 11 2024 Step Change – Coal retirement delay forecast seasonal peak daily GPG demand in New South Wales by year, 2025-35 (TJ/d)



Note: The seasonal maximum peak day demand values are the average value obtained from all reference years using a probability of exceedance (POE) of 5% meaning they are expected statistically to be met or exceeded one year in twenty, and are based on extreme weather conditions. The winter and summer demand values are closely aligned in 2026 and 2027.

2.3 Potential decarbonisation pathways of key gas use sectors

2.3.1 Decarbonisation of residential gas usage

Electrification and energy efficiency

Electrification is the displacement of fossil fuels from non-electric systems and processes by substituting their use with comparable electric processes or technologies. Electrification can occur across residential, commercial, and industrial uses, and the electrified appliances are typically more energy efficient and less emission-intensive, such as heat pumps and electric vehicles (EVs). Electrification can reduce the need for fossil fuels, such as liquid fuels and natural gas, and will increase the demand on the NEM or behind-the-meter generation sources, which can include residential rooftop solar and battery storage.

While the effects of electrification and energy efficiency measures may currently be modest, reporting from the Clean Energy Regulator suggests that consumers are continuing to invest in personal decarbonisation and energy security initiatives. The regulator has reported that the average small-scale rooftop solar installation capacity is now 9.6 kilowatts (kW), a 2.6 kW increase from Q1 of 2019, and as many as 10% of installations now include a battery storage unit¹⁹. The reporting also indicated that heat pump installation and the annual installed capacity of small-scale rooftop solar continue to increase year-on-year, with New South Wales installing 243 MW of small-scale rooftop solar and 8,508 heat pumps in Q2 of 2024 alone²⁰.

AEMO forecasts electrification of the transportation sector as a primary component of consumer-led electrification across all scenarios assessed in the 2024 ISP, with an estimated 32-72% of the road transportation fleet being EVs by 2040. Other sources of residential electrification can include replacing gas space heating and hot water systems with heat pumps and gas cook tops with electric, while energy efficiency measures can include installing double glazed windows, insulation and energy efficient lighting and appliances.

The 2024 ISP forecast a collective 6-9 terawatt hours (TWh) of residential electrification could be achieved across multiple pathways, while total energy efficiency savings of 26-41 TWh could be achieved across the residential and business sectors²¹. The electrification and energy efficiency measures forecast in the 2024 ISP would lead to an associated increase in demand on the NEM, although some of this demand increase would be met by consumer energy resources (CER)²² (such as a household purchasing an EV and charging from the grid) and a direct²³ reduction in demand for gas (such as replacing gas space heating with an electric heat pump). The 2025 GSOO forecast that these electrification and energy efficiency efforts could displace material amounts of natural gas demand, as **Table 5** shows, potentially reducing New South Wales' direct reliance on gas.

¹⁹ The actual percentage of small-scale rooftop solar installations which include a battery storage unit is likely to be higher, as the 10% figure is sourced from voluntary reporting only.

²⁰ See the Clean Energy Regulator's Quarterly Carbon Market Report June Quarter 2024, at <https://cer.gov.au/markets/reports-and-data/quarterly-carbon-market-reports/quarterly-carbon-market-report-june-quarter-2024/small-scale-technology-certificates-stcs>.

²¹ See AEMO's 2023 IASR, Table 1, at <https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios>.

²² Examples of CER include rooftop solar, battery storage units and EVs.

²³ Direct reliance on natural gas for space heating or other uses might be reduced, but as discussed in Section 2.2, GPG is required to back up the grid during periods of peak consumer electricity demand and during periods of low renewable energy generation.

Table 5 Summarised cumulative gas demand displacement in New South Wales forecast in the 2025 GSOO by year (PJ)

	2025	2030	2035
Electrification	1 - 2	8 - 21	17 - 33
Energy efficiency	<1	~ 1	2 - 3

Note: See AEMO's 2025 GSOO, figures 12 and 14, at https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2025/aemo-2025-gas-statement-of-opportunities-gsoo-report.pdf?la=en. AEMO's electrification and energy efficiency forecasts can also be accessed using its forecasting portal, at <https://aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/gas-forecasting-data-portal>.

Observations in New South Wales

As discussed in Section 2.1.1, New South Wales total gas demand in winter consists of 45% of demand from residential and small commercial users. Due to the high proportion of winter gas demand stemming from the heating load²⁴ of residential and small commercial users, the gas demand of New South Wales is seasonally shaped and correlated to weather conditions. **Table 6** shows the number of gas system demand days above 350 TJ (high demand days) and the peak system gas demand for the years 2019 to 2024.

Table 6 Number of high system demand days and the peak demand value for New South Wales, 2019-24

	2019	2020	2021	2022	2023	2024
Number of high demand days (above 350 TJ)	16	16	22	34	7	3
Peak demand (TJ)	380	370	400	384	382	357

The table shows that for 2023 and 2024 there was a decrease in high gas demand days. This is likely to be principally driven by the difference in weather conditions experienced year to year, but analysis by AEMO indicates that these differences in weather conditions do not account for the entirety of the observed decreased in peak demand and high demand days. It is plausible that a combination of cost-of-living pressures, electrification, and energy efficiency measures are beginning to decrease the expected gas demand in New South Wales. AEMO does not currently have all the information necessary to quantify the extent to which each of these factors are influencing the state's gas demand.

Efforts to accurately forecast electrification and energy efficiency measures are difficult, because these effects are spread across large numbers of residential dwellings and businesses which can vary in the amount of capital available to dedicate to these efforts, the desire to reduce their carbon footprint, supporting local, state and federal policies, and access to resources. AEMO routinely reviews the assumptions and forecasts against the latest authoritative research and invites public consultation on the IASR²⁵.

²⁴ Heating load represents gas demand attributed to gas space heating in residential and commercial spaces. This gas demand is typically seasonal and weather dependent and can vary year to year and day to day.

²⁵ Consultation activities and timeline related to the 2025 IASR is on AEMO's website, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/~link.aspx?_id=AAE29B32B1CC49DBA8795E6FBDF2D306&z=z.



2.3.2 Decarbonisation of commercial users

Electrification and energy efficiency

Commercial facilities that use gas for HVAC systems have similar pathway options to decarbonisation as those available to residential users. This load can be electrified by replacing existing gas-driven HVAC systems with heat pumps. Operators of commercial buildings are also increasing their focus on improving energy efficiency where possible in response to high energy prices.

Pathways for electrifying large gas-heated water systems, such as those at pools and aquatic centres, may be more capital-intensive and difficult to integrate with existing systems. Electric options exist, but the roll-out of this technology is likely to be slow due to the high investment cost.

Gas usage in hospitals will vary by facility, with some using gas for waste management, sterilisation processes, or back-up power systems. Electric solutions exist for most of these technologies, however their implementation could be complex and costly. A decarbonisation plan for hospitals and other health facilities would be best managed on a case-by-case basis.

There is no observable decline in gas usage in New South Wales for this sector yet.

2.3.3 Decarbonisation of industrial loads

Potential barriers to electrification and decarbonisation of certain industrial users

As discussed in Section 2.1.2, there are 25 LILs in New South Wales. Unlike residential users who have a comparatively clear pathway to electrify and decarbonise their energy use, industrial facilities in New South Wales represent a wide range of sectors with varied gas use applications. Many of these users do not currently have access to viable electrification options, and include processes that require high process heat²⁶ or use natural gas as a feedstock. The ability of these large users to decarbonise their energy use, and the time in which they can make these changes, will have an impact on long-term gas consumption in New South Wales. **Table 7** lists some examples of potential decarbonisation pathways.

Table 7 Examples of potential decarbonisation pathways which could be deployed in New South Wales' industrial sector

Decarbonisation pathway	Applicable users or processes	Impact on natural gas consumption	Example/s
Electrification	Food and beverage processing	Decrease	<ul style="list-style-type: none"> Replacing a low process heat gas boiler or process with an electric alternative.
Energy efficiency improvements	All users	Decrease	<ul style="list-style-type: none"> Pairing a boiler with a heat exchanger to reduce overall energy input requirements. Refurbishing or replacing existing plant assets with more energy efficient alternatives, even if those alternatives still require fossil fuel inputs.
Natural gas	High heat applications and steelmaking	Increase	<ul style="list-style-type: none"> Displacing metallurgical coal required as an input to blast furnaces used in steelmaking. Replacing coal or liquid fuels as the fuel used in boilers.

²⁶ Defined as temperatures exceeding 400°C in AEMO's 2025 GSOO.

Decarbonisation pathway	Applicable users or processes	Impact on natural gas consumption	Example/s
Biomethane	All users	Decrease	<ul style="list-style-type: none"> Substituting existing natural gas use by developing in-house solutions or purchasing biomethane from an available producer or retailer.
Hydrogen	Users with compatible ^A processes and assets	Likely decrease, however depends on the source of hydrogen	<ul style="list-style-type: none"> Hydrogen-natural gas blending into existing distribution networks. Using hydrogen as an energy storage medium to store excess renewable energy during surplus generation periods. Using hydrogen or hydrogen-natural gas blends as a fuel source in compatible gas-powered generation stations. Using hydrogen as a feedstock (e.g. ammonia production).
Offsetting	All users	No change	<ul style="list-style-type: none"> Purchasing Australian carbon credit units or Safeguard Mechanism credit units.
Closure	Users unable to decarbonise their operations in an economically or technologically viable manner	Decrease	

A. Hydrogen’s chemical properties and energy density are different to natural gas, so not all processes and existing assets are readily substituted with hydrogen or hydrogen-natural gas blends.

Examples of electrification and decarbonisation activities of industrial gas users

The Federal Government and New South Wales Government are implementing legislation and frameworks to support the decarbonisation of large industrial users and natural gas use. Three examples of decarbonisation efforts relevant to New South Wales are presented below. There is currently a range of potential future gas consumption outcomes for gas consumption in New South Wales, and some decarbonisation efforts may lead to greater reliance on natural gas for a period of time to reduce emissions from alternative fossil fuels or emission-intensive processes.

Displacing coal use with natural gas

Manildra’s Shoalhaven Starches facility replaced its coal-fired boilers with natural gas alternatives in 2023, reducing the emission intensity of the industrial process by up to 40% and providing future energy security to the facility²⁷. Similar fuel-switching exercises could be deployed by other industrial users in New South Wales to reduce their emissions profiles in the near term while allowing time for alternative, decarbonised technology alternatives to mature and be deployed in the market.

Hydrogen hubs

The New South Wales Hydrogen Strategy aims to enable the development of a green hydrogen industry in New South Wales. A cornerstone of the strategy is the development of hydrogen hubs, locations where producers and users²⁸ of hydrogen are clustered together, reducing the need for additional transportation, storage, or other

²⁷ See “GE powers clean fuel to Manildra, reduces carbon emissions”, at <https://www.governova.com/gas-power/resources/case-studies/shoalhaven-starches-cogeneration>.

²⁸ Examples of green hydrogen applications could include its use in fuel-cell based transportation, as a feedstock in certain processes, such as ammonia production, and as a fuel source in high-temperature process heat.

infrastructure. Three hydrogen hub projects were granted approval and funding by the New South Wales Government by August 2022, with a total of \$109 million in funding approved²⁹. The largest hub by anticipated annual hydrogen production is the Hunter Valley Hydrogen Hub (4,400 tonnes per annum), a joint initiative between Origin and Orica which aims to support the decarbonisation efforts of the region's manufacturing industry³⁰. The future of the hub is uncertain, with Origin withdrawing its involvement in the Hunter Valley Hydrogen Hub and signalling its intent to cease all involvement with hydrogen development opportunities³¹.

Low-carbon steelmaking

BlueScope's Port Kembla steelworks relies on metallurgical coal as a major input to the facility's blast furnaces, a key step in the facility's steelmaking process. The reliance on metallurgical coal in the steelmaking process has an inherent emission footprint within the final steel product, limiting the ability of BlueScope and other steelmakers to reduce the emissions intensity of their steel without removing the need for metallurgical coal.

BlueScope has reported that a steelmaking facility with a comparable production output to the Port Kembla facility could reduce carbon emissions by up to 60% by displacing the metallurgical coal required, but this would require 30-40 PJ of natural gas per year, or a 40-fold increase in the Port Kembla facility's current natural gas consumption³².

2.3.4 Gas-powered generation

As discussed in Section 2.2, GPG is forecast to play a critical role in the energy transition by backing up storage technologies during periods of low renewable energy generation.

Figure 12 shows that as coal generation capacity is forecast to exit the grid over the next decade, AEMO's 2024 ISP forecast that both GPG and storage capacity will increase, with as much as 11 GW of additional utility-scale storage and 2 GW of GPG being deployed in New South Wales. The composition of the forecast utility storage deployment is presented in **Figure 13** in the following section.

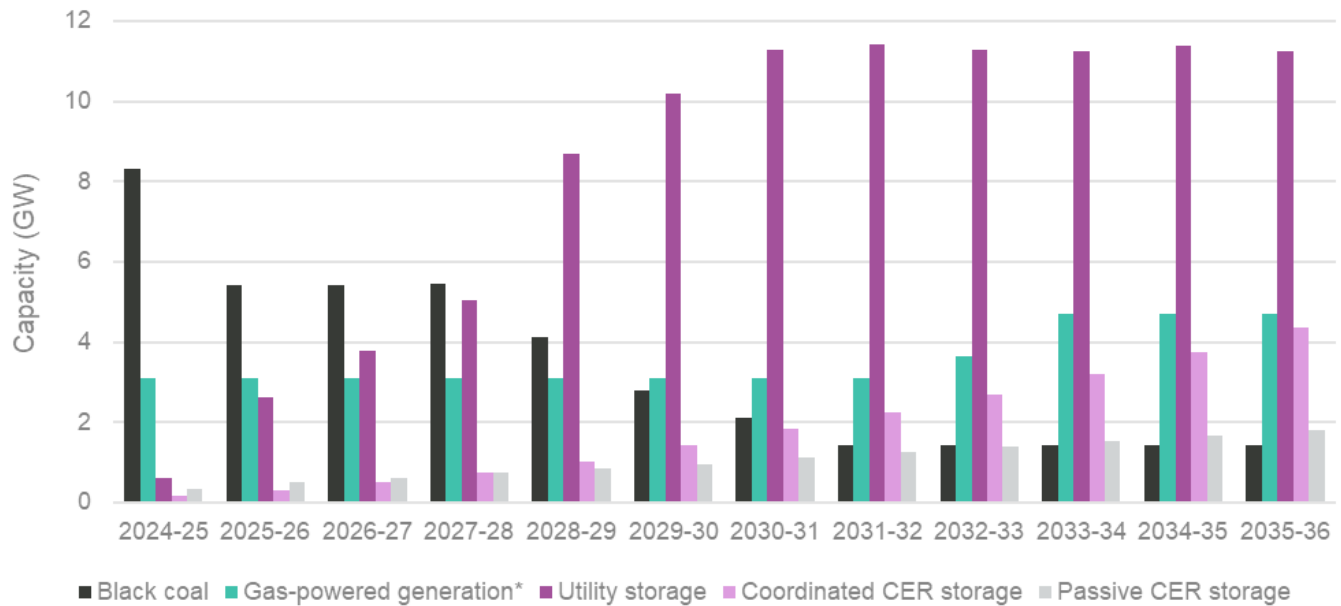
²⁹ See "Hydrogen hubs in NSW", at <https://www.energy.nsw.gov.au/business-and-industry/programs-grants-and-schemes/hydrogen-hubs-nsw>.

³⁰ See "Origin planning Newcastle hydrogen hub", at <https://www.originenergy.com.au/about/investors-media/origin-planning-newcastle-hydrogen-hub/>.

³¹ See "Update on Hunter Valley Hydrogen Hub", at <https://www.originenergy.com.au/about/investors-media/update-on-hunter-valley-hydrogen-hub/>.

³² See BlueScope's Second Climate Action Report, at <https://www.bluescope.com/sustainability/climate-action>.

Figure 12 Forecast capacity of selected generation sources by year in New South Wales, FY 2024-36 (GW)



Note: The ISP is forecast on a financial year (FY) basis, whereas the GSOO and the rest of the NGIR refer to calendar years.
 *Includes capacity from mid-merit, flexible, and carbon capture and storage (CCS)-paired GPG sources.

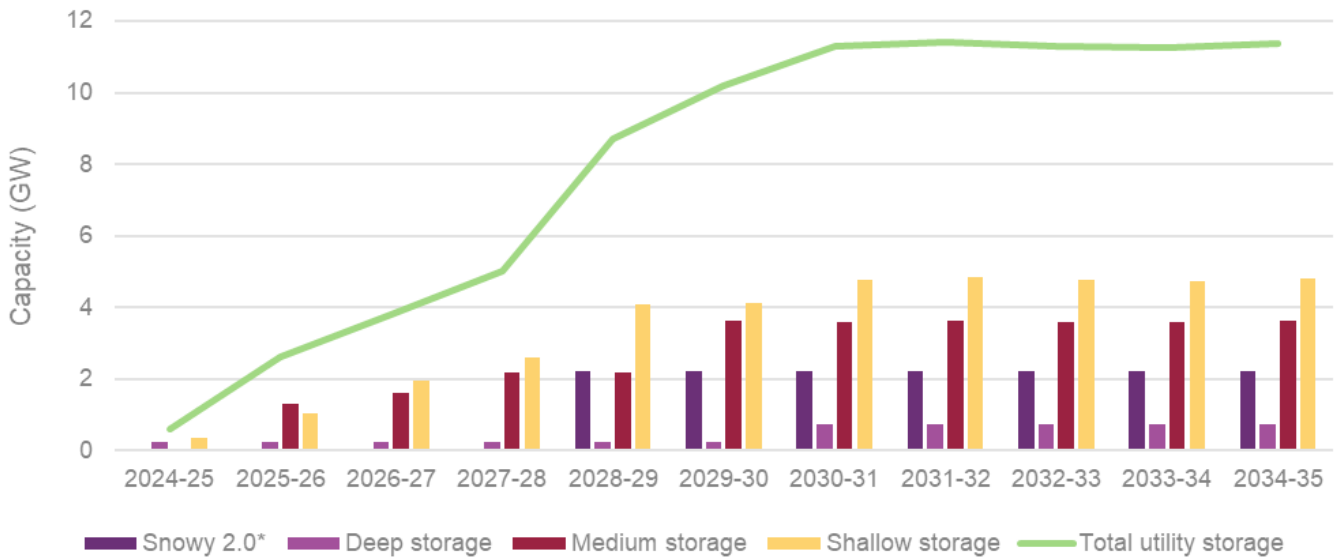
Relationship with storage technologies

The optimal development pathway in the 2024 ISP confirms the need for storage to firm the grid and contribute to the lowest-cost pathway in the transition to a net zero economy. There is a range of storage technologies available and being developed, which will need to be deployed to meet a range of circumstances during the energy transition. **Figure 13** presents the potential capacity deployment across technology types, as per the 2024 ISP, including:

- **shallow storage** – capable of dispatching electricity for less than four hours, important for managing intra-daily energy generation and demand fluctuations
- **medium storage** – capable of dispatching electricity between four and 12 hours, capable of storing large quantities of surplus renewable energy during peak generation periods and returning that energy to the grid during the morning or evening peak demand periods
- **deep storage** – capable of dispatching energy for longer than 12 hours, necessary for storing large reserves of energy and returning that energy to the grid over weeks or months to support longer-term or seasonal energy pattern variations, and
- **total utility storage** – the total capacity of shallow, medium, and deep storage in addition to the storage capacity of Snowy 2.0.

The total required GPG capacity to back up these storage technologies will depend on the amount of storage capacity installed in the NEM, particularly medium and deep storage. If storage capacity installation stalls or stagnates while coal generation continues to retire from the grid, GPG may need to be relied on more heavily to support the grid, potentially increasing both annual and peak day gas consumption related to GPG. Conversely, if storage capacity is deployed in the NEM more rapidly or at larger quantities than forecast in the 2024 ISP, there is likely to be less need placed on GPG to back up renewables and firming storage.

Figure 13 Forecast capacity of selected storage types by year in New South Wales, 2024-35 (GW)



* Snowy 2.0 displayed separately due to the scale of the project.

Decarbonisation options for gas-fired generation

Low emission fuels

New GPG facilities such as the Tallawarra B facility and the Hunter Power Station can use hydrogen or hydrogen blends to generate electricity, which enables them to both back up the grid and displace the emissions associated with using natural gas as a fuel source for these plants^{33,34}. Hydrogen used in this way can present an alternative energy storage medium, where green hydrogen can be produced during periods of surplus renewable energy generation and stored as a gas or liquid until it is needed as a fuel source for hydrogen-compatible GPG facilities.

