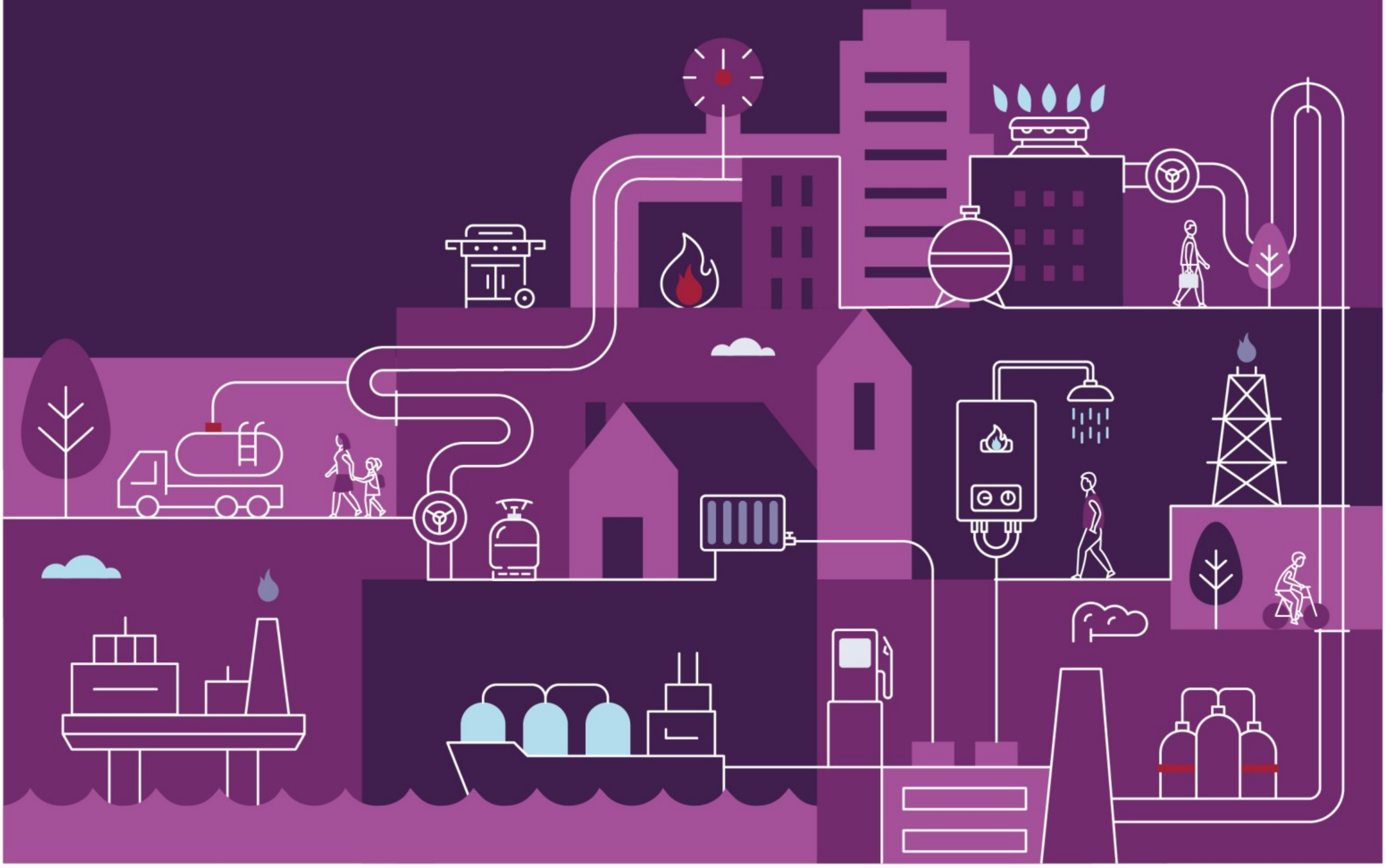
Gas Statement of Opportunities

March 2025

For Australia's East Coast Gas Market



We acknowledge the Traditional Custodians of the land, seas and waters across Australia. We honour the wisdom of Aboriginal and Torres Strait Islander Elders past and present and embrace future generations.

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

The purpose of this publication is to provide information to assist registered participants and other persons in making informed decisions about investment in pipeline capacity and other aspects of the natural gas industry.

AEMO publishes this Gas Statement of Opportunities in accordance with section 91DA of the National Gas Law and Part 15D of the National Gas Rules.

This publication is generally based on information available to AEMO as at 31 December 2024, unless otherwise indicated.

Disclaimer

AEMO has made reasonable efforts to ensure the quality of the information in this publication but cannot guarantee that information, forecasts and assumptions are accurate, complete or appropriate for your circumstances.

Modelling work performed as part of preparing this publication inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual results, because events and circumstances frequently do not occur as expected, and those differences may be material.

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Executive summary

The 2025 *Gas Statement of Opportunities* (GSOO) forecasts the adequacy of gas supplies in central and eastern Australia[1], based on information provided by gas industry participants, to meet households' and businesses' changing energy needs to 2044. The GSOO's purpose is to provide information to assist registered participants and other persons in making informed decisions about investment in the East Coast Gas Market (ECGM).

During Australia's transition to a net zero emissions future, gas will continue to be used by Australian households, businesses, and industry, and to support the operation of the electricity sector.

The 2025 GSOO forecasts risks of peak day shortfalls[2] from 2028, and structural supply gaps[3] emerging from 2029 in southern Australia. While the scale of gas consumption remains uncertain through the energy transition, particularly gas usage for electricity generation, all scenarios identify the need for new supply investments to maintain supply adequacy. Gas supply inadequacy risks forecast in the short, medium, and long term are:

- Shortfall risks under peak conditions are forecast in southern Australia from 2028, later than forecast in the 2024 GSOO due to expected falls in residential, commercial and industrial consumption of gas, and the delayed retirement of Eraring Power Station reducing forecast gas-powered generation (GPG) of electricity in the near term while it remains online. Seasonal supply gaps may emerge from 2028 if conditions lead to sustained high gas usage.
  - The completion of committed and anticipated gas supply developments is vital to minimise shortfall risks.
  - Ongoing availability and operation of all deep and shallow gas storages will be critical in minimising the risk of peak day shortfalls and seasonal supply gaps, providing operational flexibility that is important now and into the future to manage gas use variability.
- From 2028, seasonal supply gaps may emerge in southern Australia if conditions lead to sustained high gas usage, while expanded production of uncertain supply will be needed to meet domestic and export positions in northern Australia.
- In 2029 and later, despite falling forecast gas usage, annual supply gaps are forecast meaning a structural need for new gas supply beyond developments classified as committed and anticipated is necessary to maintain gas supply adequacy, as southern gas production continues to decline.

Various solutions are being considered by industry that may address these risks. In this GSOO, AEMO assesses several potential future supply, storage and transportation options, to provide additional information on potential investments and their impact on gas adequacy. All options assessed delay forecast annual supply gaps and help mitigate the risk of peak day shortfalls, to varying degrees. This assessment does not represent a merits or cost-benefit assessment of one option over another and has not considered the commercial viability of each based on current market settings. The analysis does not amount to a recommendation of any investment. Based on current forecasts, a combination of solutions will be required in the long term.

[1] This GSOO includes forecasts for all Australian jurisdictions other than Western Australia. The Western Australia *Gas Statement of Opportunities* is at https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/wa-gas-statement-of-opportunities-wa-gsoo.

[2] A peak day shortfall is driven by insufficient available gas production or transport capacity to meet extreme peaks in demand on a single day.

[3] A seasonal or annual supply gap is driven by insufficient gas production or transport capacity to meet total seasonal or yearly demand.

Key changes since the 2024 GSOO

Demand

Since publication of the 2024 GSOO, AEMO's consumption forecasts now feature:

- In forecasts of GPG in the National Electricity Market (NEM), greater consideration of weather variability with 10 historical weather patterns simulated (previously five patterns for the 2024 GSOO), and new storage development delay risks consistent with the *Electricity Statement of Opportunities* (ESOO) and Reliability Forecast Methodology[A].
- "Covered gas" is applied as an aggregation of natural gas, biomethane and hydrogen. No breakdown is presented.

Supply and transportation capacity

Between 2025 and 2026, southern producers expect to supply less gas from existing, committed and anticipated developments compared to the projections provided for the 2024 GSOO. Lower supply for these years is due to:

- The Gippsland Basin Joint Venture (GBJV) reprofiling expected production for existing fields in the **Gippsland** basin in response to lower market demand in 2023 and 2024 and lower forecast demand in 2025 and 2026, resulting in lower output forecasts for these years. This reprofiling provides for higher production in later years from these reserves.
- A downgrade of reserves at the **Thylacine North** and **Enterprise fields** in the Otway basin, as announced by Beach Energy on 12 August 2024[B], resulting in lower forecast production from these fields.

From 2027 to 2032, higher levels of gas production from existing, committed and anticipated developments compared to the 2024 GSOO, due to:

- Higher **Gippsland** production is forecast as a result of the **Turrum Phase 3** project progressing from uncertain to committed status and higher production from existing fields. Increased forecast production at Longford Gas Plant for 2028 allows Gas Plant 3 to remain online for an additional year, enabling higher peak day production quantities from the plant in winter 2028. Gas Plant 1 was retired in October 2024.
- Existing, committed and anticipated production from **Queensland** is advised by gas producers to increase due to improved forecast supplies from liquefied natural gas (LNG) producers.
- The **Carpentaria Gas Field** in the **Beetaloo** basin in the Northern Territory has progressed from uncertain to anticipated status with an initial expected production of 10 terajoules a day (TJ/d) from 2026 which will increase to 25 TJ/d or 9 petajoules a year (PJ/y) from 2027.

Key infrastructure projects to increase transportation capacity have been committed or are under construction and will contribute to additional supply capacity:

- Lochard Energy's **Heytesbury Underground Gas Storage (UGS)** expansion project (HUGS Project Phase 1)[C] at Iona UGS will increase storage inventory capacity by 1.8 PJ to 3.5 PJ, and supply capacity by up to 45 TJ/d, from 2027.
- APA Group's **Kurri Kurri Lateral Pipeline (KKLP)**[D] project is a gas transmission and shallow storage facility under construction near Newcastle. KKLP will provide 72 TJ storage capacity and 60 TJ/d peak day supply capacity for Hunter Power Station or the ECGM. The project is scheduled for completion in 2025.
- The **Northern Gas Pipeline (NGP) Reverse Capability** project was completed by Jemena in August 2024, providing the NGP with the capability to flow gas into the Northern Territory from Queensland (from Mt Isa to Phillip Creek).
- Senex Energy's **Atlas Expansion** project commenced production in February 2025 and the **Roma North Expansion** project has progressed from anticipated to committed status. The Roma North Expansion project is under construction and scheduled to be operational before winter 2025. The two projects provide additional processing capacity of 57 TJ/d and 28.5 TJ/d, respectively.
- The relicensing of APA's **Moomba Sydney Ethane Pipeline (MSEP)** to a natural gas pipeline will provide an additional 20-25 TJ/d capacity on the **Moomba Sydney Pipeline (MSP)** for 2025.
- The **MSP off-peak capacity expansion project** will increase the capacity in summer months by 80-120 TJ/d when pipeline maintenance is being undertaken in specific sections of the MSP. This project is scheduled to complete by November 2025.

A. See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/esoo-and-reliability-forecast-methodology-document.pdf?la=en.
B. See https://beachenergy.com.au/wp-content/uploads/BPT_2024_Beach_Energy_Ltd_Annual_Report.pdf.
C. See https://www.lochardenergy.com.au/our-projects/hugs/.
D. See https://www.apa.com.au/operations-and-projects/gas/gas-transmission/kurri-kurri-lateral-pipeline-kklp-project.

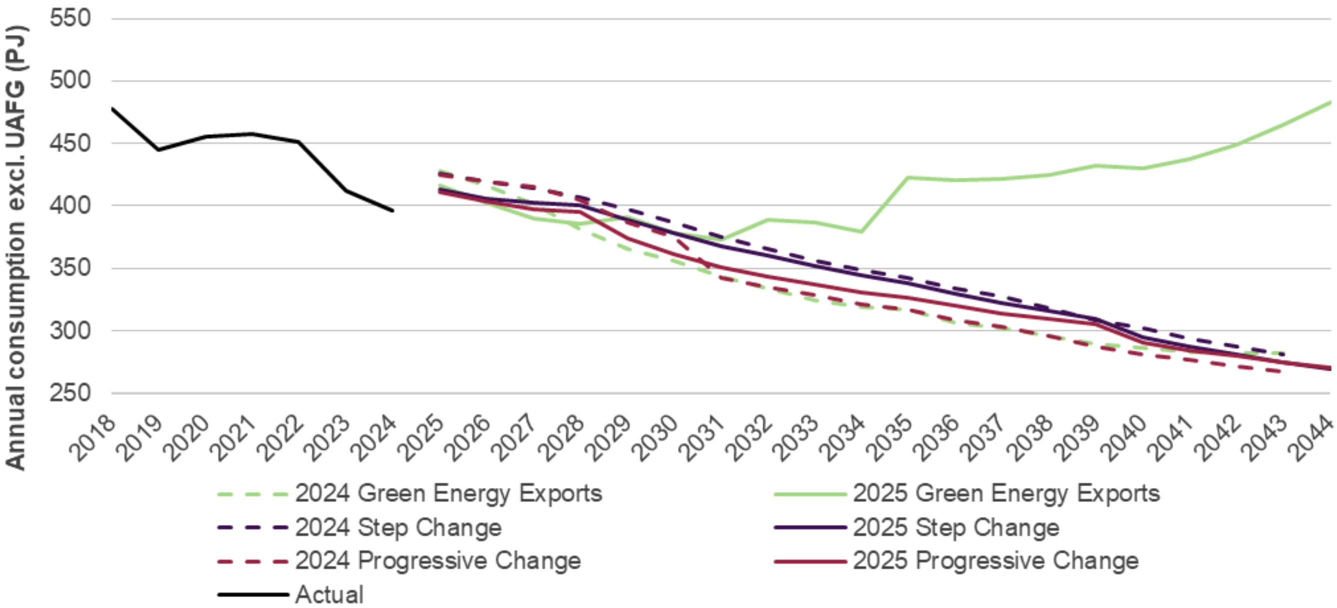
Electrification of gas use is contributing to a downward trend in forecast gas consumption for commercial, residential and industrial users

Since publication of the 2024 GSOO, gas consumption has continued to decline across commercial, residential and industrial sectors. The reduction in gas consumption has coincided with noticeably higher retail gas prices compared to recent years and a slower growth of new building approvals. Milder winter conditions in the last two years have also contributed to lower gas use and while consumption is forecast to rebound slightly, assuming long-term average conditions eventuate rather than the recent mild winters, gas consumption continues to follow a declining trend with several drivers.

Forecast gas consumption for commercial, residential and industrial users declines over the outlook period to 2044. Industrial consumption has declined in recent years, with plant disruptions affecting gas consumption, and several facilities have closed or are expecting to close in the short term. Residential and small commercial consumption is also forecast to slightly decline in the short term, with more significant levels of electrification (or fuel-switching to electricity) in the medium to longer term, in line with a transition to net zero emissions goals. In the medium term, gas consumption across the large commercial and industrial sectors is forecast to remain relatively stable with lower gas usage offsetting population and economic growth factors.

Figure 1 below shows the three 2025 GSOO scenarios AEMO has applied to assess gas supply adequacy through Australia's energy transition. As mentioned above, all scenarios assume long-term average weather conditions, rather than continued mild winters, leading to a slight recovery in the short term, before scenario-based drivers of diversity influence the long-term forecasts.

Figure 1 Actual and forecast domestic covered gas consumption, excluding GPG, all scenarios and compared to 2024 GSOO forecasts, 2018-44 (PJ)



Note: The Northern Territory is included in actual gas consumption from 2020 onwards.

As Figure 1 illustrates, like the 2024 GSOO, the potential to electrify gas loads in the residential, commercial, and certain industrial sectors accounts for much of the downward trend in forecast gas consumption over the outlook period, particularly for *Step Change* and *Progressive Change*. Electrification and other drivers in the *Step Change* scenario are forecast to reduce natural gas consumption by around 133 PJ to around 270 PJ by 2044. Relative to the 2024 GSOO forecast, an uplift in gas demand is forecast in the *Green Energy Exports* scenario. This reflects the inclusion of a broader collection of covered gases within the GSOO, rather than only natural gas that was included under previous regulations, meaning that forecast demand for natural gas, biomethane, hydrogen and synthetic methane is now included within the gas consumption projections. *Green Energy Exports* includes forecast consumption of hydrogen in the production of "green commodities" in the steelmaking, ammonia, alumina and methanol production industries, providing a significant potential growth driver relative to the other scenarios in the longer term.

Annual gas-powered generation consumption is forecast to increase from the early 2030s, with significant growth in peak day consumption

GPG plays a critical function in supporting the reliable and secure operation of the power system. When coal generation and/or renewable generation output is low, it is often the role of gas-powered facilities to increase output to firm available electricity supplies. Analysis from the 2024 *Integrated System Plan* (ISP)[4] reinforces the important role GPG is forecast to play in the NEM by helping manage extended periods of low variable renewable energy (VRE) generation, providing firming support when other dispatchable sources are unavailable, and continuing to support grid security and stability as the coal generation fleet retires in the NEM.

The temporary extension of the operating life of Eraring Power Station in New South Wales to August 2027 lowers forecast gas consumption for power generation, compared to previous forecasts that anticipated the plant closing in August 2025. Eraring has historically provided approximately 15,000 gigawatt hours (GWh) per annum of electricity, supporting power systems with reliable generation capacity. Despite these attributes, the age of the facility poses a risk that past levels of performance may not be achievable in the future.

Figure 2 illustrates recent and forecast[5] volumes of gas consumption for electricity generation in the NEM from the 2024 ISP, as well as forecast GPG in the Northern Territory, highlighting a potential escalation in the need for gas generation in the winter season compared to historical levels. Forecast gas consumption for GPG is highly weather-dependent and will be influenced by retirements of coal generators in the NEM and the capacity that replaces them. Upcoming coal retirements, including Eraring Power Station (currently announced to retire on 19 August 2027) and Yallourn Power Station (currently announced to retire on 1 July 2028), are expected to increase the GPG gas consumption to levels above historical annual gas use. The forecast requirement for higher GPG in winter increases in later years as coal generators continue to retire and winter electricity forecasts increase.

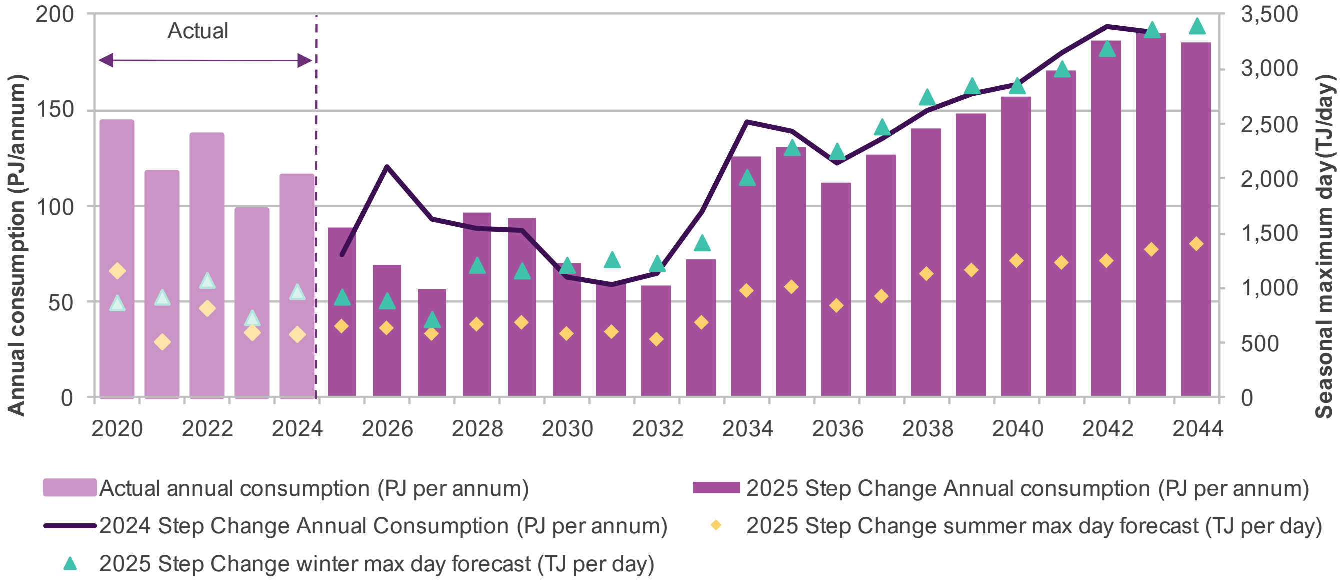
As shown in Figure 2, while annual gas consumed by GPG is forecast to rise, the peak daily consumption from GPG in winter is also forecast to grow to levels well above historical peaks. Lower winter renewable energy output, coal generation closures, and concurrent electrification of residential and commercial heating loads are primary

[4] See https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp.

[5] The GSOO GPG forecasts differ marginally to those presented in the 2024 ISP. The GSOO applies assumptions regarding bidding behaviour, operational constraints, longer generator build timelines, and generator availability to predict GPG consumption more accurately. In addition, the GSOO includes existing, committed and anticipated generation capacity information from July 2024 Generation Information (see https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information), HumeLink project status update (see https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information) and 2024 ACIL Allen fuel price forecasts. GSOO forecasts exclude Yarwun, include the Northern Territory, and are averaged across different historical weather patterns, while being presented by calendar year rather than financial year.

drivers of increasing peak day GPG forecasts. The critical role for GPG to firm renewable energy supplies will significantly influence gas infrastructure needs for flexible operations, particularly if GPG develops as forecast in the 2024 ISP.

Figure 2 Actual and forecast NEM and Northern Territory gas generation annual consumption (PJ/y) and seasonal maximum daily demand (TJ/d), *Step Change* scenario, 2020-44



Risks of peak day shortfalls in southern[6] regions are forecast from winter 2028

For this 2025 GSOO, gas producers have provided updated gas production profiles that are scheduling higher gas production in years that were identified as shortfall risks in the 2024 GSOO. Drivers of lower gas usage such as electrification and reduced industrial consumption, and continued availability of coal generation at Eraring, is enabling southern gas production reprofiling to better match shortfall risks. With gas producers' advised reprofiling of maximum daily production capacity from committed and anticipated gas supplies, increasing production expected to be available in the short term and considering the 2025 GSOO's forecast levels of peak daily demand, the risk of shortfalls during peak conditions is forecast from 2028, three years later than forecast in the 2024 GSOO.

The peak gas demand from residential, commercial and industrial consumers is driven significantly by weather conditions, and the GSOO examines a range of weather patterns from recent history to assess gas supply and demand adequacy. More extreme conditions or unexpected market events (for example, the 'millennium drought' in 2007 or unplanned gas production outages), may lead to risks that will need to be managed in operational timeframes.

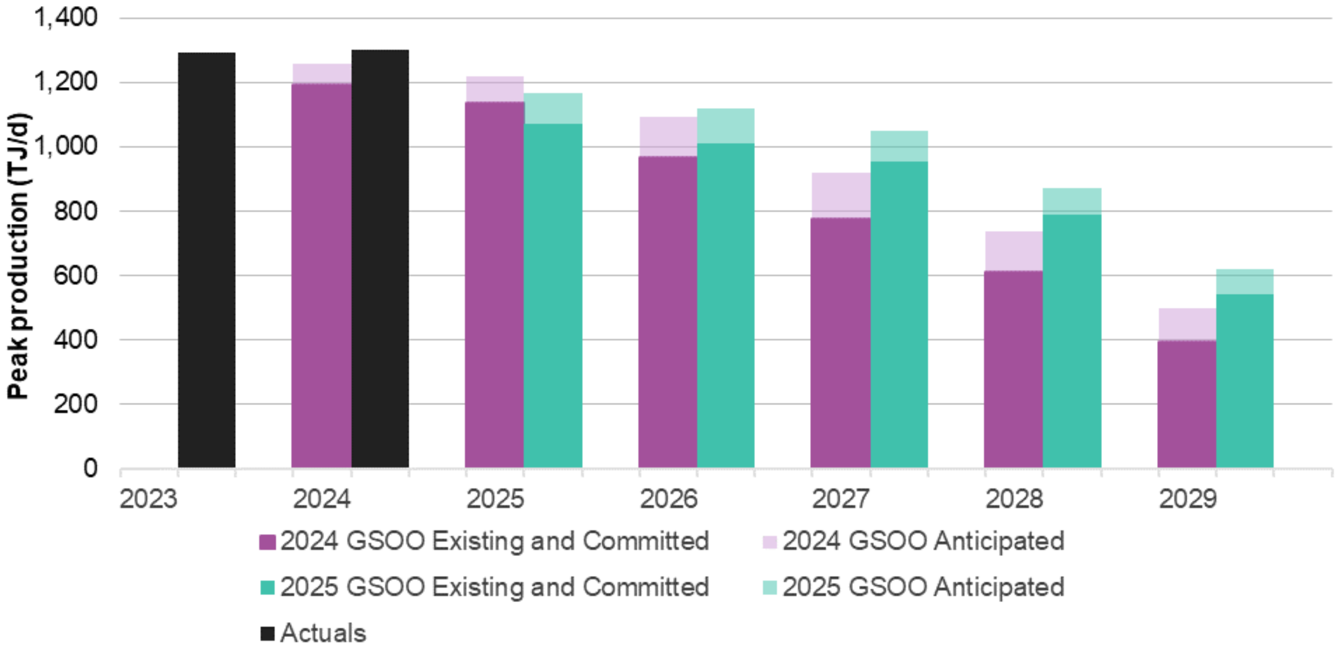
Figure 3 shows actual production in 2023 and 2024 from southern gas fields and the advised production capacity in each year to 2029. It shows that in most years[7], production capacity is generally higher from existing, committed and anticipated facilities than was advised for the 2024 GSOO, although producers still advise that production

[6] In this GSOO, "southern" regions are New South Wales (including the Australian Capital Territory), South Australia, Tasmania and Victoria, and "northern" means the Northern Territory and Queensland.

[7] Except for the 2025 calendar year.

capacity will decline. This decline is forecast to cause challenging operational conditions for southern regions and require a greater reliance on storage and gas supplied from northern regions, until a more structural solution for additional supply is developed to address forecast annual supply gaps.

Figure 3 Actual and forecast maximum daily production capacity from southern gas fields in June, 2023-29 (TJ/d)



The changing seasonal gas supply and demand dynamics in the south, and the important role of storages and gas delivered from northern regions, are emphasised in **Figure 4**. This shows the ability of committed and anticipated southern production, pipeline capacity and storage facilities to meet actual southern gas demand in 2023 and 2024, and its projected ability to meet extreme peak day gas demand in each year until 2028 in the *Step Change* scenario[8].

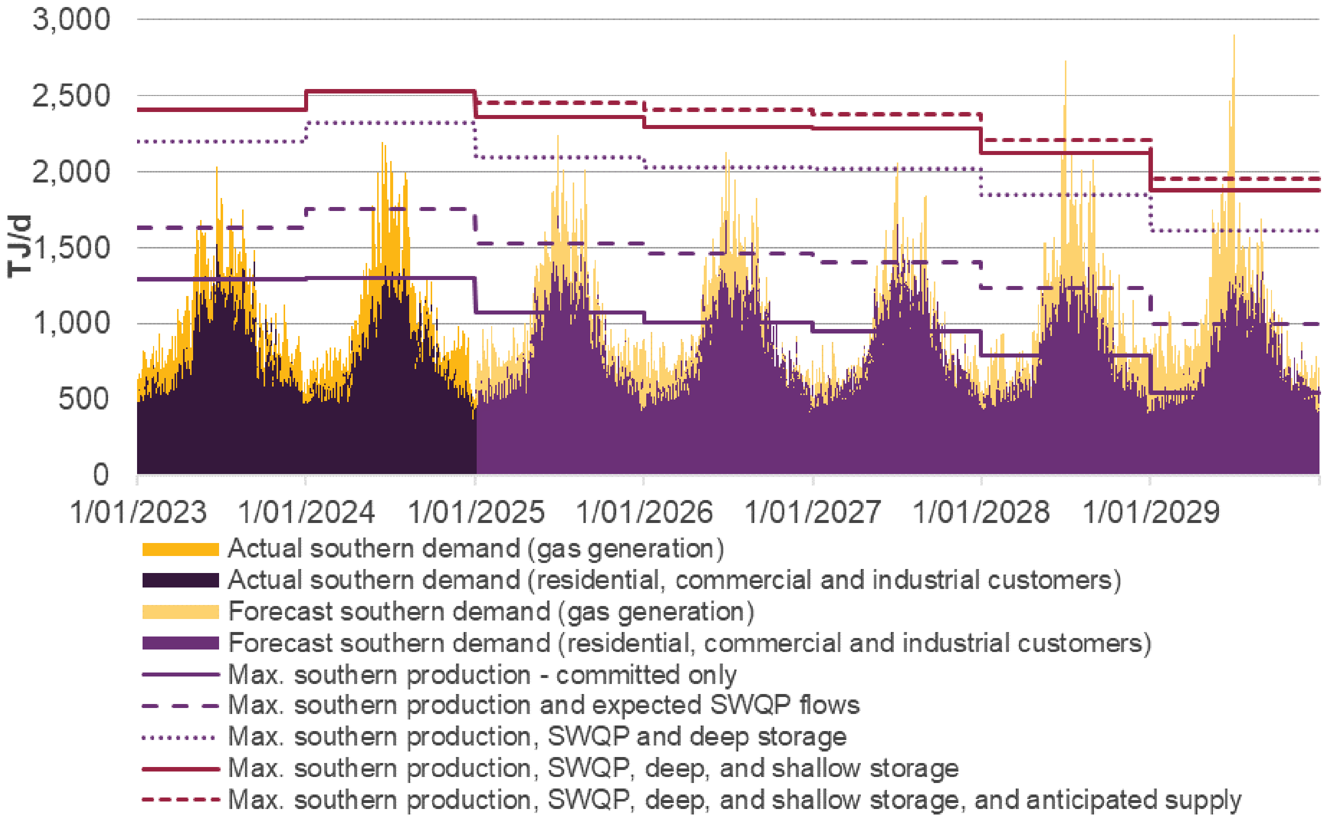
Horizontal lines in Figure 4 indicate the maximum capacity forecast to be available to meet daily gas demand, from each of the following sources cumulatively:

- Existing and committed gas production capacity from southern regions only (solid purple line), plus
- Expected gas imported from Queensland through the Southwest Queensland Pipeline (SWQP)[9] (dashed purple line), plus
- Gas injection capacity from deep storage at Iona UGS (dotted purple line), plus
- Gas injection capacity from shallow storages at Dandenong, Newcastle and Kurri Kurri (solid red line), plus
- Anticipated gas supply capacity from southern regions (dashed red line).

[8] Extreme peak day demand is characterised by 1-in-20-year highs in daily demand from residential, commercial and industrial customers and 1-in-10-year high daily gas requirements for GPG.

[9] Ongoing supply issues in the Northern Territory mean that no flow is expected down the Northern Gas Pipeline (NGP) into Queensland. Therefore, the estimate of available SWQP flow accounts for gas flow along the Carpentaria Gas Pipeline (CGP) to Mount Isa.

Figure 4 Actual daily southern gas system adequacy since January 2023, and forecast to 2029 using existing, committed and anticipated projects (TJ/d)



Peak demand levels reflect weather conditions that drive one-in-20 year gas demand, and one-in-10 year electricity peak demand. The degree to which gas demand and electricity demand peaks coincide will influence the gas supply adequacy.

Figure 4 indicates gas shortfall risks are forecast to emerge on some days in winter 2028 under extreme peak day demand conditions. While these peak day shortfalls vary in size depending on the forecast winter weather conditions and the degree of coincidence of electricity and gas demand, shortfalls are forecast under all extreme weather conditions studied.

From 2028, the southern supply-demand balance is forecast to continue to tighten, with existing, committed and anticipated pipeline infrastructure less able to deliver the forecast volumes of gas required under extreme conditions, increasing the risks to peak day adequacy on the most extreme demand days.

As Gippsland supply continues to decline and production facilities at the Longford Gas Plant are decommissioned[10], southern regions will be exposed to increased risk if either unscheduled production interruptions occur in southern states that reduce supply capacity, or low VRE conditions or coal generator outages increase the GPG demand.

[10] The retirement of Longford Gas Plant 1 in October 2024 means the two remaining gas plants are required to achieve peak day capacity of 700 TJ/d. Gas Plant 3 is forecast to retire in December 2028.

Progress of committed and anticipated projects is crucial to ensuring supply adequacy

This 2025 GSOO assessment of gas supply adequacy assumes that all committed and anticipated supply and infrastructure projects are progressed and completed to schedule. Without these, peak day shortfalls in the short term are more likely. The assessment highlights:

- On-schedule development of committed and anticipated supply is crucial to ensure sufficient supply is available to support southern demand and mitigate the risk of peak day shortfalls. This includes supply projects in northern Australia to meet established domestic and export contracts from 2025.
- The KKLP project and the HUGS Project at Iona UGS will increase the storage capacity to supply southern demand centres. It is important these projects are completed on time to maximise supply to southern regions from 2025.
- Ensuring all storages are at full capacity prior to winter is critical to reduce shortfall risks. Throughout winter, appropriate operation to manage southern storage depletion is important. In extreme cases where depletion is taking place at an accelerated rate, northern supply should be sourced to ensure southern storage is not depleted before the end of winter.
  - The Victorian Declared Wholesale Gas Market (DWGM) interim liquefied natural gas (LNG) storage measures rule change[11] requires that AEMO contract any uncontracted capacity at Dandenong LNG until the end of 2025. This will ensure the Dandenong LNG tank is full prior to winter 2025, but not beyond 2025, because the interim rule expires. The Victorian Government is seeking to extend the interim rule requirement, through a rule change with the Australian Energy Market Commission (AEMC).
- The timely developments of electricity transmission (Project EnergyConnect and HumeLink), renewable energy, and electrical storage projects in the NEM will reduce gas adequacy risks by reducing reliance on GPG operations. Maintaining high availability of coal generation capacity during the peak winter seasons (by managing planned maintenance and scheduling future retirements at the conclusion of the winter season) will also mitigate gas adequacy risks.
- Given the lead time needed to plan, obtain approval for, and build new greenfield infrastructure, demand flexibility is likely the best solution to address short-term supply shortfall risks. In extreme gas shortfall conditions, secondary fuels may be needed to operate GPG for short periods to reduce gas use while not compromising electricity reliability.