Biogas produced at some wastewater facilities and landfill sites in New South Wales, such as at several Sydney Water wastewater treatment plants³⁵ and the Eastern Creek Landfill³⁶, is captured and used as a fuel to generate renewable electricity. Biogas can also be captured, upgraded to biomethane and injected into a gas network, which was been demonstrated with excess biogas at the Malabar Wastewater Treatment Plant³⁷. Biomethane can then be transported to other GPG facilities and used to generate renewable electricity. Biomethane can also be generated from other organic feed sources such as agricultural waste.

Carbon capture and storage

Where feasible to do so, pairing GPG with carbon capture and storage (CCS) technologies can help reduce the emissions intensity associated with the electricity produced from the facility, particularly when using natural gas as

³³ See “Tallawarra B power station to be built”, at <https://www.minister.industry.gov.au/ministers/taylor/media-releases/tallawarra-b-power-station-be-built>.

³⁴ See “Hunter Power Project”, at <https://www.snowyhydro.com.au/hunter-power-project/>.

³⁵ See “How we contribute to a sustainable future”, at <https://www.sydneywater.com.au/water-the-environment/what-we-are-doing/responding-to-climate-change.html>.

³⁶ See “Renewables power station for BINGO’s Eastern Creek landfill”, at <https://lgi.com.au/renewables-power-station-for-bingos-eastern-creek-landfill/>.

³⁷ See “Malabar Biomethane Project”, at <https://www.sydneywatertalk.com.au/malabar-biomethane-project>.

the fuel source. CCS technologies capture carbon dioxide from the industrial or chemical processes they are paired with and store it, typically in underground geological formations. Not all current and future GPG plants may be capable of implementing CCS technologies, but demonstration projects such as the Gorgon and Moomba CCS projects provide examples of how CCS projects can be implemented more broadly across different use cases^{38,39}.

Carbon dioxide generated and captured in New South Wales could be transported to potential CCS locations such as depleted gas reservoirs in the Cooper Basin near Moomba or in the Gippsland Basin. No depleted gas reservoirs are located within New South Wales and exploration would be required to determine suitable formations for CCS.

2.4 Historical and forecast supply

New South Wales has no local gas production since the closure of AGL's Camden Gas Project in 2023, and demand in New South Wales and Australian Capital Territory is met by supply from:

- Longford Gas Plant in Victoria, transported by the EGP
- Orbost Gas Plant in Victoria, transported by the EGP
- Moomba Gas Plant in South Australia, transported by the MSP
- Queensland coal seam gas production facilities, transported by the SWQP and then the MSP
- Other Victorian supply from the VTS, transported by the Victorian Northern Interconnect (VNI) via Culcairn and then the MSP, and
- NGSF, transported by the Northern Trunk Pipeline.

2.4.1 Historical supply to New South Wales and Australian Capital Territory

Figure 14 shows historical supply to New South Wales and Australian Capital Territory by each of the supply sources⁴⁰. Which sources supply the most gas to New South Wales and Australian Capital Territory depends on contractual arrangements between suppliers and gas users. Wholesale market and broader international markets dynamics also play key roles in determining which supply sources are used to meet demand.

The figure shows:

- Supply from sources along the EGP, the Longford and Orbost gas plants, is steady throughout the year, which is expected as the EGP supplies steady industrial demand in New South Wales as well as the Tallawarra and Smithfield GPG facilities.

³⁸ See "Reducing greenhouse gas emissions for a lower carbon future", at <https://australia.chevron.com/what-we-do/gorgon-project/carbon-capture-and-storage>.

³⁹ See "Santos secures Moomba carbon capture and storage finance to drive decarbonisation", at <https://www.santos.com/news/santos-secures-moomba-carbon-capture-and-storage-finance-to-drive-decarbonisation/>.

⁴⁰ Supply quantities are calculated using data on the Gas Bulletin Board (GBB): <https://www.aemo.com.au/energy-systems/gas/gas-bulletin-board-gbb>. Supply from the SWQP to the MSP cannot be directly accounted using available GBB data so this quantity is estimated using transfer points at the Moomba Hub.

- Since 2022, supply from Longford has started to reduce as production at the facility has decreased with the decline in the large legacy Gippsland Basin fields. Increased supply from the Orbost Gas Plant has partially offset this decline.
- The MSP, transporting gas from the Moomba Gas Plant, is also a stable supply source to New South Wales, although typically supporting a larger proportion of winter demand and a smaller portion of summer demand.
- Queensland gas transported from the SWQP into the MSP has increasingly acted as a seasonal and peak supply source for New South Wales. The SWQP typically reverses flow direction in summer and transports gas from the southern states⁴¹ to Queensland.
- Supply to New South Wales from Victoria via the VNI typically occurs throughout the year, particularly as a supply source for the Uranquinty Power Station. Supply via the VNI was reduced through winter 2023 and winter 2024 while supply via the SWQP was increased.
- NGSF supports New South Wales demand on cold winter days, periods of increased GPG demand or during a gas production disruption.

Figure 14 Cumulative supply into New South Wales and Australian Capital Territory by source, 2019-24 (TJ/d)

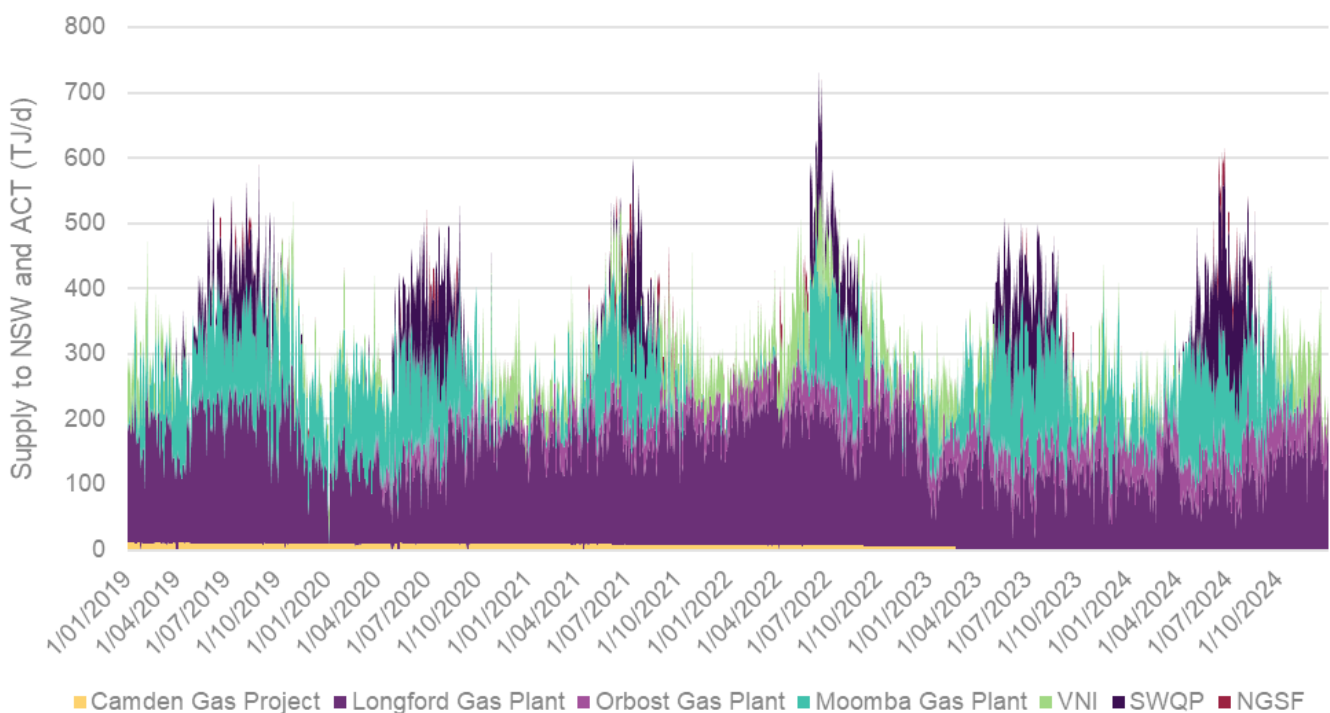
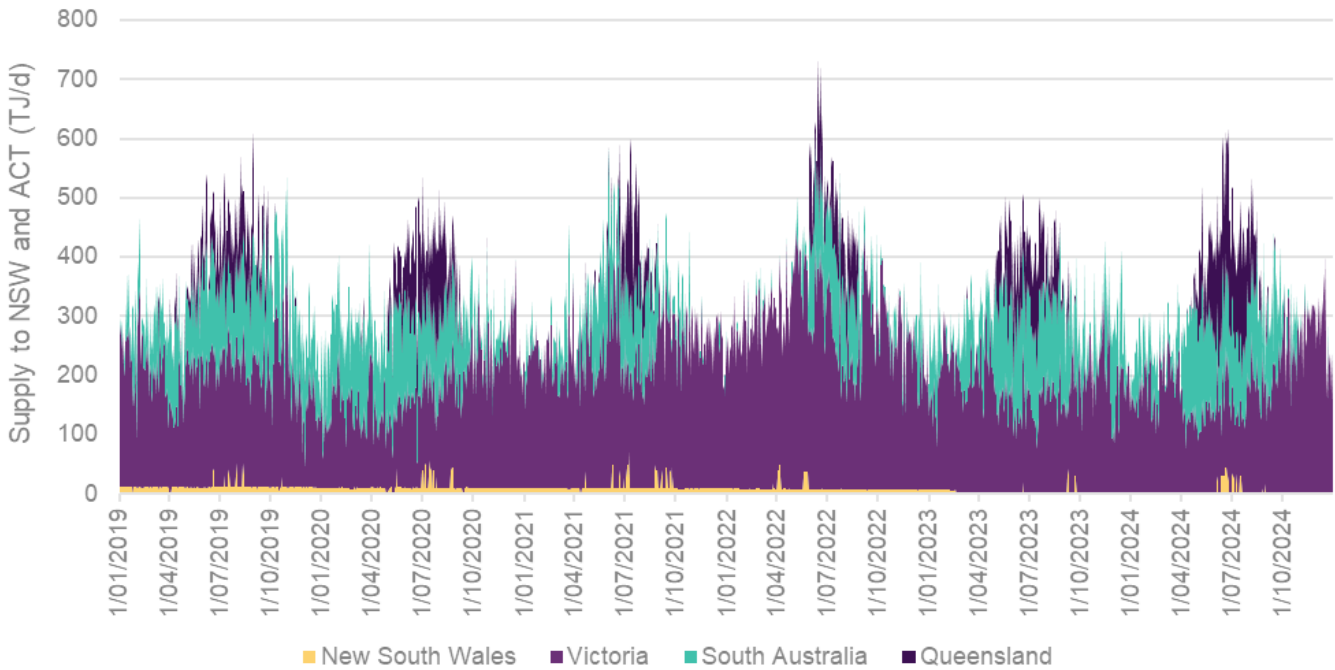


Figure 15 shows the net supply to New South Wales and Australian Capital Territory attributed to the state the gas was produced in. Gas supplied from NGSF is allocated to New South Wales.

The figure shows that Victoria and South Australia have been the states where the majority of supply has originated from to support New South Wales and Australian Capital Territory gas demand.

⁴¹ 'Southern states' in the NGIR are New South Wales, Australian Capital Territory, South Australia, Tasmania and Victoria.

Figure 15 Net supply to New South Wales and Australian Capital Territory by source state, 2019-24 (TJ/d)



2.4.2 Forecast supply to New South Wales and Australian Capital Territory

Production forecasts in this section of the NGIR use information collected for the 2025 GSOO and 2025 *Victorian Gas Planning Report* (VGPR). Surveys were conducted for these reports in September 2024 and AEMO met with most of the major producers impacting New South Wales supply in October and November 2024. The GSOO has more information on the survey process and project classification definitions.

Longford Gas Plant

Gas is produced at Longford by the Gippsland Basin Joint Venture (GBJV) between Esso Australia and Woodside Energy, and the Kipper Unit Joint Venture (KUJV) between Esso Australia, Woodside Energy and Mitsui E&P Australia.

AEMO has incorporated updated forecast information from the GBJV and KUJV partners for the 2025 GSOO into the NGIR.

Forecast production

Longford production is expected to decline over the outlook period, driven by the depletion of the large legacy gas fields in the Gippsland Basin. The Longford Gas Plant was once the largest gas production facility in the eastern states with a nameplate capacity of 1,150 TJ/d. The nameplate production capacity reduced to 700 TJ/d with the closure of Gas Plant 1 in October 2024, one of the three gas processing trains at Longford. Production capacity will continue to decline as the offshore fields deplete.

Expected production at Longford is higher than previously reported in the 2025 GSOO and VGPR primarily due to volumes from the Kipper Stage 1B and Turrum Phase 3 projects, and the reprofiling of existing proven and probable developed reserves. These reserves remain available due to lower than forecast production in 2023 and 2024, driven by lower gas consumption.

In addition to Turrum Phase 3, GBJV has advised AEMO that additional gas will be available at Longford in 2028 due to lower than expected demand for gas in 2023 and 2024 extending the life of one of the offshore fields. GBJV has advised that this field life extension will delay the forecast retirement year of Gas Plant 3 by one year from prior to winter 2028 to before winter 2029.

The combination of Turrum Phase 3 and additional Longford production in 2028 is likely to materially impact AEMO’s supply and demand balance modelling for New South Wales and all southern states in the 2025 GSOO.

The long-term outlook at Longford remains in decline and future supply from Longford to New South Wales will be a fraction of what was historically supplied. The only remaining uncertain project at Longford is the Late Life Optimisation project, which remains subject to GBJV investment decisions.

Production resilience

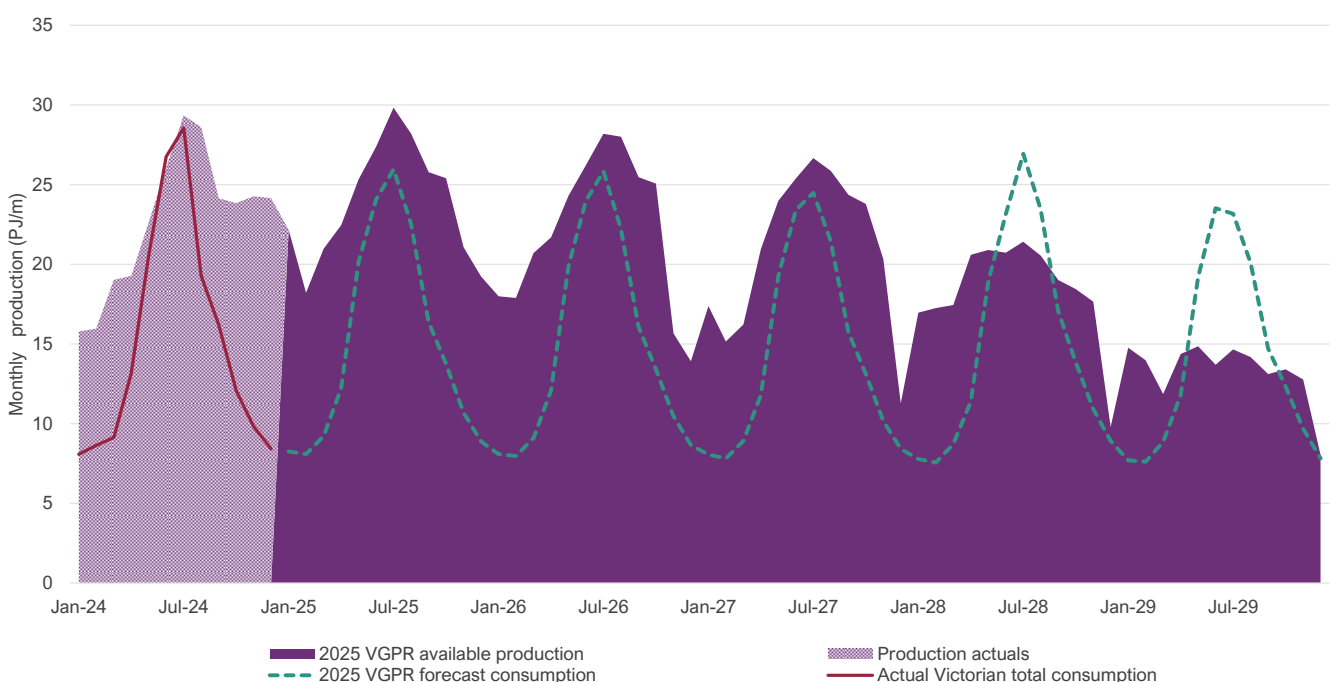
Retirement of onshore and offshore infrastructure at Longford increases the risk of supply adequacy shortfalls as the impact of an outage of the remaining production facilities increases. If either of the two remaining Longford gas processing trains are unavailable, production capacity could be reduced by up to 350 TJ/d.

The difficulty forecasting the availability of declining production and aging assets at Longford is illustrated by Error! Reference source not found., which compares:

- forecast Longford production capacity as of 22 April 2024 in the Medium Term Capacity Outlook (MTCO)
- actual Longford production capacity as reported in the Short Term Capacity Outlook (STCO), and
- actual Longford production.

The difference between actual and forecast production at Longford during this period was due to an extension of planned onshore and offshore maintenance work which continued beyond the forecast duration.

Figure 16 Actual production, 22 April 2024 MTCO production outlook and STCO production outlook at Longford Gas Plant, April to June 2024, TJ/d



Orbost Gas Plant

Orbost Gas Plant is operated by Amplitude Energy (formerly Cooper Energy) and produces gas from the Gippsland Basin. Forecasts provided by Amplitude Energy indicate that production at Orbost is expected to continue at current rates until the early to mid-2030s.

From that point forward, Amplitude will need to develop the Manta field to maintain production at Orbost. AEMO currently classifies Manta as an uncertain project, which is subject to Amplitude Energy investment decisions.

Moomba Gas Plant

The Moomba Gas Plant, which is a joint venture between Santos and Beach Energy, produces gas from fields in the Cooper Basin. Forecasts provided to AEMO for Moomba indicate that there is sufficient gas at Moomba to continue production at similar rates to current production for the outlook period if contingent resources are developed. Production forecasts at Moomba becomes more reliant on contingent⁴² resources from the late 2020s and will require ongoing drilling to bring additional gas to production.

2.5 Supply demand balance

Gas production in the southern states is falling faster than forecast gas demand. The southern states – New South Wales, Australian Capital Territory, Victoria, South Australia, and Tasmania – are located at the end of the SWQP at Moomba. The SWQP transports gas from Queensland gas production facilities to the southern states during winter. As southern production declines, demand in the southern states is forecast to rely more heavily on northern gas transported via the SWQP to support winter demand.

The SWQP capacity limits the amount of Queensland gas that can be transported to the southern states, with the SWQP also needing to supply more gas to Mt Isa due to the Northern Gas Pipeline from the Northern Territory ceasing flow in February 2024. The SWQP flowed at capacity during June 2024 due to an unplanned extension of Longford Gas Plant maintenance combined with very low wind generation, particularly in Victoria. The pipeline is forecast to reach pipeline capacity more frequently in the future.

The 2025 GSOO forecast risks of peak day shortfalls from 2028, structural supply gaps emerging from 2029 in southern Australia, and from 2028, the potential for seasonal supply gaps to emerge if conditions lead to sustained high gas usage. These supply gaps are forecast to occur most frequently in winter when southern demand is highest and could exceed combined southern production, storage inventory and the pipeline capacity from Queensland.

Demand for GPG is a strong contributor to the severity of peak day shortfalls. Peak day gas shortfall risks may be lower if reliance on gas use for electricity generation during periods of peak gas demand is reduced, including through the use of liquid fuels or the management of electricity demand.

The forecast supply gaps could impact any of the southern states, including New South Wales. The exact location of a supply gap would depend on supply and demand conditions. Considerations for New South Wales include:

⁴² Quantities estimated to be potentially recoverable from known accumulations but which are not currently considered to be commercially recoverable due to one or more contingencies.

- the state typically has the second largest gas demand of the southern states, after Victoria
- New South Wales has no local gas production
- NGSF is currently the only shallow storage facility in New South Wales, which will be joined by the KKLP when it is commissioned in 2025
- there are no market-facing deep storage facilities in New South Wales and none directly connected to pipelines supplying New South Wales
- in some regions in New South Wales gas demand can only be met by supply from the EGP, and
- most but not all GPG units in New South Wales have the capability to operate from liquid-fuel back-up.