Annual and seasonal supply gaps are increasingly forecast in southern Australia from 2028

From 2028, small seasonal supply gaps are forecast if conditions lead to sustained high gas usage, particularly in winter, even with the development of committed and anticipated supplies as currently planned. While demand flexibility may mitigate short duration peak day shortfall risks, addressing supply gaps will require a solution, or solutions, which bring in more supply.

Various interventions have been established in recent years with the intention of supporting gas adequacy in the ECGM – including the Australian Domestic Gas Security Mechanism, agreements with east coast LNG exporters

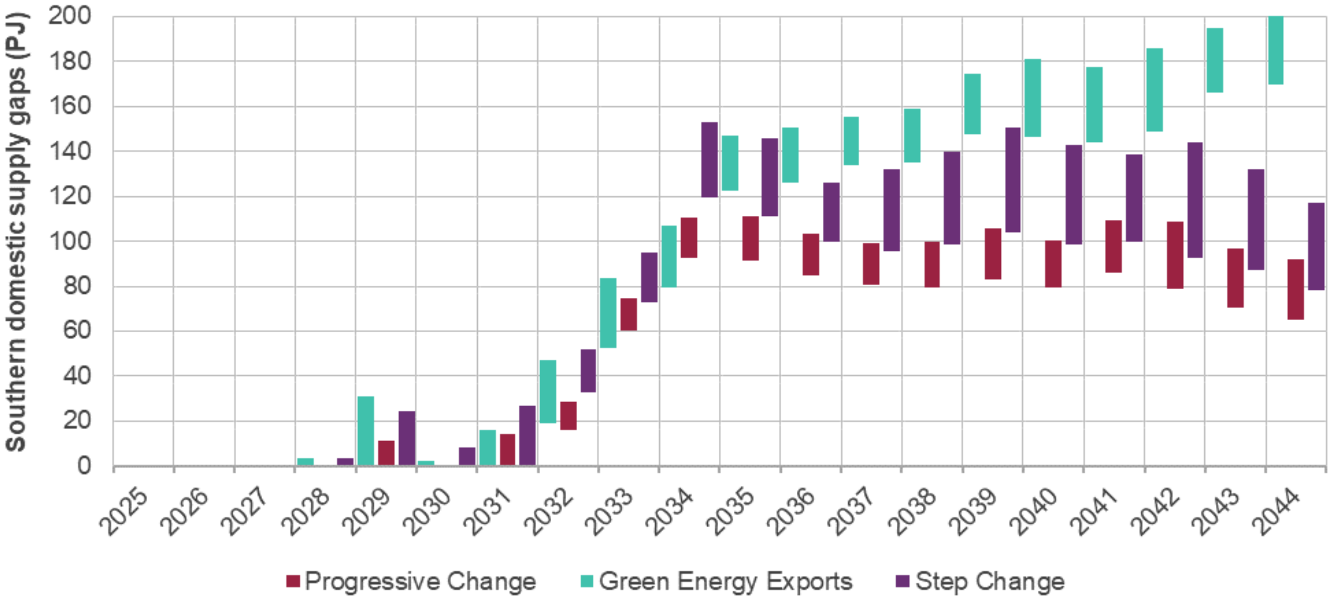
[11] Australian Energy Market Commission (AEMC), "DWGM interim LNG storage measures", 15 December 2022, at https://aemc.gov.au/rule-changes/dwgm-interim-lng-storage-measures.

to improve domestic gas supply, the establishment of a Gas Market Code aiming to improve gas contracting and transparency, policies that support customers' energy efficiency and use of alternative fuels, and agreements to temporarily maintain availability and operation of coal generators. These actions, however, are unlikely to be sufficient to address longer-term gaps in supply without investment to provide access to new gas supply.

Forecast supply adequacy for 2028 is improved compared to the 2024 GSOO due to higher available gas supply, particularly at Longford Gas Plant, as well as lower forecast demand due to higher electrification. AEMO has been advised that higher forecast production at Longford will be enabled by continued operation of the two remaining gas plants in winter 2028, with the closure of one of the two remaining gas plants now delayed to December 2028.

The emergence of projected supply gaps from 2028 and 2029, shown in **Figure 5**, are lower across later years in the horizon than forecast in the 2024 GSOO, primarily due to lower GPG forecasts and some uncertain supply now being categorised as anticipated supply. Despite the actions to reprofile forecast gas production, extend coal availability, and influence gas use decline through electrification and energy efficiency investments, supply solutions continue to be identified as necessary in this GSOO. The breadth of forecast shortfalls in this 2025 GSOO diverges across modelled scenarios from the mid-2030s, reflecting uncertainty in the speed of the energy transition affecting consumer demand and gas for electricity generation.

Figure 5 Range of domestic annual supply gaps forecast in southern regions based on existing, committed, and anticipated developments, all scenarios, 2025-44 (PJ)



Northern producers need to deliver anticipated supplies, and by 2029 more uncertain supply is required to meet export agreements and domestic supply

Northern gas producers provide critical support to keep domestic users adequately supplied[12]. LNG producers' control around 70% of total 2P reserves[13] in central and eastern Australia, and volumes of gas exported

[12] AEMO's physical gas adequacy assessments assume that gas from Queensland LNG producers is made available to the domestic market if required to avert domestic shortfalls. This includes uncontracted gas that could otherwise be exported as spot cargoes to international markets.

[13] 2P, or proved and probable, is widely accepted as the best estimate of reserves.

internationally via Curtis Island in Queensland represent around 75% of annual consumption in the ECGM. Production of gas from Queensland and the daily and seasonal operation of these facilities will have a growing impact on domestic supply adequacy as southern production declines:

- Gas production from LNG producers' existing and committed developments, in addition to domestic third-party supply, will only be sufficient to meet export and domestic supply contracts until the end of 2025.
- The development of anticipated supplies in northern regions will only maintain sufficient supply until 2028. From 2029, uncertain supply developments will be required to satisfy northern demand, LNG exports and support southern demand. In total, up to 200-500 petajoules a year (PJ/y) of new northern supply – above committed and anticipated projects – is expected to be required during the period to 2044 to meet forecast LNG exports and domestic demand.

It remains critical that LNG producers make supply available during winter in all years of the outlook period to support flows to southern regions to mitigate the risk of southern supply shortfalls.

Reliance on alternative and interim gas arrangements may persist in the Northern Territory

The Northern Territory presently relies on alternative and interim gas arrangements, including with Darwin LNG exporters[14]. There is currently reduced production from the Blacktip field, and it is not clear when production levels will be fully restored. Carpentaria Gas Field from Beetaloo Basin in Northern Territory has progressed from uncertain to anticipated status with expected production of 10 terajoules a day (TJ/d) from 2026 which will increase to 25 TJ/d or 9 PJ/y from 2027. However, this is still not enough to supply the increasing industrial demand and ongoing reliance on GPG for electricity generation in the Northern Territory.

The Northern Gas Pipeline (NGP) which transports gas eastward to Mount Isa from the Northern Territory is currently not flowing, and the resumption of these flows is not forecast in the 2025 GSOO. In August 2024, Jemena completed the NGP Reversal Capability project, which enables gas to flow towards the Northern Territory from Queensland. Reversal of the NGP provides a backup solution to address forecast supply gaps in the Northern Territory if gas supply is not available from alternative arrangements.

Proposed projects can delay shortfall risks and supply gaps to 2034

Given the identified supply gaps, the 2025 GSOO includes a collection of *what if* analyses to explore potential future supply, transportation, and storage projects.

Table 1 shows a collection of proposed projects by market participants and their capacities, timings, and individual effects on shortfalls. The options assessed are not exhaustive and are only intended to provide insights into the effectiveness of different individual options in addressing forecast supply challenges. This assessment does not consider all factors such as cost, regulatory approvals, land use, social license, safety, or operational challenges of each option, and does not amount to a recommendation or representation regarding any investment.

[14] Detail on this arrangement is at https://www.aemc.gov.au/sites/default/files/2019-08/Information%20sheet.pdf.

Table 1 Future supply, transportation and storage options assessed

Option name	New supply	Transportation capacity (if relevant)	Southern annual supply gaps delayed to	Storage capacity (if relevant)
LNG regasification terminal	New South Wales (Port Kembla) from 2026	Eastern Gas Pipeline (EGP) reversal Stages 1 and 2	2034	None
	South Australia (Outer Harbor) from 2027	Port Campbell to Adelaide (PCA) pipeline reversal, from 2028	2033	None
	Victoria (Geelong[A]) from 2028	Westernport-Altona-Geelong (WAG) pipeline conversion project [D]	2033	None
Pipeline expansions and upgrades	Uncertain northern supply	• East Coast Grid Expansion (ECGE) Stages 3[B] (Bulloo Interlink and MSP upgrades) • MSP to EGP compression • EGP reversal Stage 1 and 2 • Port Campbell to Adelaide (PCA) pipeline reversal, from 2028	2034	Riverina Storage 200-500 TJ 80 TJ/d (EGCE Stage 4)
Southern Supply	2C Southern Supply[C] and renewable gas	Hunter Gas Pipeline (Narrabri to Newcastle) – by 2028	2034	None

A. This could be either Viva's or Vopak's proposed LNG regasification terminal project.
B. Includes the conversion of the Moomba Sydney Ethane Pipeline (MSEP) to transport natural gas, which is classified as a committed project.
C. A contingent (2C) resource is a best estimate of a quantity of gas that is less certain, and potentially less commercially viable, than 2P. This option only includes production profiles from southern 2C resources reported to AEMO via the GSOO surveys. Projects included in this additional southern supply include projects in the Gunnedah, Otway, Gippsland, Bass and Cooper basins.
D. Only for the Viva regasification terminal project

Figure 6 and **Figure 7** present the forecast southern daily adequacy for each of the future potential options assessed and their individual impacts on addressing annual supply gaps between 2025 and 2035, showing that:

- **Pipeline solutions that increase north-south gas transfers** can delay the forecast supply gaps to 2034 but will require the availability of increased northern supply beyond committed and anticipated productions that increases gas available to southern consumers. Pipeline solutions will need to adequately enable gas transportation to demand centres in Victoria and South Australia; pipeline expansions that only increase transportation capacity from the north into New South Wales will not be as effective.
- **Uncertain 2C southern supply and renewable gas** may delay forecast supply gaps to 2034 and help mitigate peak day shortfall risks.
- **An LNG regasification terminal** may delay forecast supply gaps to 2033 or 2034, depending on the development of associated pipeline infrastructure to support deliverability (depending on the terminal).

In addition to the future potential options to service southern markets, increased coal seam gas (CSG) supply in Queensland is also required to support the export positions of the LNG producers.

Figure 6 Projected southern daily adequacy for each of the future options assessed, 2025-35 (TJ/d)

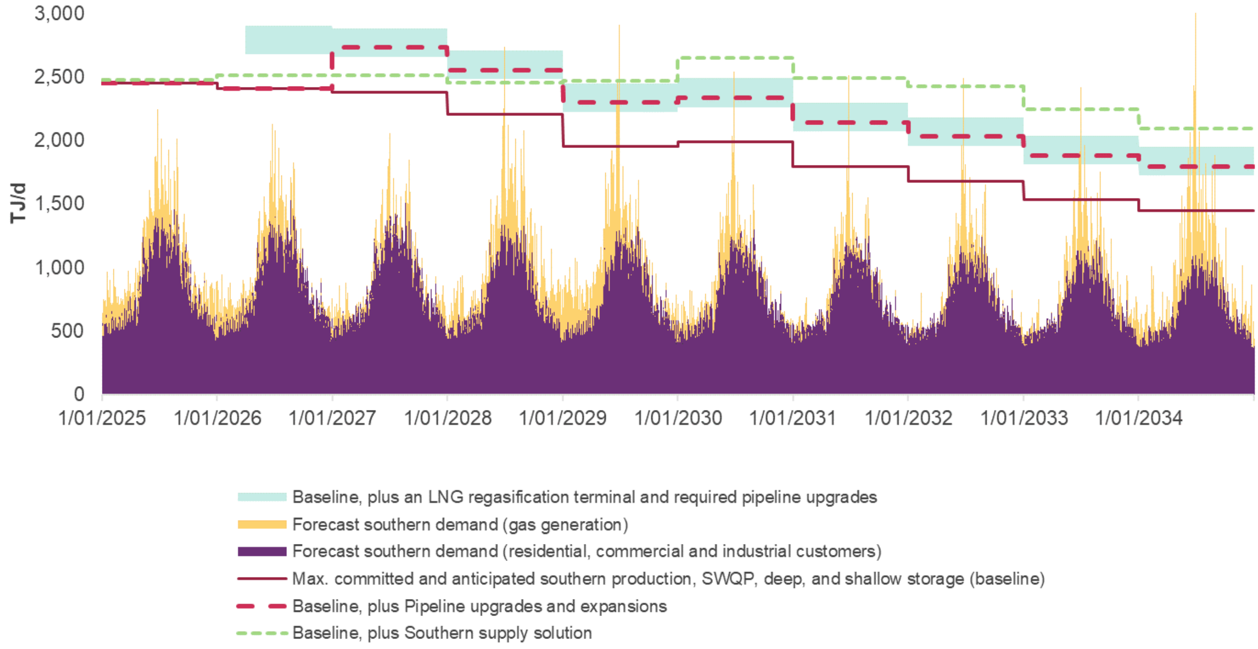
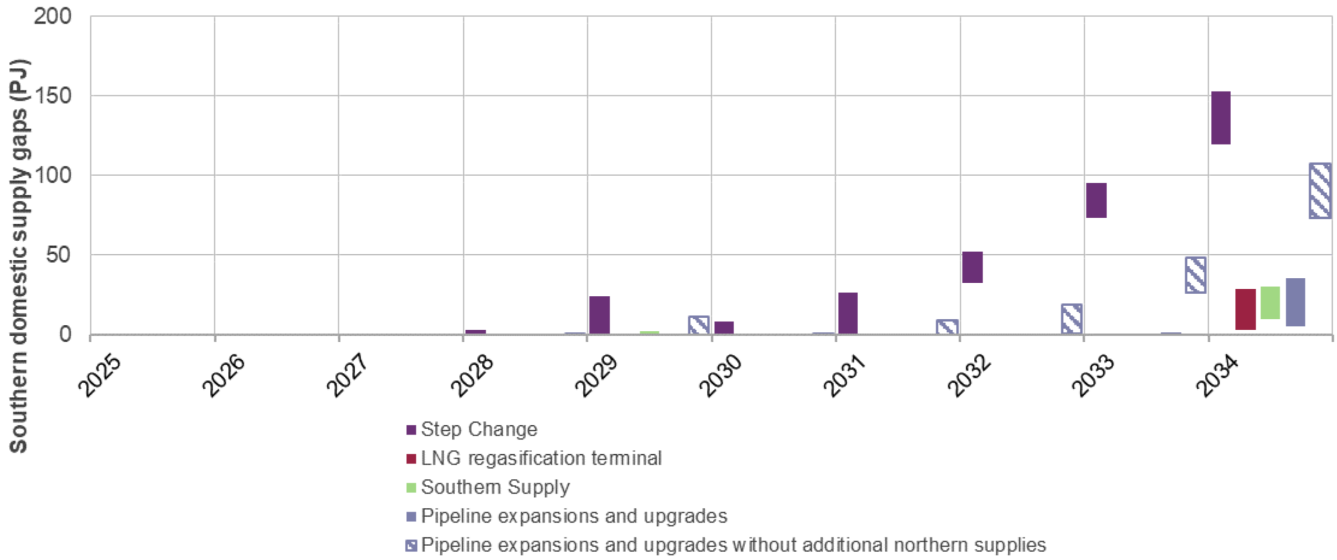


Figure 7 Range of annual shortfalls for each option assessed across various weather conditions, 2025-34 (PJ)



A combination of solutions, including new gas storage, is required to address southern gas supply risks from 2034

Gas demand for GPG is forecast to grow significantly and become more variable, especially during the winter season, due to the combined effect of coal retirements, growth in electricity use, and the need to firm high levels of VRE. To address the needs of annual, seasonal and peak day requirements of all gas users, a combination of investments that provide new gas supply is likely, as no single solution examined provides sufficient peak production and annual supply to meet the forecast supply gaps across the 20-year assessment.

In addition, increased storage to cater for peak seasonal loads is forecast to be necessary. The depth and network injection capacity of new storages will depend on the volume of new gas supplies that can be sourced locally in, or transported to, the southern demand centres. Demand response mechanisms or on-site liquid storage for GPG will complement (and may reduce the need for) gas storage investment.

Contents

1 Introduction

The *Gas Statement of Opportunities* (GSOO) assesses the adequacy of gas reserves, resources, and infrastructure to meet domestic and export needs over a 20-year outlook period across central and eastern Australia (that is, all Australian jurisdictions other than Western Australia), referred to as the East Coast Gas Market (ECGM).

The GSOO provides a physical assessment of gas adequacy by assessing the capability for existing, committed and anticipated production to meet demand for gas, including gas required for gas-powered generation of electricity (GPG) in the National Electricity Market (NEM) and in the Northern Territory. The physical assessment focuses on the needs of domestic consumers, recognising the export commitments of liquefied natural gas (LNG) producers within the ECGM, and the capability for LNG producers to offer surplus gas production to meet the needs of domestic consumers.

In conducting this assessment, the GSOO examines the limitations for supply to meet demand considering physical capabilities, rather than contractual positions and other commercial influences that could affect actual supply compared to forecasts. As such, subject to technical operating limits, transportation constraints, storage limitations, and project classification status, if supply is not available as producers have forecast, the adequacy of the gas system may differ from the assessment in the GSOO.

The GSOO analyses a selection of potential futures, focusing on the adequacy of the system to meet changing gas needs from now until 2044. Modelling and assessment of the impact of future supply, transportation and storage projects on gas adequacy is also included.

AEMO's 2025 *Victorian Gas Planning Report* (VGPR)[15] complements the GSOO by providing a focused assessment of the supply-demand balance to 2029 in Victoria's Declared Transmission System (DTS).

Definitions

The following definitions apply throughout this document when assessing the daily shortfalls and annual supply gaps:

- **Extreme peak day demand** is characterised by coincident very high daily demand from residential, commercial and industrial customers and high daily gas requirements for GPG. It is forecast using a probability of exceedance (POE) measure, with focus on two demand levels, being the level expected to be exceeded only once in 20 years and once in two years respectively.
- A **peak day shortfall** is driven by insufficient available gas production or transport capacity to meet extreme peaks in demand on a single day. Peak day shortfalls are typically calculated considering 5% POE, or one-in-20-year peak day demand.
- A **seasonal or annual supply gap** is driven by insufficient gas production or transport capacity to meet total seasonal or yearly demand.

[15] At https://www.aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/victorian-gas-planning-report.

1.1 Scenarios

Considering the uncertainties in the speed and extent of gas sector transformation, AEMO uses scenarios and sensitivities to explore the needs of gas consumers and the adequacy of gas infrastructure to meet those needs.

For the 2025 GSOO, AEMO modelled the next 20 years using scenarios from the Draft 2025 *Inputs, Assumptions and Scenarios Report* (IASR)[16] to assess the impacts of changes to specific scenario assumptions. These scenarios are described in detail in the Draft 2025 IASR and remain highly comparable to scenarios used in the 2024 GSOO. **Table 2** below summarises key parameters for each scenario, which are described as follows:

- ***Step Change*** – 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. Consumer investment in the energy transition remains strong, with households placing high value on the benefits of consumer energy resources (CER).
- ***Green Energy Exports*** – reflects the strongest decarbonisation activities and economic growth of the three scenarios. This scenario features a rapid transformation of Australia's energy sectors and is commensurate with global actions aimed at limiting temperature increase to 1.5°C, resulting in rapid transformation of Australia's energy sectors, with strong adoption of electrification global demand for green energy products (particularly green iron and ammonia products).
- ***Progressive Change*** – features investment in decarbonisation at a more gradual pace, while still sufficient to meet Australia's current 2030 Paris Agreement commitment (and other state-based policy commitments) within an economy that features less growth and greater challenges than other scenarios. Slower economic activity and population growth reduces the pace of electrification, while energy-intensive industries are at greater risk of closure, and *Progressive Change* features higher technology costs and tighter supply chains relative to other scenarios.

Table 2 Key parameters by scenario

Parameter	*Step Change*	*Green Energy Exports*	*Progressive Change*
National decarbonisation target	At least 43% emissions reduction by 2030. Net zero by 2050	At least 43% emissions reduction by 2030. Net zero by 2050	At least 43% emissions reduction by 2030, net zero by 2050
Global economic growth and policy coordination	Moderate economic growth, stronger coordination	High economic growth, stronger coordination	Slower economic growth, lesser coordination
Australian economic and demographic drivers	Moderate	Higher (partly driven by green energy)	Lower
Electrification	High	Higher	Meeting existing emissions reductions commitments
Energy efficiency across all energy forms	Moderate	Higher	Lower
International Energy Agency (IEA) 2021 World Energy Outlook scenario	Sustainable Development Scenario (SDS)	Net Zero Emissions (NZE)	Stated Policies Scenario (STEPS)

16 At https://aemo.com.au/-/media/files/major-publications/isp/2025/draft-2025-iasr-scenarios-overview.pdf?la=en.

1.2 Gas market reform

On 12 August 2022, Energy Ministers agreed[17] a set of actions to support a more secure, resilient and flexible ECGM. These actions include measures which came into effect on 4 May 2023 to provide AEMO with tools to monitor, signal and manage gas supply shortfalls within an operational timeframe.

Energy Ministers agreed to additional[18] Reliability and Supply Adequacy reforms on 8 December 2023 to seek to establish a fit-for-purpose Reliability and Supply Adequacy Framework. The below measures are expected to progress through changes to the National Gas Rules (NGR) and progressively be implemented between 2025 and 2026, with appropriate changes to the GSOO as appropriate:

- A reliability standard for gas to identify reliability and supply adequacy threats, including an objective threat signalling mechanism.
- Short- and medium-term projected assessment of system adequacy (PASA).
- Advanced notice of closure requirements.
- Further refinement and guardrails of the Stage 1 trading function, through the implementation of a supplier of last resort mechanism.

On 14 March 2025[19], Energy Ministers strongly encouraged the private sector to respond to the clear market signals and deliver the investment and projects needed to ensure gas markets are well supplied. Ministers agreed on progressing legislative drafting in parallel with further policy analysis to support a decision in July 2025 around options to address possible structural supply shortfalls in the ECGM.

Regulatory changes mean that from this 2025 GSOO, natural gas, hydrogen, biomethane and synthetic methane will be defined collectively as gas, or covered gas. Renewable gas supply projects will be treated the same way as natural gas supply, and demand forecasts will now not distinguish between gaseous fuel types.

1.3 Supplementary information

Supporting material including previous GSOO reports, supply input data files, methodology reports, and figures and data is available on AEMO's website[20], and is listed in **Table 3**.

Key materials include:

- AEMO's **demand forecasting portal**[21] – interactive access to detailed forecasts of annual gas consumption and maximum gas demand, for each region and scenario included in this GSOO.

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[17] See https://www.energy.gov.au/sites/default/files/2022-08/Energy%20Ministers%20Meeting%20Communique%20-%2012%20August%202022.docx.

[18] See https://www.energy.gov.au/energy-and-climate-change-ministerial-council/working-groups/gas-working-group/gas/consultation-stage-2-reliability-and-supply-adequacy-framework-east-coast-gas-market.

[19] See https://www.energy.gov.au/sites/default/files/2024-03/ECMC%20Communique%201%20March%202024.docx.

[20] At https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo.

[21] At https://forecasting.aemo.com.au/.

- **Supply input data files**[22] – information (including capacity) about pipelines, production facilities, storage facilities, field developments, and any new projects or known upgrades considered in this GSOO analysis. The files also provide an update of reserves and resources, and cost estimates used for GSOO modelling[23].
- **2025 VGPR** – a focused assessment of the gas supply-demand balance to 2029 in Victoria's Declared Transmission System (DTS).

Table 3 Other relevant reference materials

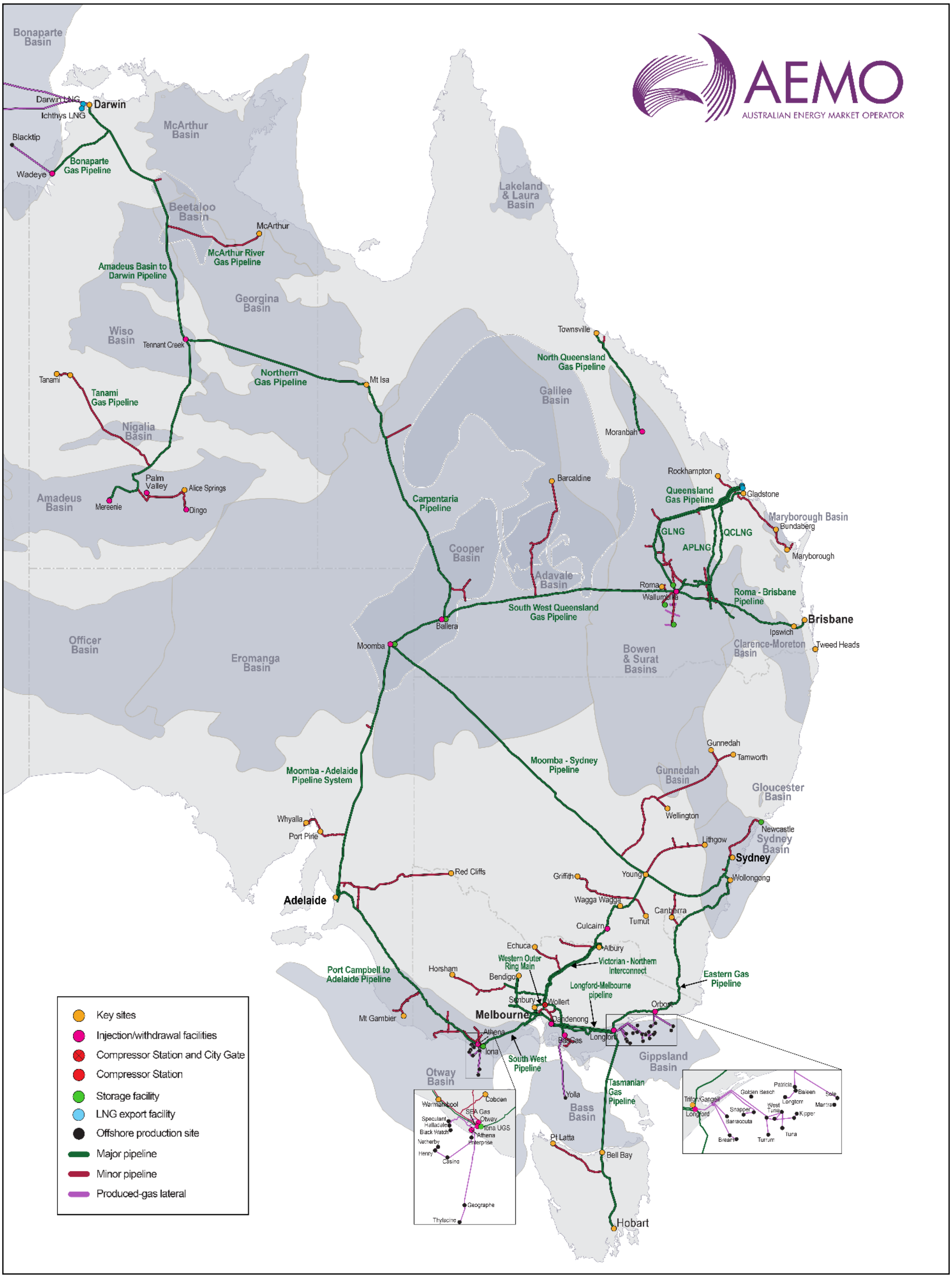
Information source	Website address and link
Gas Bulletin Board – Map and Reports	https://www.aemo.com.au/energy-systems/gas/gas-bulletin-board-gbb
2025 *Inputs, Assumptions, Scenarios Report* (IASR), and Excel Workbook	https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr
Deloitte Access Economics, Economic Forecasts 2024-25	https://www.aemo.com.au/consultations/current-and-closed-consultations/2025-iasr
CSIRO and ClimateWorks, 2022 Multi-sector energy modelling	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-climateworks-centre-2022-multisector-modelling-report.pdf
Strategy.Policy.Research, Energy Efficiency Forecasts 2023 – Final Report	https://aemo.com.au/-/media/files/major-publications/isp/2023/iasr-supporting-material/2023-energy-efficiency-forecasts-final-report.pdf
ACIL Allen: 2025 Gas, liquid fuel, coal and renewable gas projections	https://aemo.com.au/-/media/files/major-publications/isp/2025/acil-allen-2024-fuel-price-forecast-report.pdf
ACIL Allen: 2024 Natural gas price forecast workbook	https://aemo.com.au/-/media/files/major-publications/isp/2025/acil-allen-2024-price-forecast-data-files.zip?la=en

Figure 8 provides a map of the basins, pipelines, and load centres across the ECGM in this 2025 GSOO.

[22] See https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo.

[23] The published file showing reserves and resources is based on AEMO's survey of gas producers and information from Rystad Energy, supplemented by 2024 GSOO data if required.

Figure 8 Map of basins, major pipelines, and load centres



2 Gas consumption and demand forecasts

This section outlines forecasts of annual gas consumption and maximum daily gas demand across the various customer sectors of gas. The forecasts presented are for the *Step Change* scenario, unless otherwise specified. The forecasts are available on the AEMO Forecasting data portal[24].

Key insights

- Excluding gas exported from Queensland through LNG, gas consumption fell in 2024, with milder weather and lower industrial consumption contributing to the falling trend in gas consumption observed in recent years.
- **Annual consumption is forecast to decline modestly over the forecast period.** Consumption is impacted by declines from industrial users (changes in operating plans) and electrification of residential and small commercial users. The expected reduction in gas use from electrification of heating, cooking and other traditional residential and commercial appliances is also anticipated to reduce the peak day demands, particularly in southern regions.
- **Gas for generation of electricity is forecast to increase** in the longer term due to growing electricity demand, coal generation retirements, and the need to firm renewable generation supply in the National Electricity Market (NEM). Higher coal generation availability than previously expected in the short term is reducing forecast gas consumption temporarily. Increasing renewable generation and storage connections, supported by market developments and the Capacity Investment Scheme[25], is expected to support the replacement of lost energy production when coal retires, but peak gas use is forecast to increase, particularly in winter when renewable generation output is likely to be lower.

2.1 Total gas consumption forecasts

Forecast gas consumption under the *Step Change* scenario over a 20-year period is shown in **Figure 9.** Each scenario is broken down by consumer type across the ECGM, with the drivers and trends of each sector discussed in Section 2.2.

The 2025 GSOO forecast of annual gas consumption for the *Step Change* scenario projects a gradual decline in use, like that shown in the 2024 GSOO. Exports of LNG remain the largest consuming component of the forecast, representing approximately two-thirds of total gas consumption in 2044.

Residential and commercial consumption is forecast to decline over the forecast period, while industrial consumption is relatively flat after some initial plant closures.

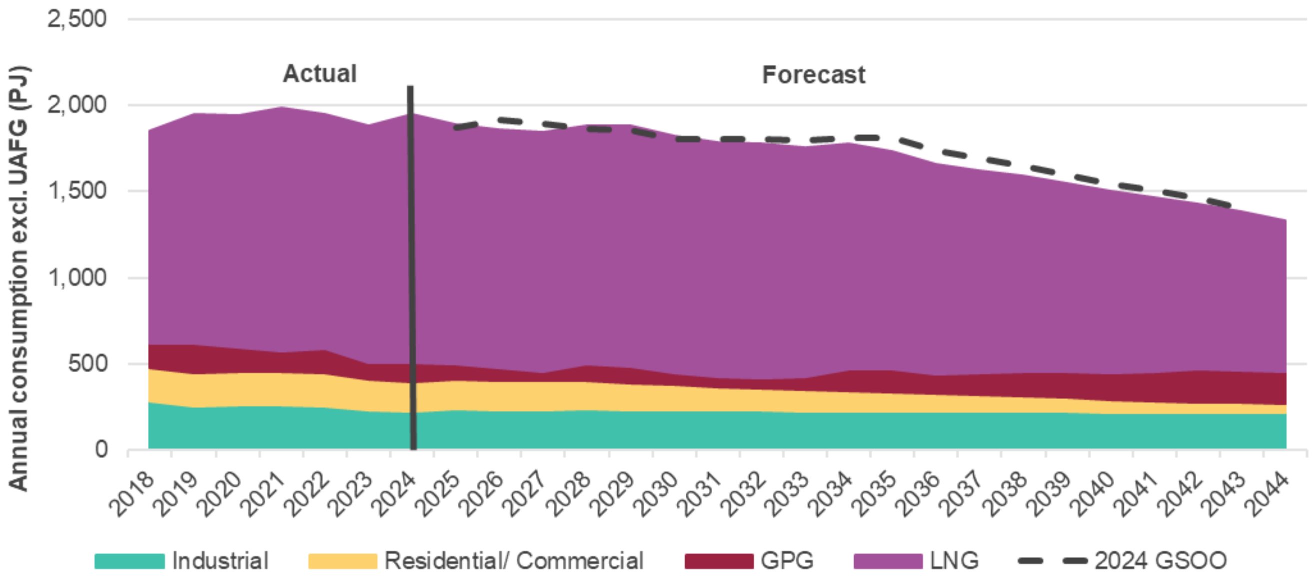
Gas consumed for gas-powered electricity generation (GPG) also varies over the forecast period, with a rising role for GPG to 'firm' electricity supplies provided by renewable generation, to ensure reliability and security of supply,

[24] At https://forecasting.aemo.com.au/. First select either **Gas/ Annual consumption** or **Gas/ Maximum Demand**, then select 'GSOO 2025' from the Publication drop-down.