Supply resilience for New South Wales is discussed further in Section 3.3.

3 Existing gas infrastructure adequacy

The purpose of this chapter is to analyse the adequacy of the existing gas infrastructure in New South Wales.

3.1 Pipeline adequacy

This section assesses the adequacy of the underlying pipeline infrastructure in New South Wales to support existing and proposed GPG and storage, and assumes gas supply is available at all sources to meet the required demand.

3.1.1 Moomba Sydney Pipeline (MSP)

The MSP transports supply to meet gas demand in western and central regional New South Wales as well as to the major demand centres of Sydney, Wollongong, Gosford, and Newcastle via Wilton. The MSP also provides southern transportation capacity towards Culcairn to supply the Uranquinty Power Station and can flow to and from the VTS.

Uranquinty Power Station

The Origin Energy-owned Uranquinty Power Station is a GPG facility located south-west of Wagga Wagga in New South Wales. The plant is fuelled by natural gas and electricity is generated by four open cycle gas turbines (OCGT).

System supportability

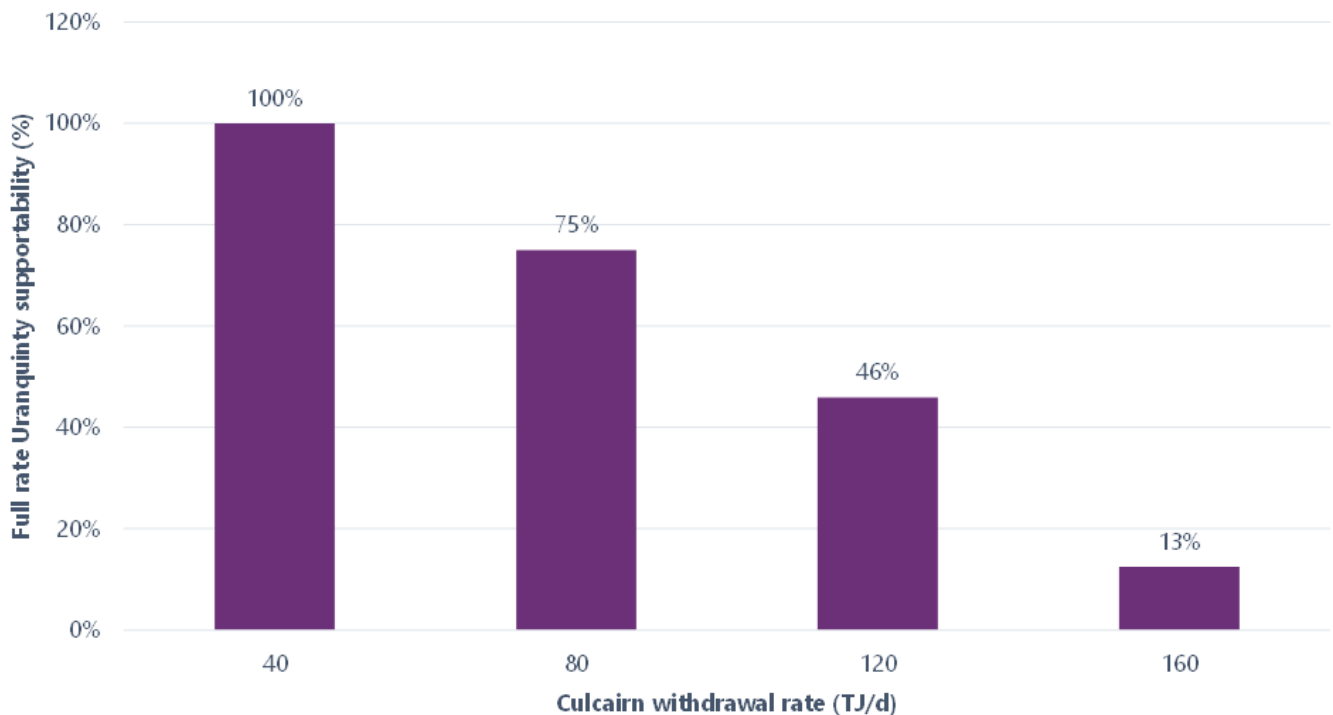
The operation of Uranquinty GPG, which is connected to the Young to Culcairn lateral within the MSP system, has been assessed to be most impacted in the modelling scenarios if there are gas exports south at the Culcairn connection to supply the VTS⁴³. This is because Uranquinty GPG is connected off a single 450 mm diameter pipeline section between Wagga Wagga and Culcairn and this section also transports gas south to the VTS.

To investigate this relationship between Uranquinty and flow to the VTS, AEMO modelled the system adequacy to support 24-hour Uranquinty GPG operation at full rate against varying levels of Culcairn withdrawal scenarios, in which the minimum Culcairn withdrawal pressure of 4,500 kPa was required to be maintained. The modelling results illustrated a strong dependency between the maximum Uranquinty GPG operation and VTS withdrawal scenarios at Culcairn.

As shown in **Figure 17**, the supportability of Uranquinty GPG was modelled to be at 100% in the scenario with Culcairn withdrawals to the VTS of up to 40 TJ/d at peak system demand. This GPG supportability drops to as low as approximately 13% as the Culcairn withdrawal quantity increases up to the highest modelled flow scenario of 160 TJ/d into the VTS. This demonstrates that Uranquinty GPG supportability within the existing MSP system is highly dependent on the Culcairn withdrawal quantity to the VTS.

⁴³ Withdrawals in the NGIR refer to flows out of New South Wales. For flows at Culcairn, withdrawals refer to flows from the MSP into the VTS.

Figure 17 Existing system supportability of Uranquinty GPG at full rate (%) with Culcairn withdrawals to the Victorian Transmission System at peak system demand (TJ/d)



The impact of New South Wales system demand on Uranquinty GPG supportability was also assessed with different Culcairn withdrawal scenarios. AEMO modelled various combinations of New South Wales system demand to determine the correlation between New South Wales system demand and Uranquinty GPG supportability.

The modelling results show that Uranquinty GPG supportability reduces as Culcairn withdrawals into the VTS increase and for non-peak day cases due to low linepack north of Culcairn. As a result, the lower system demand cases represented by winter, shoulder and summer have a reduction of between 29% and 33% in Uranquinty GPG supportability. This is a slight reduction in GPG supportability of between 5% and 8% compared to the peak demand cases. **Table 8** summarises these results.

Table 8 Uranquinty GPG supportability dependencies with system demand

Culcairn withdrawal (TJ/d)	Peak	Winter	Shoulder	Summer
40	100%	100%	100%	100%
80	75%	67%	67%	67%
120	46%	38%	38%	38%
160	13%	8%	8%	8%

3.1.2 Moomba Sydney Pipeline – publicly announced gas-powered generation

The following publicly announced GPG projects would be supplied by the MSP if they were to proceed.

Dubbo GPG project

Dubbo Firming Power Station is a proposed GPG facility that would be developed by Squadron Energy near Dubbo. The project currently proposes to install a plant capable of using hydrogen, biofuel or a hydrogen gas blend as fuel to power a generator capable of producing up to 64 MW of electricity. The facility would also include a 20 MW hydrogen electrolyser.

Natural gas for the Dubbo GPG would be supplied by the Marsden to Dubbo lateral off the MSP (officially known as the Central Ranges Pipeline).

System supportability

Analysis performed for the proposed Dubbo GPG indicates there is sufficient system adequacy available to support the peaking demand of the proposed Dubbo GPG from a connection at Dubbo. However, in the scenario where the proposed Dubbo GPG is required to operate at capacity for a sustained 24-hour period, modelling shows that under coincident peak demand conditions, this high rate operation of the Dubbo GPG facility may exceed the current Marsden to Dubbo pipeline lateral capacity. Supply was assessed to be limited by the 6,200 kPa maximum operating pressure of the pipeline, which is a much narrower diameter pipeline than the MSP mainline.

If the current operating pressure on the Marsden to Dubbo lateral pipeline was increased, modelling shows that the proposed Dubbo GPG demand could be fully supported under all operational scenarios and demand conditions.

Marulan gas-powered generation project

EnergyAustralia has proposed a new GPG facility located near Marulan, approximately two hours south-west of Sydney. The project currently proposes the construction of two power plants of up to 450 MW and 350 MW in capacity and would be fuelled by natural gas supplied from the Young to Wilton section of the MSP.

System supportability

Modelling indicates that peaking full rate operation of both units of the proposed Marulan GPG project can be supported by the existing MSP Young to Wilton pipeline. However, if the proposed Marulan GPG is required to be operated on a continuous 24-hour baseload operation, modelling analysis indicates that only one of the two proposed plants can be sufficiently supported by the MSP during coincident peak system demand conditions.

Both units operating at full rate in a baseload operation scenario was analysed to be supported with additional augmentation, such as pipeline infrastructure upgrades to increase adequacy to accommodate extreme scenarios of sustained GPG load during peak demand conditions.

3.1.3 Eastern Gas Pipeline

The EGP supplies major demand centres in the southern and coastal regions of New South Wales, as well as transporting gas to Wollongong, Sydney, and Newcastle via the Wilton and Horsley Park delivery stations. The

EGP operates at the highest operating pressure (MAOP of 14,900 kPa) of any pipeline in New South Wales and has the capacity to supply the existing Tallawarra and Smithfield GPG facilities.

Tallawarra Power Station

The EnergyAustralia-owned Tallawarra Power Station is comprised of two gas-fired generation units, Tallawarra A and Tallawarra B, that are located in Yallah, approximately 15 km south of Wollongong. Tallawarra A has generation capacity of 440 MW and Tallawarra B has generation capacity of 320 MW.

Tallawarra B is the newest operating GPG unit in New South Wales and was commissioned in early 2024.

System supportability

The Tallawarra Power Station is supplied by a 2.6 km, 250 mm diameter lateral connected to the EGP. In this location, the EGP is capable of supporting continuous 24-hour operation of both Tallawarra GPG units at full rate utilising the existing assets. Modelling did not identify any pipeline-related supportability issues for the Tallawarra Power Station.

Risks to the operability of Tallawarra GPG are the limited supply options for the EGP and asset availability along the EGP, particularly compressor availability. The EGP is supplied by the Longford Gas Plant via the VicHub compression facility and the Orbest Gas Plant. Orbest supply is not sufficient to support Tallawarra GPG and system demand connected to the EGP, meaning that Longford supply is necessary to enable Tallawarra GPG operation. This is discussed further in Section 3.3.1.

Smithfield Power Station

Smithfield Power Station is a gas-powered peaking power plant located in Smithfield, nearly Horsley Park in western Sydney.

System supportability

Smithfield GPG is supplied by a 9.8 km, 200 mm diameter lateral that is connected to the end of the EGP near Horsley Park. Similar to the Tallawarra Power Station, modelling indicates that Smithfield GPG is capable of continuous 24-hour operation at full rate using existing assets.

As for Tallawarra GPG, the main risk to operability of Smithfield GPG is supply from the Longford Gas Plant and asset availability along the EGP, particularly compressor availability and also the Smithfield regulator, which supplies gas from the EGP into the Smithfield lateral.

3.1.4 Northern Trunk Pipeline

The Northern Trunk Pipeline supplies most of the gas demand in New South Wales, including residential and commercial customers in Sydney, Gosford, and Newcastle, many of the LILs, the CLP and Colongra Power Station, NGSF, and the future KKLP and Hunter Power Station.

The Northern Trunk Pipeline is classified as a distribution pipeline but is servicing loads that are more typically supplied by transmission pipelines.

Colongra Power Station

Snowy Hydro's Colongra Power Station is supplied from Jemena's Colongra Lateral Pipeline. The Colongra storage pipeline, which is part of the CLP system, is refilled with gas via the Munmorah CS, which is connected to the Northern Trunk Pipeline on the Central Coast. Gas stored in the storage pipeline is used for the sole purpose of supplying gas to the Colongra Power Station; there are no other connections on the storage pipeline and there is no flow path back into the Northern Trunk Pipeline.

System supportability

As Colongra GPG runs on gas from the storage pipeline, the amount of gas stored in the pipeline before the power station starts corresponds to the available running time of the power station. The Munmorah CS can bring gas into the pipeline if the generator is running, but at a much lower rate than the GPG can consume. If the storage pipeline is full, the power station can run for five hours at full rate or 10 hours at half rate. Colongra GPG consists of four units, so Snowy Hydro is able to profile the operation of the four GPG units in any combination to consume the quantity of stored gas. If the storage pipeline is half-full, the power station can run for half as long.

Munmorah CS is used to refill the Colongra storage pipeline. Availability of this compressor station is necessary to refill the storage pipeline, as there is no alternative flow path to transport gas into the storage pipeline. Operation of the compressor station is limited by two factors:

- Maximum hourly quantity (MHQ) – this flow limit restricts the amount of gas that can be transferred into the storage pipeline from the Northern Trunk Pipeline. The MHQ corresponds to storage capacity of the Colongra pipeline, so if Munmorah CS is fully available the Colongra GPG can run at full rate for five hours each day indefinitely.
- Munmorah CS power – modelling indicates that the flow into the storage pipeline is limited by the total maximum power of the compressor station for some of the refill period. The station consists of two reciprocating compressor units. If only one unit was available, less gas can flow into the storage pipeline.

Colongra GPG can consume significantly more gas than the MHQ of Munmorah CS. Modelling indicates that Munmorah CS takes about 17-19 hours to refill the Colongra storage pipeline with the compressor limited by power a third of this time and limited by MHQ for the remaining two-thirds. If Colongra GPG is operating during this window, more time may be required to refill the storage pipeline.

Historically, when Colongra GPG has operated at peak rates it consumes 42-43 TJ/d. This is the maximum storage capacity of the Colongra storage pipeline and the quantity that the Munmorah CS is capable of supporting. Colongra Power Station can also be fuelled by diesel.

Hunter Power Station

The Hunter Power Station is the new Snowy Hydro-owned GPG in Kurri Kurri that is under construction. Hunter GPG will operate from the APA-owned KKLK which, similar to Colongra GPG, includes a storage pipeline from which the GPG will primarily run. The Kurri Kurri storage pipeline will be refilled via the Kurri Kurri CS, which is connected to the Northern Trunk Pipeline near Newcastle.

The KKLP system also includes a regulator station that will enable stored gas to flow back into the Northern Trunk Pipeline. The KKLP will be registered as a storage facility in the Sydney STTM, enabling stored gas to be supplied into the wholesale market.

System supportability

Hunter Power Station can only operate from the Kurri Kurri storage pipeline, so if the storage pipeline is empty, the GPG is unable to run using gas as a fuel. Kurri Kurri CS refills the Kurri Kurri storage pipeline. The minimum operational pressure of the Hunter Power Station is higher than the operating pressure of the Northern Trunk Pipeline, so the Kurri Kurri CS is necessary to enable power station operation.

The Kurri Kurri CS consists of two reciprocating compressor units which are sized such that only one unit is required to meet the MHQ into the storage pipeline from the Northern Trunk Pipeline. If one unit was to be unavailable, the MHQ can still be met. The MHQ is the only limiting factor on how much gas can flow into the storage pipeline each day from the Northern Trunk Pipeline.

Modelling indicates that the size of the storage pipeline and power of Kurri Kurri CS enable more flexibility of operations than at Colongra. Hunter GPG can operate for eight hours per day at full rate indefinitely if Kurri Kurri CS is available, or 16 hours per day with one of the two GPG units operating, with the storage quantity refilled at MHQ each day.

As for Colongra GPG, Snowy Hydro is able to profile the operating hours of the power station as required up to the total fuel limit. If instead the storage pipeline is full and allowed to deplete over five days, Hunter GPG is able to run for 10 hours for each of those five days at full rate.

The modelling above assumes that all stored gas in the Kurri Kurri storage pipeline is available to be used by the Hunter GPG, and not injected back into the STTM.

Newcastle Gas Storage Facility

AGL's NGSF is a storage facility located in Tomago, near Newcastle, with gas stored as LNG in a tank. Gas is injected or withdrawn from the Northern Trunk Pipeline at Hexham and transported to or from NGSF via the Hexham to Tomago Pipeline. When gas from Hexham reaches Tomago, it is then liquified for storage in the tank. Stored gas is then vaporised to be reinjected into the network.

NGSF is registered as a storage facility in the Sydney STTM.

System supportability – storage injections

Modelling indicates that the Northern Trunk Pipeline is capable of receiving and transporting the maximum injection capacity from NGSF of 5 terajoules per hour (TJ/h – 120 TJ/d) to meet demand in the network at any time of year. The pressure at the Newcastle end of the Northern Trunk Pipeline is modelled to be 250-350 kPa higher when NGSF is injecting. This is within the pressure limits of the network and NGSF.

System supportability – storage withdrawals

When NGSF is withdrawing from the Northern Trunk Pipeline and liquefying gas for storage, the facility can be impacted by:

- Northern Trunk Pipeline operating pressure at Hexham – the minimum pressure required for NGSF liquefaction is 3,100 kPa at the Tomago facility, which is significantly higher than the 1,750 kPa minimum supply pressure for the Northern Trunk Pipeline at Hexham.
- Sudden pipeline pressure changes – the liquefaction process at NGSF was designed for relatively stable inlet pressures. Sudden pressure changes on the Northern Trunk Pipeline when the Hexham connection pressure is lower than 4,000 kPa can disrupt the process.

Operating pressure

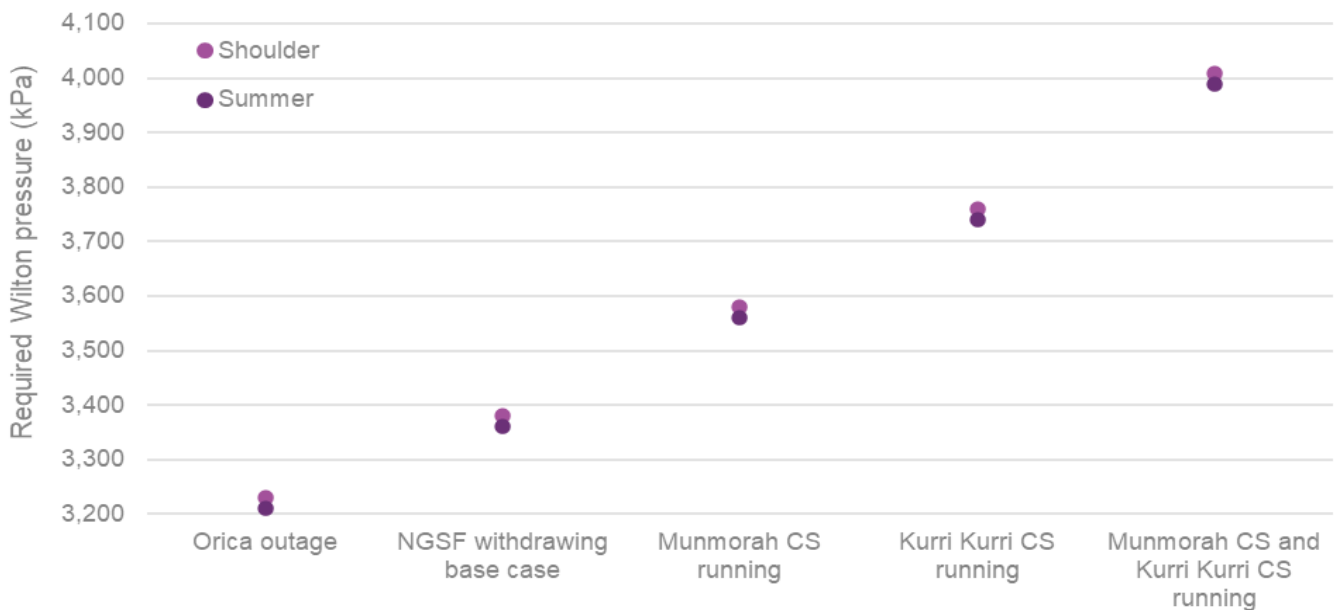
The operating pressure in the Northern Trunk Pipeline is currently controlled at Wilton. Gas is transported into the Northern and Southern Trunk Pipelines at Wilton from both the MSP and EGP. As the EGP is the higher-pressure pipeline, the Wilton EGP connection is operated on a flow-controlled basis and does not control the network pressure. The Wilton MSP connection is operated on a pressure-controlled basis with both sides of the connection contributing to the network pressure:

- JGN operates a regulator at Wilton to control the pressure into the Northern and Southern Trunk Pipelines from the MSP. This regulator has typically been set to 4,200 to 4,300 kPa.
- APA operates the Young to Wilton section of the MSP to meet a minimum pressure of 3,800 kPa at the Wilton connection point.