[25] The Capacity Investment Scheme is an Australian Government scheme to accelerate the deployment of renewable energy and storage technologies. See more at https://www.dcceew.gov.au/energy/renewable/capacity-investment-scheme.

particularly as coal generators retire and renewable generation provides a growing proportion of electricity. In 2044, GPG is forecast to represent 13% of total gas consumption, like the industrial sector, but daily use is expected to be highly variable unlike industrials.

Figure 9 Actual and forecast total annual gas consumption, all sectors, *Step Change* scenario, 2018-44 (petajoules [PJ])



Note: Northern Territory domestic gas consumption is included from 2020 onwards. Northern Territory LNG forecasts are excluded.

Key drivers for the *Step Change* scenario are:

- Short-term forecasts for residential and small commercial consumption have been revised down relative to the 2024 GSOO to reflect reductions in per-household consumption observed last calendar year in response to higher prices and milder winter temperatures[26]. AEMO considers that the observed declines in consumption in recent years are greater than expected from weather impacts.
- Residential and commercial consumption is forecast to slightly decline in the short term, with more significant fuel-switching to electric appliances forecast in the medium to longer term (particularly in Victoria and New South Wales). Electrification and other factors are expected to reduce residential and small commercial gas consumption by 125 petajoules (PJ), from 176 PJ in 2025 to 51 PJ in 2044, despite rising population and economic growth.
- Gas consumption from large commercial and industrial users is expected to decline by approximately 9 PJ by 2027 due to the permanent closures of some facilities as advised by industrial operators in this GSOO. Following this, gas consumption is forecast to remain relatively stable.
- The 2025 GSOO forecasts a long-term increase in gas consumption for GPG, with growing peak day gas volatility in winter. The forecast growth of GPG reflects an inverse correlation to the availability of coal

[26] The 2024 winter was the second-warmest on record, with all states and territories excluding Tasmania among their top 10 warmest on record (see http://www.bom.gov.au/climate/current/annual/aus/#tabs=Temperature). Victorian Effective Degree Days (EDD) in 2023 and 2024 were below the 24-year average. AEMO's forecasting approach applies long-term average weather patterns in its forecasts, rather than sustaining these historically abnormal conditions across the forecast horizon. More information on this approach is in AEMO's 2025 *Gas Demand Forecasting Methodology*.

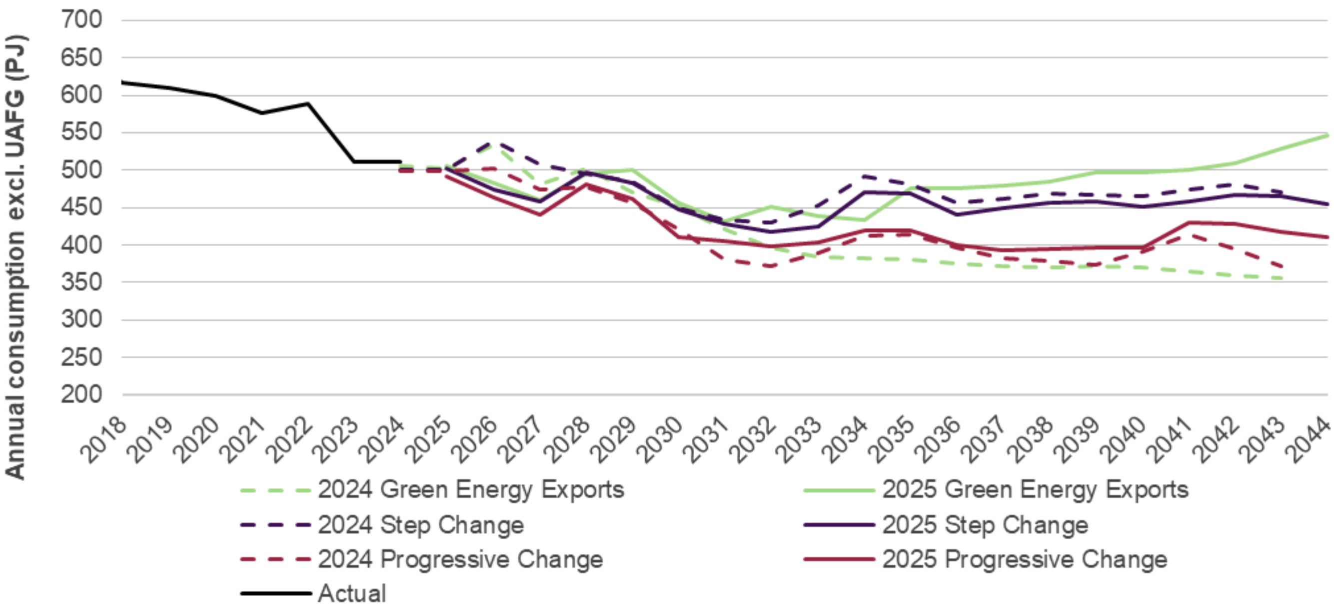
generation, with several key plant announced to retire prior to 2030, and others forecast in the 2024 *Integrated System Plan* (ISP) to close soon after in *Step Change*. The extended availability of Eraring Power Station to August 2027 provides close to 15,000 gigawatt hours (GWh) of electricity annually, reducing the need for GPG. This represents a temporary reprieve in GPG consumption relative to the 2024 GSOO, as Eraring and Yallourn power stations are announced to retire in 2027 and 2028 respectively.

Figure 10 presents forecast domestic gas consumption, showing a decline in the short and medium term across all the scenarios, reflecting the potential for electrification of residential and commercial loads. For the *Step Change* and *Progressive Change* scenarios, the overall trends are very similar to those of the 2024 GSOO, notwithstanding changes in consumption from large industrial loads (LILs) due to industrial closures and other production-based changes.

For the *Green Energy Exports* scenario, an uplift in gas demand is forecast because of the inclusion of a broader collection of covered gases within the GSOO (natural gas, biomethane, hydrogen and synthetic methane). *Green Energy Exports* includes forecast consumption of hydrogen in the production of "green commodities" in the steelmaking, ammonia, alumina and methanol production industries, providing a significant potential growth driver relative to the other scenarios in the longer term.

A key point of difference for *Step Change* between the 2024 GSOO and 2025 GSOO forecasts relates to the forecast consumption of gas for electricity generation. These differences are described in Section 2.4.

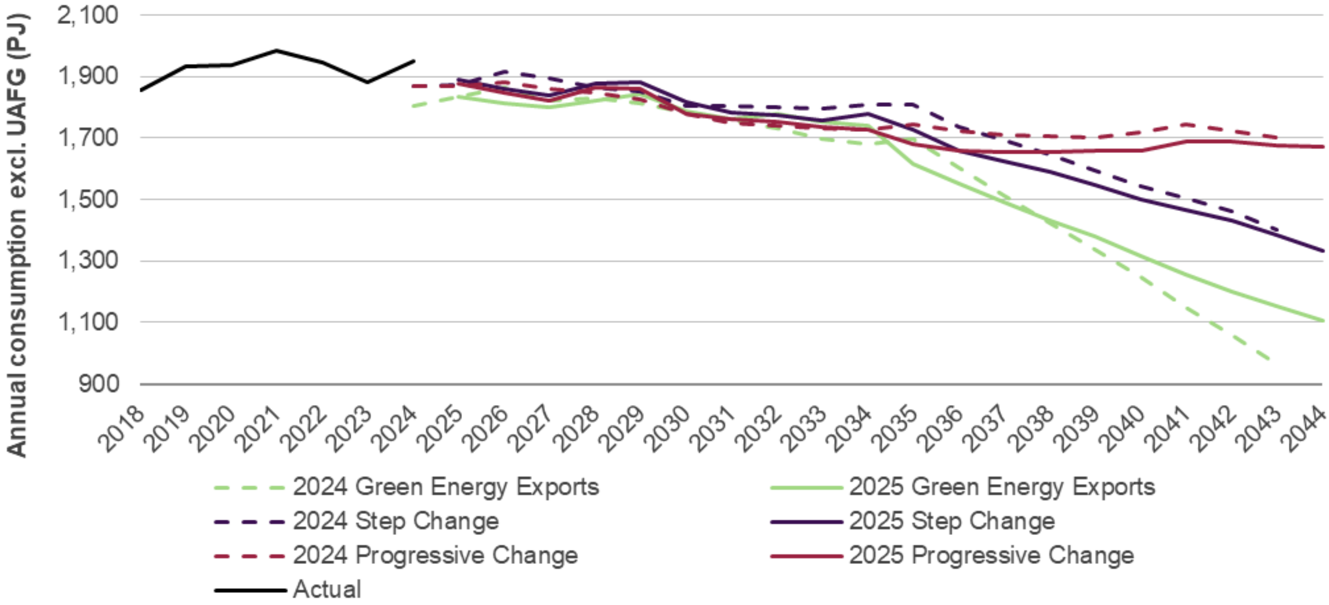
Figure 10 Actual and forecast domestic gas consumption, all scenarios, and compared to 2024 GSOO, 2018-44 (PJ)



Note: Northern Territory domestic gas consumption is included from 2020 onwards.

Figure 11 includes the consumption impact from LNG exports from Queensland. LNG export forecasts, as described in Section 2.2.3, is informed by survey responses provided by the LNG producers, and reflect long-term uncertainty, represented by a spread in forecast consumption across the scenarios.

Figure 11 Actual and forecast total annual gas consumption, all sectors, all scenarios, and compared to 2024 GSOO, 2018-44 (PJ)



Notes:

- The drop in consumption from 2024 (actual) to 2025 (forecast) is largely due to differences in LNG volumes.
- Northern Territory domestic gas consumption is included from 2020 onwards. Northern Territory LNG forecasts are excluded.

Major drivers of the gas consumption forecasts are provided in the following sub-sections.

Economic and population outlook

In 2024, AEMO engaged Deloitte Access Economics (DAE) to develop long-term economic and population forecasts for each Australian state and territory, which are a key input into AEMO's demand forecasts. DAE develops their forecasts using a macro-econometric model with key economic assumptions varied across the scenarios. These forecasts are equivalent to those published in AEMO's Draft IASR[27], which provides more information regarding the forecast trends.

Across all scenarios, economic growth is expected to remain weak in 2024-25 due to cost-of-living challenges, and weakness in dwelling and construction activity. In the medium to long term, variations in demographic profiles, labour productivity growth, decarbonisation pathways, and global conditions result in divergent economic futures in the scenarios. Key differences in the scenarios are:

- *Step Change* represents the central economic forecast, with an average annual growth rate in Australia's GDP of 1.8%.
- *Progressive Change* represents a scenario with weaker economic conditions, with industrial closure risks higher as a result. Annual average growth in Australia's GDP is lower, at 1.3%.
- *Green Energy Exports* represents a scenario with more buoyant long term economic prospects, including stimulus from global and domestic action to reduce emissions, leading to new export opportunities. The average annual growth rate in Australia's GDP is 2.5%.

[27] At https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr.

In all forecasts, AEMO anticipates that gas use per connection will continue to decline, as appliances that have traditionally used gas improve their efficiency or are replaced with alternatives. As such, this 'effective' connections forecast may not be representative of the forecast number of physical connections but represents the equivalent number of connections if all connections maintained historical usage levels.

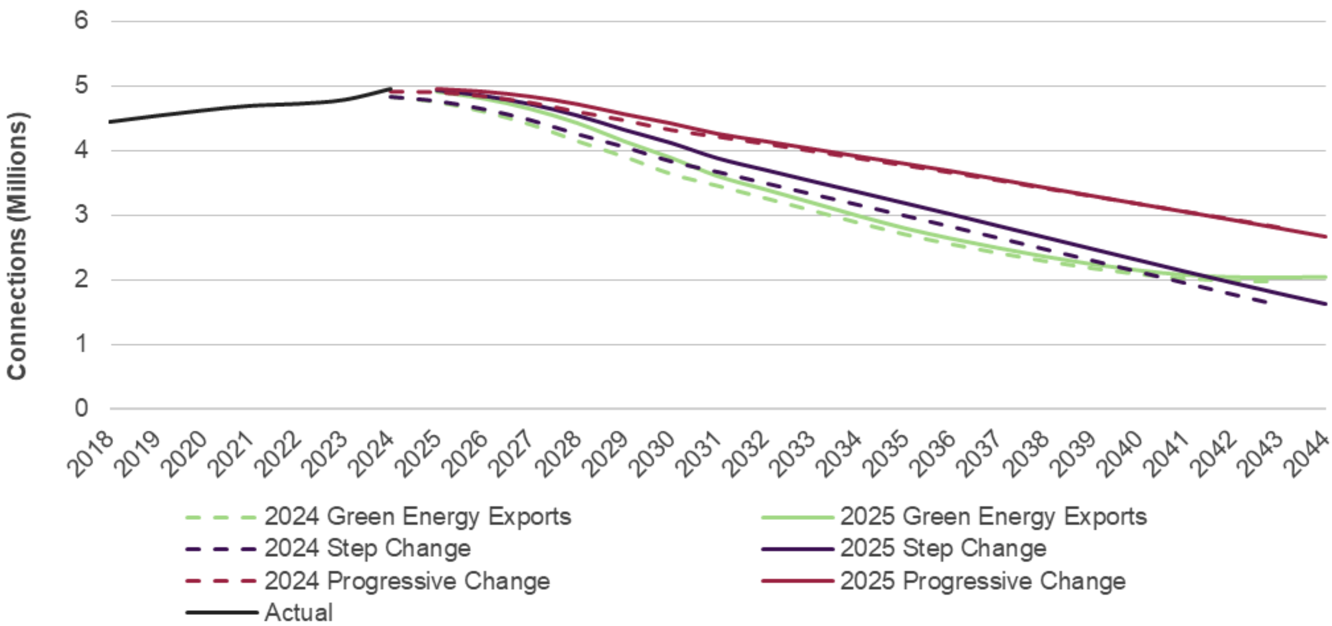
This alternative representation of electrification may be broken down further to account for new residential dwellings and commercial businesses that may never connect to gas, existing gas connections that partially fuel-switch to electricity, and existing gas connections that entirely fuel-switch to electricity (that is, disconnections).

Figure 12 shows actual and forecast effective connections over the forecast period. The connection forecast is driven by population growth and economic activity, adjusted for fuel-switching to electricity. Variance in effective connections across the scenarios reflects these fundamental assumptions relating to electrification.

The *Progressive Change* scenario retains the highest number of effective connections as it features the lowest amount of fuel-switching to electricity. Much greater levels of fuel-switching occur in the *Step Change* and *Green Energy Exports* scenarios, resulting in lower effective connections. Despite the population growth, the impact of electrification results in a halving of effective connections over the forecast.

After 2040, the *Green Energy Exports* scenario allows limited blending of hydrogen into the gas mix (up to 10% by volume), stemming the tide of declining effective connections.

Figure 12 Actual and effective forecast residential and commercial business connections, all scenarios and compared to the 2024 GSOO, 2018-44

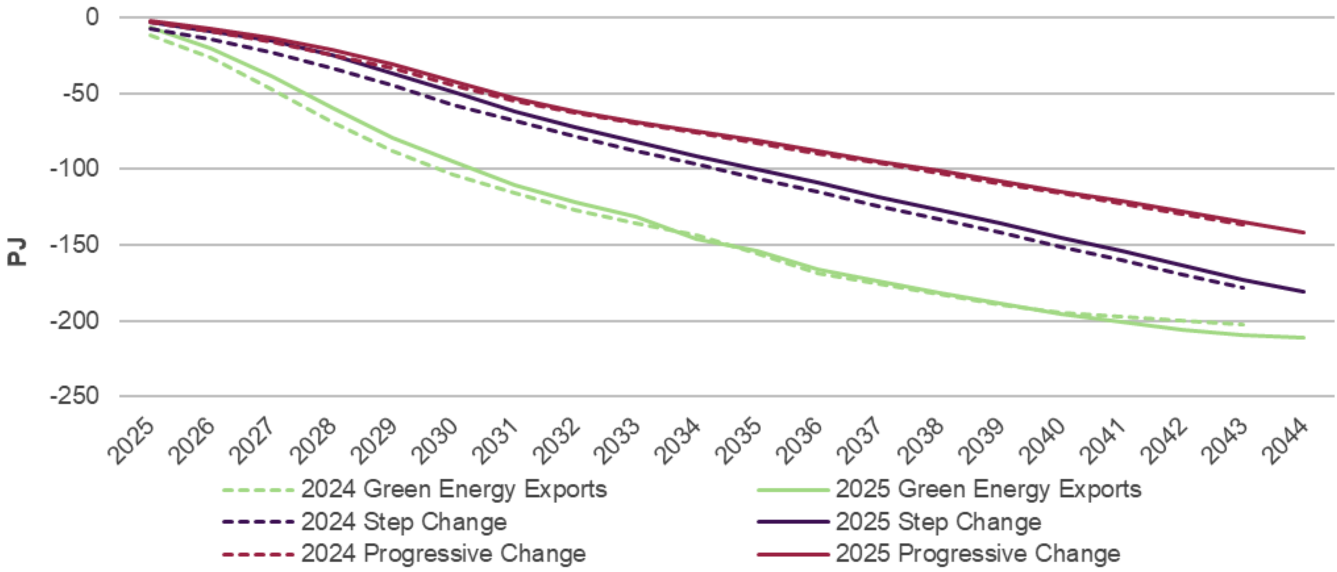


Note: 'Effective connections' presented here reflects a number of connections that is equivalent to if household consumption was maintained at historical levels.

Electrification

Electrification, or fuel-switching to electricity, reduces gas consumption across residential, small commercial and large industrial consumers and is expected to be a key driver of decarbonisation in Australia. **Figure 13** shows electrification projections across all scenarios.

Figure 13 Forecast changes in gas consumption from electrification by scenario, and compared to 2024 GSOO, 2025-44 (PJ)



The 2025 GSOO reflects a similar scale of gas reduction from electrification investments as was presented in the 2024 GSOO. Most electrification impacts are expected from residential and commercial consumers, such as from existing policies that are restricting new gas connections in Victoria and the Australian Capital Territory.

Reductions of gas consumption from electrification investments in the industrial sector are more modest, given the technical and operating challenges of replacing high temperature and process-specific production steps in operating facilities. The Australian Government's Safeguard Mechanism may encourage some fuel substitution, particularly in low-temperature process alternatives, but many processes have limited current electric alternatives that are technically or commercially available. Technological advancements in hydrogen alternatives in the medium to longer term to processes that currently rely on natural gas feedstocks may provide alternative options to natural gas, and this uncertainty is explored in the scenario variations.

Energy efficiency

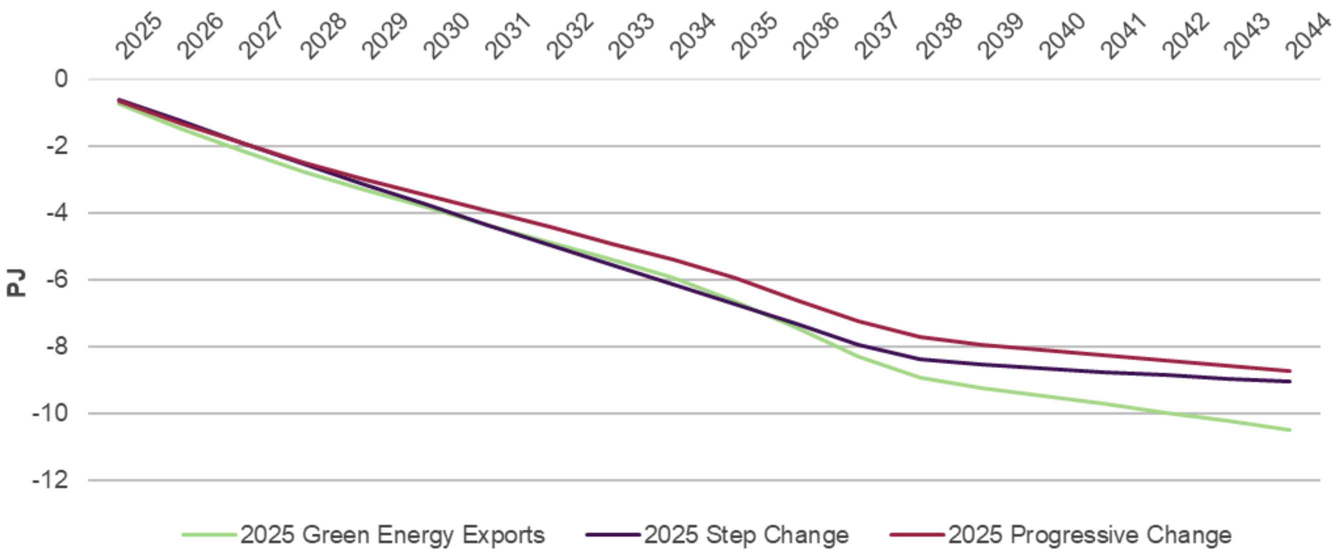
Various federal and state-based policy initiatives provide stimulus for gas consumers to improve their energy efficiency, through appliance improvements and/or through building thermal efficiency improvements. These policies include:

- The National Construction Code 2022 (NCC 2022), including whole of home (WHO) provisions, which allow households to offset their energy consumption with efficient appliances, as well as distributed photovoltaic (PV) systems and batteries.

- State energy efficiency schemes including the New South Wales Energy Savings Scheme (ESS), Victorian Energy Upgrades (VEU), and South Australia's Retailer Energy Productivity Scheme (REPS).
- Disclosure measures covering Commercial Building Disclosure (CBD), and the National Australian Built Environment Rating System (NABERS).
- Amendments to the Safeguard Mechanism (April 2023), designed to drive significant energy efficiency savings for Australia's largest emitting enterprises.
- Additional prospective policies including minimum energy performance standards (MEPS) for rental homes, and universal mandatory disclosure of energy ratings for existing homes (UMD) also are considered with variations in scale across the scenarios. Additional energy efficiency savings are greatest in *Green Energy Exports* given the higher relative drive for emissions reduction savings, whereas *Progressive Change* has lower, or slower effectiveness hindered by the weaker economic conditions and the lesser scale of emissions savings ambition.

Figure 14 shows energy efficiency savings forecasts for gas use for all scenarios. These forecasts mirror those of the GSOO 2024 as they are based on common assumptions contained in the 2023 IASR. Insights from the finalisation of the 2025 IASR will influence the 2026 GSOO.

Figure 14 Forecast reduction in gas consumption from energy efficiency by scenario, 2025-44 (PJ)



Wholesale and retail gas prices

Retail gas price forecasts are a key influence on gas consumption, as cost pressures across the economy will influence any discretionary gas used by consumers. In AEMO's forecasting approach, this is captured through an inelastic demand to price for residential, commercial, and small industrial customers, as outlined in AEMO's gas demand forecasting methodology. For the 2025 GSOO, AEMO retained the same elasticities applied in the 2024 GSOO, reflecting a modest response in total gas consumption from price movements. Larger changes in gas consumption through electrification or industrial closures may be in response, in part at least, to gas pricing, however these structural impacts to gas consumption are considered more effectively within those consumption drivers rather than as a higher elasticity to price fluctuations year-to-year.

AEMO engaged ACIL Allen to prepare wholesale gas price forecasts[28] which are considered with other data sources such as Australian Energy Regulator (AER) data, and data published by gas infrastructure operators to forecast retail prices. The wholesale price forecasts consider the influence of international prices on gas prices across the ECGM through LNG netback pricing, and levels of local competition.

Forecast prices are higher than those forecast for the 2024 GSOO, reflecting a range of changes including declining gas production in Victoria and having greater regard to spot market constraints in meeting winter peak demands.

The low assumed elasticity to price, coupled with low variations in wholesale price forecasts over time, results in year-on-year impacts of less than 1 petajoule a year (PJ/y) to 2044 from changes in forecast prices.

Hydrogen

Since the 2024 GSOO, changes to the National Gas Laws and NGR[29] have come into effect, requiring AEMO's gas supply adequacy assessment to be performed based on all covered gases, including natural gas, hydrogen and biomethane. As a result, the demand forecasts are presented based on total covered gases, on the understanding that this demand can be met by supply of any covered gas.

The only exception to this is 'dedicated hydrogen' (included as a subset of total covered gas), which is hydrogen required specifically for use as feedstock (that is, such hydrogen cannot be substituted by other gases). While hydrogen for transport is also 'dedicated', it is excluded from the forecast as is considered 'remote'. Further detail on the inclusions for the dedicated hydrogen forecast can be found in the 2025 *Gas Demand Forecasting Methodology*[30].

Forecast dedicated hydrogen demand to produce green commodities was applied in the 2025 GSOO based on modelling used in the Draft 2025 IASR. The consultant's results for hydrogen for all green commodities in the *Green Energy Exports* scenario were scaled to match the Australian Government Department of Climate Change, Energy, the Environment and Water (DCCEEW) National Hydrogen Strategy Central scenario[31], and further filtered to remove demand considered to be 'remote' from the ECGM.

Figure 15 shows the domestic gas consumption profiles of the *Green Energy Exports* scenarios of the 2024 GSOO and 2025 GSOO. The profile of covered gas consumption in the 2025 GSOO comprises a population of significant LILs with plans to employ covered gases (and/or electrify) at scale. These insights were informed by survey results. The analysis of a wider body of covered gas use (dedicated hydrogen for production of green commodities) was informed by industry-level analysis in the Draft 2025 IASR.

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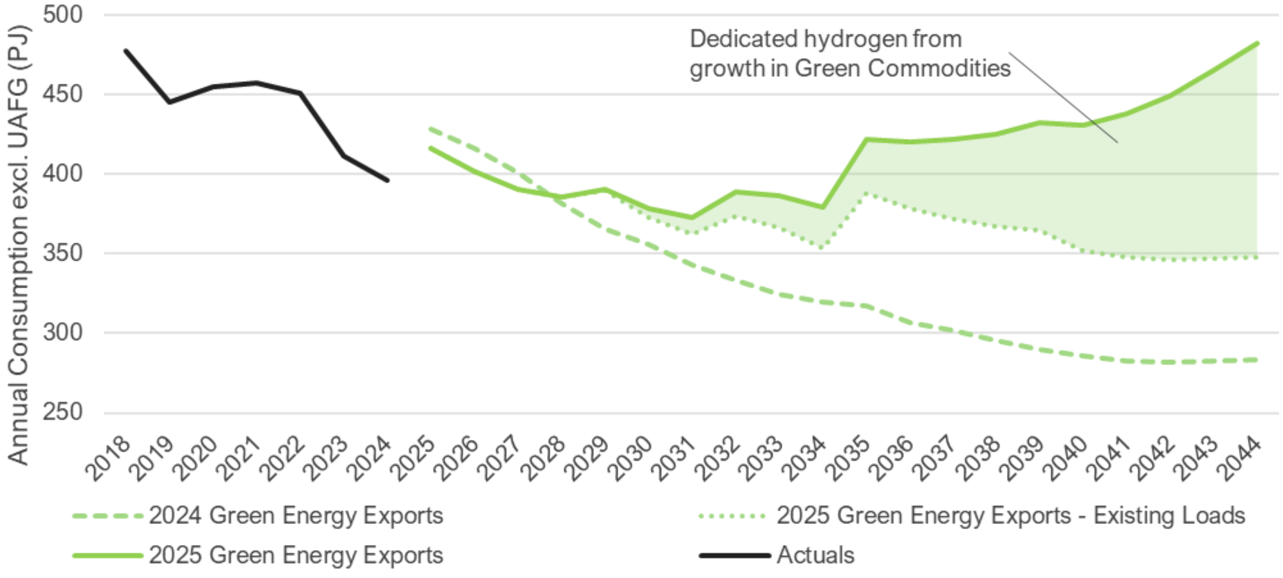
[28] ACIL Allen, *Gas, liquid fuel, coal and renewable gas projections*, at https://aemo.com.au/-/media/files/major-publications/isp/2025/acil-allen-2024-fuel-price-forecast-report.pdf.

[29] See https://www.energy.gov.au/energy-and-climate-change-ministerial-council/working-groups/gas-working-group/gas/extending-national-gas-regulatory-framework-hydrogen-and-renewable-gases.

[30] See https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo.

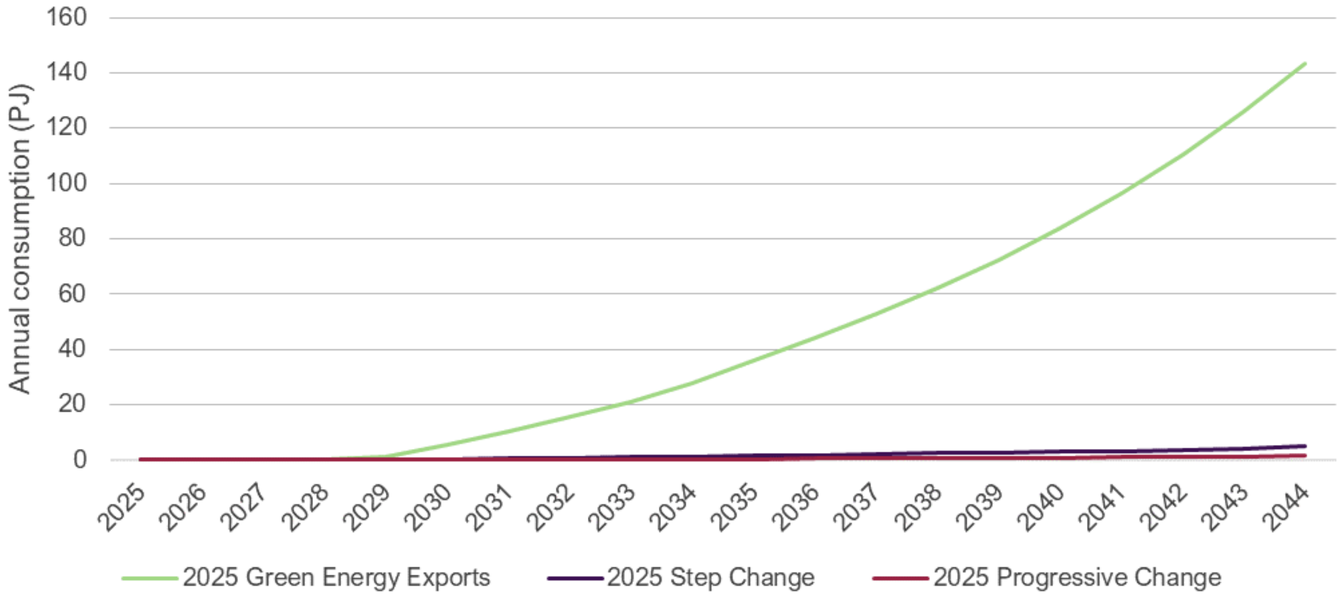
[31] See https://www.dcceew.gov.au/energy/publications/australias-national-hydrogen-strategy.

Figure 15 Actual and forecast domestic covered gas consumption, excluding GPG, *Green Energy Exports* scenario with dedicated hydrogen consumption for green commodities, and compared to 2024 GSOO, 2018-44 (PJ)



The remaining connected hydrogen for green commodities is largely dominated by the iron/steel sector, with small amounts for fuel-switching of existing natural gas usage in ammonia and alumina, as shown in **Figure 16**.

Figure 16 Forecast dedicated hydrogen demand, all scenarios, 2025-44 (PJ)



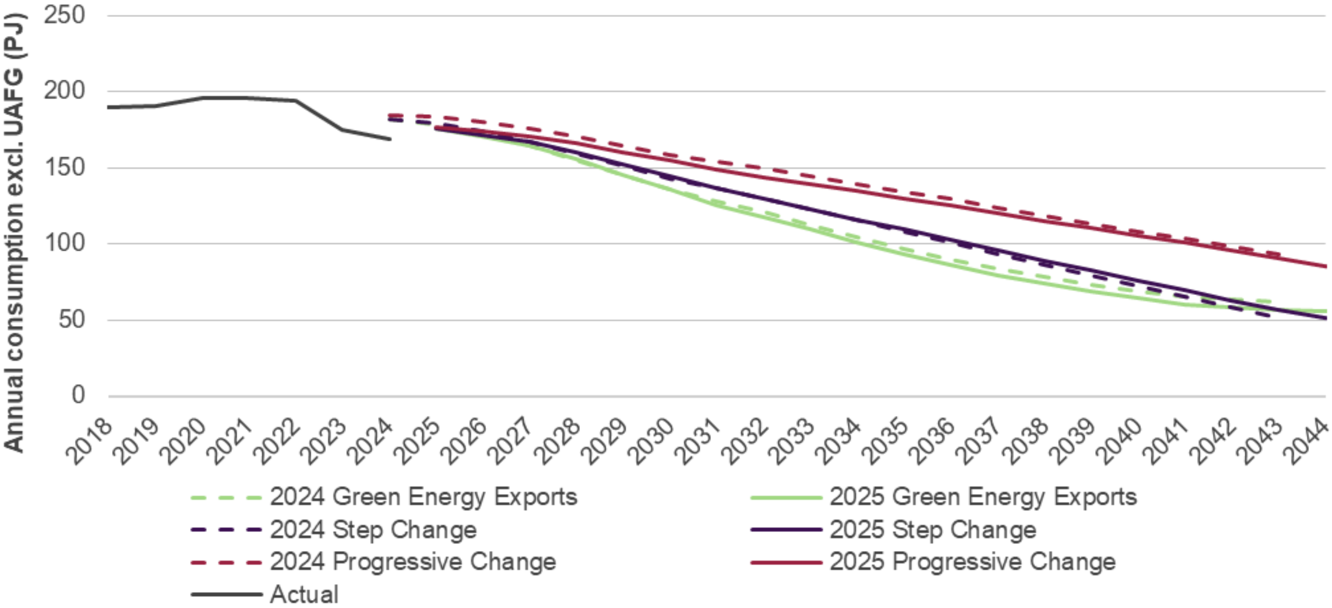
2.2 Consumption forecasts by sector

2.2.1 Residential and commercial consumption

Residential and commercial consumers are defined in the GSOO as those that use volumes of gas that are less than 10 terajoules (TJ) per annum and have a basic gas meter. AEMO forecasts residential and commercial gas consumption on a per connection basis. Forecasts are driven by population growth and economic activity and are adjusted for fuel-switching to electricity. Gas fuel savings from more efficient use and consumer price behaviour also influence the consumption forecast, as outlined in Section 2.1.