If the MSP is operating at a higher pressure than the JGN Wilton setpoint, the JGN setpoint dictates the pressure in the Northern Trunk Pipeline. If the Young to Wilton section of the MSP is operating at lower pressures than the JGN setpoint, the pressure at Wilton is only as high as the MSP supply pressure.

In addition to the settings at Wilton, other major loads supplied from the Northern Trunk Pipeline can influence the pressure in the pipeline. This includes Munmorah CS, Kurri Kurri CS, and LILs in Newcastle including Orica's Kooragang Island facility.

To illustrate the influence that these other major loads have on the Hexham pressure, **Figure 18** shows the outcomes of modelling conducted to determine the minimum pressure required at Wilton to meet the NGSF liquification minimum pressure. The Orica outage is included as an indication of the influence of Newcastle LILs on the Northern Trunk Pipeline pressure only and does not imply this load is controllable.

Figure 18 Minimum Wilton pressure to meet NGSF liquefaction minimum pressure (kPa)

In winter, the operating pressure at Wilton is typically higher than 4,300 kPa, but the pressure at the Hexham connection would typically be too low to enable NGSF liquefaction. This is also the period when NGSF is most likely to be vaporising and injecting into the STTM to meet higher winter demands.

The summer and shoulder periods are when NGSF is most likely to be withdrawing gas to refill storage. This is also when other pipeline operators undertake maintenance as gas demand is lower and pipelines do not need to run at capacity. Pipeline maintenance often requires operating pressures to be lowered to enable work to be conducted safely. As a consequence, the Wilton pressure may be lower than 4,300 kPa, as:

- JGN may set the Wilton MSP regulator setpoint lower to facilitate maintenance to be conducted on the Northern Trunk Pipeline or elsewhere in the network.
- APA may operate the Young to Wilton section of the MSP at lower pressure to facilitate maintenance on the MSP. APA routinely undertakes dig-up inspection programs on the MSP during summer which requires lower pipeline pressures to meet safety requirements.

The result of lower Northern Trunk Pipeline pressures in summer or shoulder is that NGSF may not be able to refill until network pressures are increased.

Pressure changes

The liquefaction process at NGSF is sensitive to fluctuations in the inlet pressure at Tomago when the Northern Trunk Pipeline pressure at Hexham is less than 4,000 kPa. As noted above, the Hexham pressure is most likely to be lower than 4,000 kPa during the summer and shoulder periods when there are maintenance activities on the MSP, the Northern Trunk Pipeline, or elsewhere in the JGN network. This is also the period when NGSF is most likely to be refilling.

The connection at Hexham to NGSF is located at the far northern end of the Northern Trunk Pipeline, nearly the furthest point on the pipeline from the pressure-controlling supply point at Wilton and the flow-controlled supply

point at Horsley Park. The Northern Trunk Pipeline is also a single line with limited linepack to dampen pressure changes.

Sudden changes that cause pressure fluctuations in the Northern Trunk Pipeline at Tomago include the starting of the Munmorah CS on the Central Coast. Historically, operation of Munmorah CS can lead to a sudden change in Northern Trunk Pipeline pressure, impacting the liquification process at NGSF, despite being located over 50 km away.

Modelling indicates that the operation of Kurri Kurri CS will also cause pressure fluctuations at Tomago and potentially will be more impactful due to the closer proximity of Kurri Kurri CS to Tomago. The KKLK also has more powerful compressors and higher MHQ than Munmorah CS.

Actions by LILs are less likely to cause sudden pressure changes in the Northern Trunk Pipeline, as very few facilities consume as much gas as the storage pipeline compressors withdraw, and industrial facilities typically ramp up gas usage slowly.

Interactions

The Northern Trunk Pipeline has supported a large proportion of residential, commercial, and industrial gas demand in New South Wales for many years, as well as the Colongra Power Station from 2009 and NGSF from 2015. While historically there have been some influences on NGSF operation from Munmorah CS through the Northern Trunk Pipeline, modelling indicates that when the Hunter Power Station connects in 2025, it will introduce more complex interactions between these loads. This will be exacerbated by the forecast increase in the requirement for GPG to back-up renewable generation, as discussed in Section 2.2.3.

Table 9 summarises the impact of the key operational factors for the Northern Trunk Pipeline on the operation of Munmorah CS and flow into the Colongra storage pipeline, operation of Kurri Kurri CS and flow into the Kurri Kurri storage pipeline, and the NGSF liquefaction process.

Table 9 Key factors impacting the Northern Trunk Pipeline and the impact on each of Munmorah CS, Kurri Kurri CS and Newcastle Gas Storage Facility liquefaction

Factor		Munmorah CS	Kurri Kurri CS	NGSF liquefaction
Reduced Wilton pressure	Impact	<ul style="list-style-type: none"> Lower pressure at inlet 	<ul style="list-style-type: none"> Lower pressure at inlet 	<ul style="list-style-type: none"> Lower pressure at Hexham
	Outcome	<ul style="list-style-type: none"> More time spent power-limited and less gas can be transported into the Colongra storage pipeline 	<ul style="list-style-type: none"> Runs at higher power but can still maintain MHQ 	<ul style="list-style-type: none"> Pressure may be too low to liquify
Munmorah CS operation	Impact		<ul style="list-style-type: none"> Lower pressure at inlet 	<ul style="list-style-type: none"> Lower pressure at Hexham Pressure drop at Hexham
	Outcome		<ul style="list-style-type: none"> Runs at higher power but can still maintain MHQ 	<ul style="list-style-type: none"> Pressure may be too low to liquify Pressure fluctuation may cause issues with the liquefaction process
Kurri Kurri CS operation	Impact	<ul style="list-style-type: none"> Lower pressure at inlet 		<ul style="list-style-type: none"> Lower pressure at Hexham Pressure drop at Hexham
	Outcome	<ul style="list-style-type: none"> More time spent power-limited and less gas can be 		<ul style="list-style-type: none"> Pressure may be too low to liquify

Factor		Munmorah CS	Kurri Kurri CS	NGSF liquefaction
		transported into the Colongra storage pipeline		<ul style="list-style-type: none"> Pressure fluctuation may cause issues with the liquefaction process
NGSF withdrawing at Hexham	Impact	<ul style="list-style-type: none"> Negligible impact 	<ul style="list-style-type: none"> Lower pressure at inlet 	
	Outcome	<ul style="list-style-type: none"> Negligible impact 	<ul style="list-style-type: none"> Runs at higher power but can still maintain MHQ 	
NGSF injecting at Hexham	Impact	<ul style="list-style-type: none"> Higher pressure at inlet 	<ul style="list-style-type: none"> Higher pressure at inlet 	
	Outcome	<ul style="list-style-type: none"> Less time spent power-limited and more gas can be transported into the storage pipeline 	<ul style="list-style-type: none"> Runs at lower power 	

The factors discussed above are compounding. As an example, if the Wilton pressure is lower due to summer maintenance activities and Kurri Kurri CS starts operating, this will have a more severe impact on NGSF liquification than either factor in isolation.

3.2 Storage adequacy

New South Wales has three types of gas storage facility:

- LNG tank storage – this includes NGSF
- pipeline linepack – this refers to gas stored in the transmission and distribution pipelines themselves, and
- dedicated storage pipelines – this is a special case of pipeline linepack where a dedicated pipeline is designed and operated specifically to store gas rather than transport gas as its primary purpose. This includes the Colongra and Kurri Kurri storage pipelines.

All these storage types are considered shallow storage that hold limited volumes, so they are unable to sustain high rates of supply for extended periods. Typically, shallow storage inventories can be depleted on the scale of days or weeks.

New South Wales does not have any deep storage such as underground gas storage (UGS) facilities that have larger storage inventories and can supply gas from storage for longer periods.

3.2.1 Newcastle Gas Storage Facility

NGSF has a storage capacity of 1,500 TJ and a daily vaporisation capacity of 120 TJ/d to inject gas into the Northern Trunk Pipeline. The facility has the inventory to provide 12.5 days of supply at full rate. Typical of LNG tanks, the maximum daily liquefaction capacity of 12.5 TJ/d is much lower than the vaporisation rate. Refilling the tank from empty takes at least 120 days, 10 times longer than it does to empty the tank.

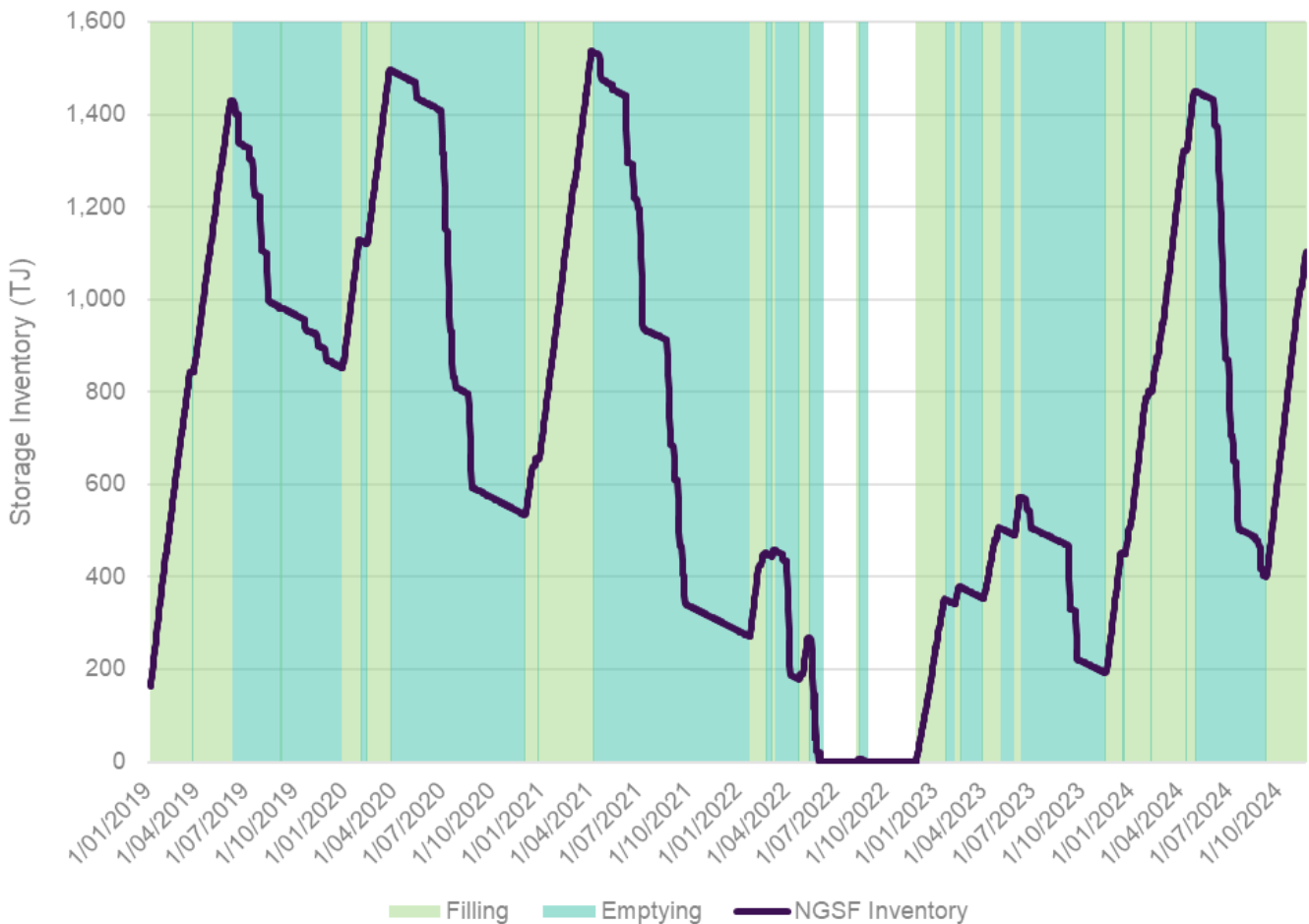
LNG is stored as a liquid in the non-pressurised tank at cryogenic temperatures. To maintain the low temperatures in the tank while storing the LNG, some of the liquid is allowed to vaporise as boil-off gas and this is injected into the Northern Trunk Pipeline or supplied to the nearby Tomago Aluminium smelter.

Figure 19 shows the historical usage of the NGSF facility from 2019 to 2024.

For most of this period, AGL has operated the facility in discrete periods where the facility was either filling or emptying. Filling is typically undertaken in the summer period from January to March, and emptying is typically in the winter months from June to August. Lower rates of supply outside of the peak winter months is boil-off gas.

In 2021, AGL announced that it was demerging the company and intending to sell NGSF⁴⁴. After emptying the facility in winter 2021, AGL did not refill NGSF. This was followed by a period of under-utilisation for the facility, which also faced technical difficulties operating at such low inventory for an extended period, including management of gas quality. In May 2022, AGL’s demerger proposal was withdrawn⁴⁵ and NGSF was no longer for sale⁴⁶. AGL has since retained ownership of NGSF. During winter 2022, NGSF did not have any inventory to support gas demand, and limited inventory was available for winter 2023.

Figure 19 Actual Newcastle Gas Storage Facility storage inventory, 2019-24 (TJ)



⁴⁴ AGL, Confirmation of intention to demerge, announcement of dividend actions and affirmation of earnings guidance, 30 June 2021, at https://www.agl.com.au/content/dam/digital/agl/documents/about-agl/media-centre/2021/210630_aglstructuralseparationupdate.pdf.

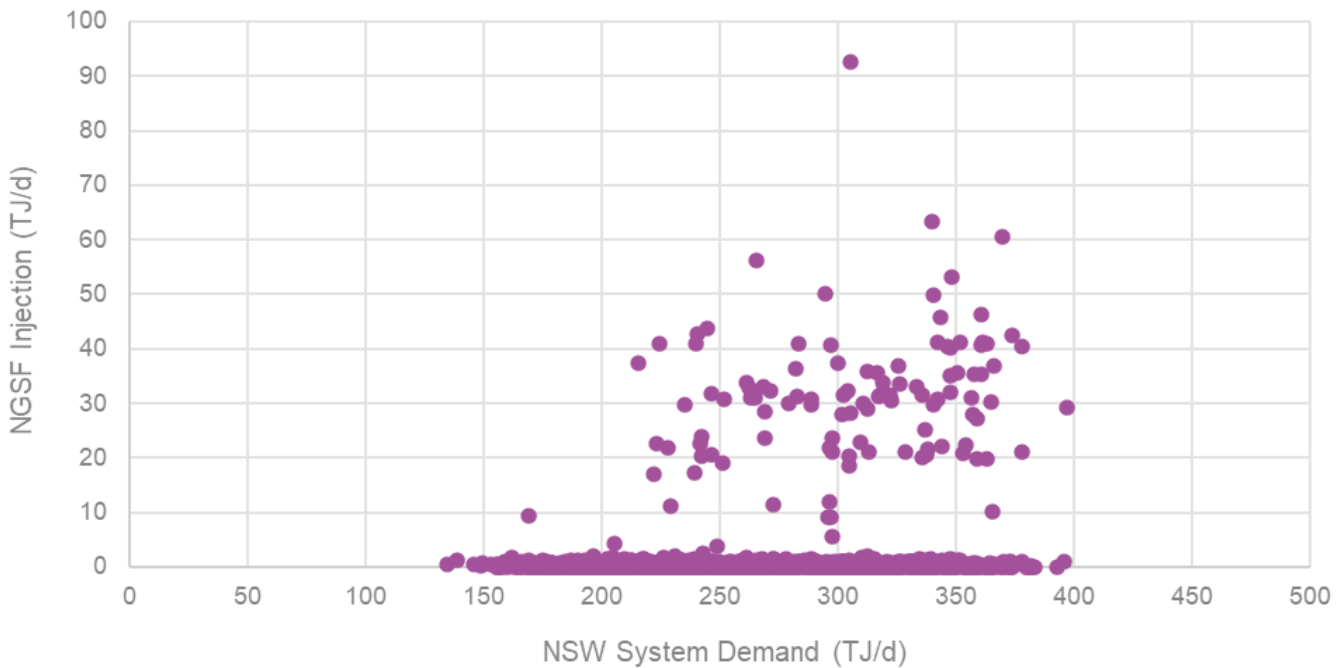
⁴⁵ AGL, Withdrawal of Demerger Proposal, 30 May 2022, at <https://www.agl.com.au/about-agl/investors/structural-update>.

⁴⁶ Newcastle Herald, “AGL takes Newcastle gas storage plant off the market”, 19 August 2022, at <https://www.newcastleherald.com.au/story/7867762/agl-takes-newcastle-gas-storage-plant-off-the-market/>.

Figure 20 plots the daily injection rate of NGSF against New South Wales system demand. GPG demand was excluded as AGL does not own or operate any GPG assets in New South Wales, however AGL does have GPG assets in Victoria and South Australia.

The chart shows little correlation between NGSF injections and New South Wales demand.

Figure 20 Newcastle Gas Storage Facility daily injection compared to New South Wales system demand, 2019-24 (TJ/d)



3.2.2 Pipeline linepack

Pipeline linepack refers to the quantity of gas in transmission and distribution pipelines. The amount of linepack in a pipeline will change depending on the supply and demand conditions, pressure, and temperature. As part of normal pipeline operations, a minimum amount of linepack must be stored in the pipeline at all times to maintain operation limits, but anything above that quantity of linepack can be considered a form of gas storage.

Use of pipeline linepack as a form of storage depends on the specific pipeline system and the contracting arrangements used by the operator. Some pipeline operators sell storage services which commercially utilise the linepack as storage. This typically results in a reduction in the transportation capacity available to be contracted, as there is a trade-off to ensure pressures can be maintained when stored linepack is accessed. For other pipelines, this may not be possible and linepack is only accessed for managing issues or outages.

Longer, higher pressure, larger diameter pipelines hold more linepack; transmission pipelines in New South Wales like the MSP and EGP hold significant quantities of stored gas. This stored gas helps mitigate the risk of production outages, upstream transmission issues, or sudden increases in demand.

Table 10 summarises the results of modelling conducted to provide an indication of how much linepack was available to support New South Wales GPG in the event of a total supply outage on each pipeline.

This modelling prioritised supply to GPG over other demand, while still meeting minimum pressures, and overlooked all market and contractual considerations. Quantities will depend on actual operational conditions on

any given day, asset availability and contractual arrangements between the pipeline operator and gas users. This information should be used as an indication only.

Table 10 Estimated Moomba Sydney Pipeline and Eastern Gas Pipeline linepack quantities available to GPG (TJ)

Pipeline	Supply priority	Estimated linepack	
		Summer	Winter
MSP	Uranquinty GPG	500 TJ	700-800 TJ
EGP	Tallowarra GPG	150-170 TJ	
	Smithfield GPG		

3.2.3 Colongra and Kurri Kurri storage pipelines

Table 11 summarises the available stored gas in the Colongra and Kurri Kurri storage pipelines. This quantity assumes the storage pipeline starts full and is fully depleted. The Colongra storage pipeline stores gas for the Colongra GPG only, where gas stored in the Kurri Kurri storage pipeline can be used to supply Hunter GPG or the Sydney STTM via the Northern Trunk Pipeline.

Table 11 Estimated Colongra and Kurri Kurri storage pipeline linepack quantities (TJ)

Pipeline	Supply options	Available linepack
Colongra storage pipeline	Colongra GPG	37 TJ
Kurri Kurri storage pipeline	Sydney STTM	60 TJ
	Total KKLP storage	72 TJ

Table 12 shows the estimated operating hours for each GPG facility from stored linepack alone, if all the available linepack in each storage pipeline was used for generation until the pipeline was fully depleted and no gas was supplied into the storage pipeline by the compressors during this period. These hours will vary depending on exact conditions and actual fuel consumption rates of the GPG.

Table 12 Modelled operating hours available to gas-powered generation from stored linepack (hours)

GPG	Operating hours			
	One unit	Two units	Three units	Four units
Colongra GPG	20	10	7	5
Hunter GPG	21	10	-	-

3.2.4 Storage interactions

The existing gas storage facilities in New South Wales operate independently of each other, as there is limited interaction between the systems that support them and the demand they supply. AEMO conducted modelling to investigate whether supply from NGSF will interact with future KKLP storage supply into the Northern Trunk Pipeline, as the new KKLP is close to Hexham.

Figure 21 shows the modelled profile of injections, with NGSF injecting at a flat hourly rate while the Kurri Kurri storage pipeline is injecting from 06:00 to 22:00 and then refilling overnight using the Kurri Kurri CS.