Figure 17 shows forecast residential and commercial consumption for all scenarios. Gas consumption is forecast to decline over the outlook period, consistent with trends observed in the 2024 GSOO. Despite lower consumption in 2023 and 2024 due to milder winters[32], forecast consumption rebounds in 2025 in line with AEMO's forecasting approach, which applies long-term average weather patterns. More information on this approach is in AEMO's 2025 *Gas Demand Forecasting Methodology*[33].

Figure 17 Actual and forecast residential and commercial annual consumption, all scenarios and compared to 2024 GSOO, 2018-44 (PJ)



Note: The Northern Territory is included in actual gas consumption from 2020 onwards.

In the *Step Change* scenario:

- Residential and commercial gas consumption in 2044 is forecast to be around 50 PJ, down by 125 PJ from the level of gas consumption in 2025.
- Electrification is the key driver of reduced gas consumption across the residential and commercial sectors over the forecast. When compared to the other scenarios, except Victoria and the Australian Capital Territory, the

[32] Victorian effective degree days (EDD) in 2023 and 2024 were below the 24-year average. EDD is used to quantify the impact of a range of meteorological variables. It is derived from heating degree days (HDD, calculated by subtracting the average daily temperature from a comfort level temperature) adjusted for wind chill, solar insulation and seasonal factors.

[33] See https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo.

Step Change scenario envisages that a larger share of new dwellings will be built without a gas connection or employ gas solely for cooking.

- Energy efficiency accounts for a 10 PJ of reduction in gas consumption by 2044.

In other scenarios:

- A slower decline in gas consumption from residential and commercial consumers is forecast in *Progressive Change* due primarily to reduced investments in electrification, from more challenging economic conditions. Rather, consumers instead invest in less structural changes, with greater use of energy efficient measures instead.
- The *Green Energy Exports* scenario in contrast is forecast to advance high levels of fuel switching to achieve the strong decarbonisation objective of this scenario. From 2040, some demand for hydrogen as a fuel source is expected through distributed supply, stemming the year -on-year reductions in gas consumption.

2.2.2 Industrial consumption

AEMO forecasts industrial sector consumption for the following customer category definitions for the GSOO:

- Large industrial loads (LILs) – customers in this category consume an amount of gas greater than or equal to 500 TJ per annum, accounting for over 65% of total industrial sector consumption. Each LIL is forecast individually, informed by future consumption predictions provided via survey and interview from the operators of the facility. This category comprises large customers such as mining operations, mineral processing and primary metal producers, fertiliser and chemical producers, steelmaking, building materials and paper production facilities, oil refineries and some large food processors. Any on-site electricity generation that consumes gas is also included.
- Small to medium industrial loads (SMILs) – customers in this category consume between 10 TJ and 499 TJ per annum at each individual site. SMIL forecasts are developed in aggregate, instead of at the individual site level.
- In addition to covered gases (natural gas, biomethane, hydrogen), the *Green Energy Export*s scenario includes hydrogen specifically “dedicated" to the production of green commodities. Existing gas consumers are those surveyed participants across the steelmaking, ammonia and alumina industries that plan to incorporate dedicated hydrogen over the forecast period. Gas use profiles also reflect changes in production, non-gas fuel switching and electrification. Total gas consumption also includes the contribution from “new” consumers of dedicated hydrogen.

For the *Step Change* scenario:

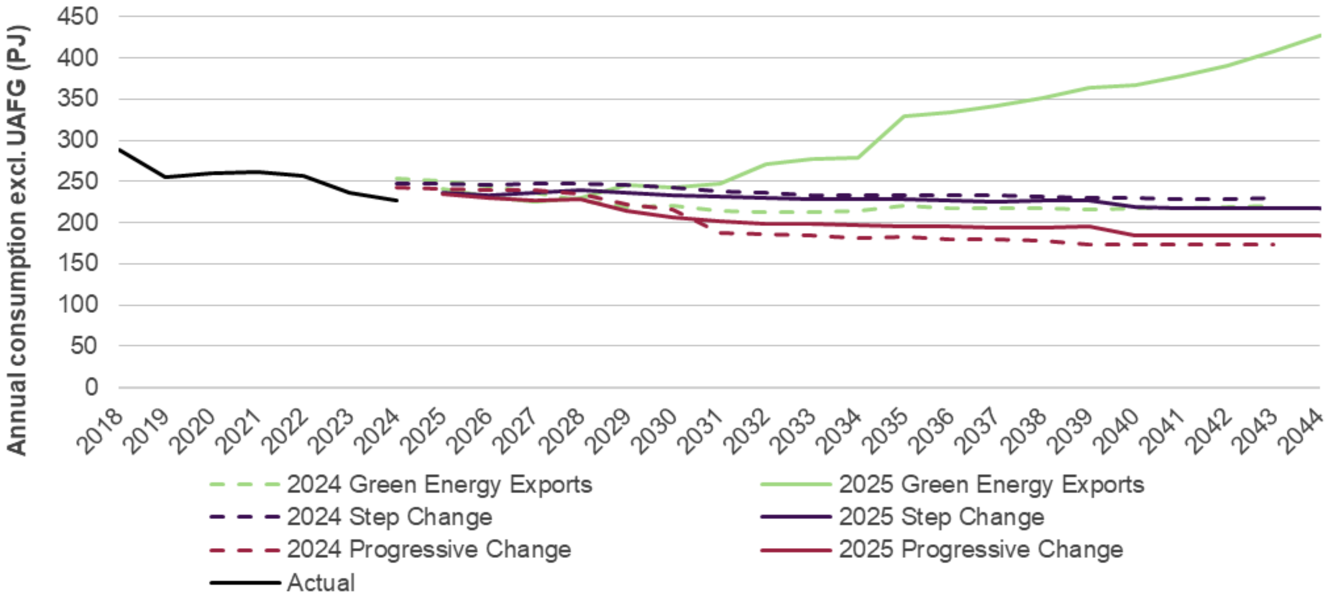
- Consumption is forecast to be over 230 PJ through 2026 to 2030 before declining to below 220 PJ in 2040 due to changes in production (LIL closures, slower economic activity), electrification and fuel-switching across the alumina, steelmaking and fertiliser industries.
- Electrification is forecast to offset natural gas consumption by 10 PJ in 2040, comparable with the impact forecast in the 2024 GSOO.
- The short to medium term profile of LIL gas consumption of 2025 GSOO is lower than in the 2024 GSOO, reflecting the early closure of facilities in Victoria and New South Wales. These facilities consumed over 4 PJ in

2023. Gas consumption from large commercial and industrial users is expected to decline by approximately 9 PJ by 2027 due to the permanent closures of some facilities as advised by industrial operators in this GSOO.

In other scenarios:

- *Progressive Change* forecasts lower gas consumption to 2030 compared to the 2024 GSOO, followed by higher levels over the remaining forecast period. These changes reflect revisions to the operating plans of consumers in the survey data, which include changes to asset closure plans and production plans.
- In *Green Energy Exports*, stable consumption of covered gas is expected in the near term until stronger growth in gas is forecast as new users are assumed to deploy hydrogen to produce green commodities.

Figure 18 Actual and forecast industrial consumption, all scenarios and compared to 2024 GSOO, 2018-44 (PJ)



Note: The Northern Territory is included in actual gas consumption from 2020 onwards.

2.2.3 LNG export

AEMO derives export consumption forecasts from surveys provided by the Queensland LNG producers which include contracted LNG exports, firm domestic supply contracts, and expected spot LNG export sales. These forecasts exclude expected LNG exports from the Northern Territory, which are not considered as participants of the ECGM, and are exempt from inclusion in the GSOO.

To service LNG producers' contract positions, sometimes access to third-party gas (or use of other suppliers in global gas portfolios) may be necessary to deliver to the relevant international customer.

LNG exported from Queensland's Curtis Island in 2024 was 1,440 PJ, a 70 PJ increase from 2023, and higher than survey responses indicated in the 2024 GSOO.

Figure 19 shows recent and forecast LNG exports for different scenarios and compared to the 2024 GSOO.

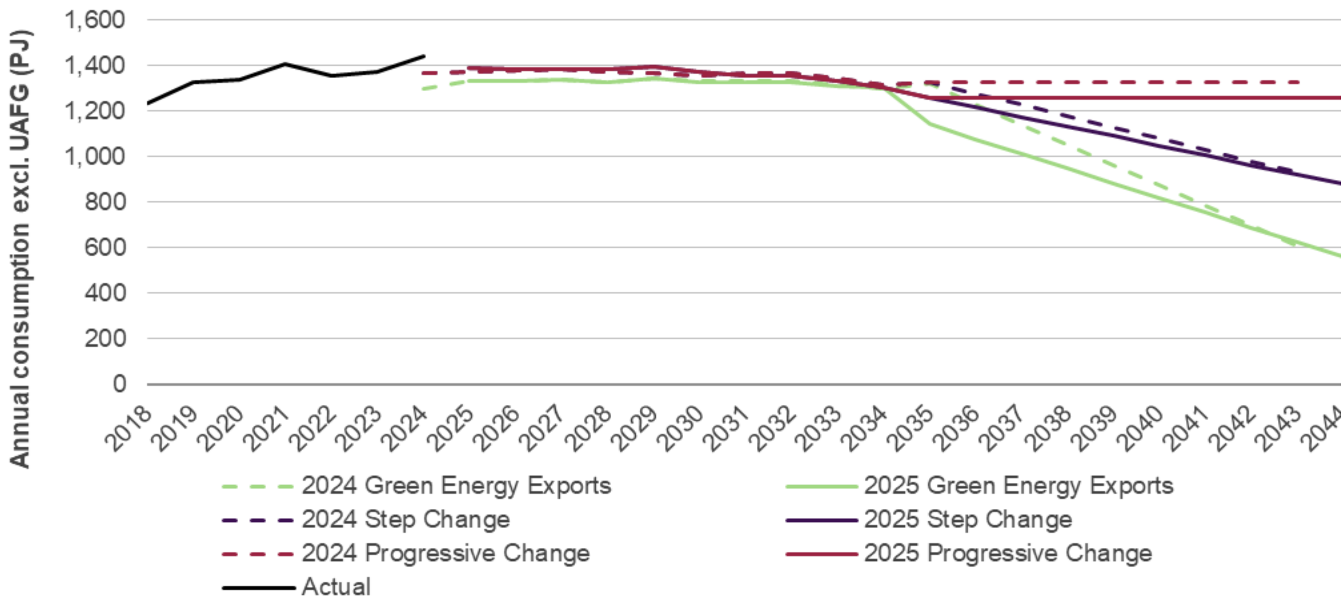
LNG exporters have forecast a level of LNG exports in 2025 of between 1,330 PJ (quantity under long-term contracts) and 1,387 PJ (quantity under long-term contracts and expected spot sales). The higher end of this range is 16 PJ higher than advised for the 2024 GSOO and 53 PJ lower than actual LNG exports in 2024.

The LNG producers advised a forecast outlook to 2035, beyond which AEMO has assumed a scenario dispersion in line with trends estimated in International Energy Agency (IEA) forecasts[34]. Differences between the 2024 and 2025 GSOO forecasts after 2035 in all scenarios are driven by lower exporting assumptions aligned with the World Energy Outlook (WEO) forecast.

The following applications of the 2024 IEA WEO to forecasts after 2035 is consistent with the 2024 GSOO:

- In the *Progressive Change* scenario, lower global economic growth and reduced steps towards global decarbonisation mean LNG exports have been forecast to be flat across the horizon, with greater continued use of current energy forms.
- The *Step Change* and *Green Energy Exports* scenarios apply increasing levels of decarbonisation action globally to lower energy sector emissions, so reducing levels of LNG export are forecast as many countries seek alternative energy forms with lower emissions footprints.
- The significant spread in forecast LNG export by 2044 reflects the strong uncertainty regarding the scale of export demand across these scenarios.

Figure 19 Actual and forecast liquefied natural gas consumption, excluding exports from the Northern Territory, all scenarios, and compared to the 2024 GSOO, 2018-44 (PJ)



2.3 Maximum daily gas demand forecasts

The maximum daily gas demand forecasts are split into three main components:

- Gas demand from residential, commercial and industrial customers.
- Gas for LNG export.

[34] The IASR aligns AEMO scenarios with IEA scenarios. AEMO has therefore aligned IEA forecasts of LNG export from Australia from the 2024 World Energy Outlook (see https://www.iea.org/reports/world-energy-outlook-2024) with AEMO forecasts where possible.

- GPG.

The following section discusses the seasonality of peak demand, followed by the maximum daily demand forecast for the first two components listed above, with GPG covered in Section 2.4.

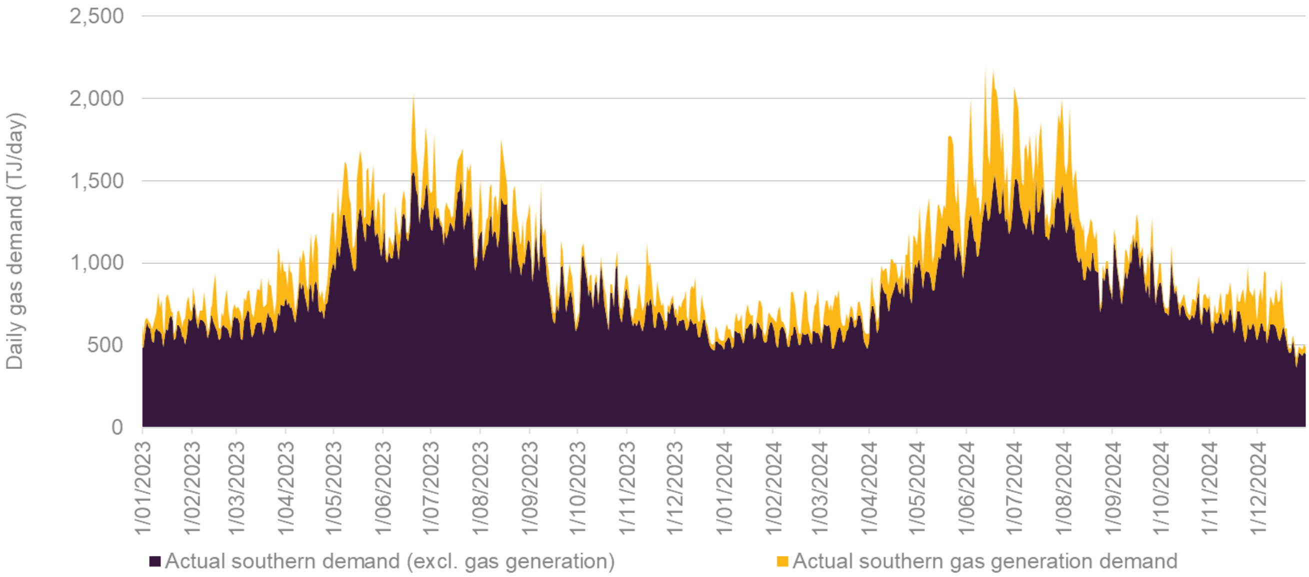
2.3.1 Seasonal variance and extreme peaks

Daily demand for residential, commercial and industrial consumers is strongly seasonal, with the maximum demand occurring in winter driven by the demand for space heating, particularly in the south. Customers in the northern states (Queensland and the Northern Territory) and industrial consumers in general show less seasonality in demand due to lower heating requirements.

The highest southern daily gas demands from residential, commercial and industrial consumers observed each year typically only occur on a relatively small number of days, when conditions compound to lead to very high utilisation of residential and commercial heating appliances. It is possible for these events to occur in conjunction with conditions in the electricity sector leading to high requirements for GPG.

Figure 20 below demonstrates the historical volatility and the strong seasonality of daily peak demand in the southern regions of New South Wales (including the Australian Capital Territory), South Australia, Tasmania and Victoria in 2023 and 2024.

Figure 20 Actual domestic daily gas demand in southern regions from January 2023 to December 2024, showing seasonality and peakiness (TJ)



Daily demand by residential, commercial and industrial consumers is shown as the dark purple area in the chart. While industrial loads and some household and commercial loads (such as cooking and hot water) operate consistently across the year, significant additional gas is used for heating in households and businesses in the winter months, leading to winter peaks in southern regions that may be two to three times higher than in summer.

Gas volumes required for GPG (yellow in chart) depend on the requirements of electricity consumers and the availability of other electricity generating technologies. High GPG may coincide with high gas demand by residential, commercial and industrial consumers, as cold weather in winter that drives higher gas demand typically also leads to higher electricity demand, and winter typically has lower utilisation of renewable resources (with shorter days reducing PV output, for example). As outlined in Section 2.1, the impact of electrification will contribute to the magnitude of winter peaks for GPG potentially growing at a significantly faster pace than summer peaks (depending on investments in other electricity technologies such as battery and hydro storages), and consequently, GPG is likely to become increasingly at risk of winter peaking.

Gas used for LNG exports may also be seasonal but is less impactful on seasonal peak conditions because the export is from Queensland, with much less demand volatility in the north. LNG demand has its typical seasonal peak in summer when key Asian markets experience their northern hemisphere winter.

2.3.2 Forecasts and trends in maximum daily gas demand excluding gas generation

Table 4 and **Table 5** show recent actual observed daily maximum demand for each region, as well as the seasonal forecasts of daily gas demand for all sectors excluding GPG in the *Step Change* scenario, across the summer and winter seasons. These forecasts include unaccounted for gas (UAFG) that is lost while being transported through the gas network.

Maximum daily demand is forecast with a probability of exceedance (POE), meaning the statistical likelihood identified through forecast models as to whether the forecast will be met or exceeded. A one-in-20 forecast is expected to be exceeded, on average, only once in 20 years, while a one-in-two forecast is expected, on average, to be exceeded every second year.

2024 was generally a mild year across most regions, which had the effect of reducing demand for gas. Hence, there is typically a noticeable increase between 2024 and the first year of the forecast period (2025), due to AEMO's methodology applying return to average weather conditions, with one-in-two year or one-in-20-year peak demand forecasts leveraging a longer history to construct the peak day gas distribution.

Regional forecasts for all scenarios (as described in Section 1.1) are available on AEMO's National Electricity and Gas Forecasting portal[35].

[35] At https://forecasting.aemo.com.au/. Note the peak day forecast estimates are at time of the combined peak for residential, commercial and industrial usage. The peak day gas used for electricity generation presented represents the gas generation at the time of the combined residential, commercial and industrial peak. Gas for gas generation may be higher than the presented value at other times when looking only at that demand sector.

Table 4 Total 1-in-2 and 1-in-20 forecast maximum demand, winter, all sectors excluding gas generation, including UAFG (terajoules per day [TJ/d])

	NSW		QLD (incl LNG)		QLD (excl LNG)		SA		TAS		VIC		NT	
	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20
2022	466		4087		346		134		22		1093		17	
2023	436		4229		316		133		20		982		18	
2024	464		4476		288		132		22		976		19	
Step Change														
2025	465	491	4,124	4,138	304	318	139	148	22	24	1,071	1,156	18	20
2026	458	484	4,112	4,125	296	309	139	147	23	24	1,047	1,130	18	20
2030	414	437	4,067	4,081	293	306	128	136	22	23	902	972	26	29
2035	362	382	3,748	3,761	280	292	115	121	24	26	711	763	27	29
2040	315	333	3,162	3,174	276	289	102	108	24	26	530	568	1	2

Table 5 Total 1-in-2 and 1-in-20 forecast maximum demand, summer, all sectors excluding gas generation, including UAFG (TJ a day [TJ/d])

	NSW		QLD (incl LNG)		QLD (excl LNG)		SA		TAS		VIC		NT	
	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20
2022	282		4534		339		97		21		585		17	
2023	267		4669		328		87		20		420		18	
2024	255		4686		297		84		19		312		19	
Step Change														
2025	294	321	4,628	4,641	312	325	93	101	21	23	419	502	19	21
2026	291	318	4,615	4,627	303	315	94	102	22	23	411	492	19	21
2030	270	293	4,565	4,578	301	314	90	96	21	23	366	435	28	31
2035	247	268	4,207	4,218	288	300	84	91	23	25	310	363	28	31
2040	226	243	3,545	3,557	284	296	80	85	23	25	261	298	1	1

Outlook for *Step Change*

Forecast regional trends in winter maximum daily gas demand (excluding gas for LNG export and GPG) are:

- **Southern mainland regions (Victoria, New South Wales** and **South Australia)** are projected to have the greatest potential for peak demand decline, with each of the three regions' maximum daily demand forecast to reduce by at least 30%, as the trends forecast to affect annual consumption also impact peak gas demand. Policies that support electrification, such as Victoria's Gas Substitution Roadmap, encourage this consistent decline over time. As outlined previously, regions that observed mild conditions in 2023 and 2024 (Victoria and South Australia more than New South Wales) are anticipated to rebound most in peak day gas consumption if average weather conditions are experienced.

- **Queensland** is projected to have an almost steady state for maximum daily demand during the forecast period, given less sensitivity particularly for residential and commercial users to cold temperatures. However, some slight downturn in demand from the end of 2020s is forecast, driven by industrial customer electrification.
- **Tasmania** is forecast to maintain a stable level of gas demand across the forecast horizon. The region has a material quantity of large industrial facilities, and responses to the 2025 GSOO surveying process for these customers reflect this stability.
- **Northern Territory** is anticipating industrial consumption expansion in the 2020s, prior to later industrial closures towards the end of the forecast period.

2.4 Gas consumption for electricity generation

GPG continues to play a crucial role in the NEM and the Northern Territory, primarily as a 'mid-merit' generator and a back-up source during instances of lower coal or renewable generation. GPG is also a critical source in meeting electricity demand at peak consumption periods.

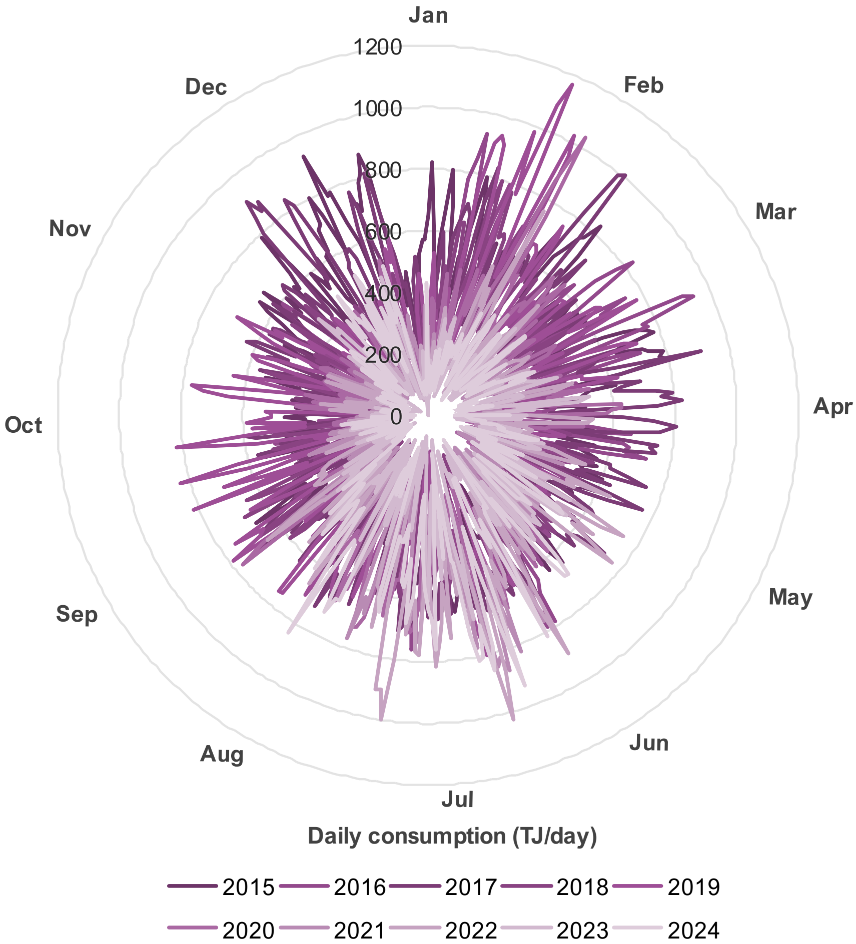
The 2025 GSOO GPG forecasts align with the optimal development path (ODP) identified in the 2024 ISP [36]. GPG is expected to provide critical support during periods of low variable renewable energy (VRE) output and as a back-up source to maintain system security and reliability, particularly after existing coal generators have retired. However, the extent to which GPG is required to operate will depend on several factors, including fuel costs, infrastructure availability, and the viability of alternative energy sources. These GPG forecasts, particularly late in the GSOO horizon, are therefore uncertain.

The role of gas generation is expected to change

Figure 21 shows historical daily volumes of gas consumption for electricity generation between 2015 and 2024.

[36] The gas generation forecasts differ marginally to those presented in the 2024 ISP report. The least-cost dispatch assumptions applied in core ISP modelling is replaced with assumptions regarding updated coal retirements, generator bidding, operational constraints, new generating capacity build timelines, transmission augmentation timelines, and availability of other generators to predict GPG consumption more accurately. Forecasts exclude the Yarwun (near Gladstone) and Diamantina (Mt Isa) power stations in Queensland and are averaged across different historical weather patterns. Yarwun and Diamantina are excluded due to their inclusion in the industrial load forecast instead. While Yarwun is NEM connected, Diamantina is not. The forecasts in the GSOO are also primarily presented on a calendar year rather than a financial year basis. For more information see Generation Information - July 2024, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/2024/nem-generation-information-july-2024.xlsx and NEM Transmission Augmentation Info - August 2024, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

Figure 21 Actual NEM gas generation daily consumption, 2015-24 (TJ/d)

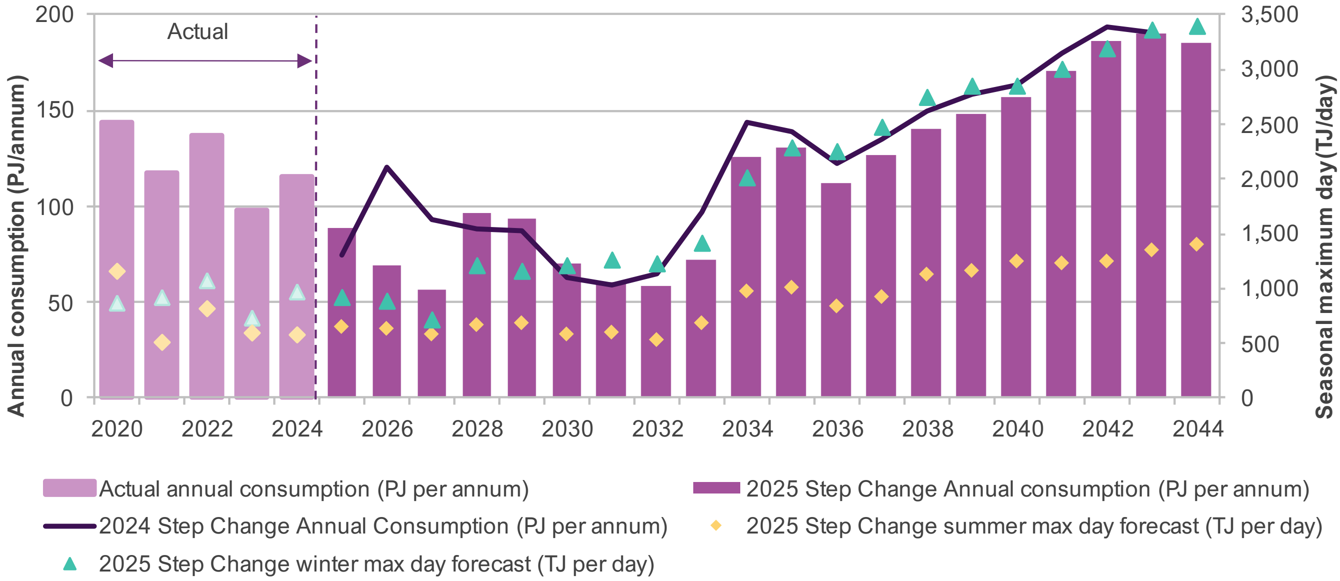


This figure highlights a gradual shift in seasonal usage patterns:

- During **summer,** frequent and high spikes in generation were observed historically (as shown in the darker-coloured data in the top half of the figure), however in more recent years, summer generation has reduced, with fewer and smaller spikes.
- During **winter,** consistent and less volatile operating levels occurred historically, however, in more recent years the frequency and magnitude of operation has been greater than summer months (as shown in the lighter-coloured data in the bottom half of the figure), and as high as 1,000 TJ/d (similar to maximum daily demand observed in summer periods historically).

Figure 22 shows recent actual volumes of GPG consumption, and forecasts based on the *Step Change* scenario.

Figure 22 Actual and forecast NEM and Northern Territory gas generation annual consumption (PJ/y) and seasonal maximum daily demand (TJ/d), Step Change scenario, 2020-44



Note: Northern Territory actual and forecast GPG consumption is included.

The figure shows that GPG consumption is expected to decline in the short term as new renewable and storage capacity comes online, supported by market developments and the Capacity Investment Scheme[37]. The lower short-term GPG forecast is different to the 2024 GSOO forecast across the same short-term horizon, which did not incorporate the ongoing operation of Eraring Power Station beyond its previous announced retirement date. Eraring Power Station is now expected to operate until August 2027, temporarily lowering the need for GPG if it remains available through that period. Historically, Eraring has provided approximately 15,000 GWh per annum over the past decade; with ongoing development of renewable generation and storage, it is expected that other generation sources than GPG will provide the primary electricity production replacement, but GPG will still be called on to firm the NEM during times of low output or availability from other resources, potentially with greater frequency.

Demand for firming capacity is forecast to rise in later years due to increasing electrification and the progressive retirement of coal power stations across the NEM. A significant shift in GPG seasonality also emerges, continuing the trend shown in Figure 22, with winter GPG consumption projected to increase. This change reflects growing electricity demand during colder months when generation from renewable generators is typically lower, especially for solar resources during the shorter days.

Figure 23 also shows that during the period to 2028:

- GPG is forecast to decline in the short term, reaching a low of 55 PJ/y in 2027.
- The extension of the operating life of the Eraring Power Station has contributed to a lower forecast for GPG during 2026 and 2027, compared to the 2024 GSOO GPG forecast.

[37] The Capacity Investment Scheme is an Australian Government scheme to accelerate the deployment of renewable energy and storage technologies. See more at https://www.dcceew.gov.au/energy/renewable/capacity-investment-scheme.

- GPG is forecast to peak in winter and will range between 700 terajoules per day (TJ/d) and 1,200 TJ/d, due to reduced winter renewable generation availability, while ongoing development of large-scale batteries and deep storages in the NEM reduce the summer exposure if storages are managed effectively.

Between 2028 and 2032:

- GPG consumption is forecast to rise between 90 PJ/y and 100 PJ/y due to lower coal generation availability in the NEM after the retirement of Eraring and Yallourn power stations in 2027 and 2028 respectively, then slowly decline as more renewable and storage capacity is commissioned, coupled with new transmission build.
- The forecast shows winter peak demand rising to approximately 1,200 TJ/d in this period, while the summer peak demand remains at a similar level to previous years.

In the long term, beyond 2032:

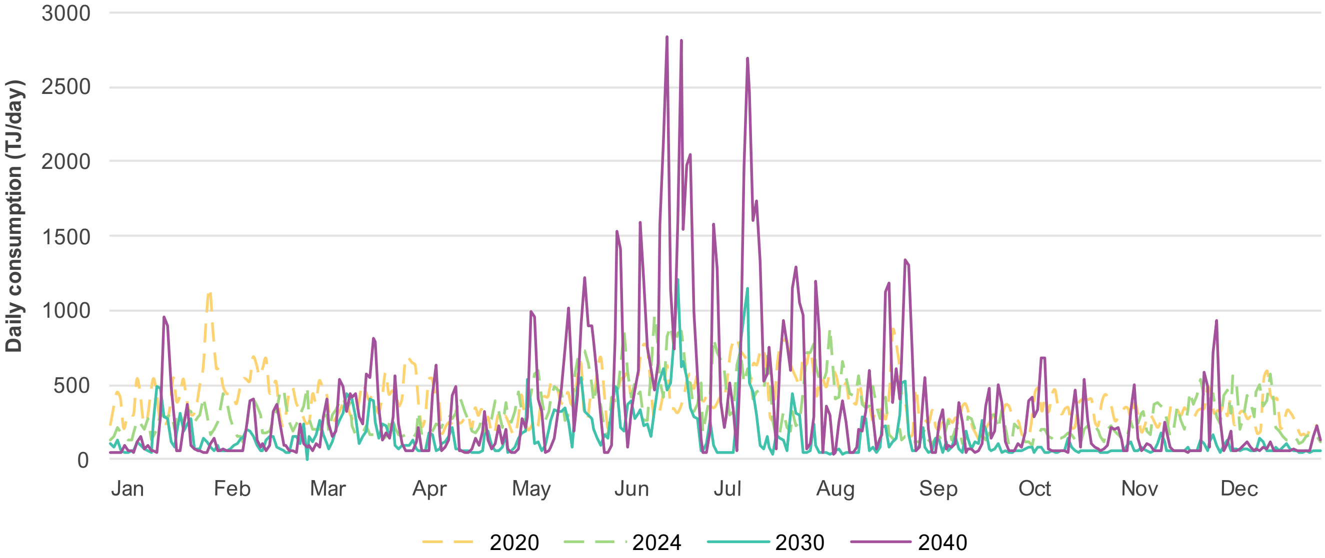
- GPG consumption is forecast to increase to 110-190 PJ/y to support electricity demand growth and high renewable penetration as coal power plants progressively retire.
- Peak demand is forecast to sharply rise, particularly in winter when renewable energy generation is typically lower. Consistent with AEMO's 2024 ISP, during periods of renewable generation scarcity, sources of electricity supply may trend to GPG, although alternatives such as diesel and electricity storage (pumped hydro and batteries) could provide a greater share of this firming capacity.