Figure 21 Modelled storage injections from Newcastle Gas Storage Facility and Kurri Kurri Lateral Pipeline (TJ/h)

Modelling indicates that NGSF and KKLP injections will interact due to the proximity of the two connections and the injection pressure range of the facilities. NGSF has a lower maximum injection pressure (5,000 kPa) than the MAOP of the Northern Trunk Pipeline, while KKLP can inject up to the MAOP of the Northern Trunk Pipeline. This would result in the NGSF injections being backed-off while KKLP would be able to continue injecting if the Northern Trunk Pipeline operating pressure is above 5,000 kPa. The extent of the back-off effect depends on the demand in the network as higher demand absorbs more supply at the same pressure.

In winter, NGSF can only inject at a reduced rate of 76-82% of maximum capacity if KKLP is supplying gas into the Northern Trunk Pipeline following the profile in **Figure 21** above. Winter is when NGSF is utilised the most. In summer and shoulder periods, the injection rate of NGSF further reduces to 68% of maximum capacity.

3.3 Supply resilience

The assessment of supply adequacy in Section 3.1 considered the capacity of the New South Wales pipeline network while assuming that the gas supply required to meet demand is always available and that all transmission assets are available. This section explores the resilience of that supply.

3.3.1 Short-term resilience

The MSP transports gas from Victoria, South Australia and Queensland, while the EGP transports gas from Victoria only. Each pipeline has unique supply resilience characteristics when considered on a short-term basis, hours or days.

MSP

The MSP can be supplied from the Moomba Gas Plant or from Queensland via the SWQP at Moomba, and from Victoria via Culcairn or from the EGP at Wilton. The diversity of supply onto the MSP means that the pipeline as a whole is resilient to issues at each individual supply source. The length of the MSP from Moomba to Wilton at approximately 1,300 km means there can be considerable linepack stored to help mitigate issues with supply.

Using the same modelling approach as in Section 3.1.1, Uranquinty GPG can operate from MSP linepack for up to 45 hours if this demand is prioritised. This is illustrative only; if there is an issue with the MSP and there is supply available in Victoria, Uranquinty GPG can run indefinitely from Victorian supply via Culcairn.

The MSP mainline has six compressor units⁴⁷, which also provides operational flexibility in the event of an issue with a single unit, although the pipeline capacity will decrease with the loss of compression and some stations such as Young are more important for transportation capacity than others. The MSP laterals to Griffith, Lithgow and Marsden are single lines, so supply to connection points on these laterals may not be possible if there is an issue on the lateral. Supply to Bathurst, Lithgow, Oberon, and Wallerawang was interrupted in 2022 when the Young to Lithgow lateral was damaged by flooding⁴⁸.

The MSP mainline was constructed in 1976 and is close to 50 years old, the typical design life for a pipeline (although the operational life often exceeds this). APA undertakes a considerable maintenance program on the MSP each year through the shoulder and summer periods which often includes dig-ups of sections of the pipeline and stress-corrosion cracking repairs. The MSP operates at a lower maximum operating pressure (MOP) than the design pressure throughout the year to ensure safe operation.

Different sections of the mainline MSP have different MOPs to account for the condition of the pipeline in different locations. The first section of the MSP from Moomba through remote parts of South Australia, Queensland and New South Wales has the lowest MOP and requires the most maintenance. As part of its announced further East Coast Gas Expansion Plan⁴⁹, APA has a proposal to bypass this section of the MSP with the Bulloo Interlink.

Northern and Southern Trunk Pipelines

The Northern and Southern Trunk Pipelines can be supplied by either the MSP or EGP at Wilton, by the EGP at Horsley Park, by NGSF, and in future by the KKLP. Additionally, the Wollongong network supplied by the Southern Trunk Pipeline can also be supplied by the EGP. Diversified supply from different locations means the network has some resilience to supply issues at each individual source.

Each of the trunk pipelines is a single line which can be vulnerable to single-point issues, however the distribution network is highly interconnected, which reduces the risk of complete supply outages. For example, an issue in a section of the Northern Trunk Pipeline is likely to reduce supply capacity but some demand can be met. Unlike the MSP and the EGP, there is much less stored linepack available to mitigate issues.

The Northern and Southern Trunk Pipelines were constructed between the mid-1970s and the early 1980s with the oldest sections close to 50 years old. The maximum pressures at the receipt points into the trunk pipelines are currently limited to satisfy code and licence requirements. This is similar to the MSP which operates at lower pressures to satisfy integrity concerns.

⁴⁷ One unit between Moomba Gas Plant and Bulla Park CS, two units at Bulla Park CS, one unit between Bulla Park CS and Young CS, and two mainline units at Young CS.

⁴⁸ The Guardian, 4 November 2022, “Thousands left without natural gas in Lithgow and Bathurst amid cold snap”, at <https://www.theguardian.com/australia-news/2022/nov/04/thousands-left-without-natural-gas-in-lithgow-and-bathurst-amid-cold-snap>.

⁴⁹ APA’s East Coast Gas Expansion Plan, at <https://www.apa.com.au/news/asx-and-media-releases/apas-east-coast-gas-expansion-plan>.

EGP

The EGP was constructed in 2000 and does not have integrity concerns like the MSP or Southern and Northern Trunk Pipelines. The pipeline has seven compressor units, with four located at Longford CS and one each at the three mainline compressor stations. The four units at Longford CS allow for redundancy at the start of the pipeline and the other stations do not need to all operate to transport typical quantities in recent periods.

The EGP is supplied from the Longford and Orbost gas plants in Victoria, both producing gas from the Gippsland Basin. While reverse pipeline is theoretically possible (noting that the compressors are the EGP can currently only flow north)⁵⁰, the EGP cannot currently be supplied from the MSP at Wilton, as the EGP operates at a much higher pressure. The limited sources of supply on the EGP mean that if there is an ongoing issue with Longford, only demand up to the capacity of Orbost's production can be met on the EGP.

Production from Longford is forecast to reduce with the decline in the large legacy Gippsland Basin fields, and the impact of unplanned outages are expected to increase with less redundancy at the plant⁵¹. Supply may also be interrupted if there is an issue on the EGP between the supply sources in Victoria and demand, as most of this demand is located hundreds of kilometres north along the pipeline.

Demand solely supplied by connection points off the EGP is susceptible to these supply issues. This includes Tallawarra GPG, Smithfield GPG, and several large industrial facilities including Manildra's Shoalhaven Starches plant in Bomaderry. Demand at Wollongong can be partly met by supply from the Southern Trunk Pipeline. Tasmanian gas demand is also met by this same source; supply to the Tasmanian Gas Pipeline is via a connection on the EGP after the Longford CS.

Orbost Gas Plant should have sufficient capacity to meet the average winter demand of residential, commercial, and industrial loads along the EGP, but not also supply Tallawarra GPG or Smithfield GPG. In the event of a Longford Gas Plant outage, production from Orbost would also be the only supply available to meet demand in Tasmania and some demand in eastern Victoria.

The full length of the EGP from Longford to Sydney is 797 km and operates at a high pressure, translating to a large quantity of pipeline linepack. Using the same modelling approach as in Section 3.1.3, AEMO assessed that in the event that both Longford and Orbost were unavailable or a transmission issue occurred in Victoria that cut the supply to New South Wales, if supply to the GPG is prioritised then Tallawarra GPG can operate from EGP linepack alone for 15-18 hours at full rate or Smithfield GPG for 15-20 hours, while maintaining supply to other locations on the EGP.

3.3.2 Long-term resilience

Assessment basis

As discussed in Section 2.4, New South Wales is currently reliant on the importation of natural gas from other states to meet gas demand.

⁵⁰ Jemena announced on 21 February 2025 that it will proceed with the EGP reversal project: <https://www.jemena.com.au/media/jemena-takes-crucial-next-step-to-avoid-gas-shortfall/>.

⁵¹ For more information on redundancy at Longford Gas Plant, see the VGPR, at <https://aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/victorian-gas-planning-report>.

AEMO performed a long-term resilience assessment using the demand forecasts from AEMO's 2025 GSOO **Step Change** scenario, completed within a nodal network model.

The assessment highlights the potential impacts of a slowing of interstate gas supply to New South Wales from 2025 to 2035, assuming current and committed projects from the 2025 GSOO are implemented within the east coast gas system. AEMO used the outcomes of this reference case, referred to as the **Base Case**, to compare against a number of scenarios. The model replicated the gas infrastructure assets of the east coast of Australia, with a focus on the southern states (those south of the Moomba end of the SWQP – New South Wales, Australian Capital Territory, Victoria, South Australia, and Tasmania).

The modelling parameters⁵² of the **Base Case** were adjusted to create an additional seven scenarios to assess the adequacy of gas supply and infrastructure assets under uncertain future conditions within the east coast and New South Wales. The scenarios assessed within the model are listed in **Table 13**.

Table 13 Suite of scenarios modelled in the long-term resilience assessment

Scenario	Description	Assessment classification	NGIR section
Base Case	The reference case of the analysis. Assessed the gas supply adequacy of New South Wales from 2025 to 2035 using primarily 2025 GSOO data. The Base Case capped the quantity of Queensland gas available to be transported south ^A .	Supply constrained	3.3.2
Peak Day GPG Supportability	The same gas infrastructure as the Base Case but with the inclusion of a peak GPG demand day for the New South Wales GPG units in July each year of the outlook period.	Supply constrained	3.3.2
Prolonged GPG Demand Supportability	The same gas infrastructure as the Base Case but with the inclusion of an eight-day period of elevated GPG demand across South Australia, Victoria, New South Wales, and Tasmania occurring each year in June.	Supply constrained	3.3.2
Unconstrained Northern Supply	The same gas demand and infrastructure assets as the Base Case but modelled the removal of gas supply limitations in Queensland. This allowed the model to bring more supply to the southern jurisdictions via the Moomba node with the limiting supply constraint now becoming the availability and transport capacity of the SWQP.	Supply augmentation	3.3.2
Port Kembla Energy Terminal	Additional gas supply was introduced into the Base Case by connecting PKET to New South Wales via the EGP and including Jemena's EGP reversal project. The model allowed additional gas supply of 35 PJ to be made available in 2026, ramping up to 130 PJ/year from 2029 onwards. The EGP reversal initially allows 200 TJ/d capacity towards Longford then increasing to 325 TJ/d.	Supply augmentation	4.2.1
Narrabri Gas Project and Hunter Gas Pipeline	Additional gas supply introduced into the Base Case by connecting the proposed Narrabri Gas Project in New South Wales to the wider network via the Hunter Gas Pipeline. The production facility commences operation in 2029 with a maximum daily production capacity of 150 TJ/day when not limited by the upstream gas fields.	Supply constrained	0
East Coast Grid Expansion future stages	Additional gas transmission assets and storage introduced into the Base Case. Significant and	Supply augmentation ^B	4.2.3 (Gas transmission assets)

⁵² Modelling parameters refers to the configurable objects and values within the model, such as gas supply, demand, and infrastructure assets.

Scenario	Description	Assessment classification	NGIR section
	staggered augmentations of the SWQP, MSP and VNI increase gas transmission capacity, with the first suite of augmentations commencing from 2025. A new gas transmission pipeline connects the Ballera node to the MSP (Bulloo Interlink) from 2028, with the effective southern haul capacity to 700 TJ/day. A gas storage pipeline is constructed in two stages at Culcairn, stage one adds 200 TJ of storage in 2028 and stage two adds an additional 300 TJ of storage in 2029.		4.3.2 (Riverina storage pipeline)
East Coast Grid Expansion with Unconstrained Northern Supply	The same gas infrastructure augmentations and additions as with the East Coast Grid Expansion, but modelled the removal of gas supply limitations in Queensland.	Supply augmentation	4.2.3 (Gas transmission assets) 4.3.2 (Riverina storage pipeline)

A. The annual volumes of gas transported into the southern states via the SWQP in the Base Case have been constrained based on historical gas flow information and observed market responses to potential gas supply shortfalls. This constrained annual gas flow via the SWQP is lower than comparable reference scenarios and modelling in the 2025 GSOO and is intended to highlight the vulnerability of the southern states to supply shortfalls if additional gas supply capacity is not developed within the east coast.

B. The **East Coast Grid Expansion future stages** scenario improves gas transmission capacity to the southern states but the modelling results are characteristic of the other supply constrained scenarios. This is due to a lack of gas supply availability to move into the augmented gas transmission pipelines or the Riverina storage bottle.

Assessment results

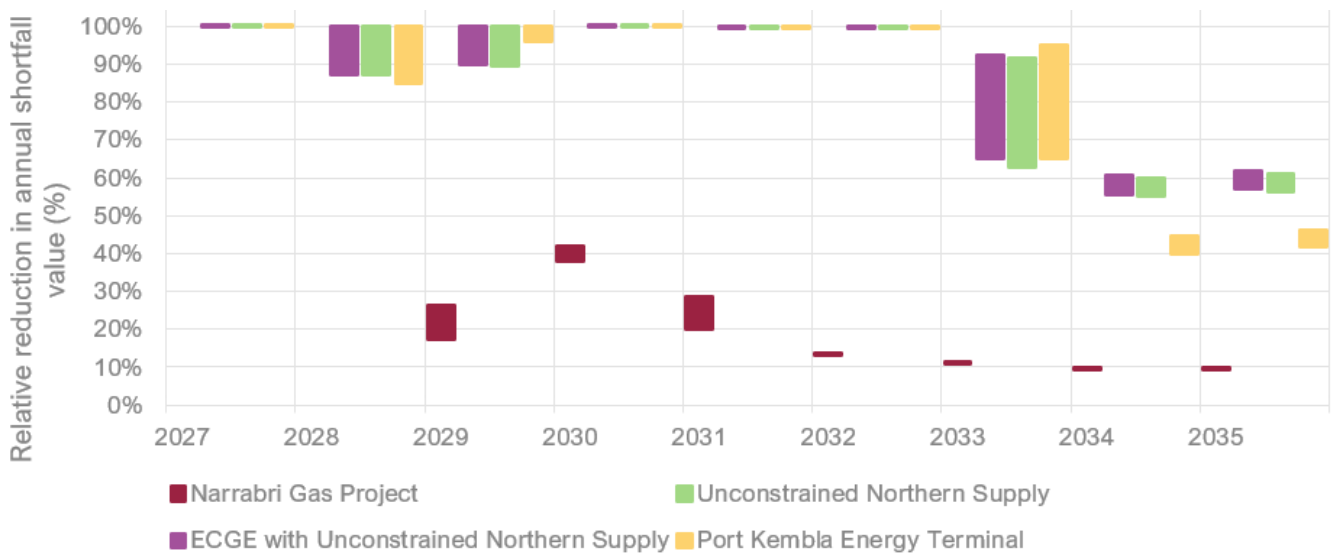
The long-term resiliency assessment results can be grouped into two distinct classes – supply constrained and supply augmentation. While the assessment results are not identical between similarly classified scenarios, there are core observed impacts on the east coast gas system shared between them. The potential reductions in the shortfalls observed in supply augmentation scenarios relative to the **Base Case** are displayed in **Figure 22** from 2027 onwards, when the risk of supply gaps begin to occur.

Except for the proposed Narrabri Gas Project, which has modest additions of supply within the model, the supply augmentation scenarios are effective at reducing most shortfalls observed within the **Base Case** with three key time periods of interest:

- During periods of high GPG demand in the late 2020s, the supply augmentation scenarios can resolve the majority of the observed seasonal supply gaps across the demand forecasts assessed. These scenarios may, however, still be inadequate to meet days of elevated and coincident GPG and system demand.
- From 2030 to 2033, the supply augmentation scenarios resolve the majority of both the seasonal shortfalls and the peak day shortfalls observed in the **Base Case**, but with some daily shortfalls still possible under some conditions.
- From 2033 onwards, the supply augmentation scenarios become less effective at reducing both seasonal supply gaps and peak day shortfalls as legacy fields continue to decline and contribute increasingly less supply within the model.

As discussed in Section 4.2.2, the Narrabri Gas Project is observed to reduce the severity of shortfalls within the **Base Case** but is the least effective of the four supply augmentation scenarios assessed.

Figure 22 The observed reduction in annual supply gap ranges relative to the base case by supply augmentation scenario and by year, 2027-35 (PJ)



Note: The Narrabri Gas Project is not modelled as a supply source until 2029.

Supply constrained scenarios

The results of these scenarios typically observe adequate gas supply into the southern states until 2027, when there is an increase in forecast GPG demand due to the retirement of the Eraring and Yallourn coal power stations in 2027 and 2028 respectively, and a continued decline in gas supply from legacy fields across the east coast gas system. Shortfalls can occur within the model for certain conditions prior to 2027 but these shortfalls are of a smaller magnitude and occurrence compared to 2027 and onward.

Forecast GPG demand decreases in 2030 as firming storage technologies and additional renewable energy generation are expected to continue to be deployed in the NEM, reducing the annual supply gap for 2030. Later in the 2030s, the supply gap continues to increase as the available supply from committed and anticipated gas fields continues to deplete.

Supply constrained scenarios highlight that without additional supply sources, augmentations of existing gas storage or transportation assets are likely to be ineffective at addressing the supply gaps observed in the scenarios from 2027, particularly when paired with scenarios that increase demand within New South Wales or other southern states, including the **Peak Day** and **Prolonged GPG Demand Supportability** scenarios.

Supply augmentation scenarios

The potential impact of the supply augmentation scenarios is varied. The **Port Kembla Energy Terminal** and **Narrabri Gas Project** scenarios add a local supply source within New South Wales, reducing reliance on gas importation from other states, but the scale of their potential supply is not equivalent. The **Unconstrained Northern Supply** and the **East Coast Gas Expansion with Unconstrained Northern Supply** scenarios provide more net supply to the southern states, but do not provide local supply sources within New South Wales. All supply augmentation scenarios modelled rely on additional supply sources or assets maintaining high levels of availability and uptime to effectively produce, transport and store enough gas to effectively mitigate future shortfalls, particularly as the potential structural shortfalls begin to occur in the **Base Case** from 2027.

The supply augmentation scenarios increase the gas supply resilience of the southern states through three primary means:

- increasing the net supply available to the southern states to satisfy daily gas demand, and
- allowing storage facilities to refill their inventory during periods of lower total gas demand (for example, during the summer period) so that storage inventories can be used during other periods in the relevant year, such as meeting peak day demand and meeting winter heating load demand, and
- increasing daily gas transmission capacity available to transport gas across the east coast gas system to demand centres or storage facilities.

The **Narrabri Gas Project** scenario does increase available supply within the model, but at a reduced scale and benefit compared to the other three scenarios.

Unconstrained Northern Supply

In the **Unconstrained Northern Supply** scenario, the structural shortfalls observed in the supply constrained scenarios are delayed from 2027 to 2033. Daily or peak day shortfalls are still possible prior to 2033, particularly during 2028 and 2029 when there is elevated peak day GPG demand, if demand is higher than forecast or if there are gas infrastructure outages which limit the transport or availability of gas supply sources.

While shortfalls are expected to be delayed compared to the **Base Case**, there is an increased reliance on the SWQP and MSP to transport increasing volumes of gas into the southern states, and a need for the pipeline to maintain near 100% availability and operating capacity throughout each year.

3.4 Ability of existing infrastructure to support future GPG

AEMO undertook technical analysis of the existing gas infrastructure in New South Wales to assess the adequacy of the system to support future GPG. Future GPG supportability was analysed from a theoretical gas system adequacy perspective only, and was assessed on the basis of the following three major supportability factors:

- **Transmission availability** – gas infrastructure capacity available to accommodate further large gas demand.
- **Supply availability** – dependence on current gas supply sources.
- **Operational impact** – vulnerability to nearby gas demands or operational changes in the gas network.

Using these three factors, a gas infrastructure locational supportability factor for future GPG loads can be derived for each existing pipeline system in New South Wales.

The gas infrastructure locational analysis conducted for the NGIR is also overlaid with data from the 2024 *Enhanced Locational Information* (ELI) report⁵³ published by AEMO in June 2024, which is the same as the analysis presented in the *Update to the 2023 Electricity Statement of Opportunities* (Update to the 2023 ES00) published by AEMO in May 2024⁵⁴.

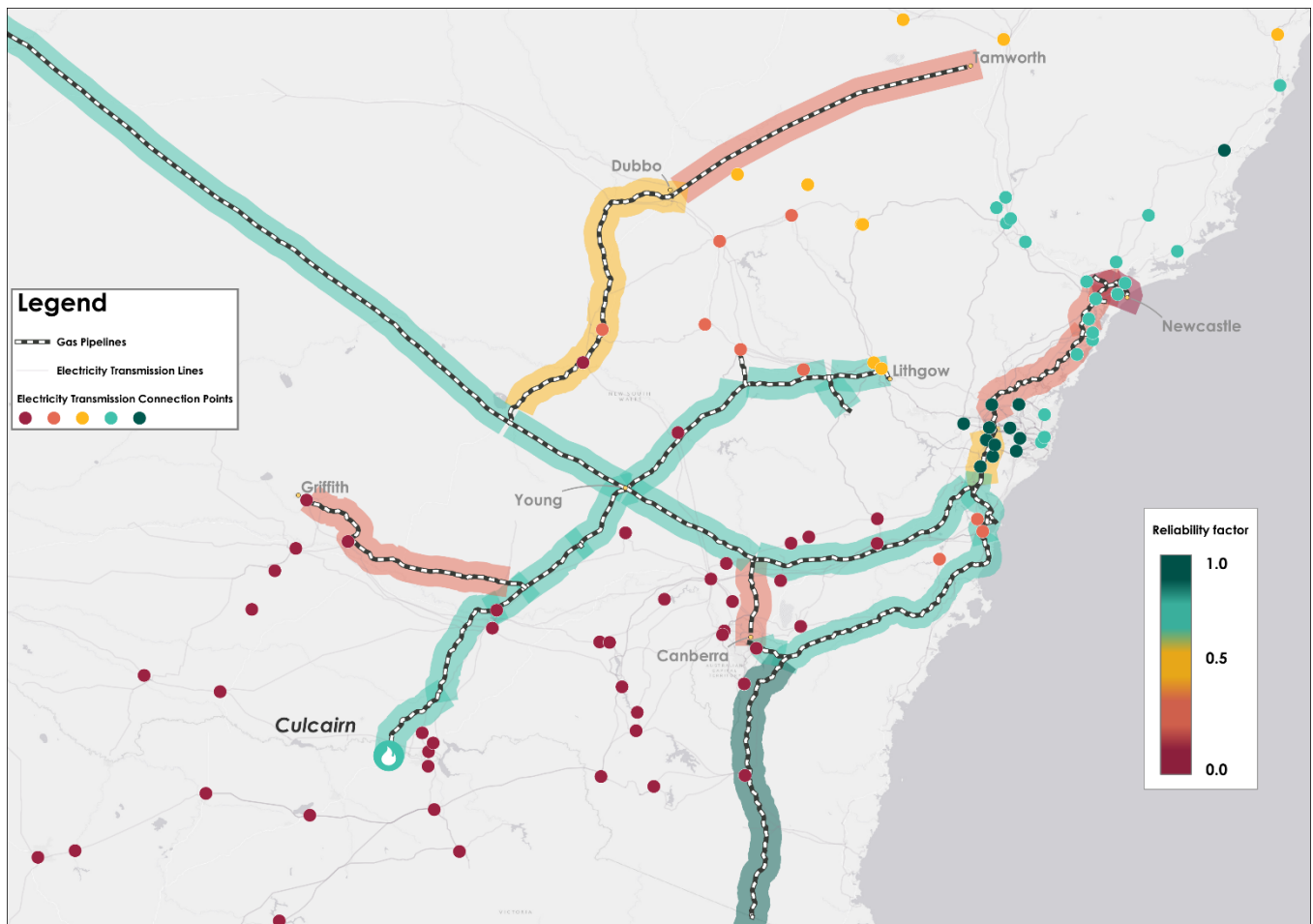
⁵³ At <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/enhanced-locational-information>.

⁵⁴ At <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-es00/2023-nem-electricity-statement-of-opportunities-es00>.

The Update to the 2023 ESOO performed a study on the relative reliability benefits of generators located at various connection points across the NEM for the 2023 *Electricity Statement of Opportunities (ESOO) Central* scenario and **Actionable transmission** sensitivity to identify the expected reliability impact of new supplies. Electricity transmission project status and other data is based on information available to AEMO as at April 2024. Timing of some electricity transmission projects may have changed since publication of the Update to the 2023 ESOO and the ELI, which may adjust the factors presented in ELI. For more detail on the assumptions used in the NEM analysis, refer to the Update to the 2023 ESOO.

Figure 23 shows the existing gas infrastructure locational supportability for potential future GPG in New South Wales (shown as a colour gradient along existing gas pipelines) along with the NEM connection points reliability benefit of generators from the ELI using the **Actionable transmission** sensitivity assessment (shown as a colour gradient for each electricity transmission connection point studied in New South Wales)⁵⁵.

Figure 23 Gas infrastructure locational supportability for future GPG and NEM generators connection points reliability benefits for New South Wales



The existing gas infrastructure locational GPG supportability analysis shows high gas supply supportability factors for GPG located along most of the MSP and EGP in the southern and western regions of New South Wales.

⁵⁵ Refer to Figure 31 in the ELI Report.

Meanwhile, the Sydney and Newcastle areas along the Northern Trunk Pipeline are assessed to have low to poor future GPG supportability factors.

Using the ELI data, NEM generator connection points in the Sydney and Newcastle areas are shown to have a 100% relative benefit, indicating that they are optimal locations for the electricity network, while locations in southern and western New South Wales, and the coastal north, are shown to have reduced relative reliability benefits due to electricity system congestion at times of New South Wales reliability risk.

This assessment demonstrates that total energy system supportability for GPG may be in conflict when considering both gas and electricity infrastructure.

Additional locational future GPG supportability analysis for proposed gas project scenarios including PKET and the Hunter Gas Pipeline (HGP) are summarised in Appendix A1.

4 Options for improving supply adequacy in New South Wales

This chapter provides an assessment of options for improving gas supply adequacy in New South Wales.

4.1 Existing infrastructure options

4.1.1 Northern Trunk Pipeline

As discussed in Section 3.1.4, the major loads of Munmorah CS, Kurri Kurri CS, and NGSF were modelled to interact with each other through the Northern Trunk Pipeline. The operation of the Munmorah CS, Kurri Kurri CS, or both compressors simultaneously can impact the liquefaction process at NGSF. The pressure at Wilton also influences the operability of these loads and exacerbates other interactions.

The connection of the Hunter Power Station via the KKLP in 2025, and the increasing requirement of GPG to back up renewable generation, indicate that this situation will worsen in the future. Renewable droughts or coal generation outages during the summer or shoulder period requiring sustained higher GPG consumption, such as those discussed in Section 2.2.2, could severely restrict the ability to refill NGSF.

Increase Wilton pressure

To improve overall Northern Trunk Pipeline system supportability, the supply pressure into this pipeline at Wilton could be increased. This would require JGN to increase the Wilton MSP regulator pressure setpoint. This would require the Young to Wilton section of the MSP to be operated at the increased Wilton MSP regulator pressure setpoint or higher.

The Northern Trunk Pipeline is designed to operate up to an MAOP of 6,895 kPa, however the maximum receipt pressure into the Northern and Southern Trunk Pipelines is currently limited to 4,500 kPa in accordance with technical code and licence requirements that JGN must abide by due to the age of the pipeline. The Wilton MSP regulator has typically been set at 4,200 kPa or 4,300 kPa. A setpoint increase from 4,300 kPa to 4,500 kPa would assist with network interactions, however modelling indicates that this will not be sufficient to overcome all network interactions.

Increasing the setpoint beyond 4,500 kPa must be assessed in accordance with the limitations of the code and pipeline licence. Safety considerations must outweigh operational limitations. Increased network pressures may also require upgrades at connection points, including to heaters or meters. JGN has proposed higher receipt pressures⁵⁶ and is actively working on implementing this change to coincide with the connection of the Hunter Power Station in 2025.

APA typically operates the Young to Wilton section of the MSP at a higher pressure than the current Wilton MSP regulator pressure setpoint. The periods when the Young to Wilton section of the MSP is operating a lower

⁵⁶ See Schedule 8 of the 2025-30 JGN New South Wales Gas Distribution Network access arrangement draft submission for proposed higher pressures, at <https://www.aer.gov.au/documents/jgn-2025-2030-access-arrangement-june-2024>.

pressure, and therefore dictating the Northern Trunk Pipeline pressure, is typically when APA is conducting planned maintenance on this section of the MSP.

Planned maintenance is critical to ensure the safe operation of any pipeline, and reduced pipeline pressure during maintenance is necessary for work to be conducted safely.

While reduced Wilton pressure during Young to Wilton MSP maintenance is unavoidable, the impact of this maintenance may be mitigated by increased market awareness of when the maintenance is planned to occur. APA reports planned MSP maintenance on the Gas Bulletin Board as part of its MTCO submission⁵⁷. Historical MTCO submissions can be aligned with Wilton pressure using data published on the JGN website⁵⁸ to infer which maintenance periods impacted the Young to Wilton section of the MSP.

APA previously submitted more detailed information in the Description field of the MSP MTCO submission. This allowed direct correlation between specific maintenance windows and lower Wilton pressure. APA no longer provides this level of detail.

A JGN increase to the Wilton MSP regulator setpoint may see the operating pressure of the Young to Wilton section of the MSP become the pressure limit for the Northern Trunk Pipeline more frequently.

Reduce sudden pressure changes

Options to reduce the impact on the NGSF liquefaction process caused by Munmorah CS and Kurri Kurri CS starting and causing a sudden pressure change in the Northern Trunk Pipeline include:

- APA introducing a ramp restriction on Kurri Kurri CS
- Jemena Gas Pipeline introducing a ramp restriction on Munmorah CS, and
- increasing the operating pressure of the Northern Trunk Pipeline.

Introducing a ramp restriction on the operation of the compressor station for the Kurri Kurri and Colongra storage pipelines is the most direct method of limiting pressure changes. This may not be possible due to the operational configuration of the compressors. If a large ramp restriction was required, it could result in each compressor station operating below its allowed MHQ limit for an extended period. This would impact the refilling of each storage pipeline, and may impact the quantity of gas available to the power stations if the compressors do not have additional time to operate to make up for the reduced flow rate when they start their refill operation. This restriction would impact the Colongra Power Station more than Hunter Power Station.

Consideration of this initial reduction in storage pipeline refill rate must be balanced with the benefits that a ramp restriction would add to network operability, including the ability to reliably refill NGSP. A variation on this approach would be to only require a ramp restriction during the summer and shoulder period when NGSF is refilling.

⁵⁷ The MTCO submission is on the GBB, at <https://www.aemo.com.au/energy-systems/gas/gas-bulletin-board-gbb/data-gbb/gas-flows>.

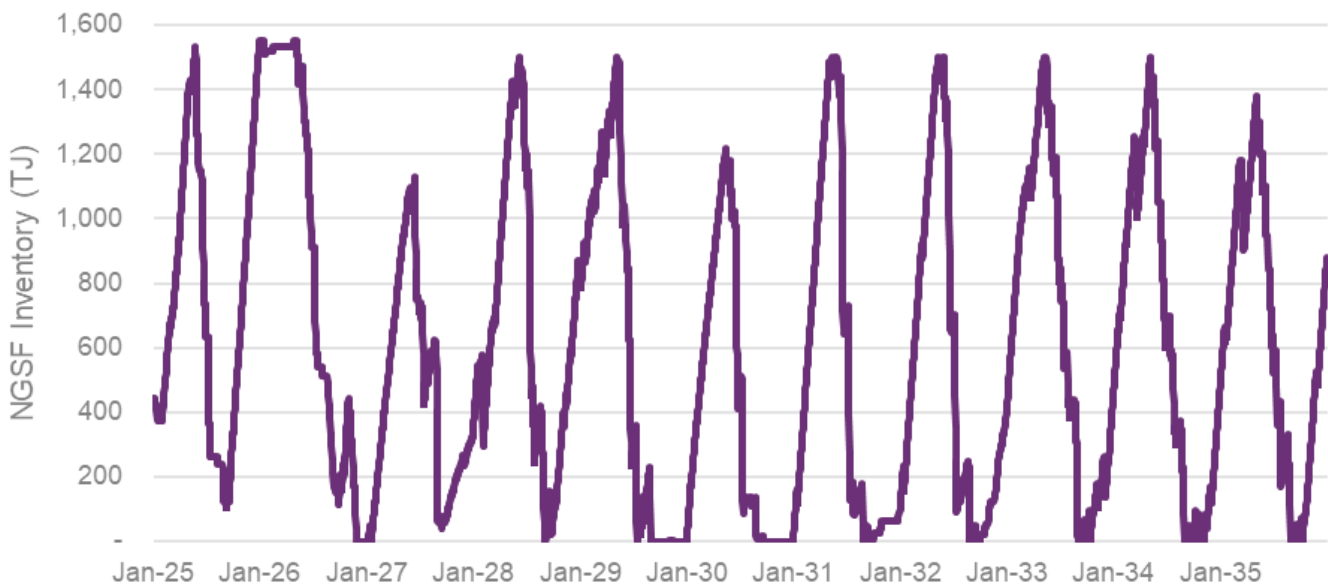
⁵⁸ JGN publishes gas network data on a monthly basis, as required by the National Gas Rules. See <https://www.jemena.com.au/gas/jemena-gas-network/jgn-service-and-access-information/>.

4.1.2 Newcastle Gas Storage Facility

As discussed in Section 3.2.1, historical supply from NGSF has not demonstrated a strong correlation with New South Wales demand. With the forecast risk of gas shortfalls and supply gaps increasing, all forms of gas storage are vital to meeting peak demands and managing gas supply disruptions. The ongoing availability of stored gas ahead of winter conditions continues to be important to mitigate supply adequacy risks.

Figure 24 shows the modelled utilisation of NGSF out to 2035 from the *Unconstrained Northern Supply* scenario defined in Section 3.3.2. In this modelling, the available supply from Queensland is uncapped to demonstrate the utilisation of NGSF independent of supply concerns. If supply is not available, NGSF cannot be refilled and the facility would be underutilised.

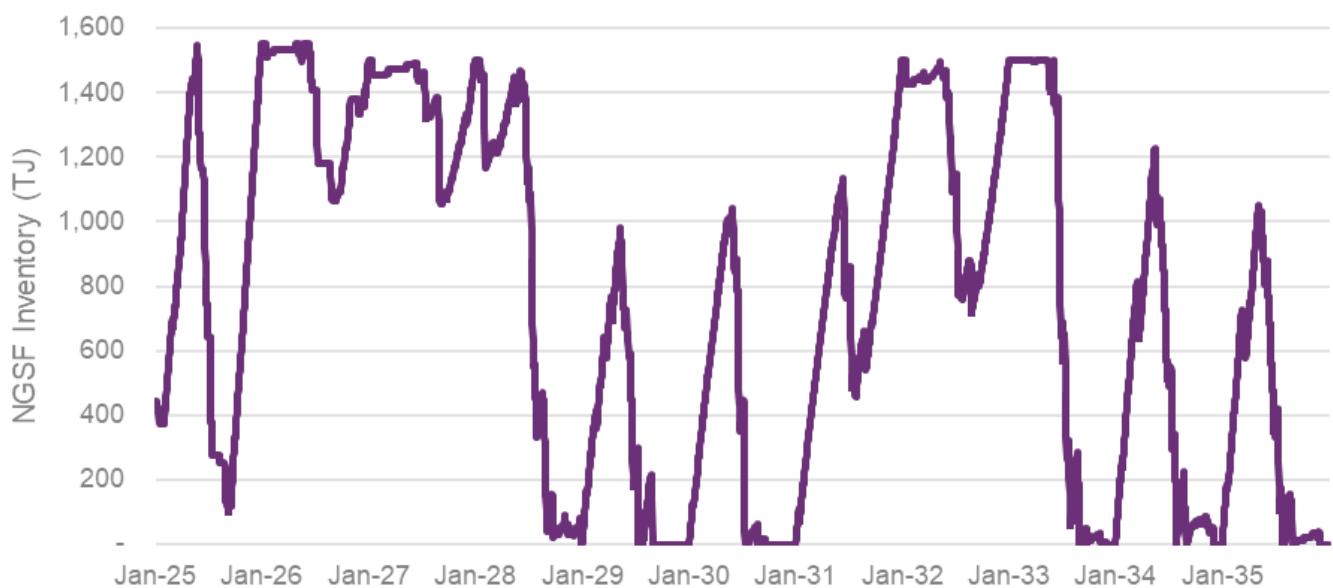
Figure 24 Modelled Newcastle Gas Storage Facility utilisation, *Unconstrained Northern Supply* scenario, 2025-35 (TJ)



Note: Model outcome using a weather reference year of 2019 and a system demand POE of 1 in 2.

The chart shows the critical role that storage is forecast to play in meeting peak demand as production declines faster than gas consumption. Without NGSF, the forecast supply gaps are worsened by a magnitude equal to the capacity of the facility. To fully take advantage of the role that NGSF could play in meeting New South Wales peak demand, the facility could be managed as a peak-shaving facility and used most when demand is highest, gas supply is restricted, or when there is an extended period of high GPG demand in winter. This may not align with AGL's operational strategy for the facility.

Figure 25 shows the results of modelling the utilisation of NGSF out to 2035 if PKET is operational from 2026. The purpose of this modelling is to demonstrate the forecast utility of NGSF even if a new supply source comes online. Even with a large new supply source such as PKET, NGSF is called on in winter and heavily utilised in 2028 and 2029 following the forecast closure of Eraring Power Station. Section 4.2.1 discusses the PKET project in more detail.

Figure 25 Modelled Newcastle Gas Storage Facility utilisation with Port Kembla Energy Terminal supply available from 2026, 2025-35 (TJ)

Note: Model outcome using a weather reference year of 2019 and a system demand POE of 1 in 2.

Shallow storages such as NGSF are also important risk mitigation assets if effectively managed and filled ahead of winter. These assets provide greater operational flexibility to mitigate unplanned gas production facility outages or high gas generation demand, particularly if additional supply is needed at short notice as increased supply from Queensland can take time to ramp up. NGSF can take over 100 days to refill (depend on the inventory drawdown that has occurred, so having the facility full ahead of each winter period mitigates outage risks. Without NGSF, New South Wales does not have a large facility providing this role.

4.2 Proposed supply project options

The following section considers a range of proposed gas supply projects in New South Wales. AEMO conducted modelling to perform a system capacity assessment to investigate how to improve supply adequacy, examine potential system weaknesses beyond project completion, and identify opportunities for future infrastructure enhancement beyond the project.

Projects assessed included:

- pipeline expansion – APA’s ECGE future stages
- import terminal – Squadron’s PKET, and
- new production – Santos’ Narrabri Gas Project (NGP) and Hunter Gas Pipeline (HGP).

Analysis of the current and proposed renewable gas projects was out of scope and was excluded in this technical assessment. Projects at existing gas production facilities that backfill production were not included in this assessment as this supply can be transported by existing infrastructure.

Table 14 summarises the potential expansion options analysed for each proposed project and the corresponding opportunities for system capacity benefits that were modelled for each potential option.