Forecast demand from gas generators will drive large peaks in daily consumption

Figure 23 presents the actual daily consumption profile in 2020 and 2024 and forecast profiles for 2030 and 2040 under one-in-10-year peak electricity demand conditions. It highlights the shifting role of gas in the NEM, transitioning from a consistent provider of electricity year-round to a more seasonal firming role, primarily in winter. It shows that:

- In 2020, gas consumption was relatively steady throughout the year, with peaks in summer exceeding 1,000 TJ/d to support peak demand conditions in summer.
- In 2024, summer peaks were observed to be around 500 TJ/d, significantly lower than in previous years. In contrast, winter peaks reached nearly 1,000 TJ/d during periods of low renewable energy availability, indicating the beginning of a seasonal shift in peak GPG demand. By 2030, renewable generation and storage are forecast to provide increasing energy production and firming capacity, reducing the potential need for gas generation while these resources are available, and conditions allow for effective management of energy storages. However, higher winter demands are increasingly forecast as electricity is used for heating. Coupled with reduced availability from coal generators as they retire, peak gas consumption may exceed 1,000 TJ/d in winter.
- By 2040, gas consumption is forecast to become more dependent on available renewable generation across the seasons. Under extreme conditions, forecast demand exceeds 1,000 TJ/d for more than 30 days and may surpass 2,500 TJ/d, nearly 2.5 times historical levels during the winter if electricity demands peak at times of low coincident renewable availability. Summer risks are forecast to remain, as cooling loads during hot conditions may still drive high peaking generation needs as demand increases. Lower consumption levels across the year may occur during more normal conditions with similar exposure to winter risks.

Figure 23 Actual and forecast NEM and Northern Territory daily gas consumption for electricity generation in 2020, 2024, 2030, and 2040, *Step Change* scenario, reference year 2019 (TJ/d)



GPG forecasts remain highly variable due to several unpredictable factors, including:

- Outages in coal power stations or transmission infrastructure.
- Fuel supply constraints.
- Fluctuations in electricity demand and renewable generation.
- The pace of investment in alternative firming technologies and energy storage solutions.

In the longer term, the degree of investment in renewable electricity generation, transmission developments, and storage developments (from consumer and utility-scale investments of various depths) will all influence the overall need for gas to contribute to the firming requirements of the NEM. More information on the development pathway for the NEM is available in the 2024 ISP[38].

Impact of unforeseen events

GPG consumption has shown a declining trend since 2019, but several spikes in consumption have occurred as a result of unforeseen events in recent years, including:

- In 2019, extreme heatwaves and bushfires led to outages at Victorian coal generators, and there were coal fuel shortages in New South Wales.
- In 2020, the collapse of transmission towers on the Heywood interconnector and prolonged outages at Queensland's coal-fired power stations resulted in higher GPG usage. In 2021, flooding at Yallourn coal mine disrupted supply of coal generation, while an explosion at Callide Power Station removed generation capacity.
- In 2022, the Russia-Ukraine conflict triggered a surge in global gas and coal prices, exacerbated by domestic flooding that reduced coal supply and prolonged periods of low renewable output.

[38] At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp.

- In 2024, the NEM experienced prolonged periods of low wind conditions and low rainfall yields across the southern and eastern regions, leading to considerable drops in wind availability and hydro generation while increasing the reliance on gas generation substantially.

Given the historical frequency of such disruptive events, AEMO accounted for such risks in the 2025 GSOO's GPG forecast by applying reductions in coal fuel availability, some limitations to coal capacity factors and the potential for generation developments to be delayed during construction and commissioning[39]. These assumptions act as a proxy for major unplanned events affecting other generators and represent a reasonable assumption of their impact on GPG.

Range of outcomes impacting GPG consumption

Forecast annual GPG varies across the 2024 ISP scenarios. **Figure 24** shows actual and forecast annual GPG usage for these scenarios in both the 2025 and 2024 GSOOs. Reduced forecast GPG consumption in 2026 and 2027 relative to the 2024 GSOO forecast is due to the extension of Eraring Power Station which temporarily increases coal availability above what was previously expected. Forecast annual GPG from the 2030s is lower than the 2024 GSOO due to the higher levels of renewable and storage capacity now forecast to be operational.

The timing of coal closures has a key influence on GPG requirements. If coal generators retire during the winter peak demand period, greater GPG consumption is anticipated than if the coal generators remain operational over the season. Retiring coal capacity after the winter season may improve gas adequacy, but will require consideration of gas adequacy when coal generators determine their retirement timing.

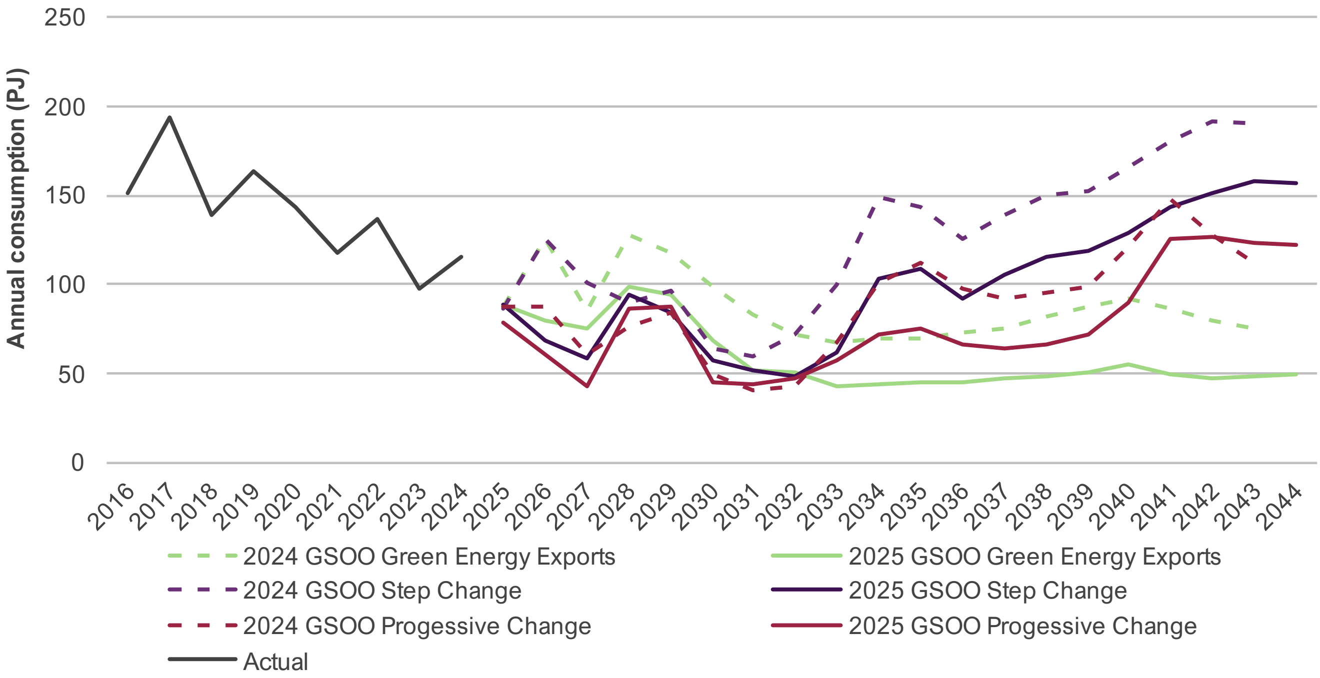
For this 2025 GSOO, AEMO has applied the specific coal closure date when one has been provided by the power station operators, and has applied a post-winter closure timing for generators when the coal closure date is not yet specified (but identified as either a coal closure year, or forecast to close ahead of the formal closure year in the 2024 ISP).

Compared to the *Step Change* scenario:

- The ***Green Energy Exports*** scenario is forecast to have slightly higher GPG consumption until 2032 as accelerated electricity load growth increases the use of GPG, until greater renewable generation, transmission and electricity storage projects can be commissioned (aligned to the 2024 ISP developments in this scenario).
- The ***Progressive Change*** scenario has lower GPG consumption due to slower growth in electricity demand and longer assumed availability of coal capacity (aligned to the 2024 ISP developments in this scenario).

[39] The delays to projects under construction and anticipated are consistent with the approach applied in the ESOO methodology, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/esoo-and-reliability-forecast-methodology-document.pdf.

Figure 24 Actual and forecast NEM and Northern Territory gas generation consumption, by scenario, 2016-44, reference year 2019 (PJ)



Notes:

- From 2020 onwards, Northern Territory actual and forecast GPG consumption is included.
- This chart shows the GPG forecast for the 2019 reference year only and may appear different to other charts in this report.

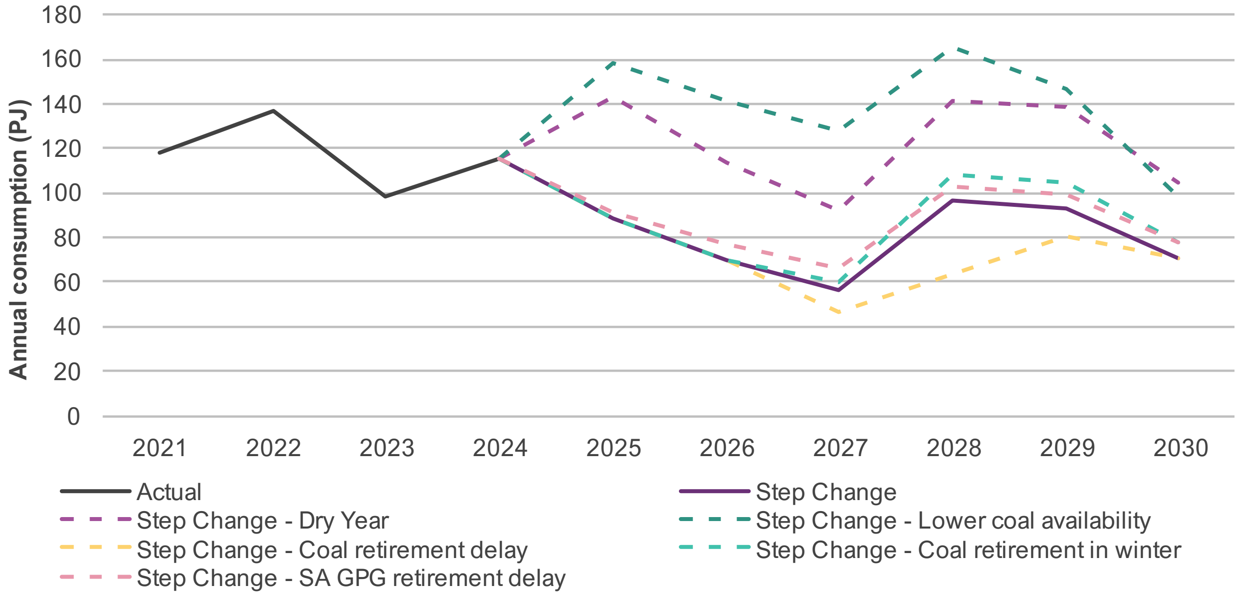
The 2025 GSOO also considered five sensitivities that explore plausible outcomes affecting gas consumption for electricity generation during the next five years, to 2030. Forecast annual volumes of gas generation consumption for the sensitivities with significant impacts on GPG are presented in **Figure 25.**

In comparison to the *Step Change* scenario:

- ***Step Change – Dry Year*** assessed the impact of a prolonged rainfall drought similar to the Millennium Drought (2006-07) that resulted in approximately 45% lower inflow yield than an average year. Consequently, annual GPG is forecast to be approximately 63% higher, depending on VRE penetration. While it is extremely unlikely that low rainfall yields will occur in all years, the sensitivity demonstrates the potential need in any year if rainfall yields were at extremely low levels.
- ***Step Change – Lower coal availability*** assessed the impact of key coal power plant outages similar to those observed in 2022. In these conditions, GPG demand could be double the forecast consumption in *Step Change*.
- ***Step Change – Coal retirement delay*** estimated the impact of the closure of the Eraring Power Station being extended by 20 months, as indicative of a coal retirement delay. In this sensitivity, GPG would be about 34% lower in 2028.
- ***Step Change – Coal retirement in winter*** assessed the effect of coal power plant retirements taking place in winter rather than post-winter as modelled in the *Step Change* scenario. In this case, annual GPG would be up to 12% higher than if retirements were timed after the winter season.

- ***Step Change – SA GPG retirement delay*** estimated the impact of the retirement of the gas-fired power plants in South Australia being delayed by five years. Annual GPG would be 6-16% higher under this sensitivity.

Figure 25 Actual and forecast NEM and Northern Territory gas generation consumption, sensitivities to *Step Change* scenario, 2021-30 (PJ)



Note: Northern Territory actual and forecast GPG consumption is included.

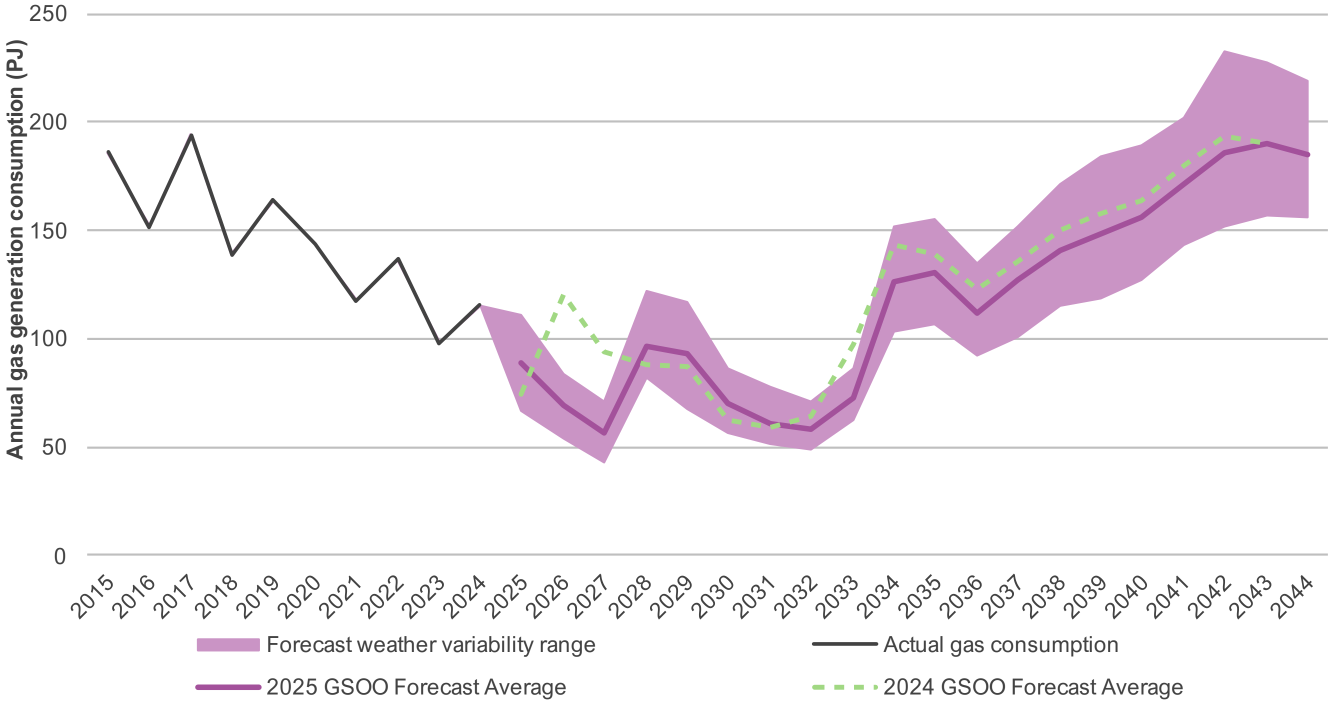
Weather variability

A range of different weather patterns[40] from a spread of historical weather conditions was used to generate the GPG forecast. **Figure 26** shows the range of projected annual GPG usage outcomes resulting from weather-driven variation in electricity demand profile, wind and solar availability, and rainfall inflows to hydro reservoirs. The GPG forecast published in the 2025 GSOO represents the average of these weather patterns, but the figure shows that reasonable variation may exist each year depending on prevailing weather conditions.

As higher generation from renewable sources will help achieve net zero economy targets, GPG is forecast to be more weather-dependent and volatile in future years, as it will be increasingly influenced by renewable energy intermittency and the development of firming capacity alternatives.

[40] AEMO simulated 10 weather patterns for the 2025 GSOO.

Figure 26 Actual gas generation consumption and forecast variation in consumption due to weather conditions, *Step Change* scenario, 2015-44 (PJ)



Note: From 2020 onwards, Northern Territory actual and forecast GPG consumption is included.

3 Gas supply and infrastructure forecasts

This section provides an overview of the reserves, resources and production forecasts for supplies connected to the ECGM and contracted supply. It also gives an overview of existing and proposed pipelines, storages, and LNG regasification terminals.

Key insights

- Overall, the sum of reported reserves and resources in existing, committed and anticipated supply has decreased since the 2024 GSOO. There has also been a reduction in the total reported resources available from prospective and uncertain supply projects.
- In comparison to the 2024 GSOO, annual forecast southern production capacity from existing, committed and anticipated fields is lower for 2025 and 2026, as gas producers estimated a lower need for gas supply in these years. This is enabling greater forecast production capacity in 2027 to 2032.
- Despite increased production in these years, southern production is still forecast to decline significantly, from 364 PJ in 2025 to 226 PJ in 2029, similar to the decline forecast in the 2024 GSOO.
- Northern annual production is forecast higher compared with the 2024 GSOO, due to improved forecast supplies from Queensland LNG producers.
- Several key infrastructure projects that will increase transportation capacity have commenced construction or have become committed and will support additional supply capability, if gas supplies are available to utilise that capacity.

3.1 Changes since the 2024 GSOO

Key infrastructure projects that increase storage and transportation capacity are under construction or have become committed since the 2024 GSOO

The following projects are under construction or have become committed[41] since the 2024 GSOO and will improve the midstream delivery capability of gas supply to southern demand centres:

- Lochard Energy's **Heytesbury Underground Gas Storage (UGS)** expansion project (HUGS Project Phase 1)[42] at Iona UGS will increase storage inventory capacity by 1.8 PJ to 3.5 PJ, and supply capacity by up to 45 TJ/d, from 2027.
- APA Group's **Kurri Kurri Lateral Pipeline (KKLP)** [43] project is a gas transmission and shallow storage facility under construction near Newcastle. KKLP will provide 72 TJ storage capacity and 60 TJ/d for the new Hunter

[41] Existing and committed' means gas fields and production facilities that are already operating or have obtained all necessary approvals, with implementation ready to commence or already underway. 'Anticipated' means developers consider the project to be justified on the basis of a reasonable forecast of commercial conditions at the time of reporting, and reasonable expectations that all necessary approvals (such as regulatory approvals) will be obtained and final investment decision (FID) made. 'Uncertain' projects are at earlier stages of development or face challenges in terms of commercial viability or approval.

[42] See https://www.lochardenergy.com.au/our-projects/hugs/.

[43] See https://www.apa.com.au/operations-and-projects/gas/gas-transmission/kurri-kurri-lateral-pipeline-kklp-project.

Power Station or the Sydney Short Term Trading Market (STTM). The project is scheduled for completion in 2025.

- The **Northern Gas Pipeline (NGP) Reverse Capability** project was completed by Jemena in August 2024, providing the NGP with the capability to flow gas into the Northern Territory from Queensland (from Mt Isa to Phillip Creek).
- Senex Energy's **Atlas Expansion** project commenced production in February 2025 and the **Roma North Expansion** project has progressed from anticipated to committed status. The Roma North Expansion project is under construction and scheduled to be operational before winter 2025. The two projects provide additional processing capacity of 57 TJ/d and 28.5 TJ/d, respectively.
- The conversion of APA's **Moomba Sydney Ethane Pipeline (MSEP)** to a natural gas pipeline will provide an additional 20-25 TJ/d capacity on the **Moomba Sydney Pipeline (MSP).** Ethane removal work has been carried out in 2025 and completion is scheduled for 2025.
- The **MSP off-peak capacity expansion project** will deliver two pressure regulation skids to increase the capacity in summer months when pipeline maintenance is being undertaken in specific sections of the MSP. This project is scheduled to complete by November 2025 and can increase the off-peak capacity of the MSP by 80-120 TJ/d.

Forecast southern production from existing, committed and anticipated developments in 2025 and 2026, however, has lowered relative to the 2024 GSOO:

- **Forecast production for Gippsland basin is lower for 2025 and 2026 than the forecasts provided for the 2024 GSOO.** The Gippsland Basin Joint Venture (GBJV) projects lower supplies in 2025 and 2026 due to changes in planned maintenance activities and impacts on production associated with Turrum Phase 3 project mobilisation activities.
- **A downgrade of reserves at the Thylacine North and Enterprise fields in the Otway basin**, as announced by Beach Energy on 12 August 2024, results in lower forecast production from these fields.

Lower forecast production in the coming two years, helped by reduced expected consumption from GPG due to Eraring's continued availability, has helped enable the reprofiling of gas production from existing reserves so forecast southern production from 2027 to 2032 is now higher, and higher expected supply availability from northern producers is also anticipated:

- Higher Gippsland production is forecast as a result of Turrum Phase 3 project progressing from uncertain to committed status and higher production from existing fields. Increased forecast production at Longford Gas Plant for 2028 allows Gas Plant 3 to remain online for an additional year, enabling higher peak day production quantities from the plant in winter 2028. Gas Plant 1 was retired in October 2024.
- Existing, committed and anticipated production from Queensland is expected to increase due to improved forecast supplies from Queensland LNG producers.
- The Carpentaria Gas Field in the Beetaloo basin in the Northern Territory has progressed from uncertain to anticipated status with an initial expected production of 10 TJ/d from 2026 which will increase to 25 TJ/d or 9 PJ/y from 2027.

- Improved forecast production from Queensland LNG producers and Beetaloo fields offsets the forecast reduction in supply from the Blacktip field in the Northern Territory and the delay of the Surat Gas Project in Queensland.

3.2 Reserves, resources and supply

Gas supply is dependent on continued investment to identify, prove, and then commercialise gas reserves and resources. Production forecasts for the 2025 GSOO rely on survey responses provided by producers forecasting the available quantities of gas, plans for extraction, and the capability and capacity of gas processing plants. While survey responses reflect a producer's current best estimate of anticipated production, gas production forecasts provided by market participants are exposed to technical and commercial uncertainties.

AEMO's GSOO forecasts of gas supply reflect the best advice and updated data provided to AEMO. The surveys for the 2025 GSOO were conducted for most gas producers in September 2024, and any material changes that occurred after the survey responses and were received up to February 2025 have been reflected in this GSOO. Project proponents provide consideration of project development lead time in their survey advice.

In this GSOO, the following definitions apply[44]:

- **Existing and committed** – gas fields and production facilities that are already operating or have obtained all necessary approvals, with implementation ready to commence or already underway.
- **Anticipated** – developers consider the project to be justified on the basis of a reasonable forecast of commercial conditions at the time of reporting, and reasonable expectations that all necessary approvals (such as regulatory approvals) will be obtained and final investment decision (FID) made.
- **Uncertain** – these projects are at earlier stages of development or face challenges in terms of commercial viability or approval.

3.2.1 Reserves and resources

Gas reserves and resources are classified based on technical and commercial viability to assess future supply availability and development risks:

- **Proven and probable (2P) reserves** are the best estimate of commercially recoverable gas from known accumulations, with at least a 50% probability that the actual recovered volumes will meet or exceed these estimates. In general, 2P reserves are associated with production projects that are existing, committed, or anticipated.
- **Contingent (2C) resources** are discovered gas volumes that lack current commercial viability for development, requiring further appraisal and investment before they can be classified as reserves. In general, 2C reserves are associated with uncertain projects.
- **Prospective resources** are estimated gas volumes from undiscovered accumulations that remain highly speculative, as they have not been confirmed through drilling or exploration activities.

[44] Updated Project Commitment Classification Classes (consulted in Gas Wholesale Consultative Forum (GWCF) held 5 June 2024 – Meeting #43, under business agenda "Update to GSOO/VGPR project classifications".

The reserves and resources estimate for the 2025 GSOO[45] includes all major fields connected to the ECGM, excluding fields in the Northern Territory developed specifically for LNG export. The volume of the estimated reserves and resources may change over time as they are developed, reassessed, or depleted.

Figure 27 shows that, compared to the 2024 GSOO, the total volume of reserves and resources across all categories has declined. The reclassification of 2C resources into 2P reserves suggests that certain gas projects are progressing toward commercial viability. There may be some differences in quantities reported in the 2024 GSOO due to differences in reporting methodology and submission timelines.

Figure 27 Reserves and resources: 2024 GSOO versus 2025 GSOO

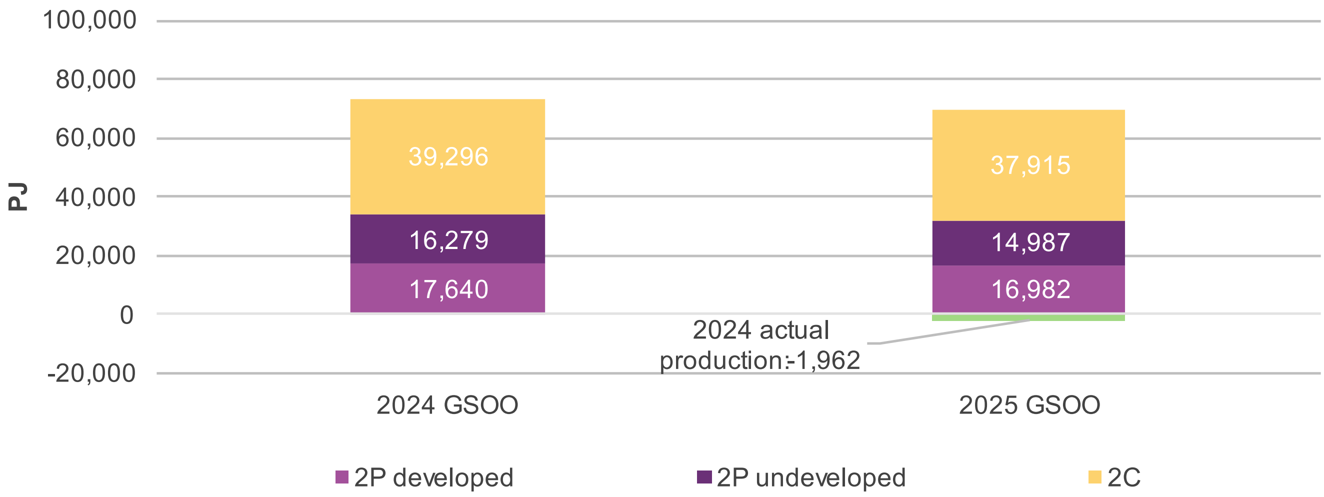
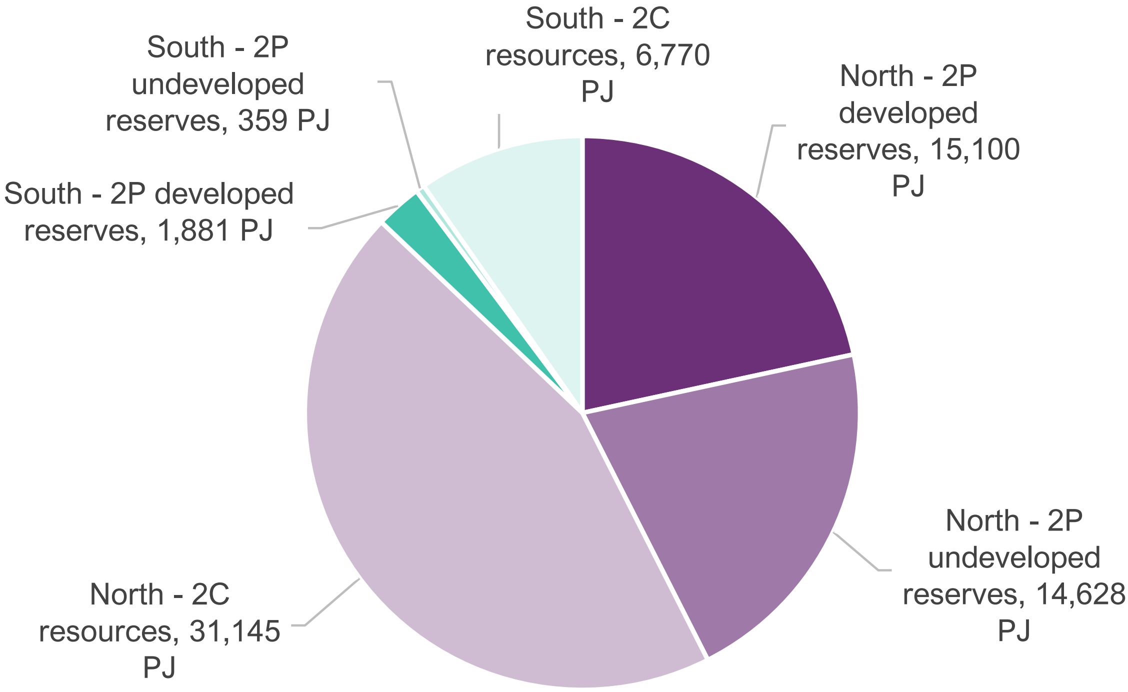


Figure 28 shows that the majority of 2P reserves and 2C resources are in the North, with around 70% of developed and undeveloped 2P reserves in the ECGM controlled by Queensland's LNG producers, where southern regions are experiencing a continued decline in reserves and resources.

[45] AEMO is reporting reserves and resources data in the 2025 GSOO as submitted to the Gas Bulletin Board, following the implementation of the Gas Transparency Measures in March 2023 and the completion of a full reporting period under these obligations. See more, https://aemo.com.au/energy-systems/gas/gas-bulletin-board-gbb/data-gbb/reserves-resources-reporting-and-facility-developments

Figure 28 Split of reserves and resources across northern and southern regions for the 2025 GSOO (PJ)



3.2.2 Available annual production

Following extraction, gas needs to be processed to meet standard gas quality specifications for transport in transmission pipelines and onward distribution to consumers. The rate at which gas can be produced is determined by a variety of factors, including:

- Capacity of the production plant, including maintenance and potential downtimes.
- Capacity of the additional processing plant (to manage specific impurities in the raw gas stream from the gas field, such as mercury or CO_2).
- Pressure in the gas well, which determines the rate of flow, particularly for conventional gas.
- The drilling program to access gas pockets, particularly for coal seam gas (CSG).
- The quality of the gas, particularly in terms of the need for additional processing.

Table 6 shows the annual production forecast from existing, committed and anticipated fields from 2025 to 2029, as advised to AEMO by gas producers. These quantities represent maximum annual production capability. The quantity of actual production depends on demand from domestic consumers and international exports. The table shows that:

- Gas production volumes from existing, committed and anticipated sources are generally higher than volumes projected for the 2024 GSOO. This production figure is in close alignment with that published by the Australian Competition and Consumer Commission (ACCC) in its December 2024 Gas Inquiry 2017-2030 Interim Report[46].

[46] ACCC. Gas Inquiry December 2024 interim report, at https://www.accc.gov.au/about-us/publications/serial-publications/gas-inquiry-2017-30-reports/gas-inquiry-december-2024-interim-report.

- Southern[47] gas production is forecast to decrease by over 30% over the next five years, driven by depleting legacy gas fields in the Gippsland region.
- Production forecasts in southern regions provided to AEMO are lower in 2025 and 2026, but higher from 2027 onwards, compared to the 2024 GSOO, due to gas production reprofiling, outlined previously.
- In the north, gas producers' production estimates from existing, committed and anticipated sources are higher than the 2024 GSOO.

Table 6 Forecast of available annual production as advised by gas producers, 2025-29 (PJ)

	Commitment criteria	2025	2026	2027	2028	2029
North (NT[A] and QLD)	Existing and committed	1,576	1,511	1,402	1,307	1,187
	Anticipated	60	123	250	341	429
	Total	**1,635**	**1,633**	**1,651**	**1,648**	**1,616**
	Difference from 2024 GSOO	*56*	*70*	*37*	*95*	*133*
South (VIC, NSW, SA[B])	Existing and committed	304	292	271	247	192
	Anticipated	33	39	35	54	34
	Total	**338**	**330**	**306**	**301**	**227**
	Difference from 2024 GSOO	*-40*	*-27*	*2*	*65*	*55*
Total gas production in the ECGM		**1,973**	**1,963**	**1,958**	**1,949**	**1,843**
Total difference from 2024 GSOO		*16*	*43*	*40*	*161*	*188*

A. Northern Territory supply excludes gas production from LNG export facilities in Darwin.
B. The Queensland component of the Cooper Eromanga basin appears in the South Australia category.

From 2028 onwards, the long-term production outlook represented by existing, committed and anticipated volumes for southern gas fields continues to be forecast in decline in this 2025 GSOO.

Figure 29 shows southern annual production from committed fields after 2028 is forecast to fall well below quantities produced during recent years. Substantial quantities of supply remain uncertain and subject to extensive feasibility studies before they can be classified as firm supply.

[47] "Southern regions" refers to fields and plants located downstream of the Southwest Queensland Pipeline (SWQP) and includes gas supply from the Cooper Eromanga basin.