Table 14 Summary of system opportunity for proposed projects' potential options

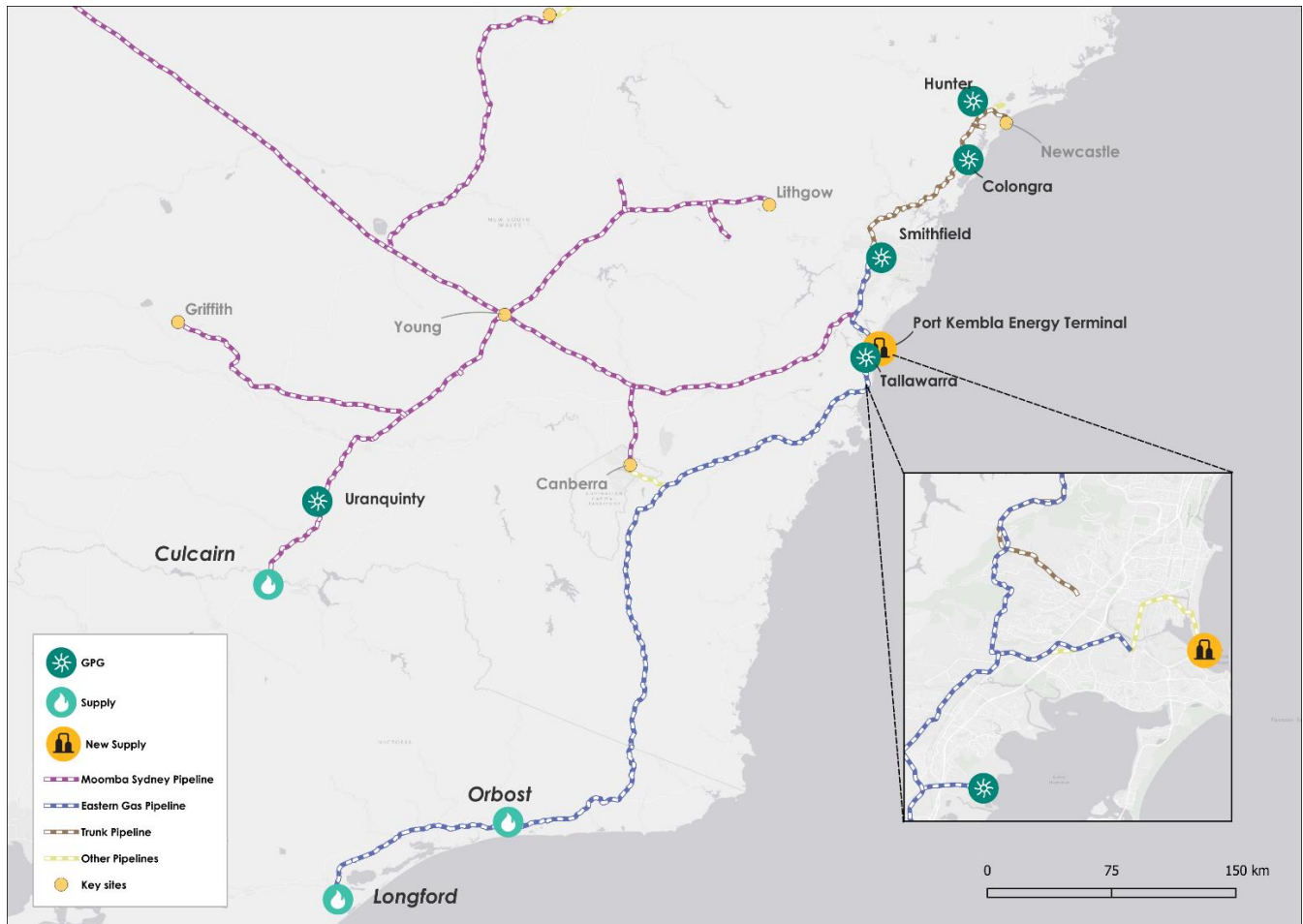
Proposed project	Project proponent	Infrastructure options	Summary of system opportunity
Port Kembla Energy Terminal	Squadron Energy	Port Kembla Pipeline lateral	<ul style="list-style-type: none"> Reduce Longford and Orbost gas plants' supply dependency Diversify EGP supply options
		EGP flow reversal	<ul style="list-style-type: none"> Further reduce Longford and Orbost gas plants' supply dependency Enable future storage options with southern transport capacity
		Wilton expansion	<ul style="list-style-type: none"> Reduce Moomba supply dependency Increase transportation capacity of EGP
		Wilton expansion and EGP expansion	<ul style="list-style-type: none"> Reduce Moomba supply dependency Increase transportation capacity of EGP Improve GPG supportability for proposed and other future GPG
Narrabri Gas Project and Hunter Gas Pipeline	Santos	Narrabri to Newcastle	<ul style="list-style-type: none"> Improve GPG supportability for the Hunter and Colongra power stations Provide opportunity for direct connection of KKLK and NGSF to new supply Improve NGSF operational supportability
		Wallumbilla to Newcastle	<ul style="list-style-type: none"> Reduce Longford and Moomba supply dependency
		Wallumbilla to Newcastle and Wilton MSP station modification	<ul style="list-style-type: none"> Increase transportation capacity to MSP Further reduce Longford and Moomba supply dependency
East Coast Grid Expansion	APA	ECGE future stages	<ul style="list-style-type: none"> Increase transportation capacity to MSP Increase maximum capacity of the MSP with the Bulloo Interlink Reduce Longford supply dependency Add shallow storage with the Riverina storage pipeline and improve Uranquinty GPG supportability

4.2.1 Port Kembla Energy Terminal

PKET is a proposed Squadron Energy-owned LNG import terminal project located in the Illawarra region south of Sydney. Jemena has completed construction of the 12 km Port Kembla Pipeline to connect PKET to the EGP as shown in **Figure 26** below. LNG cargos would be vaporised by a floating storage and regasification unit (FSRU) moored at the terminal. Gas would then flow into the lateral pipeline with an expected maximum injection rate of 500 TJ/d⁵⁹ to supply customers via the EGP.

⁵⁹ Injection rate based on PKET supply capacity, at <https://www.squadronenergy.com/our-projects/port-kembla-energy-terminal>.

Figure 26 Proposed Port Kembla Energy Terminal project location



Options to reduce vulnerability to existing supply

The PKET project would provide an alternative gas supply source into New South Wales and provide a range of system capacity benefits including a significant reduction in dependency on the current declining supply from the Longford Gas Plant. AEMO modelled options to transport PKET supply to the following regions:

- Demand along the EGP in the southern region of New South Wales.
- Demand along the MSP in the central and western regions of New South Wales.

These options were modelled to determine the augmentation options to minimise the current reliance on existing supply from Longford and Moomba from a technical capacity perspective.

In addition to the completed Port Kembla Pipeline, Jemena is progressing an EGP flow reversal project that involves modification works at some of the EGP compressor stations. This modification, coupled with PKET, would provide the EGP with sufficient transportation capacity south to support all current southern New South Wales system demand including Tallawarra GPG that are supplied from the EGP.

Pipeline modelling using the expected 500 TJ/d maximum supply rate from PKET confirmed that the EGP with reverse flow capability has no issues delivering high rate gas supply from PKET. As discussed in Section 3.3.1, these south coast demands are currently reliant on gas supply from Gippsland, hence sufficient supply

transportation from PKET via the EGP provides a secondary major source of supply for this region and can reduce the vulnerability of the currently declining source of supply from the Longford Gas Plant.

The potential to supply gas demands along the MSP in the central and western regions of New South Wales from PKET was explored through a range of possible expansion options, including a staged approach to progressively increase transportation capacity. The first stage assessed was Jemena's proposed Wilton EGP expansion project to increase the Wilton EGP delivery point capacity to up to 320 TJ/d into the MSP and 200 TJ/d into the Northern and Southern Trunk Pipelines.

This expansion would enable the maximum 500 TJ/d of PKET supply to be fully utilised by the Wilton EGP delivery station including being supplied into the MSP and the Northern and Southern Trunk Pipelines. This option was modelled to reduce the Moomba supply requirement by approximately 65% during periods of peak system demand conditions. This decrease in the supply requirement at Moomba is achievable in ideal modelling conditions⁶⁰ while also supporting the current New South Wales GPG fleet at full rates, with PKET supply providing an alternative supply source to support MSP demand.

AEMO also modelled expansion options to further reduce the requirement for supply from Moomba, to achieve a theoretical minimum injection rate at Moomba. System analysis shows that a further transportation capacity increase is limited by the capacity of the EGP to transport more PKET gas into the MSP to supply the remaining demand. Modelling indicated that further expansion to increase the EGP transportation capacity was required to achieve this, including additional compression infrastructure and upgrades along the EGP. Expansions that were modelled included two new compressor stations on the EGP and an upgrade to the existing Michelago CS, where the new compressor station locations were theoretical locations only.

This would increase the system capacity to support all of the MSP demand currently relying on Moomba supply, including the Uranquinty Power Station. These infrastructure expansion options were modelled to sufficiently increase the EGP and MSP transportation capacity to theoretically achieve a full offset of Moomba supply with PKET supply.

Options to improve storage supply

AEMO also modelled the southern flow capacity of the EGP with PKET connected to investigate a scenario with potential gas storage available near Longford. The total southern transportation capacity along the EGP was modelled to determine the maximum withdrawal quantity that could in theory be available under ideal conditions to be used for energy storage utilisation at the proposed Golden Beach Energy Storage facility discussed in Section 4.3.1.

Southern flow quantities in excess of 300 TJ/d were modelled to be theoretically possible during low demand conditions to be transported south on the EGP for refilling of the proposed Golden Beach Energy Storage facility that would connect to the EGP near Longford. This proposed storage refill and EGP bi-direction utilisation option could enable an additional alternative supply from the EGP Longford CS into the New South Wales.

⁶⁰ Ideal modelling conditions included a sustained maximum injection rate of 500 TJ/d at PKET, all the existing and two additional compressors operated at theoretical maximum power, and gas transported by pipeline systems that were fully optimised for this scenario.



Long-term supply outlook assessment of PKET

The PKET scenario delays structural shortfalls from 2027 to 2033, compared to the **Base Case** discussed in Section 3.3.2, but the annual shortfall for 2033 to 2035 is larger compared to the **Unconstrained Northern Supply** scenario due to the lower annual supply limit of the modelled import terminal (maximum of 130 PJ/y).

This scenario has two benefits for New South Wales compared to the Base Case:

- A significant supply source is added within the southern states, reducing reliance on gas transport from Queensland via Moomba and the MSP to support gas demand.
- By adding a new supply source, rather than augmenting existing sources, there is increased resilience as southern supply is now sourced from three locations – Moomba/Queensland, Longford Gas Plant/Orbost/Golden Beach and PKET – rather than two.

4.2.2 Hunter Gas Pipeline

The Santos owned HGP project is in negotiations to connect the Narrabri Gas Plant (NGP) to the Northern Trunk Pipeline at Newcastle. A further stage would then potentially connect the Wallumbilla Gas Supply Hub in Queensland to New South Wales, which would extend the HGP to a total length of 833 km. The impact of the proposed HGP project has been analysed through the two stages as follows:

1. Stage 1 – HGP pipeline construction to connect NGP and the existing North Trunk Pipeline at Newcastle.
2. Stage 2 – Extension of HGP pipeline from NGP north to connect the Wallumbilla Gas Hub in Queensland to the North Trunk Pipeline at Newcastle.

The HGP project was modelled to determine the progressive capacity impact in each stage, with Stage 1 illustrated in **Figure 27** below.

Figure 27 Proposed Hunter Gas Pipeline project Stage 1 from Narrabri to Newcastle



Options to reduce vulnerability to existing supply

Stage 1 – HGP from Narrabri to Newcastle

Modelling was undertaken with the maximum expected supply capacity from HGP of up to 150 TJ/d to be transported by HGP to a new connection on the Northern Trunk Pipeline at Newcastle. The purpose of this modelling was to assess the adequacy of the existing Northern Trunk Pipeline to receive additional gas supply at Newcastle. The capacity analysis shows that the existing Northern Trunk Pipeline capacity is sufficient to receive the proposed quantity of 150 TJ/d supply from Narrabri via the HGP.

This proposed supply quantity into the Newcastle area was assessed to provide a secondary source of supply and could increase the security of supply for the existing large demands in the area such as the Hunter Power Station, NGSF, or large industrial loads in Newcastle such as Orica’s Kooragang Island facility. Therefore, the maximum HGP supply capacity into the existing Northern Trunk Pipeline at Newcastle was determined to be capable of reducing the current reliance on existing supply sources at the maximum proposed capacity.

Stage 2 – HGP from Wallumbilla Gas Hub to Newcastle

Stage 2 of the HGP is proposed to further expand on Stage 1 by extending the HGP from Narrabri to the Wallumbilla Gas Hub, with the full length of HGP running from Wallumbilla to Newcastle. AEMO analysed the

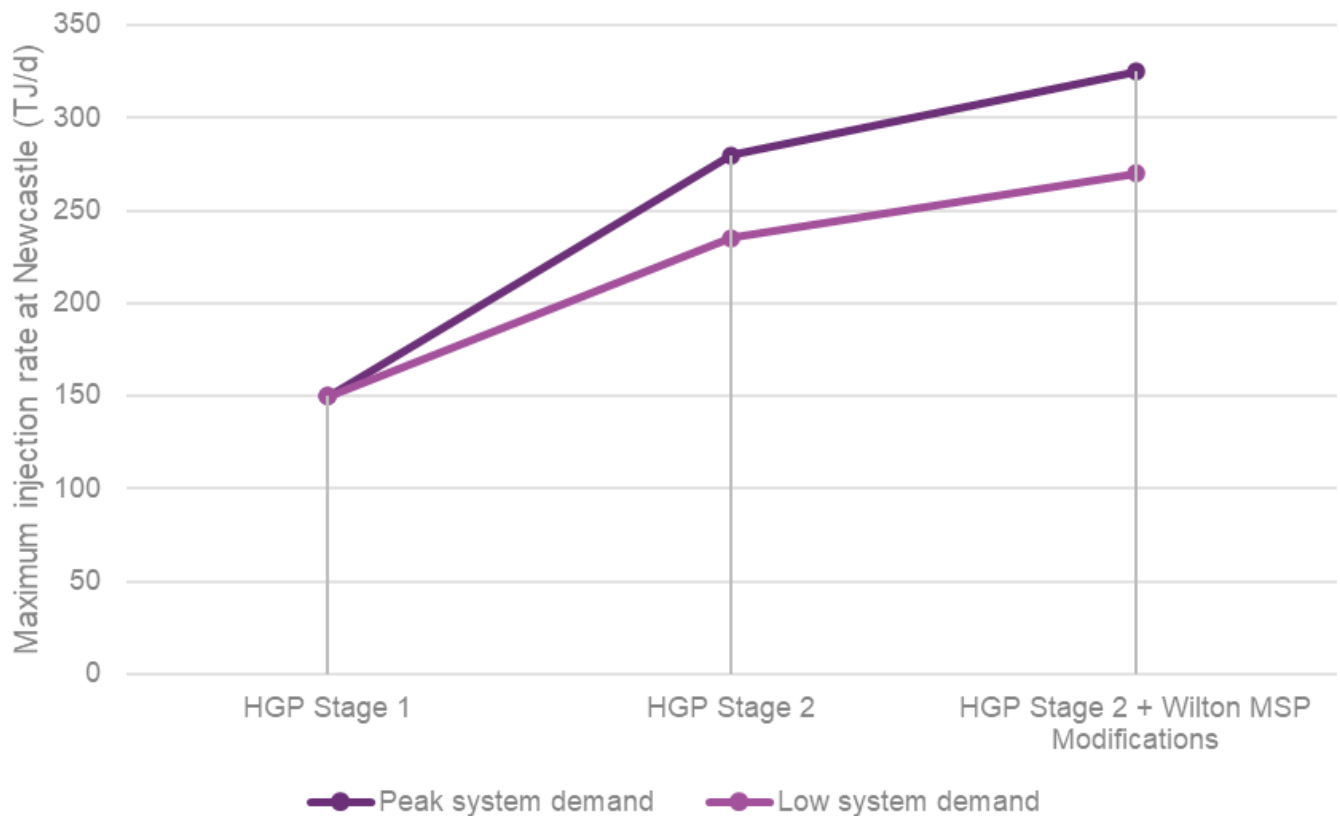
ability of the Northern Trunk Pipeline to transport more gas south to determine the extent to which gas demand beyond the Newcastle area could theoretically be supplied by the expanded capacity of HGP Stage 2. In this analysis, a detailed pipeline model of Stage 2 of the HGP was not added to the network; instead it was assumed that the HGP would be designed such that the supply capacities modelled could be transported to Newcastle.

Modelling indicated that the total quantity of supply that could be injected at Newcastle into the Northern Trunk Pipeline is limited by the southern transportation capacity of the pipeline and the lack of a flow path into the MSP. The Wilton MSP delivery station is currently configured for one-way flow only, limiting the maximum injection capacity at Newcastle to approximately 235 TJ/d to 280 TJ/d for low and peak demand conditions, respectively. Gas cannot flow from Newcastle into the EGP at Wilton EGP due to the high operating pressure of the EGP.

Enabling bi-directional flow at the Wilton MSP delivery station would allow gas supply from the HGP to support more demand on the MSP and increase the injection capacity at Newcastle to between 280 TJ/d and 325 TJ/d for low and peak demand, as shown in **Figure 28** below. This increase in supply capacity at the HGP connection at Newcastle allows HGP supply to meet more Northern Trunk Pipeline demand and some of the demand on the MSP. Overall, this would result in a reduction on the dependencies for the current supply sources into New South Wales from Moomba, Longford and Orbost.

Beyond this capacity, a constraint still exists on the amount of gas that the Northern Trunk Pipeline can transport south from Newcastle.

Figure 28 Modelled Northern Trunk Pipeline receipt capacity with proposed Narrabri (HGP Stage 1) and Wallumbilla (HGP Stage 2) HGP supply connection at Newcastle (TJ/d)



Another option enabled by the connection of the HGP is the possibility of direct connections from the HGP that may avoid the current demand interactions in the Northern Trunk Pipeline and avoid capacity restrictions at Newcastle. These direct connections may also increase the supply capacity from Wallumbilla. These alternative connections could include connecting the HGP directly to the Hunter Power Station or KKLP, or additional future GPG loads in the area that could use the existing electricity transmission system infrastructure in the Newcastle area.

An additional alternative to bring more HGP supply into New South Wales could be a connection from the HGP to the MSP, where there is existing transmission infrastructure available to effectively move more gas throughout New South Wales. This would further increase supply capacity from HGP and minimise supply dependency on current supply sources.

Beyond these alternative connections, extensive augmentation, including an extension of the EGP to Newcastle or additional compression in the existing system, would be required to increase the HGP supply capacity.

Options to improve storage supply

As discussed in Section 3.1.4, NGSF utilisation has been modelled to be dependent on Hunter Power Station operation due to existing constraints on the Northern Trunk Pipeline. If HGP were to connect to Hunter Power Station, KKLP, or NGSF, this would provide direct supply that should eliminate the interdependency between NGSF and Kurri Kurri CS operation and would result in a significant increase in the supportability of these facilities with HGP supply.

Long-term supply outlook assessment of the Narrabri Gas Project

The Narrabri production facility is modelled to start injecting gas into New South Wales via the HGP from 2029 at a maximum rate of 150 TJ/day. The majority of the gas forecast to be produced by the facility would be sourced from uncertain field reserves. While the facility would add a local gas supply source to New South Wales and reduce reliance on gas imports from the other states, the additional production would come online after forecast structural gas shortfalls begin to occur, and could only partly offset the shortfalls observed from 2029 onwards.

4.2.3 APA's East Coast Grid Expansion future stages

The proposed future stages of APA's ECGE project that are currently in early design phase involve progressively increasing the capacity of sections of the MSP to provide increased transportation capacity for the New South Wales transmission system, starting from as early as 2025. The initial stages of the project will increase the capacity of the MSP by 20-25 TJ/d⁶¹ through a project currently under construction converting the existing Moomba Sydney Ethane Pipeline to transport natural gas, followed by a proposed project to install an additional mainline compressor station located between the Bulla Park and Young compressors.

Subsequent major expansions proposed to commence from 2028 include the construction of the Bulloo Interlink which connects the SWQP to the MSP, bypassing the first segments of the MSP and increasing the capacity by a further 105 TJ/d. The proposal also includes the addition of the Riverina Storage Pipeline, which provides an inventory of up to 500 TJ to provide support for Uranquinty Power Station operation or other system demand to

⁶¹APA's East Coast Gas Expansion Plan, at <https://www.apa.com.au/news/asx-and-media-releases/apas-east-coast-gas-expansion-plan>.

improve management of peak demand and outage events. The current scope of these expansions would be subject to further changes based on expansion priorities.

A theoretical alternative expansion option to the Riverina Storage Pipeline was modelled to minimise Uranquinty GPG operational impact on southern supply capacity and improve supportability to Uranquinty GPG. The alternative expansion option involved an approximately 158 km pipeline extension from Young to Uranquinty and a direct supply connection to Uranquinty GPG. By providing direct supply to Uranquinty GPG, the Young to Wagga supply capacity could be increased by at least 120 TJ/d while also providing linepack storage, depending on the diameter of the pipeline.

Long-term supply outlook assessment of the ECGE

As discussed in Section 3.3.2, without additional supply sources, the augmentation of existing gas infrastructure assets is unlikely to provide significant benefit in the future management of gas supply shortfalls. When the augmentations of the MSP and SWQP are paired with additional supply availability from the northern states and the highest potential⁶² maximum supply capacity is achieved, structural shortfalls are delayed to 2033, however peak day shortfalls would still occur on days with elevated and coincident system and GPG demand. This increased northern states supply outcome is only achieved if the Bullo Interlink maintains high availability and capacity values, with over 150 PJ/y being required to flow south each year from 2031 onwards.