Figure 29 Actual and forecast annual production from southern gas fields (excluding supply from LNG regasification terminals), 2021-44 (PJ)

3.2.3 Maximum daily production capacity

Maximum daily production capacity defines the quantity of total gas that can be injected into the system each day. This measurement of capacity is critical to the operation of the gas markets to ensure sufficient gas is available to meet peak winter demands. Most production facilities operate at or near maximum capacity, so annual supply forecasts are proportional to maximum daily or peak production capacity. Maximum daily production capacity is limited by the flows from connected gas fields, and by the maximum daily processing capacity at the gas plant. The combination of field flows and processing capability represents the maximum technical capacity of these facilities. The capability of mid-stream infrastructure to deliver this gas to demand or storage facilities is the other major factor in determining the gas supply adequacy assessments in Chapter 4.

Southern daily production capacity

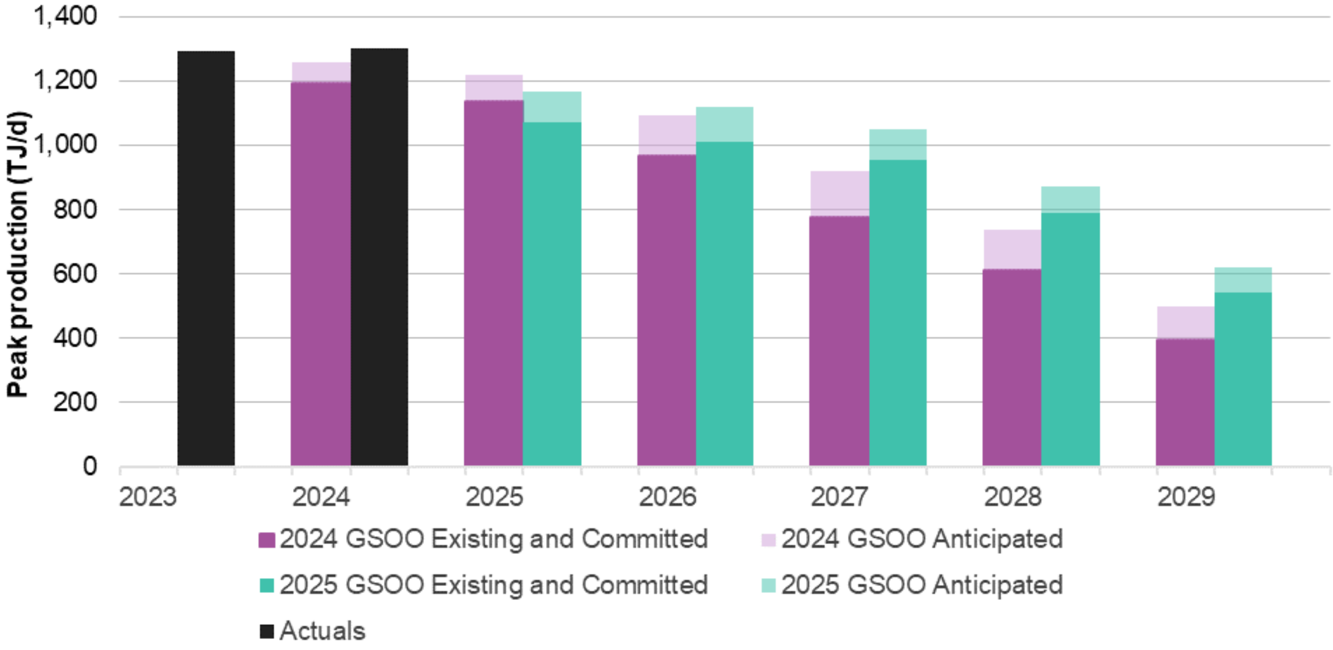
Consistent with the forecast decline in annual production (see Section 3.2.2), **Figure 30** shows that the maximum daily production capacity[48] from existing, committed and anticipated southern fields is projected to decrease by 47% from 1,165 TJ/d in 2025 to 618 TJ/d in 2029.

There is an uplift[49] in maximum daily production capacity from committed and anticipated supplies since publication of the 2024 GSOO, as a result of existing field production reprofiling and anticipated projects progressing from uncertain to anticipated status. Gippsland makes up a large proportion of total southern supply and is now forecast to produce 680 TJ/d until mid-2025. This represents a 198 TJ/d decrease in Gippsland's peak day production capacity during 2025, compared with the capacity previously reported in the 2024 GSOO.

[48] Maximum daily quantities have been reported as forecast capacities in June each year. Producers will typically plan for maximum throughput over winter months to accommodate high gas demands.

[49] Except for 2025.

Figure 30 Actual and forecast maximum daily production capacity from southern gas fields in June, 2023-29 (TJ/d)



As legacy fields in the Gippsland region deplete, southern daily capacity will continue to decline. Decommissioning works at Longford Gas Plant are already underway, with Gas Plant 1 shut down in October 2024. Supply resilience in the south is expected to substantially reduce as:

- **Legacy Gippsland basin fields deplete** – the Longford Gas Plant has historically relied on large legacy fields in the Gippsland basin to scale production up and down to respond to issues with other fields or platforms. As the production capacity of these legacy fields declines, Longford Gas Plant will have reduced ability to maintain production by ramping up these fields to cover a reduction in capacity from other fields. However, as compared to the production estimates informing the 2024 GSOO, Longford Gas Plant 3 operation expected to extend to December 2028, thereby improving the forecast maximum daily production in winter 2028.
- **Redundancy in plant capacity reduces** – the shutdown of Longford's Gas Plant 1 has left two remaining gas plants, with both required to achieve the 2025 peak day capacity of 700 TJ/d. If either of the two remaining plants is unavailable, the total production capacity of Longford could be reduced by up to 350 TJ/d.

Northern daily production capacity

In the north, production is relatively constant except when maintenance activities are required. Processing facilities operate at near full capacity all year so maximum daily production capacity is proportional to annual production. Northern gas fields are operated predominantly for LNG export demand and domestic demand from local customers does not vary seasonally.

3.2.4 Wells drilled

The continued development of gas supply for both domestic consumption and LNG exports necessitates the drilling of new wells across key gas basins. This process involves three primary types of wells:

- **Exploration wells**, which identify potential new gas reserves in areas indicated by geological surveys.

- **Appraisal wells**, which assess the commercial viability and extent of discovered gas resources.
- **Development wells**, which facilitate gas extraction through optimised reservoir management.

As part of the 2025 GSOO survey process, gas producers and explorers reported their drilling activity to AEMO. The reported drilling activity data is summarised in **Figure 31,** which shows:

- A decline in drilling activity for development wells is expected in 2025 and the first half of 2026 compared to previous years.
- The Surat and Bowen basins remain the focal point of drilling efforts, driven by the need to sustain CSG production for LNG export. Due to lower per-well productivity, CSG fields require a higher number of wells compared to conventional gas fields.

Figure 31 Historical and forecast number of development wells drilled, 2023 to June 2026

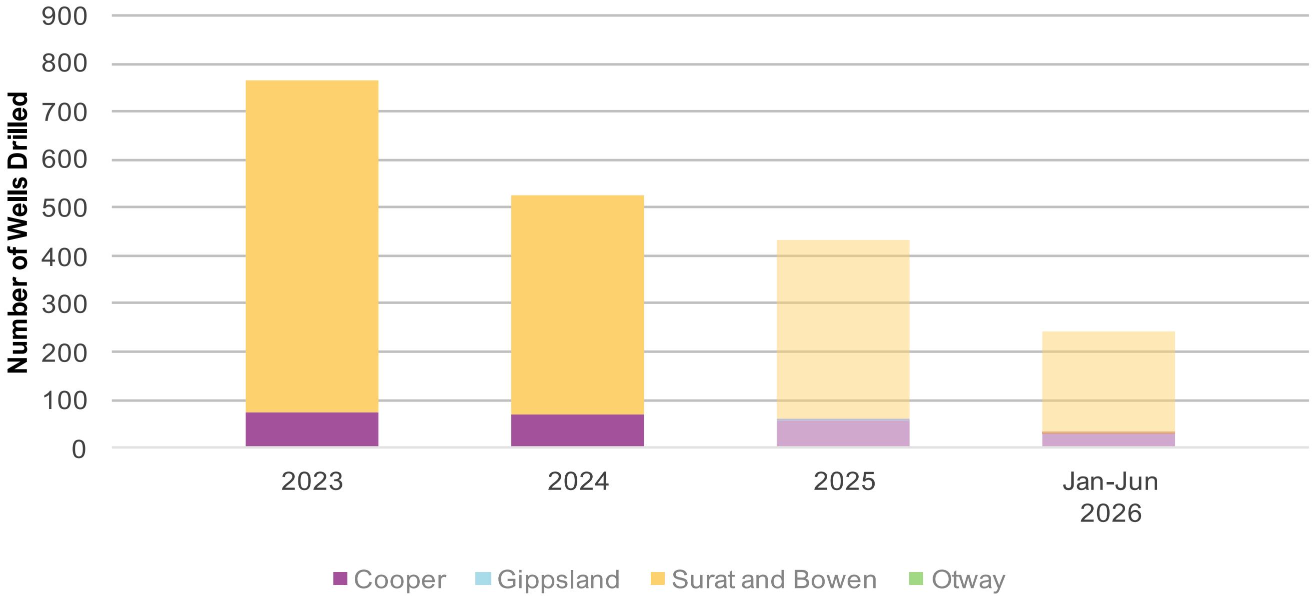


Figure 32 demonstrates the historical and forecast year-on-year exploration and appraisal activity for all basins in the ECGM. The exploration and appraisal activity in 2025 forecast to decline relative to 2024.

A consortium of gas producers (ConocoPhillips, Amplitude Energy, Beach Energy, Woodside) has contracted the Transocean Equinox[50] drill rig for exploration and well decommissioning in the Otway Basin, starting in 2025. If successful, the wells could connect to existing gas infrastructure near Port Campbell and help supply gas to the southern market later in the decade. For more information, see Chapter 4 of the 2025 VGPR.

[50] Beach Energy, Annual Report 2024, 12 August 2024, at https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/2A1540360/BPT_2024_Beach_Energy_Ltd_Annual_Report.pdf.

Figure 32 Historical and forecast number of exploration and appraisal wells drilled, 2023 to June 2026

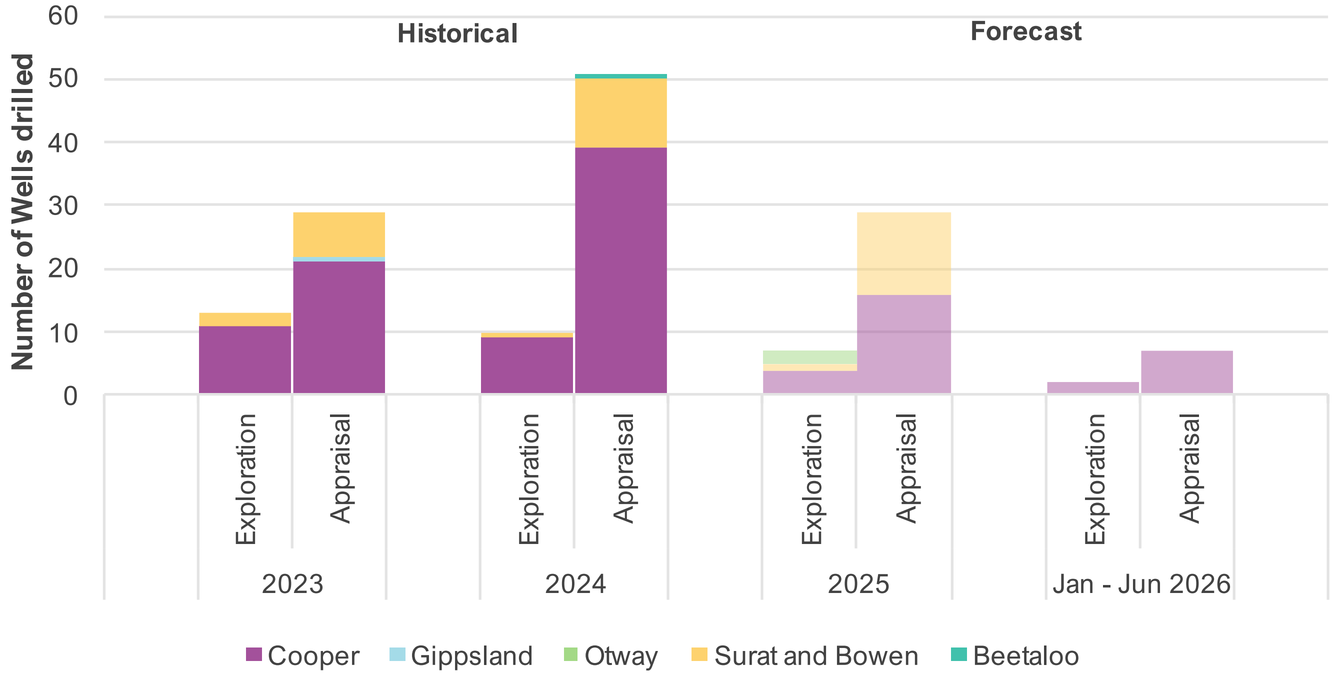
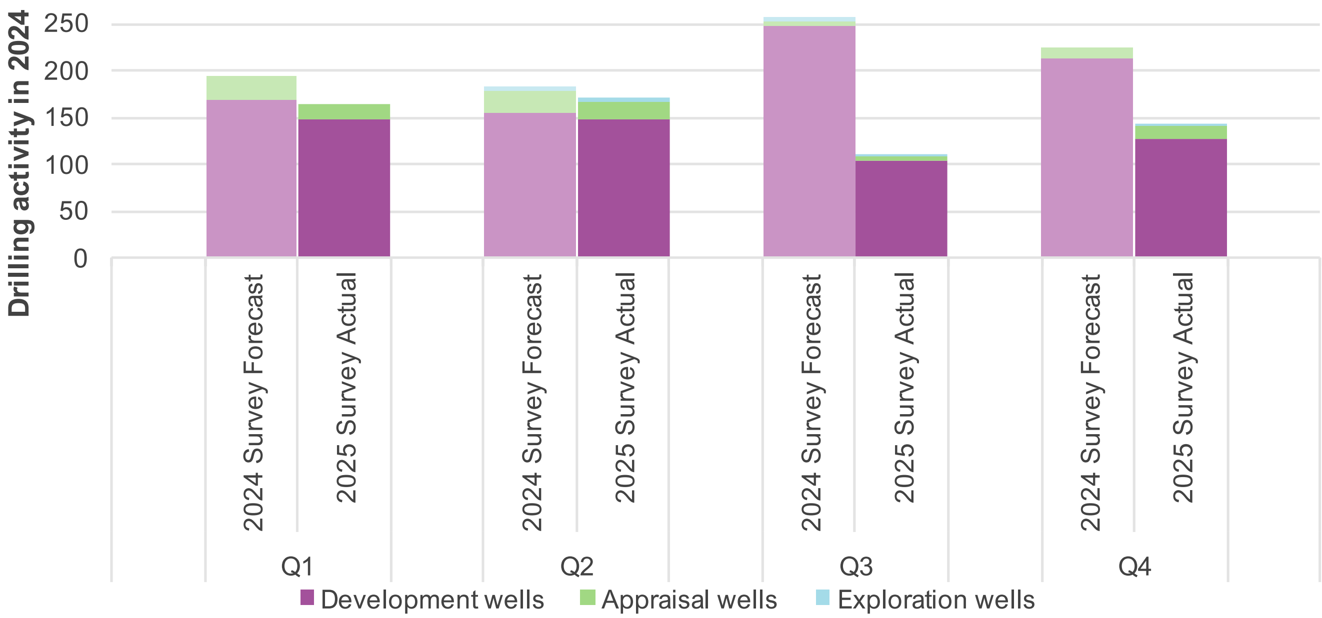


Figure 33 shows that the total number of actual wells drilled in 2024 (reported to AEMO in the 2025 GSOO survey process) were lower than the forecasts reported to AEMO in the 2024 GSOO survey process. Survey participants reported reasons such as uncertainty related to state legislations for the planned developments and delays in obtaining production licenses and necessary regulatory approvals for deferring or scaling back drilling activity. Future supply adequacy assessments may need to account for these variances to improve accuracy of forecasts.

Figure 33 2024 GSOO survey forecast versus 2025 GSOO survey actual number of wells drilled, 2024



3.2.5 Renewable gas opportunities

Renewable gas refers to biomethane[51], or hydrogen produced via electrolysis using renewable energy resources. While biomethane is a proven technology widely used in Europe[52] and other countries, there is relatively low existing production in Australia. Biomethane has the potential to provide a low or zero emissions molecular fuel source to blend into gas pipelines, lowering the emissions intensity of gas use[53]. As such, it provides a decarbonisation alternative to electricity for industries that cannot easily electrify their industrial processes, should production be available.

The 2025 GSOO includes current and future supply from a small number of existing, committed or anticipated biomethane[54] gas projects. These include Jemena's Malabar biomethane project[55], Delorean's Edinburgh Parks and Horsley Park[56], and Optimal Renewable Gas's projects[57] across New South Wales, Victoria and Tasmania. Many of the additional proposed renewable gas supply projects identified in AEMO's 2025 GSOO surveys still face various economic, regulatory, and technical uncertainties. Therefore, forecasting the timing and volumes of gas available from renewable sources is challenging.

AEMO's Draft 2025 IASR includes insights provided by ACIL Allen to forecast biomethane available volumes by feedstock type, state, and scenario. The supply adequacy assessment in the 2025 GSOO does not consider the ACIL Allen forecast volumes, however, if developed, these available volumes could increase biomethane production above the level of existing, committed and anticipated supply identified in the 2025 GSOO surveys. This analysis[58] identified that the majority of biomethane potential supply may be developed from crop residues, with over half the potential production volumes, while waste products offer another potential primary source. ACIL considered that between approximately 100 PJ and 200 PJ of potential production in the ECGM may be feasible, depending on the scenario, with higher economic growth leading to greater potential resource.

3.3 Midstream gas infrastructure

Midstream infrastructure connects the gas producers to end consumers and is key for daily and seasonal balancing of gas supply and demand. The infrastructure includes pipelines for gas transport, storage facilities and potential LNG regasification terminals[59].

[51] Biomethane is produced by the anaerobic decomposition of organic matter, and can be produced from multiple feedstocks, including agricultural and municipal waste streams, wastewater treatment facilities and forestry residues.

[52] See https://energy.ec.europa.eu/topics/renewable-energy/bioenergy/biomethane_en#:~:text=The%20Biomethane%20Industrial%20Partnership%20(BIP,of%20its%20potential%20by%202050.

[53] See https://www.dcceew.gov.au/sites/default/files/documents/national-greenhouse-accounts-factors-2022.pdf, page 13.

[54] Hydrogen supply is not yet included in the assessment since hydrogen cannot not be injected into the transmission network, only the distribution or hydrogen-only pipelines. Any behind the meter (distribution) hydrogen is netted off, any direct-connected has been included in the demand forecasts.

[55] See https://www.jemena.com.au/future-energy/future-gas/Malabar-Biomethane-Injection-Plant/.

[56] See https://www.aumanufacturing.com.au/delorean-to-construct-sa-bioenergy-project.

[57] See https://optimalrenewablegas.com.au/our-projects/.

[58] See https://aemo.com.au/-/media/files/major-publications/isp/2025/draft-2025-inputs-assumptions-and-scenarios-report-stage-1.pdf?la=en.

[59] LNG export terminals are considered consumers.

The shifting dynamics in gas production and consumption patterns are likely to impact the operation and reliance of midstream infrastructure. The gas adequacy modelling undertaken by AEMO is based on the technical capability of midstream infrastructure and does not consider contracted positions.

Figure 8 in Section 1.3 is a map of the basins, pipelines, and load centres across the ECGM in this 2025 GSOO.

3.3.1 Major gas transmission pipelines

This section highlights key pipelines that facilitate the transport of gas between the north and south and are integral to the supply adequacy assessment provided in Chapter 4.

South-West Queensland Pipeline (SWQP)

The SWQP extends from Wallumbilla to Moomba and is interconnected with the Carpentaria Gas Pipeline (CGP) that can deliver to or receive gas from the NGP. The SWQP operates as a critical gateway that links the expansive northern gas fields to the southern regions that are characterised by high seasonal gas demand.

Moomba – Sydney Pipeline (MSP)

The MSP links the Moomba Gas Hub in northern South Australia with Sydney and intersects with the Victorian Northern Interconnect (VNI) at Young, facilitating gas transfers to Victorian consumers. The MSP is crucial for delivering gas from northern Australia to New South Wales, Victoria and Tasmania. It balances gas supply between regions and flows north to Queensland to deliver gas from offshore Victoria at times of southern surplus.

During summer, annual inspection works on the MSP can reduce its operational capacity. These works are strategically scheduled to avoid winter when full MSP capacity may be required, while still providing appropriate summer capacity. Due to a dynamic of the pipeline that simultaneously delivers between the Young – Sydney route and the VNI lateral, the overall MSP's transport capacity depends on the demand distribution between Sydney and Victoria. In general, the total MSP capacity is higher when the quantities delivered south via the Young – Sydney route are higher.

Following the FID[60], the conversion of APA's Moomba Sydney Ethane Pipeline (MSEP) to a natural gas pipeline is a newly committed project that will add an additional 20-25 TJ/d capacity to the MSP for 2025. In addition, the MSP off-peak capacity expansion project will deliver two pressure regulation skids to increase the capacity in summer months when pipeline maintenance is being undertaken. This project is scheduled to complete by November 2025 and can increase the off-peak capacity of the MSP by 80-120 TJ/d.

[60] See https://www.apa.com.au/news/asx-and-media-releases/apas-east-coast-gas-expansion-plan.

Additional uncertain gas transmission pipeline developments

A number of potential new pipeline projects have been announced by developers but have provided only sufficient evidence of commitment to classify these potential developments as uncertain. These include:

East Coast Grid Expansion project

APA Group completed some upgrades as part of the East Coast Grid Expansion (ECGE) in 2024 that provides a 13% and 19% increase in capacity for the SWQP and the MSP pipelines respectively.

APA Group is also proposing a series of further staged upgrades and expansions[61] to expand gas transportation capacity on the East Coast Grid that links Queensland with southern markets.

Stage 3 focuses on building capacity to move about 24% more gas between northern basins and southern markets. This includes the proposed delivery of the Bulloo Interlink, a new 380km, 28-inch pipeline connecting the SWQP to the MSP, and two new compressors on the MSP. The Bulloo Interlink is designed to transport gas from northern basins such as the Surat in Queensland and the Beetaloo in the Northern Territory, amongst others. The project would progressively increase MSP capacity from 590 TJ/d to 700 TJ/d. SWQP capacity would increase from 512 TJ/d to 605 TJ/d and capacity between Young and Melbourne would increase from 190 TJ/d to 229 TJ/d.

Stage 4 involves the delivery of the proposed new Riverina Storage Pipeline (RSP) in New South Wales (NSW), along with new compression and pipeline infrastructure. RSP has a proposed storage capacity of 200-500 TJ. This storage could be used to supply gas to Uranquinty Power Station, meet nearby demand in New South Wales or transported south to Victoria.

EGP Reversal Project

The EGP is presently configured for unidirectional flow from Longford towards Sydney. Jemena plans to reconfigure the EGP to allow for bidirectional flow if the Port Kembla Energy Terminal (PKET) LNG regasification terminal is commissioned.

PCA Reversal Project

In its current configuration, the PCA is only designed to flow from east to west (Victoria to South Australia) but SEA Gas has confirmed the potential reconfiguration for bi-directional flow. This project allows PCA to receive gas from the proposed LNG regasification terminal at Outer Harbor, South Australia, or from the MAPS for west – east transportation.

Westernport Altona Geelong (WAG) pipeline project

Viva Energy and its joint venture partner Exxon Mobil are investigating the conversion of the WAG crude pipeline to a high-pressure gas transmission pipeline. The WAG pipeline runs from Viva Energy's refinery in Geelong to Altona and then continues to Westernport. If converted to natural gas, the WAG pipeline could increase the capacity of the SWP. More information on the WAG project can be found in the 2025 VGPR, Chapter 5.

[61] See https://www.apa.com.au/news/asx-and-media-releases/apas-east-coast-gas-expansion-plan.

South West Pipeline (SWP)

The SWP operates as a bi-directional pipeline between Port Campbell and Lara in Victoria, where it links with the Brooklyn – Lara Pipeline (BLP). The SWP is typically utilised for transporting gas from Port Campbell and the Iona UGS facilities towards Melbourne, as well as supporting the refilling of the Iona UGS reservoir. Additionally, it facilitates supply of gas to areas west of Port Campbell, such as the Mortlake Power Station, and to South Australia via the Port Campbell to Adelaide (PCA) pipeline.

The SWP's capacity for transporting gas from Port Campbell to Melbourne varies depending on system demand, reaching its peak capacity on a one-in-20 system demand day. This capacity increased to 506 TJ/d following the completion of the Western Outer Ring Main (WORM) project in February 2024. The capacity for flow from Melbourne to Port Campbell is maximised on days of low demand, with the current maximum at 350 TJ/d, having risen by 154 TJ/d following the completion of WORM.

Northern Gas Pipeline (NGP)

The Northern Gas Pipeline is a pipeline that connects Tennant Creek in the Northern Territory to Mount Isa in Queensland. It was commissioned in 2019 to provide a transportation route for gas production facilities in the Northern Territory to provide gas to Mount Isa and eastern Australia, when local production exceeds demand. The Northern Gas Pipeline Reverse Capability project was completed by Jemena in August 2024, providing the NGP with the capability to flow gas into the Northern Territory from Queensland (from Mt Isa to Phillip Creek).

Moomba – Adelaide Pipeline System (MAPS)

The Moomba – Adelaide Pipeline System connects the Moomba production facility to Adelaide. The pipeline also supplies regional South Australian load, including via separate laterals that run to Port Pirie and Whyalla, and to Angaston where it connects with the APA Riverland Pipeline. The MAPS supports limited northerly flow, receiving gas in Adelaide via a receipt point with the Port Campbell – Adelaide (PCA) SEA Gas pipeline; it does not flow into the PCA.

Eastern Gas Pipeline (EGP)

The EGP runs from the gas processing plants located at Longford and Orbost in Victoria's Gippsland basin, extending its reach to Sydney, with an interconnection at Hoskinstown to supply Canberra. Port Kembla Lateral pipeline[62] is a dedicated lateral connecting Port Kembla Gas Terminal (PKGT) to the EGP. The construction and connection to the EGP is completed, but commencement of operations is conditional on commencement of LNG regasification terminal operations.

Port Campbell to Adelaide Pipeline (PCA)

The SEA Gas PCA pipeline connects the Adelaide STTM and other South Australian demand points to supply from the Otway basin in Victoria, including Iona UGS. There is an existing capability for gas to flow from the PCA into the MAPS but the pressure differential between the two pipelines precludes flows from MAPS to the PCA absent the installation of compression. The PCA is the sole source of supply to the Ladbroke Grove power station via the

[62] See https://www.jemena.com.au/gas/pipelines/Eastern-Gas-Pipeline/port-Kembla-pipeline-project/.

South East South Australia (SESA) pipeline and, to Mount Gambier and surrounds via the SESA pipeline and the South East Pipeline System (SEPS).

Other pipelines

Table 7 lists other major midstream infrastructure servicing domestic consumers.

Table 7 Additional major existing midstream infrastructure

Name	Description and relevant information
Amadeus Gas Pipeline (AGP)	Connects the Amadeus basin in the south of the Northern Territory to Darwin in the north. The pipeline is bi-directional.
Bonaparte Gas Pipeline (BGP)	Connects supply from the Blacktip field to the AGP at Ban Ban Springs.
Carpentaria Gas Pipeline (CGP)	Connects Mount Isa and the NGP to Queensland's pipeline system, at Ballera on the SWQP.
Victoria Northern Interconnect (VNI)	Connects Wollert (on the Melbourne ring) to Young, intersecting with the MSP.
Brooklyn – Lara Pipeline (BLP)	Connects supply from the SWP at Lara to Brooklyn.
Longford – Melbourne Pipeline (LMP)	Connects Melbourne to supply from Longford Gas Plant. Does not provide access to the Orbost Gas Plant.
Roma – Brisbane Pipeline (RBP)	Connects Brisbane to supply from Wallumbilla Gas Hub.
Tasmanian Gas Pipeline (TGP)	Connects Bell Bay to supply from Longford Gas Plant.
North Queensland Gas Pipeline (NQGP)	Connects Townsville to supply from Moranbah Gas Plant.
Sydney – Newcastle Pipeline (SNP)	Connects Newcastle to Sydney (and draws supply from the MSP and EGP). Presently this is not considered to be a transmission pipeline but is a large full regulation distribution pipeline.
Western Outer Ring Main (WORM)	Connects the SWP/BLP at Plumpton and the Longford Melbourne Pipeline (LMP) at Wollert. The project includes the installation of additional compression. The project was commissioned in February 2024.

3.3.2 Storage facilities

Gas storage facilities are essential for balancing yearly gas production (PJ/y) and fluctuating, seasonal and daily domestic demand (TJ/d), ensuring that gas is available during periods of higher demand when required.

Storage facilities sited near load centres are important so gas can be supplied promptly during peak demand periods, thus maintaining a reliable and efficient gas system. Pipeline capacity constraints can impact storage operations, affecting the ability to refill storage to full capacity and to deliver gas at maximum withdrawal rates.

Table 8 lists existing market-facing storage facilities and proposed upgrades or facilities.

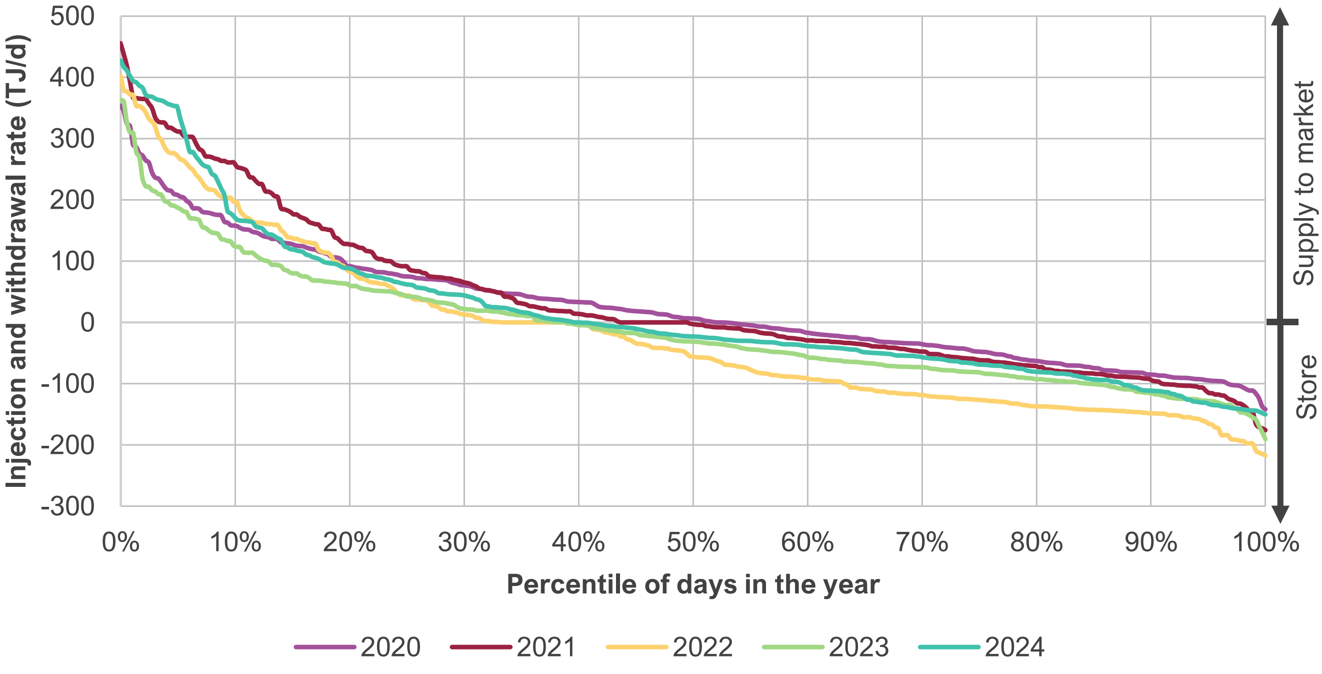
Table 8 Key existing market-facing and proposed storage infrastructure

Name	Maximum storage capacity (PJ)[A]	Maximum withdrawal rate (TJ/d)	Connecting location
Silver Springs	46	25	Wallumbilla, Queensland
Iona UGS • Existing • Upgrade (HUGS Phase 1 - Committed) • Upgrade (HUGS Phase 2 – Uncertain)	 24.4 26-28 Up to 32.6	 570 570-615 Up to 765	Otway Basin, Victoria
Newcastle LNG Storage	1.5	120	Newcastle, New South Wales
Dandenong LNG Storage	0.68	87[B]	Melbourne, Victoria
Golden Beach Storage (Proposed)	30	375	Gippsland Basin, Victoria
Kurri Kurri Lateral Pipeline (KKLP) (Under construction)	0.072[C]	60[D]	Newcastle, New South Wales

A. The maximum storage capacity includes buffer gas, excluding cushion gas.
B. This storage can supply at faster rates for short periods of time, but that is non-firm supply and not able to be supported across a 24-hour period.
C. Expected nameplate storage capacity.
D. This maximum withdrawal rate is into Sydney STTM.

Figure 34 illustrates how the Iona UGS has been critical historically in meeting demand by injecting gas at high rates, particularly in 2021 and 2024, when the facility observed many days with high daily withdrawal rate, exceeding 450 TJ/d.

Figure 34 Cumulative distribution of net changes in storage level for Iona UGS, 1 January 2020 to 31 December 2024 (TJ/d)



Shallow storage facilities at Dandenong (Victoria), Newcastle (New South Wales) and the future KKLP need to have inventories ready to provide operational flexibility and help mitigate risk of shortfalls. Despite high withdrawal rates, these storages hold limited volumes, so they are unable to sustain high rates of injection for extended periods.

The AEMC published an interim rule on 15 December 2022[63] requiring AEMO to contract any uncontracted capacity within the tank and to fill that capacity to reduce the likelihood of curtailment within Victoria. In accordance with the NGR, the Dandenong LNG storage facility inventory will remain maximised for winter 2025, however refilling operations after this period may be impacted. The Victorian Government is seeking to extend the interim rule requirement, through a rule change with the AEMC.

BOC's aging liquefaction plant at Dandenong LNG has been experiencing increased issues with reliability. The liquefaction plant remains in operation, however, unplanned outages continue to occur and there is an increased risk of a major failure occurring, posing a risk for refilling the Dandenong LNG tank. The *Step Change – Dandenong LNG de-commissioning* sensitivity in Section 4.1.2 assesses the impact on adequacy if Dandenong is unavailable.

Additional uncertain storage developments

A number of potential new pipeline projects have been announced by developers, but have provided only sufficient evidence of commitment to classify these potential developments as uncertain. These include:

Golden Beach Energy Storage Project

GB Energy is proposing a gas production and energy storage project within the Gippsland Basin, approximately 3 kms offshore from the township of Golden Beach. The project would leverage the Golden Beach gas field for storage, with some initial new supply provided before transitioning to a storage project. The proposal outlines a capacity to store up to 30 PJ of gas. If developed, the uncertain project would provide up to 375 TJ/d to southern demand centres.

Heytesbury Underground Gas Storage Project Phase 2

Lochard Energy has proposed upgrade to the Iona UGS storage facility at Port Campbell, Victoria. Phase 1 of the project is committed and will increase storage inventory capacity by 1.8 PJ to 3.5 PJ, and supply capacity by up to 45 TJ/d, from 2027. Phase 2 is still uncertain and would expand the current capacity of the Iona UGS up to 32.6 PJ, and increase the maximum withdrawal rate up to 765 TJ/d.

3.3.3 Gas processing plants

Natural gas extracted from wells often contains impurities that are either unsafe or not suitable for combustion, including water, nitrogen, carbon dioxide, sulphur and heavier hydrocarbons. Gas processing plants reduce the level of impurities in gas to an acceptable level and separate out liquids, making it suitable for domestic and international consumers.

[63] See AEMC, "DWGM interim LNG storage measures", 15 December 2022, at https://www.aemc.gov.au/rule-changes/dwgm-interim-lng-storage-measures.

There are a total of 42 existing gas processing facilities in the ECGM. **Table 9** lists the committed, anticipated and uncertain gas processing plant facilities that may be developed in the future, as advised by project proponents.

Table 9 Committed, and proposed gas processing plants

Name	Status	Purpose	Region
Mimas – Roma North Facility	Committed	To support production for Senex Energy's Roma North expansion	Queensland
Atlas East Facility	Committed	To support production for Senex Energy's Atlas expansion	Queensland
Girrahween	Proposed	To support production from Arrow's Surat gas project	Queensland
Golden Beach	Proposed	To process gas from the Golden Beach gas field in the Gippsland Basin	Victoria
Lynwood	Proposed	To support production from Arrow's Surat gas project	Queensland
Narrabri Gas Project	Proposed	To process gas from Santos' Narrabri development	New South Wales
Carpentaria Gas Plant	Proposed	To process gas from Empire Energy's Carpentaria gas field	Northern Territory

3.3.4 Proposed LNG regasification terminals

LNG regasification terminals offer pathways to access gas from international and domestic suppliers and can operate as virtual pipelines when domestic supply or existing infrastructure is unavailable to service demand centres.

LNG regasification terminals require access to a floating storage and regasification unit (FSRU)[64] to store and regasify LNG. Terminals also require pipelines and other infrastructure to be constructed to deliver gas into the ECGM. In some cases, additional downstream pipeline augmentations may be necessary to ensure regasified LNG volumes can be delivered efficiently to where it is needed.

LNG regasification terminal developers have proposed the projects outlined in **Table 10**. No regasification terminal projects are considered committed or anticipated in the 2025 GSOO, as in all cases uncertainty remains regarding the timing of on-shore infrastructure development, or the location commitment of the FSRU, as outlined in the table below.

[64] An FSRU stores and regasifies LNG, before it is injected into a transmission system.

Table 10 Proposed LNG regasification terminals

Name	Region	Timing	Capacity	Additional considerations
Port Kembla Energy Terminal (PKET)[A]	New South Wales	2026[A]	500 TJ/d 130 PJ/y	• Construction of the onshore infrastructure associated with PKET is complete with commissioning work underway. • Secured a long-term contract for an FSRU in 2021, yet pending a firm date for FSRU arrival in Australia. • Located near Sydney with a pipeline connecting into the EGP. The lateral connecting PKET to the EGP has been completed. • Jemena has proposed an upgrade to the EGP to become bi-directional. If the PKET project is commissioned, the EGP reversal will initially deliver the capacity for 200 TJ/d in reverse flows south to Victoria and could be upgraded to 325 TJ/d.
Venice Outer Harbor LNG Project[B] **Port Adelaide**	South Australia	2027	405 TJ/d 110 - 144 PJ/y	• Pending FID. • All necessary approvals acquired. • Stage 1 site preparations are complete[C]. • SEA Gas has proposed a project to reverse the PCA pipeline and allow flow from Adelaide to Port Campbell in Victoria.
Viva Energy Gas Terminal[D] **Geelong**	Victoria	2028	750 TJ/d 140 PJ/y	• Pending FID. • Located adjacent to the Geelong Oil Refinery. • Working to secure an FSRU for the project. • Pending State Government Supplementary Environmental Effects Statement (EES) approval. • The WAG pipeline conversion would increase the capacity of the SWP.
Vopak Victoria Energy Terminal[E] **Port Phillip Bay**	Victoria	2028	Up to 778 TJ/d ~270 PJ/y	• Pending FID. • In August 2023, the Victorian Minister of Planning published a decision requiring an EES to be completed for the project[F].
Adelaide Energy Bridge[G]	South Australia	2025	150 TJ/d 50 PJ/y	• Separate project to Venice Outer Harbor that will act as an interim supply until the Outer Harbor project is complete. • 150 TJ/d available to South Australia from before the end of 2025 until the end of 2028.

Note: Timing and capacity have been advised by project proponents in 2025 GSOO surveys.
A. For more, see https://www.squadronenergy.com/our-projects/port-kembla-energy-terminal.
B. For more, see https://veniceenergy.com/outer-harbor-lng-project/.
C. For more, see https://veniceenergy.com/2024/02/15/chairmans-update/.
D. For more, see https://www.vivaenergy.com.au/energy-hub/gas-terminal-project/about-our-project.
E. For more, see https://victoriaenergyterminal.com.au/.
F. For more, see https://www.planning.vic.gov.au/environmental-assessments/browse-projects/referrals/Vopak-Victoria-Energy-Terminal.
G. See https://www.theaustralian.com.au/business/mining-energy/agp-lng-details-plans-to-fasttrack-gas-imports/news-story/c3ceea488328cc2f635c3f33f3ec8772.

4 Gas supply adequacy assessment

This chapter provides a gas supply adequacy assessment for the ECGM, based on the demand and supply forecasts in chapters 2 and 3.

Key insights

In the south:

- Shortfall risks under peak conditions are forecast from 2028, three years later than forecast in the 2024 GSOO. Lower projected demand for gas from increasing electrification and lower industrial consumption has reduced forecast demand, while a temporary higher availability of coal generation capacity from the delayed retirement of Eraring Power Station has reduced the expected gas consumption for GPG.
- Effective use of deep and shallow gas storages will continue to be critical in minimising the risk of peak day shortfalls and seasonal supply gaps in tight conditions. The effective preparation and availability of southern storage facilities ahead of winter will be needed to mitigate supply adequacy risks.
- From 2028, AEMO forecasts risks of peak day shortfalls in winter, and potential seasonal supply gaps, in southern Australia if sustained high gas usage conditions occur. The completion of committed and anticipated production, storage and infrastructure developments is vital to minimising this risk.
  - Risks of seasonal supply gaps are identified later than forecast in the 2024 GSOO, due to the advised reprofiling of gas production to increase supply in southern Australia in 2026 to 2029, additional supply from projects progressing to committed such as Turrum Phase 3, and lower forecast gas consumption (including as a result of the delayed retirement of Eraring Power Station).
- In 2029 and later, a structural need for new gas supply is projected (although smaller than forecast in the 2024 GSOO), despite declining residential, commercial and industrial consumption, as southern gas production is advised to continue to decline.

In the north:

- Northern producers need to deliver anticipated supplies before 2026, and by 2029 more uncertain supply is required to meet export agreements and domestic supply.
- Continued reliance on interim emergency gas arrangements with Darwin LNG exporters may be needed if ongoing supply issues continue in the Northern Territory. In the meantime, gas continues to be supplied to Mt Isa from Queensland, reducing the capacity available to transport gas to southern regions.

Definitions

The following definitions apply throughout this chapter when assessing the daily shortfalls and annual supply gaps:

- **Extreme peak day demand** is characterised by coincident very high daily demand from residential, commercial and industrial customers and high daily gas requirements for GPG. It is forecast using a POE measure, with focus on two demand levels, being the level expected to be exceeded only once in 20 years and once in two years respectively.

- A **peak day shortfall** is driven by insufficient available gas production or transport capacity to meet extreme peaks in demand on a single day. Peak day shortfalls are typically calculated considering 5% POE, or one-in-20-year peak day demand.
- A **seasonal or annual supply gap** is driven by insufficient gas production or transport capacity to meet total seasonal or yearly demand.

This GSOO provides a physical assessment of gas adequacy, assessing the capability of forecast gas production[65] to meet peak day, seasonal and annual gas demand. In conducting this assessment, the GSOO examines the limitations for supply to meet demand considering physical capabilities, rather than contractual positions and other commercial influences that could affect actual supply compared to forecasts. As such, subject to technical operating limits, transportation constraints, storage limitations, and project classification status, if supply is not available as producers have forecast, the adequacy of the gas system may differ from the assessment in the GSOO. LNG exporters are assumed to offer gas (including gas supplied to them by third parties) to the domestic market as required [66].

The supply adequacy assessments in this chapter:

- Account for all pipeline transmission capacity and constraints, and limitations from production facilities, storage and other relevant infrastructure.
- Do not consider gas stored in pipeline linepack as an available source of supply[67], except in the case of the under-construction KKLP[68].

Use of scenarios for the adequacy assessment

This 2025 GSOO focuses on the *Step Change* scenario for both short- and long-term supply adequacy assessments. As detailed in Section 1.1 the *Step Change* scenario reflects observed and continuing trends impacting residential, commercial, and industrial gas consumption. The GSOO also includes gas supply adequacy assessments for two other scenarios as outlined in Section 1.1, to analyse the effect of alternative futures on investment decisions regarding new gas supply to meet an uncertain demand. This section also provides insights into seasonal consumption patterns, including monthly variance expected from weather variations in any given scenario.

[65] Total gas production across the ECGM reflects the estimates provided by all gas producers, including LNG exporters, via survey.

[66] In September 2022, the Australian Government and the three east coast LNG producers signed a Heads of Agreement for excess gas produced by the LNG producers to be offered to the domestic market first before being sold to the international market.

[67] Imbalance in pipeline linepack is primarily an operational tool that can be utilised on a day to supply gas to consumers. The availability of linepack is dependent on system pressures and is not guaranteed, so it is appropriate to exclude it as a source of supply in adequacy assessments. Contracted parking arrangements on pipelines are generally small in volume and also are not modelled.

[68] KKLP is equipped with its own compressors to boost system pressures, and can be used as a flexible supply source for the ECGM.

Use of data in charts

Unless otherwise specified, charts for peak day adequacy modelling refer to **extreme peak demand conditions** using one-in-20-year[69] peak demand conditions and the 2019 reference year which has very high daily demand from residential, commercial and industrial customers and high daily gas requirements for GPG. The charts therefore forecast a worst-case outcome for peak day shortfalls, across the reference years modelled. Charts showing annual supply gaps show the range of outcomes across reference years, unless otherwise specified.

4.1 Southern supply adequacy

4.1.1 Peak day adequacy

Peak day shortfalls are most likely in extreme cold temperatures, particularly if peak electricity demand or low availability of alternatives (coal, renewable energy) triggers a high need for GPG.

Southern regions are forecast to be at greatest risk of peak day shortfalls from 2028, three years later than forecast in the 2024 GSOO. The delay in peak day shortfall risks relative to the 2024 GSOO is primarily attributable to a reduction in peak gas consumption from GPG, as a result of the extended availability of Eraring Power Station, southern gas producers' reprofiling of gas supply to increase gas production across most of the short-term and supply projects progressing from uncertain to committed status, such as Turrum Phase 3.

Figure 35 shows the historical capability of existing, committed and anticipated southern production, pipeline capacity and gas storages to meet actual southern gas demand in 2023 and 2024, and the forecast capability to meet 1-in-20 demand forecasts from 2025 to 2029 in the *Step Change* scenario.

Vertical lines show daily demand volumes from gas users (purple) and from GPG (yellow). Horizontal lines in Figure 35 indicate the maximum capacity forecast to be available to be supplied to meet peak gas demand:

- Existing and committed gas production capacity from southern regions only (solid purple line).
- Expected gas imported from Queensland through the SWQP (dashed purple line).
- Gas injection capacity from deep storage at Iona UGS (dotted purple line).
- Gas injection capacity from shallow storages at Dandenong, Newcastle and KKLP (once constructed in winter 2025) (solid red line).
- Anticipated gas production capacity from southern regions (dashed red line).

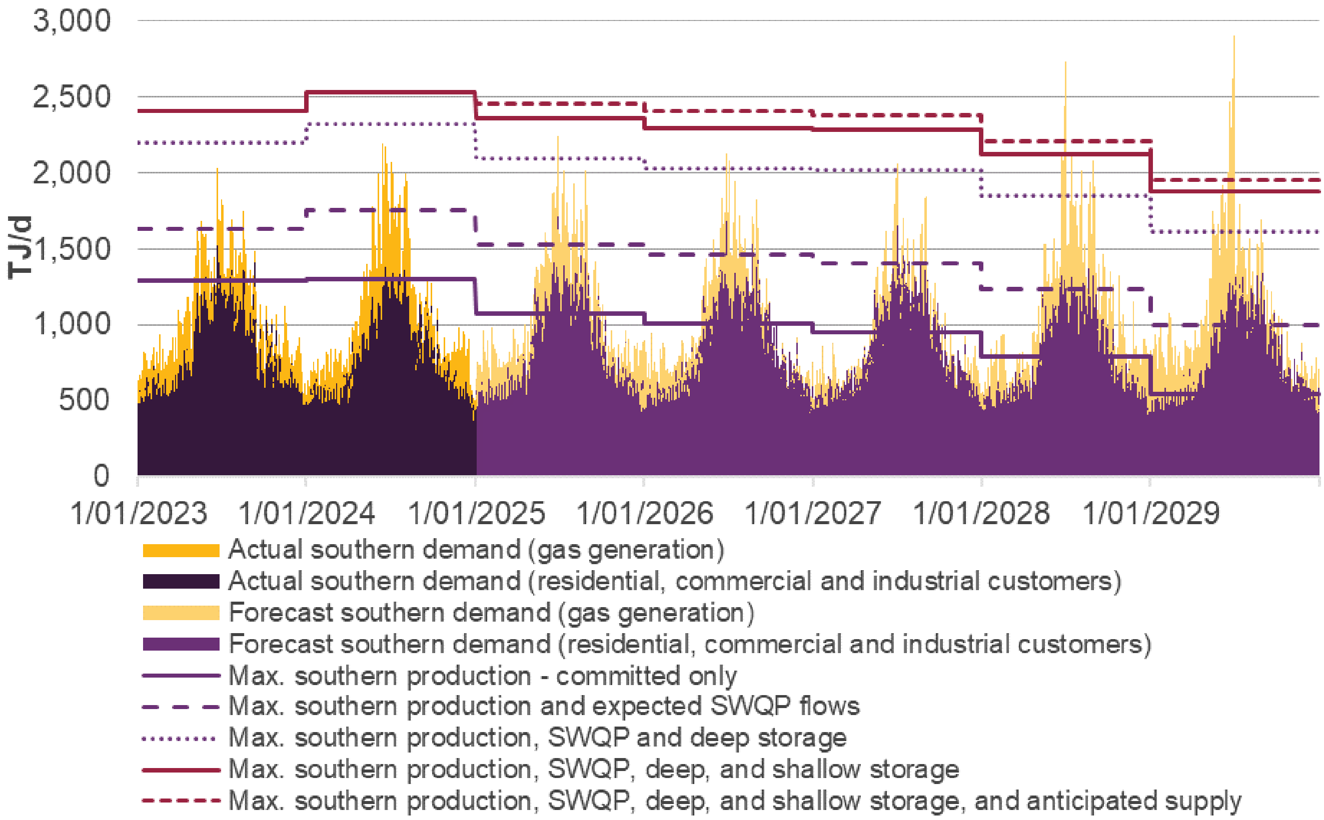
This figure illustrates that the ability of the ECGM to deliver adequate gas to southern regions will change over the next five years:

- **The risk of peak day shortfalls from 2025 forecast by the 2024 GSOO is delayed until 2028,** mostly due to lower forecasts for residential, commercial and industrial users and the temporary reduction in expected GPG requirements with the extended availability of Eraring Power Station.

[69] Forecasts with a one-in-20 probability of exceedance are expected to be met or exceeded one in every 20 years, representing more extreme weather. Average conditions assume a one-in-two forecast, which is expected to be met or exceeded one in every two years.

- **Risks of peak day shortfalls are identified from 2028** under peak demand conditions, and continues to be at risk in future years as southern production capacity is forecast to continue to decline.
  - Prior to 2028, tight supply-demand conditions mean that any unscheduled production interruptions in southern regions that reduce the supply capacity of existing, committed or anticipated facilities, or if electricity conditions require higher than forecast GPG coincident with high gas demand conditions may lead to gas supply inadequacy.
- **Expanded pipeline capacity along the SWQP and MSP** (following completion of the ECGE Stage 1 & 2 expansion and the MSEP conversion project) will be increasingly relied on to meet southern gas demand, with gas flows reaching flow limits under high demand conditions from 2025 for around 10-20% of the year. Without further expansions of the pipeline network, or expanded southern storage capabilities, northern supplies will be increasingly constrained from providing any available supply to southern customers.
- **Deep and shallow storages** are forecast to continue to provide critical injection capacity close to large demand centres, and will require appropriate management to ensure maximum injection rates can be provided on peak days and/or sustained across multiple high demand days when necessary. Under extreme weather conditions, the existing capacity provided by storages is still forecast to be insufficient to avoid gas shortfalls.

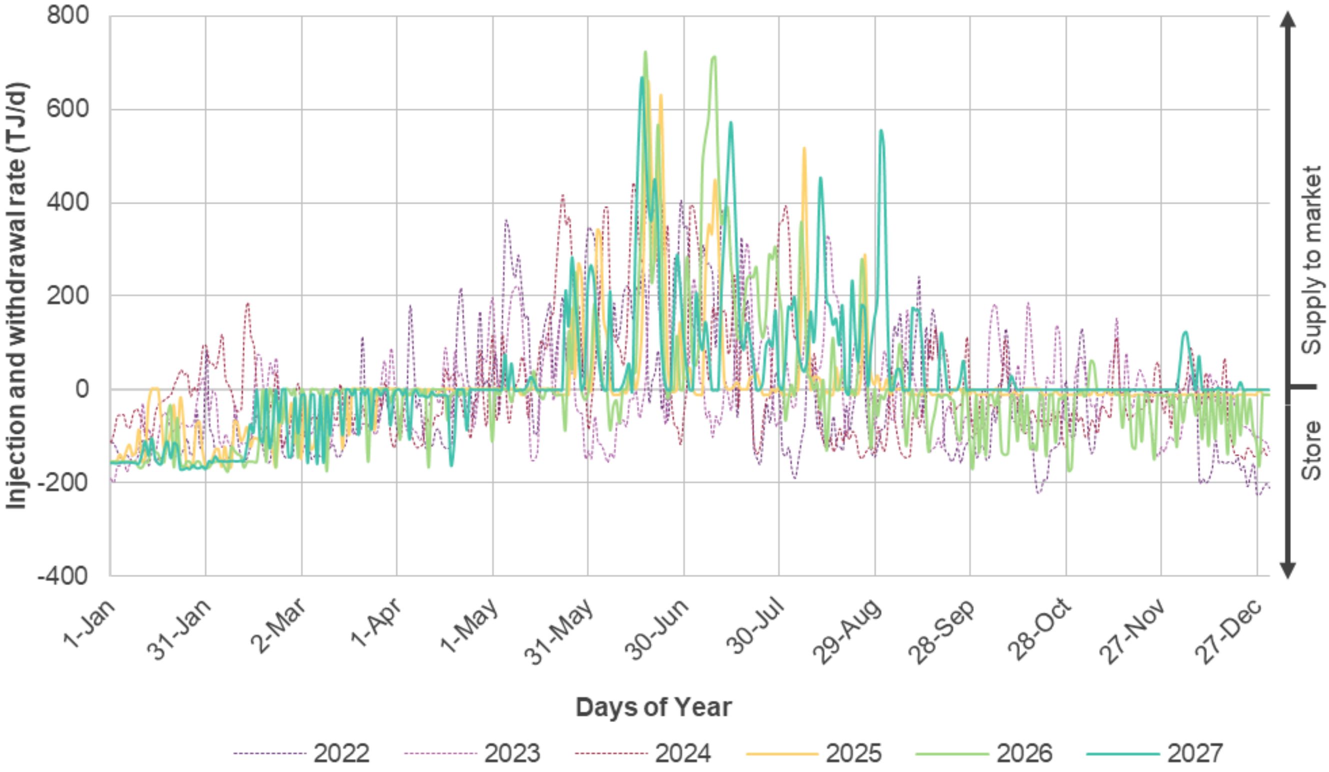
Figure 35 Actual daily southern gas system adequacy since January 2023, and forecast to 2029 using existing, committed and anticipated projects, reference year 2018 (TJ/d)



Note: Actual maximum southern production and SWQP flow rates are shown for 2023 and 2024.

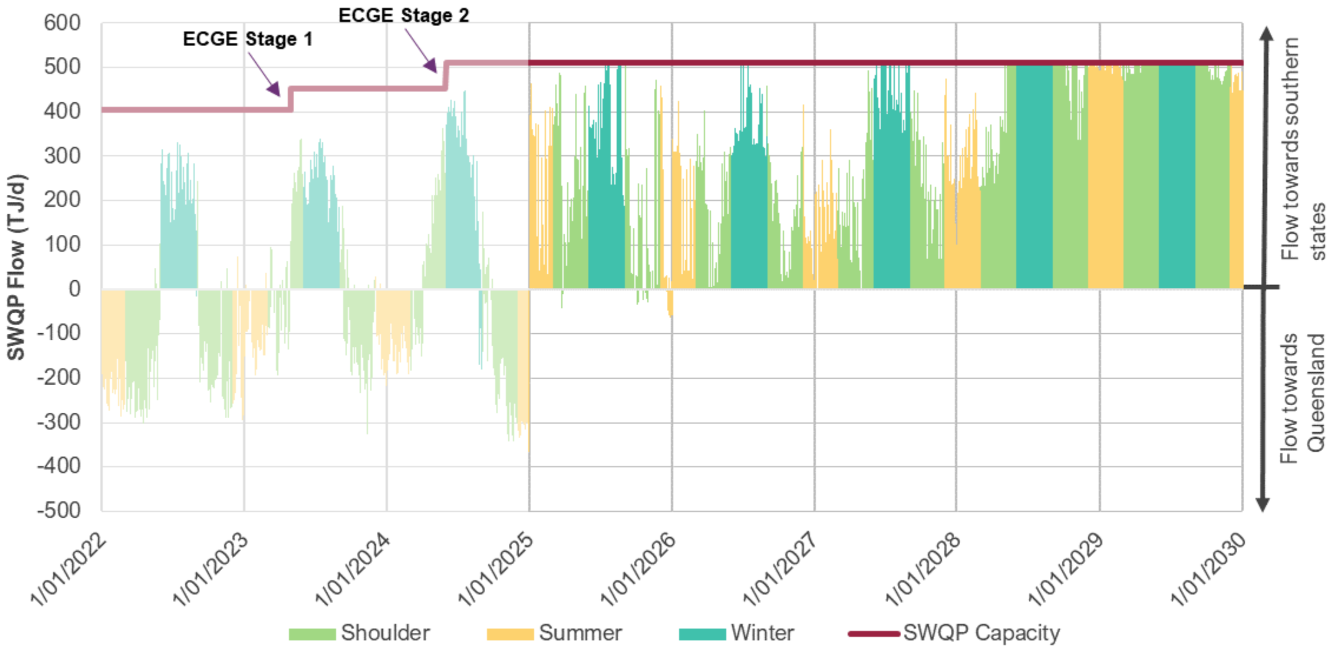
Figure 36 demonstrates the potential for high reliance on large injections of gas from southern storages, with injections up to 300 TJ/d above recent maximum rates (but within technical operational capabilities of the storage facilities). The figure indicates that operation of shallow and deep storages at technical limits may be needed for up to five days each year, under the forecast 1-in-20 demand conditions.

Figure 36 Daily actual (2022 to 2024) and projected (2025 to 2027, existing and committed only, *Step Change*) storage injection and withdrawal rates for deep and shallow storages (TJ/d)



From 2025, refilling southern storages ahead of winter peak demand periods will rely more heavily on gas transported from northern fields via the SWQP, as southern production declines. **Figure 37** shows an increasing trend for more higher utilisation of SWQP to support southerly flow to the southern states. The pipeline is forecast to increasingly reach pipeline capacity from 2025 onwards.

Figure 37 Actual (2022 to 2024) and projected (2025 to 2030, reference year 2018, *Step Change*) gas flows along the SWQP (TJ/d) – positive flows are southbound



Factors that may impact the volume of gas supplied

Volumes of gas supplied may be impacted by:

- Maintenance at gas facilities – while planned maintenance typically occurs in summer when demand is low, unplanned maintenance (often the result of equipment failure) results in unexpected and sometimes significant reductions in supply capacity, which must be met from other supply sources, often at very short notice. If unplanned maintenance occurs on key production or transmission facilities during winter and supply is significantly reduced, peak day shortfalls may result.
- UAFG[70] – typically between 3% and 5% of total gas usage results from gas leakage, or inaccuracies in gas measurement or heating values.

Near-term solutions to resolve forecast peak day shortfall risks are limited

Consistent with the 2024 GSOO, it is critical that committed and anticipated supply and infrastructure projects are completed on schedule to minimise peak day shortfall risks.

The 2025 GSOO's supply adequacy assessment recognises that:

- Development of northern and southern anticipated supply is crucial to ensure sufficient supply is available to support southern demand and mitigate the risk of peak day shortfalls. This is especially critical for 2028-29 when considerable amounts of new anticipated supply is projected for these years.

[70] AEMO's demand forecasts presented in Chapter 2 and applied to the adequacy assessments in Chapter 4 include estimates of losses associated with UAFG.

- The KKLP project and the HUGS Project Stage 1 at Iona UGS will increase the storage capacity to supply southern demand centres. It is important these projects are completed on time to maximise supply to southern regions from 2025.
- Ensuring all storages are at full capacity prior to winter is critical to reduce shortfall risks. Throughout winter, appropriate operation to manage southern storage depletion is important, including the delivery of northern supply to ensure southern storages are not depleted before the end of winter.
  - The Declared Wholesale Gas Market (DWGM) interim LNG storage measures rule change[71] requires that AEMO contract any uncontracted capacity at Dandenong LNG until the end of 2025. This will ensure the Dandenong LNG tank is full prior to winter 2025, however not beyond this year, because the interim rule expires. The Victorian Government is seeking to extend the interim rule requirement, through a rule change with the AEMC to extend these measures.
- The timely development of electricity infrastructure (renewable energy, storage, and electricity network developments) in the NEM will reduce gas adequacy risks by reducing the reliance on GPG operations. Maintaining high availability of coal generation capacity during the peak winter seasons (by performing planned maintenance and scheduling retirements at the conclusion of the winter season where possible) will also mitigate gas adequacy risks.
- Given the lead time needed to plan, obtain approval for, and build new greenfield gas infrastructure, demand flexibility is likely the best solution to address forecast short-term supply shortfall risks. In extreme conditions that risk gas shortfalls, the use of GPG's secondary fuels, where available, may be needed to maintain gas adequacy while retaining reliability and security of the power system.

4.1.2 Annual and seasonal adequacy

With improvement in forecast gas supplies and reduced forecast demand, the risk of seasonal supply gaps are forecast from 2028 in sustained high gas use conditions, ahead of more structural annual supply gaps commencing in 2029, one year later than the 2024 GSOO. These supply gaps are forecast to occur in most cases during winter when southern demand is highest.

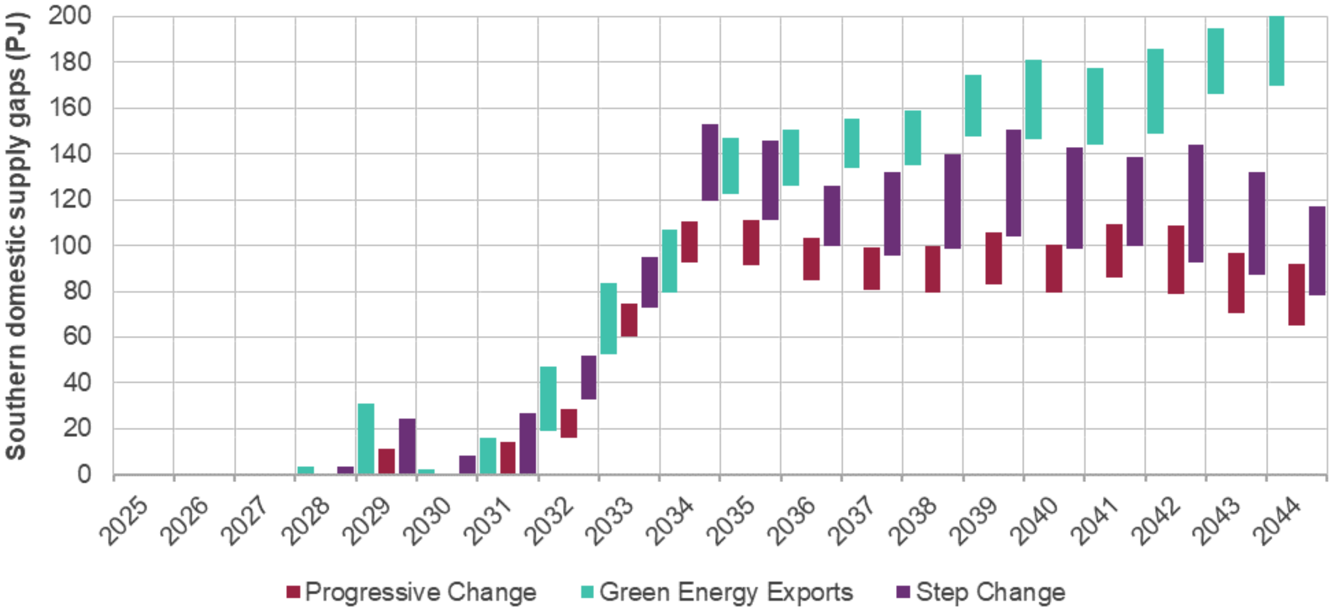
Supply gaps identified in the next decade will be influenced by the ongoing availability of coal generators in the NEM. The 2025 GSOO applies the forecast closure schedules from the 2024 ISP that may be earlier than announced closure schedules[72], to achieve emissions reduction objectives.

Figure 38 presents forecast domestic annual supply gaps in southern states across all scenarios. The range reflected in these outcomes results from the application of multiple weather patterns to seasonal variations in forecasting demand (including the forecasting of demand for GPG). The forecast supply adequacy assessment includes all existing, committed and anticipated supply developments.

[71] AEMC, "DWGM interim LNG storage measures", 15 December 2022, at https://aemc.gov.au/rule-changes/dwgm-interim-lng-storage-measures.

[72] Official generator closures are as published in the Generation Information pages, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Where new information on generator closures has been provided following the publication of the 2024 ISP, the official closures have been used.

Figure 38 Range of domestic annual supply gaps forecast in southern regions based on existing, committed, and anticipated developments, all scenarios, across different weather patterns, 2025-44 (PJ)



This annual adequacy assessment for the *Step Change* scenario shows that, for periods between 2025 and 2032:

- Small seasonal supply gaps are forecast in 2028, driven by an increase in forecast GPG demand as Eraring and Yallourn power stations are due to close. Section 2.4 explores additional sensitivity analysis to examine the impacts of NEM market impacts.
- In general, an annual supply gap, estimated at around 10-40 PJ/y, is forecast between 2029 and 2032 in southern regions. A growing spread in the supply gaps across the simulated weather conditions demonstrates the magnitude that solar and/or wind volatility may have on gas supply adequacy.
- Between 2029 to 2032, with more electrical storages and electricity transmission investments expected to be available to increase utilisation of renewables within the NEM, forecast GPG reduces, as shown by the reduced supply gap variance in these years.
- The supply gaps may increase to 90-140 PJ/y from 2033 due to ongoing reductions in gas supply (see Section 3.2.2), particularly if GPG is forecast to be needed regularly in the NEM as further coal generation retires and more heating loads electrify, increasing winter electrical loads (see Section 2.4).
- The range of forecast annual supply gaps increases after 2034, reflecting more variability in the highly weather-dependent forecast of GPG (see Section 2.4 – Weather variability).

The forecast range of annual shortfalls from the *Progressive Change* scenario is observed to follow a similar trend, but with lower volume and less variable than forecast from the *Step Change* scenario. This is mostly due to the lower and less volatile GPG forecast from slower coal retirement assumptions in this scenario.

For *Green Energy Exports*, the volume and range of shortfalls forecast to 2033 are similar to the *Step Change* scenario. From the mid-2030s onwards, annual shortfalls are forecast to be higher than the *Step Change* scenario by 30-40 PJ/y, mostly due to increased demand for hydrogen to produce green commodities.