4.3 Proposed storage projects

4.3.1 Golden Beach

The Golden Beach Energy Storage Project involves development and production from the Golden Beach gas field in the Gippsland Basin, followed by the conversion of the field to a UGS facility. The storage facility would have the capacity to store 30 PJ of gas, with a nominal working volume of 19 PJ, and a supply capacity of 375 TJ/d. This is equivalent to the capacity of the EGP, so the full Golden Beach supply quantity could be transported to New South Wales, but more likely it will be shared with Victoria and Tasmania depending on market conditions.

Golden Beach Energy is planning to connect the facility to both the EGP and VTS at Longford. A deep storage facility at this location would be able to directly support New South Wales gas demand, increasing security of supply. The facility would also act as a third source of supply to the EGP, which would help reduce the locational supply risk to demand on this pipeline, as discussed in Section 3.3.1.

4.3.2 Riverina storage pipeline

As part of APA's ECGE, discussed in Section 4.2.3, APA is proposing to add a storage pipeline on the Young to Culcairn lateral of the MSP with a similar design to the KKLK. The proposal includes two stages – the first stage adds a storage pipeline with a capacity of 200 TJ, and the second stage adds another 300 TJ of storage capacity. The two storage pipelines may be co-located on the lateral or in different locations depending on the final design.

⁶² Supply within the model is not always able to be fully utilised due to gas transmission outages or constraints, limiting the ability to flow gas from the point of supply to the point of demand on a given day.

The storage pipeline would act as a shallow storage facility and provide inventory to supply Uranquinty GPG and any new GPG in the area, support New South Wales demand, or be transported into Victoria. Uranquinty GPG would be able to operate for approximately 28 hours at full rate solely from the inventory of the first stage of this storage project.

Long- term supply outlook assessment of the Riverina Storage Pipeline

The Riverina Storage Pipeline is only effectively utilised in the ECGE scenario when paired with additional gas supply. The first 200 TJ of the storage pipeline was not modelled to be implemented until 2028, when structural supply shortfalls are already occurring in the **Base Case** and as such there is no perceived benefit in utilising the storage pipeline on a given day, compared to meeting daily demand needs or storing what excess supply there may be into existing storage facilities.

When there is additional supply available, the Riverina Storage Pipeline is utilised across all points in the year, as opposed to other southern storage facilities which primarily empty during the winter period in the model. This is reflective of the storage pipeline's location, where it can be used to meet GPG demand at Uranquinty and can also be used within the model to meet peak day demand in either New South Wales or Victoria.

4.3.3 Iona Underground Storage expansion

Lochard Energy's Iona UGS is located near Port Campbell in south-west Victoria, so it is not directly connected to the New South Wales gas transmission network. However, the interconnected nature of the east coast gas system means that any new storage in the south is valuable to all southern states in light of the forecast supply gaps.

Lochard Energy is increasing the capacity of Iona UGS with the Heytesbury UGS project, which will increase storage capacity by up to 3.5 PJ at the 24.4 PJ facility. Lochard Energy is also considering a second phase of Heytesbury UGS which would further increase the storage inventory and supply capacity of the facility.

4.3.4 Port Kembla Energy Terminal

The PKET project is proposing to supply gas from an FRSU, a modified LNG tanker ship that can hold approximately 4 PJ and supply gas at a maximum daily rate of 500 TJ/d. This quantity of LNG held in the FSRU is capable of meeting New South Wales winter demand for around 10 days, so the FSRU could be considered a form of shallow storage that can be refilled with replacement shipments of LNG.

To ensure that stored gas is available to meet demand when required, the quantity at the facility would need to be managed:

- contractually, to ensure quantities are met with regards to the shipping schedule – this is both on a shipment-to-shipment basis as well as in total across a year to meet regulatory requirements, and
- physically, to ensure assets in the facility that need to stay at cryogenic temperatures do not warm up – sufficient inventory would need to be held to maintain cold temperatures, even if that meant restricting the daily offtake rate while waiting for a delayed shipment.

PKET is discussed further in Section 4.2.1.

4.4 Other infrastructure options

4.4.1 Newcastle Gas Storage Facility

The facility that has been modelled to be impacted the most by the limitations of the Northern Trunk Pipeline is NGSF. Modelling indicates that with the connection of KKLP in 2025, interactions between loads on the Northern Trunk Pipeline will become more frequent. Lower pressures and pressure changes impact NGSF withdrawals (Section 3.1.4) while higher pressures impact NGSF injections (Section 3.2.4). If the operating pressure of the Northern Trunk Pipeline is increased, NGSF injections are more likely to be backed-off if KKLP is simultaneously injecting.

If HGP connects at Newcastle, injections into the Northern Trunk Pipeline from Narrabri are also likely to interact with NGSF injections depending on pressure settings, although a direct connection from HGP to NGSF would help with constraints associated with NGSF withdrawals.

An alternative option to augmenting the Northern Trunk Pipeline is for AGL to upgrade NGSF to operate at a wider range of operating settings, which may include the installation of compression on the Hexham to Tomago pipeline. Depending on the extent of upgrades required, this may not be commercially viable for the facility.

4.4.2 Northern Trunk Pipeline GPG

Table 15 summarises potential expansion options modelled to improve the sustained operation and supportability for the two GPG locations of Colongra and Hunter power stations supplied by the Northern Trunk Pipeline.

Table 15 Summary of potential expansion options and capacity benefits for Northern Trunk Pipeline GPG

System	Potential options	Summary of supportability improvements
Northern Trunk Pipeline	Munmorah CS and Kurri Kurri CS upgrade	<ul style="list-style-type: none"> Increase sustained operating hours for Colongra and Hunter Power Stations running individually
	Northern Trunk Pipeline expansion	<ul style="list-style-type: none"> Enable simultaneous operation of Munmorah CS and Kurri Kurri CS while meeting storage functional requirements

Munmorah Compressor Station and Kurri Kurri Compressor Station upgrade

Modelling was undertaken to explore options to lift the MHQ limitation on the Munmorah CS and Kurri Kurri CS discussed in Section 3.2.3. This was done by increasing the power of the compressor stations. This would improve the sustained operation of the Colongra and Hunter power stations.

Modelling explored increasing the Munmorah CS flow limit to refill the Colongra storage pipeline by upgrading the compressor power by four times the current size, and looked at doubling the Kurri Kurri CS power. These compressor upgrades indicated a theoretical MHQ increase at each compressor station, with the Munmorah CS MHQ tripled and the Kurri Kurri CS MHQ doubled. Consequently, operating hours increased from five hours to 14 hours for the Colongra Power Station and from eight hours to 16 hours for the Hunter Power Station.

This modelling was conducted to assess each upgrade independently. When operated together, the two larger compressor stations greatly increased the interactions on the Northern Trunk Pipeline. The impact on NGSF liquification would also be severe. These results indicated that increasing either of the current compressor MHQs would result in negative effects on overall system operability.

Northern Trunk Pipeline expansion options

Due to capacity limitations in the Northern Trunk Pipeline resulting in operational interactions between the Colongra Lateral Pipeline, KKLP and NGSF discussed in Section 3.1.4, potential augmentation options were modelled to achieve simultaneous operations of both the Munmorah and Kurri Kurri compressor stations while also meeting the operational requirements to enable liquefaction at NGSF.

Modelling showed that this scenario could only be met with extensive Northern Trunk Pipeline expansions. This could include increasing the operating pressure of the Northern Trunk Pipeline and a pipeline extension from Horsley Park to Newcastle. This pipeline expansion could be the duplication of the Northern Trunk Pipeline or an extension of the EGP. This potential option was modelled with the possibility to segregate supply to NGSF which would minimise dependencies on other large loads such as Munmorah CS and Kurri Kurri CS demands. As a result, this potential expansion was modelled to alleviate existing Northern Trunk Pipeline constraints, improving storage and GPG supportability in the Newcastle area.

4.5 Project challenges, risks and uncertainties

The current investment environment for all projects related to gas is challenging and highly uncertain. Many of the projects discussed in the NGIR and the GSOO do not have firm timelines. Some of the key uncertainties impacting gas projects in New South Wales include:

- **Unclear market signals** – most industry participants consider that residential gas demand is declining and the reliance on GPG will increase in future as coal fired power stations retire. However, uncertainty around the timing of these structural changes in demand makes it difficult for industry to know when to commit to projects, both on the supply side (such as when to contract supply at a proposed project like PKET) and on the demand side (such as when to build new GPG).
- **Financing** – natural gas, as a fossil fuel, is increasingly unpalatable for some investors who are screening investments on the basis of environment, social and governance (ESG) issues. This can be particularly challenging for smaller industry players who do not have large capital bases and rely on financing from other sources. Listed companies may also face challenges on ESG grounds for any investment in gas from their shareholder base. This applies to all gas projects, including production, storage, GPG projects, and in some cases even renewable gas projects.
- **Inflation** – following the COVID-19 pandemic, Australia and many other countries entered a period of steep inflation. Inflation is now stabilising but the impact on projects remains high as sectors such as construction, materials, and equipment were among those with the greatest increase in costs. This is compounded by factors such as high global demand for gas turbines or limited local access to specialised equipment like offshore drilling rigs.
- **Regulatory approvals** – regulatory processes for gas projects are becoming increasingly stringent and can take extended periods of time to complete, depending which body is reviewing the project application. This can be complicated by court challenges which can greatly extend project timelines and costs.

Outcomes of these factors include extended development timelines, stalled projects, and, in the case of GPG, increased reliance on other energy sources such as coal generation.

A1. Future GPG supportability with proposed supply project scenarios

AEMO has evaluated gas infrastructure locational supportability factors for New South Wales for scenarios with proposed new gas supply projects such as PKET or supply from Narrabri via the HGP utilising the GPG supportability analysis discussed in Section 3.4.

Figure 29 shows the gas infrastructure locational supportability for potential future GPG facilities in New South Wales with the proposed PKET project connected, along with the NEM connection points reliability benefit of generators from the 2023 ESOO **Actionable transmission** sensitivity in the ELI.

The gas infrastructure locational GPG supportability analysis shows a significant improvement in gas infrastructure GPG supportability factors throughout the length of the EGP, particularly near the proposed PKET connection and extending north to include the Sydney area.

Figure 29 Gas infrastructure locational supportability for future GPG with Port Kembla Energy Terminal connection and NEM generators connection points reliability benefits for New South Wales

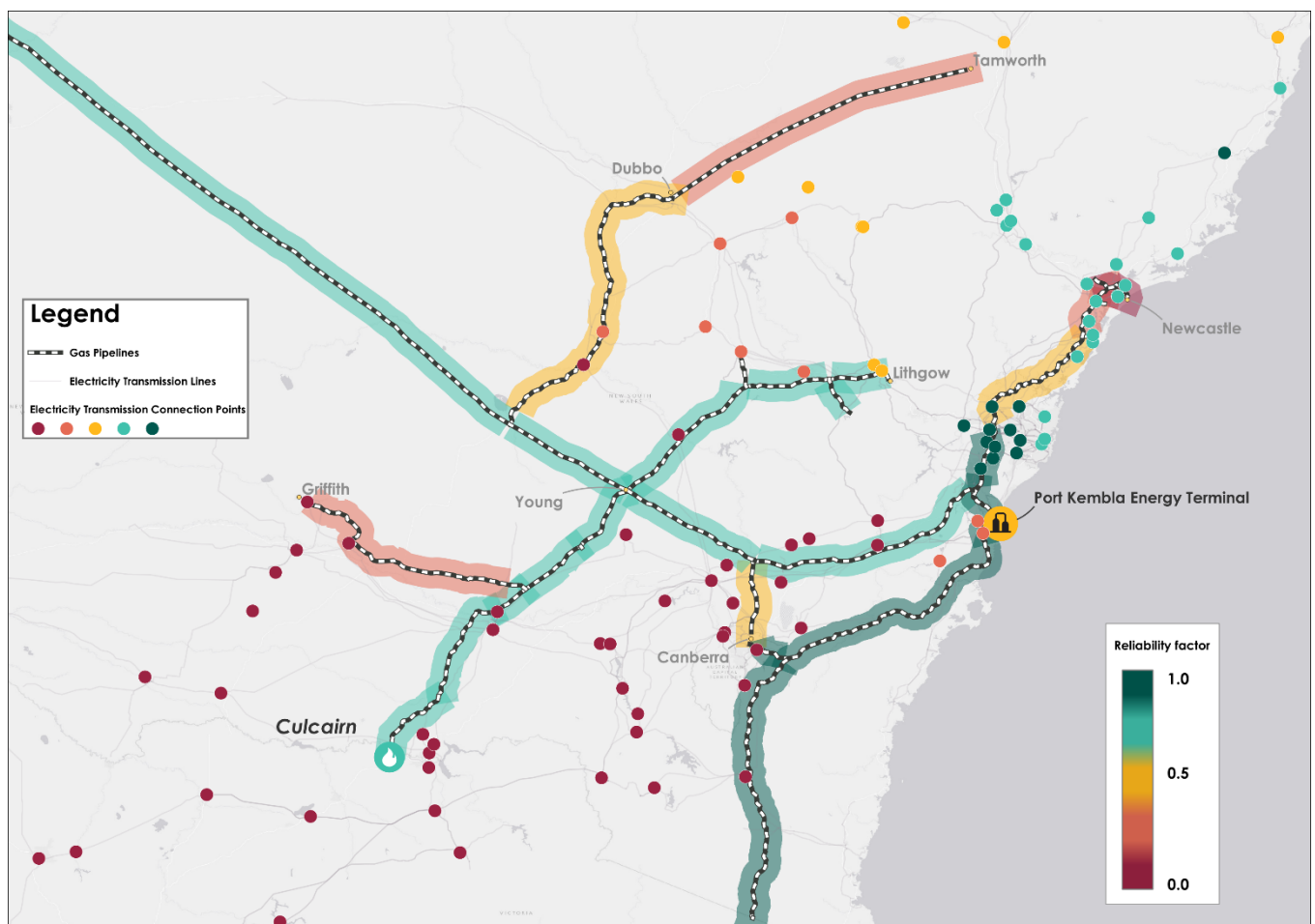
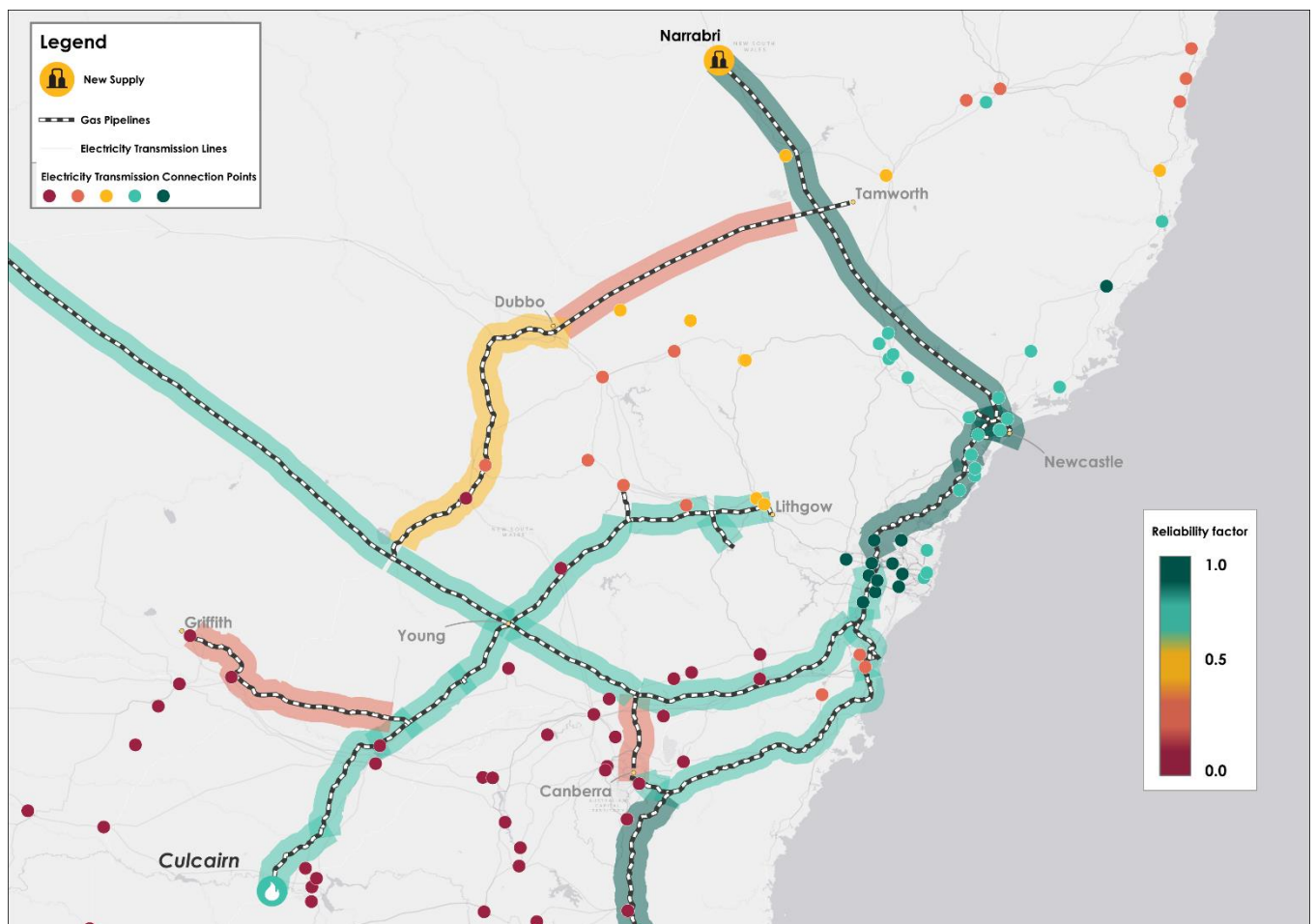


Figure 30 shows the gas infrastructure locational supportability for potential future GPG facilities in New South Wales with the proposed Narrabri Gas Plant and the HGP connected to the Northern Trunk Main at Newcastle, along with the NEM connection points reliability benefit of generators from the 2023 ESOO **Actionable transmission** sensitivity in the ELI.

For this future GPG supportability analysis scenario, the gas infrastructure GPG supportability factors were determined to increase significantly in the Newcastle area, shifting from low to poor supportability with existing gas infrastructure to high supportability factors with HGP connection.

Figure 30 Gas infrastructure locational supportability for future GPG with Narrabri and Hunter Gas Pipeline connection and NEM generators connection points reliability benefits for New South Wales



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Measures and abbreviations

Units of measure

Term	Definition
GW	gigawatts
km	kilometres
kPa	kilopascals
kW	kilowatts
mm	millimetres
MW	megawatts
PJ	petajoules
PJ/y	petajoules per year
TJ	terajoules
TJ/d	terajoules per day
TJ/h	terajoules per hour
TJ/y	terajoules per year
TWh	terawatt hours

Abbreviations

Term	Definition
AEMO	Australian Energy Market Operator
CCS	carbon capture and storage
CER	consumer energy resources
CG	city gate
CLP	Colongra Lateral Pipeline
CS	compressor station
ECGE	East Coast Grid Expansion
EGP	Eastern Gas Pipeline
ELI	Enhanced Locational Information
ESG	environment, social and governance
ESOO	<i>Electricity Statement of Opportunities</i>
EV	electric vehicle
FSRU	floating storage and regassification unit
GBJV	Gippsland Basin Joint Venture
GPG	gas-powered generation
GSOO	Gas Statement of Opportunities
HGP	Hunter Gas Pipeline
HVAC	heating ventilation and air-conditioning
IASR	<i>Inputs, Assumptions and Scenarios Report</i>

Term	Definition
ISP	<i>Integrated System Plan</i>
JGN	Jemena Gas Networks
KKLP	Kurri Kurri Lateral Pipeline
KUJV	Kipper Unit Joint Venture
LIL	large industrial load
LNG	liquefied natural gas
MAOP	maximum allowable operating pressure
MHQ	maximum hourly quantity/ies
MTCO	Medium Term Capacity Outlook
MSP	Moomba Sydney Pipeline
NEM	National Electricity Market
NGIR	New South Wales Gas Infrastructure Review
NGSF	Newcastle Gas Storage Facility
PKET	Port Kembla Energy Terminal
POE	probability of exceedance
STCO	Short Term Capacity Outlook
STTM	Short Term Trading Market
SWQP	South West Queensland Pipeline
UGS	underground gas storage
VGPR	<i>Victorian Gas Planning Report</i>
VNI	Victorian Northern Interconnect
VRE	variable renewable energy
VTS	Victorian Transmission System