Examining forecast supply gaps in the *Step Change* scenario in southern regions

Based on current production forecasts, **Figure 39** and **Figure 40** demonstrate the utilisation of existing, committed, and anticipated supplies to meet southern demand in 2025 and 2029 in the *Step Change* scenario. They show that:

- In 2025, AEMO forecasts indicate local gas production, imported northern supplies via the SWQP and use of storage facilities will likely meet forecast southern demand under weather conditions observed in recent history. During winter a risk of shortfall remains if very high peaks in demand for GPG occur due to very extreme weather conditions or unexpected NEM events (see Section 2.4 for more information about different extreme GPG forecasts).
- In 2029, AEMO forecasts indicate supply gaps during winter months, with smaller shortfalls also forecast outside of winter, as southern production is projected to decline by approximately 50% compared to 2025, and there is not sufficient southern production or pipeline capacity beyond existing, committed and anticipated projects to transport northern gas towards southern markets.

Figure 39 Forecast gas supply sources to meet southern daily demand, *Step Change* scenario, 2025 (TJ/d) (2019 reference year)

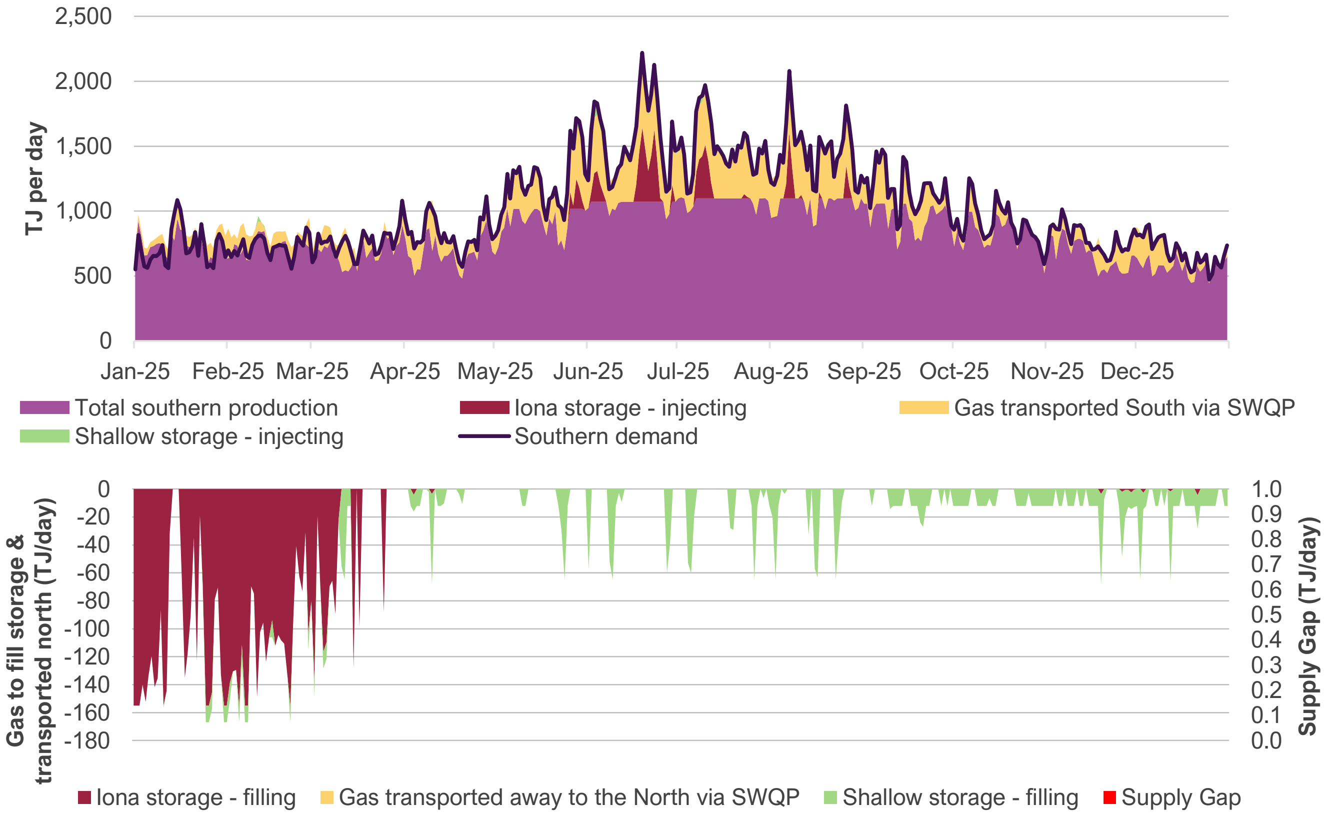


Figure 40 **Forecast gas supply sources to meet southern daily demand, *Step Change* scenario, 2029 (TJ/d), (2019 reference year)**

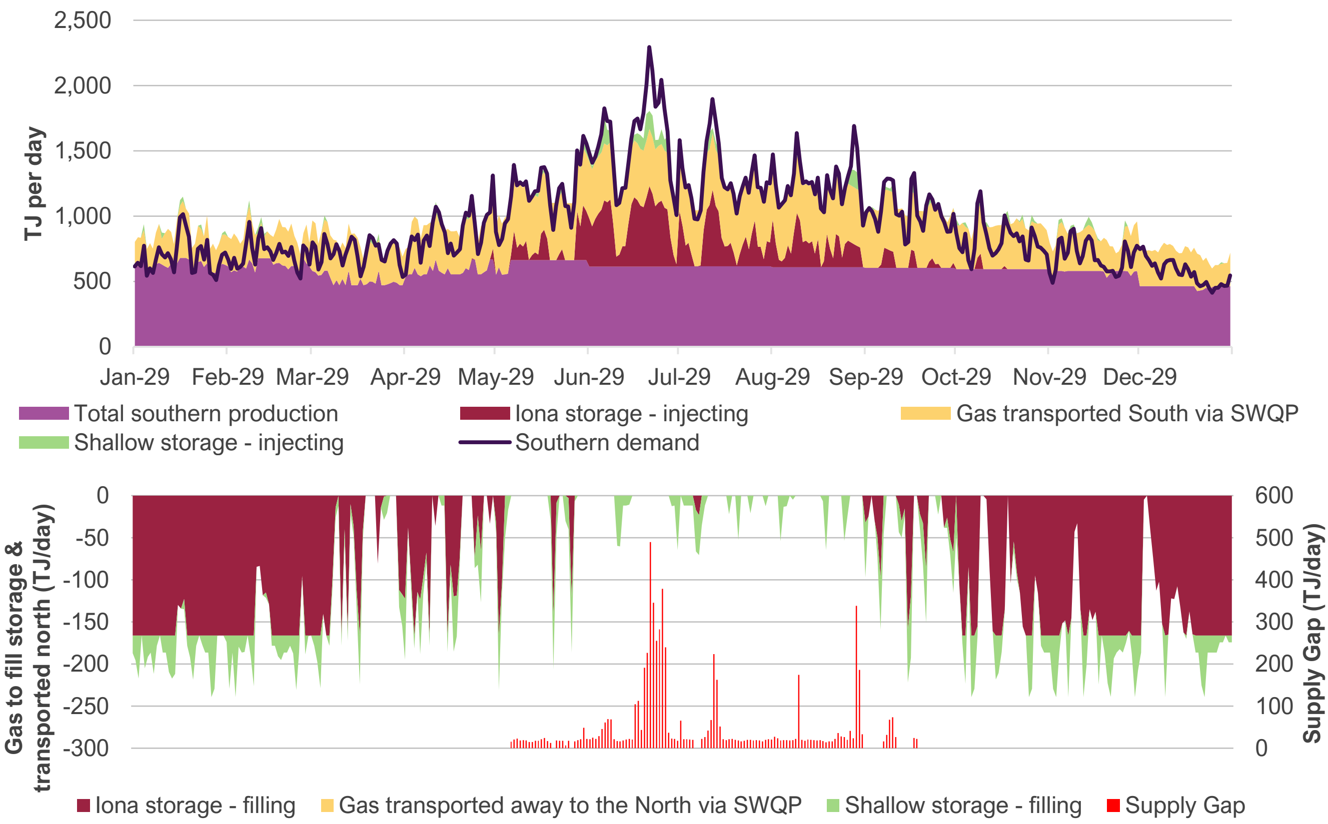
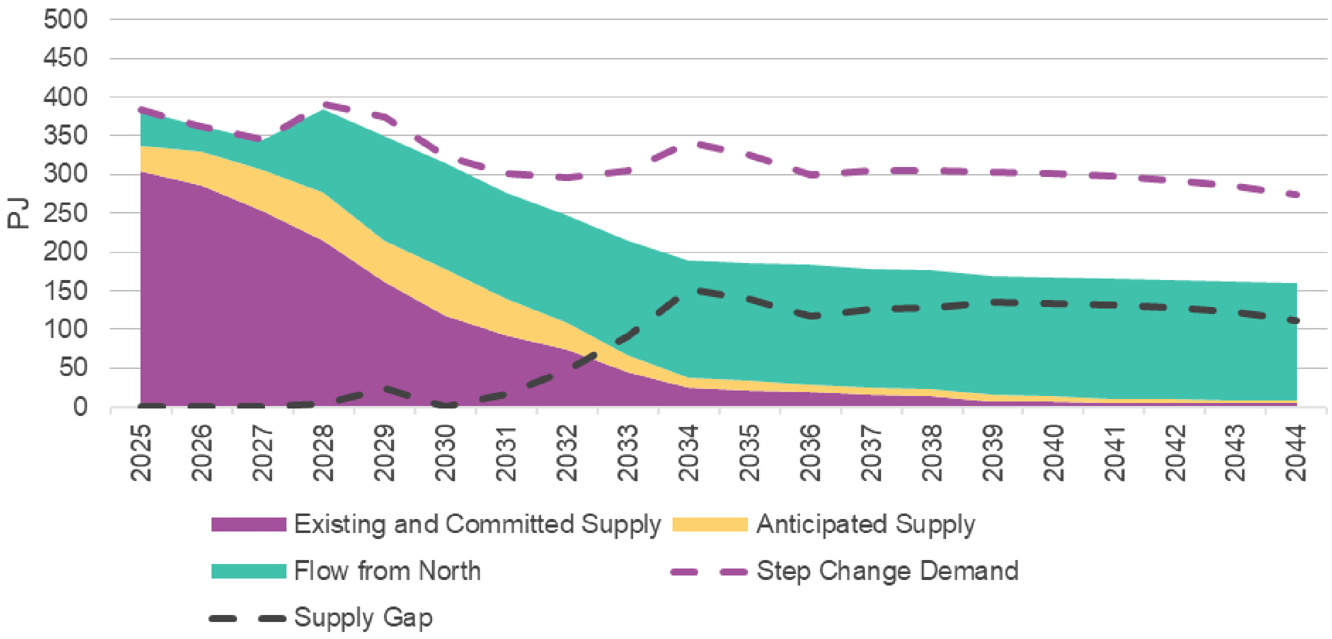


Figure 41 illustrates the growing forecast annual gas supply inadequacy with existing, committed, and anticipated supplies in the *Step Change* scenario. It shows that:

- Additional new supply, beyond what is considered committed and anticipated, might be required to develop to meet southern demand from 2028. The forecast supply gap in 2028 is expected to be between 0 PJ and 4 PJ, depending on weather conditions.
- After 2028, if there is no additional development of new southern supplies and storages, additional supply from northern uncertain projects is forecast to be required for southern regions to maintain sufficient supply to domestic consumers.

Figure 41 Projected annual adequacy in southern regions, *Step Change* scenario, with existing, committed and anticipated developments, 2025-44 (PJ)



Adequacy under various market conditions

A range of market conditions and events may affect the volume of gas produced or consumed in the ECGM across the 20-year outlook period. These conditions and events are examined through a range of sensitivities impacting both the timing and magnitude of peak day shortfall and annual supply risks.

AEMO has assessed a range of plausible sensitivities built on the *Step Change* scenario and their impacts on southern annual adequacy, as shown in **Figure 42**. Further information on the demand sensitivities can be found in Section 2.4.

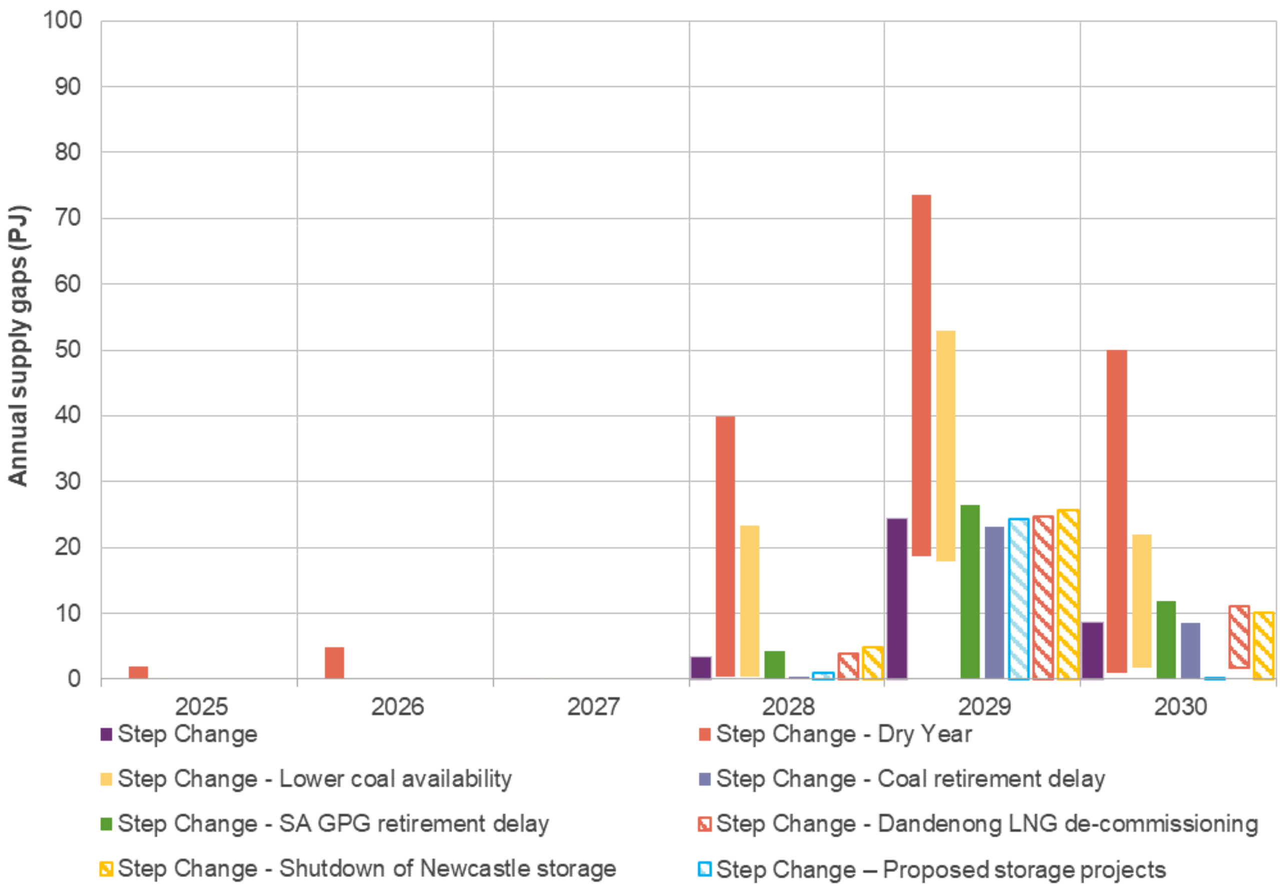
The demand sensitivities are:

- ***Step Change – Dry Year*** – assesses the impact of a prolonged rainfall drought similar to the Millennium Drought (2006-07), that resulted in approximately 45% lower inflow yield than an average year. Consequently, annual GPG is forecast to be approximately 65% higher and can significantly increase peak day and annual shortfalls from as early as 2025.
- ***Step Change – Lower coal availability*** – determines the effect of abnormally high number of unplanned coal power plant outages by replicating the unplanned outage occurrences of 2022. In certain years, GPG could be double than the forecast consumption in *Step Change.* This sensitivity also causes peak day shortfall from 2025 and increase forecast annual supply gap from 2028.
- ***Step Change – Coal retirement delay*** – estimates the impact of the closure of the Eraring Power Station being extended by 20 months, as indicative of a coal retirement delay. In this sensitivity, GPG would be about 70% lower in 2028. Risks of seasonal supply gaps are removed in 2028 in this sensitivity.
- ***Step Change – SA GPG retirement delay*** – estimates the impact of the retirement of the gas-fired power plants in South Australia being delayed by five years. Annual GPG would be 6-17% higher under this sensitivity.

The supply sensitivities are:

- ***Step Change – Dandenong LNG de-commissioning*** – assesses the impacts of Dandenong closure due to issues with the liquefaction plant from 2025 and possible closure after 2027. Although this sensitivity will not increase the annual supply gaps materially, it reduces operational resilience in Victoria from 2025 and can increase the risks of peak day shortfalls from 2028.
- ***Step Change – Shutdown of Newcastle storage*** – assesses the impacts of the Newcastle Gas Storage closure from 2025. The Newcastle Gas Storage Facility is currently operating with government support. This facility's shutdown might be a possibility beyond 2025. Although this sensitivity will not increase the annual supply gaps materially, it reduces operational resilience in New South Wales from 2025 and can increase the risks of peak day shortfalls from 2028.
- ***Step Change – Proposed storage projects*** – assesses the impacts of proposed storage projects (HUGS Phase 2 and Golden Beach). This sensitivity can address the seasonal supply gaps observed in 2028. Beyond 2028, these storages help to reduce the annual supply gaps, but will require additional supplies beyond anticipated and committed productions to operate more efficiently.

Figure 42 Forecast annual supply gaps for *Step Change* and other sensitivities, 2025-35 (PJ)

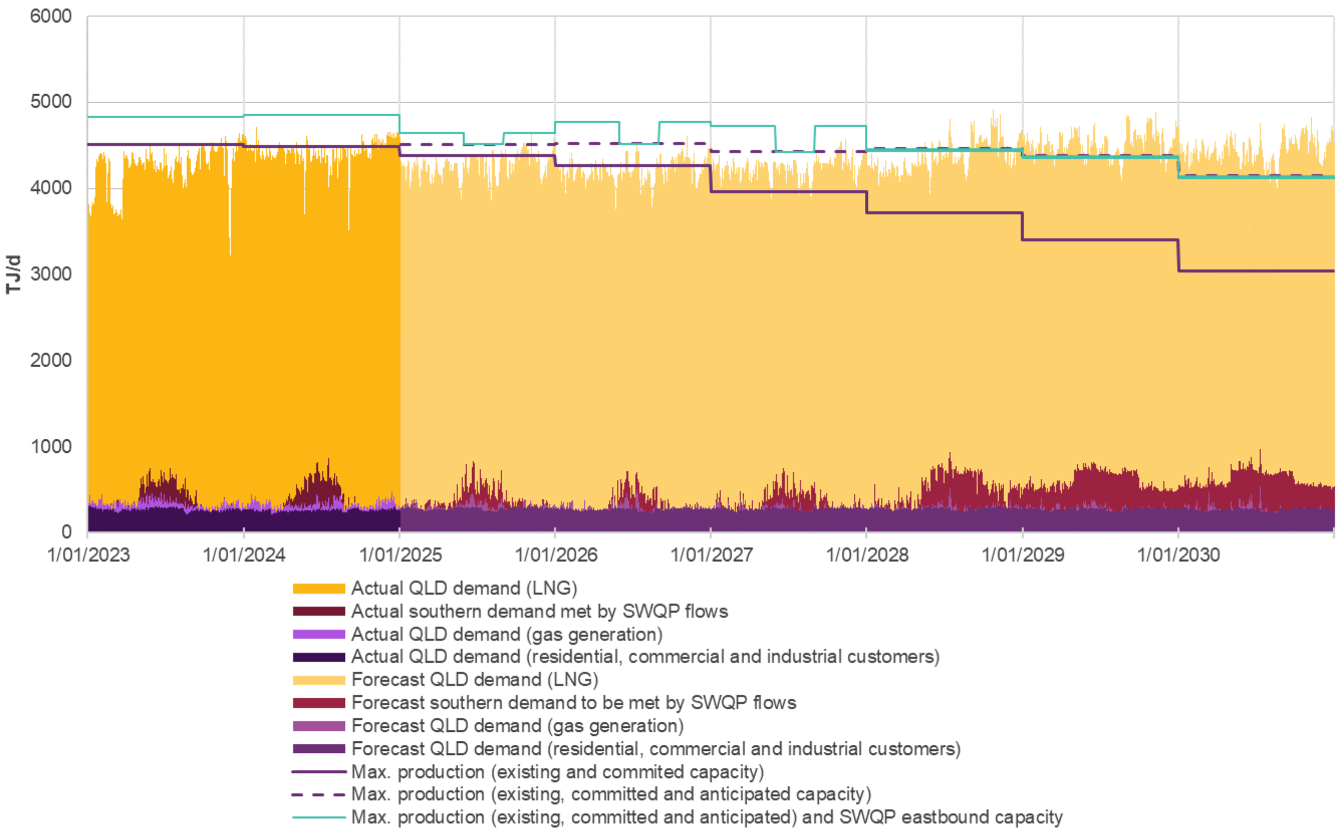


4.2 Northern supply adequacy

The actual and projected supply and demand of Queensland gas from 2023 to 2030 under *Step Change Scenario* is shown in **Figure 43**. According to current projections, to satisfy LNG export demand, anticipated northern supplies will need to be developed from 2025, with uncertain supplies required from 2028 to meet the stable demand for LNG.

The operation of LNG facilities will need to be flexible to prevent excessive drawdown from the gas network during peak domestic demand periods, particularly in winter. While northern regions exhibit minimal seasonal demand fluctuations, gas flows along the SWQP to southern regions typically increase in winter due to higher consumption in the south. From 2026, gas is not expected to be available to flow to northern regions along the SWQP, necessitating greater reliance on anticipated and uncertain northern supply developments due to declining southern production.

Figure 43 Actual and forecast Queensland gas demand and supply, including existing, committed and anticipated projects, and flows along the SWQP, 2023-30, *Step Change* (TJ/d)

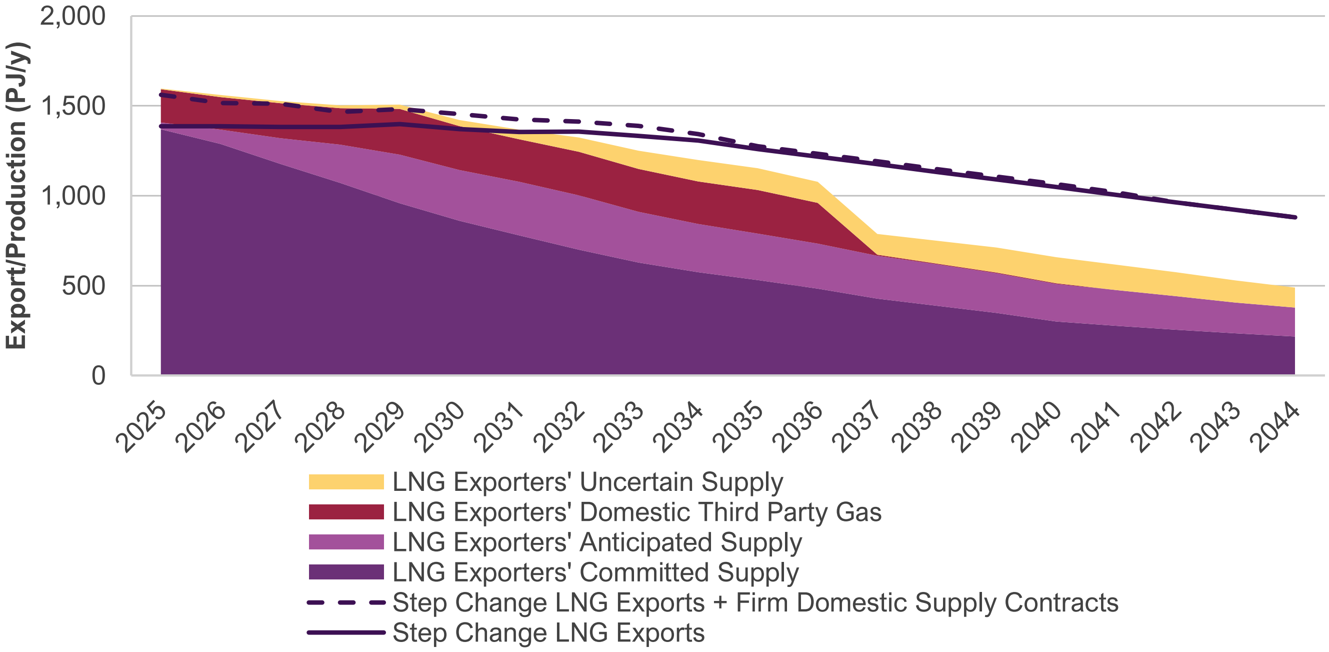


Note: SWQP eastbound capability remains after 2027, but there is not sufficient forecast gas available from southern states to flow to Queensland. In this chart, Max production (existing, committed and anticipated) and SWQP eastbound capacity line is deliberately drawn lower than the Max production (existing, committed and anticipated) line for visibility purpose. It should be interpreted that there is no available gas to flow to Queensland on the SWQP after 2027.

Figure 44 provides additional insights into LNG producers' supply and demand balance, showing their production, third-party gas, expected export contracts and firm domestic supply commitments.

It shows that the LNG producers have committed to firm contracts to supply substantial volumes of gas domestically in the near term. LNG producers' existing and committed developments, and domestically sourced third-party supply, can meet these contractual obligations to 2025 only. After 2025, additional supplies from anticipated productions are needed to fulfill both domestic contractual requirements and exporting demands. From 2032, expansion of uncertain supply, which may include expanded CSG well developments, will be required to balance with forecast demand.

Figure 44 LNG producers' committed, anticipated and uncertain production and domestic third-party gas in comparison to forecast exports and firm domestic supply contracts, *Step Change* scenario, 2025-44 (PJ/y)



The Northern Territory may need to extend its reliance on emergency gas arrangements

Supply from the Blacktip field in the Northern Territory reduced during 2024 and it is currently unknown when production may be restored to previous levels. If supply cannot be restored, Power and Water Corporation (PWC), which manages large wholesale gas supply and transportation, may need to continue to purchase gas from Darwin LNG exporters[73] in the near term, and make arrangements for alternative sources of supply in the longer term.

Carpentaria Gas Field from Beetaloo Basin in Northern Territory has progressed from uncertain to anticipated status with an initial expected production of 10 TJ/d from 2026 which will increase to 25 TJ/d or 9 PJ/y from 2027. However, this is still not enough to supply the increasing industrial demand and ongoing reliance on gas generators for electricity generation in the Northern Territory.

The 2025 GSOO considers supply adequacy for Northern Territory domestic customers and excludes any assessment of adequacy of gas exported through Darwin LNG.

Given supply disruptions at Blacktip, the NGP which transports gas eastward to Mount Isa from the Northern Territory is currently not flowing, and this GSOO does not forecast the resumption of these flows. Mount Isa therefore is currently supplied from east coast suppliers via the CGP, which reduces the gas available to southern

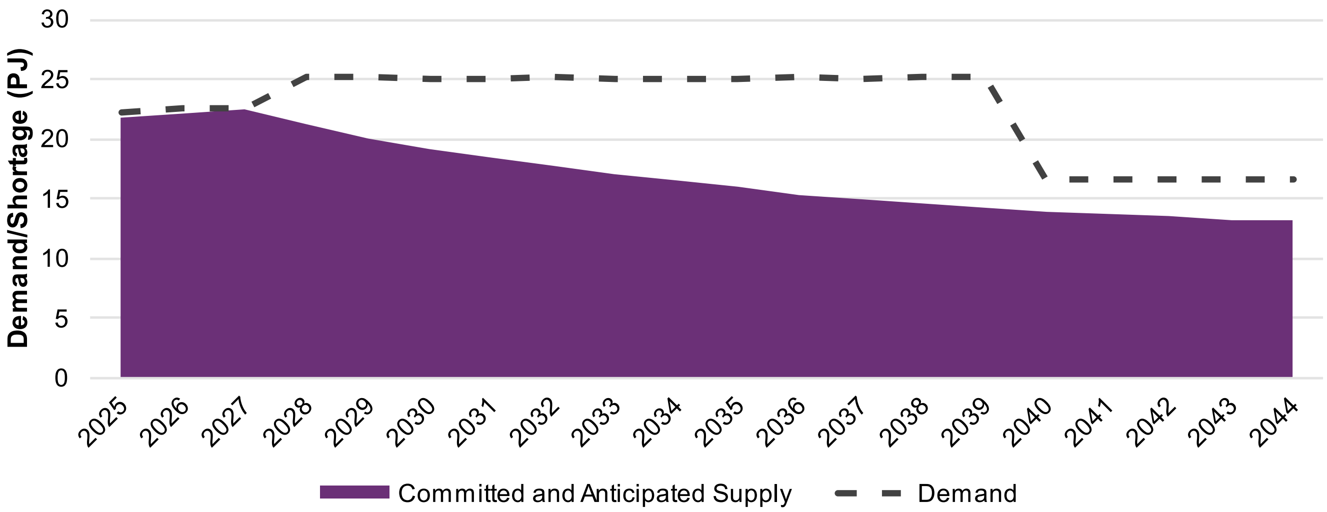
[73] Detail on this arrangement can be found at https://www.aemc.gov.au/sites/default/files/2019-08/Information%20sheet.pdf.

markets from Queensland[74], impacting the capability for the pipeline system to seasonally replenish storages, and for critical supply under peak demand conditions.

Jemena has recently completed the NGP Reversal Capability project in 2024, which enables gas to flow towards the Northern Territory from Queensland. Reversal of the NGP provides a backup solution for Northern Territory customers to address forecast supply gaps in the Northern Territory if gas supply is not available from alternative arrangements. The use of this reverse flow capability however is anticipated to only apply when insufficient emergency gas supply is available. As such, AEMO has not modelled this capability to meet Northern Territory supply gaps ahead of the use of LNG emergency supplies.

Figure 45 depicts the potential supply gap in the Northern Territory that may need to be filled by emergency gas supply arrangements or alternative gas sources during the period to 2044.

Figure 45 Forecast annual demand and shortage in the Northern Territory, *Step Change*, 2025-44 (PJ)



Supply forecasts for the Northern Queensland region have improved but supply to GPG may be limited

The 2024 GSOO reported that there was sufficient gas supply to customers in North Queensland, supplied by the North Queensland Gas Pipeline (NQGP), until 2034 only. Since the 2024 GSOO, AEMO has received updated development information regarding the Moranbah gas field, and gas producers have provided updated production forecasts.

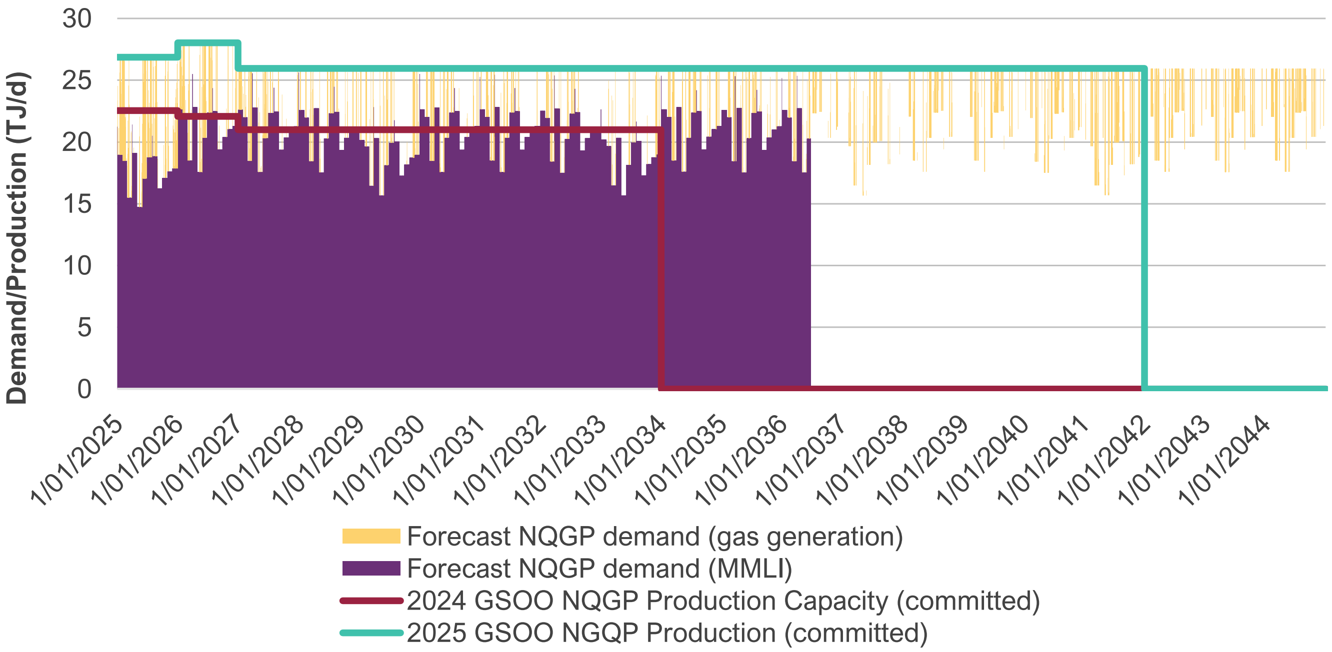
AEMO's GPG forecasting in this 2025 GSOO has taken into account inflexible production operations injecting into the NQGP that limit the flexibility of Townsville Gas Turbine to ramp up in response to demand spikes. GPG forecasts at Townsville were capped to the plausible limitation, with other generators in the NEM increasing their generation in response as needed.

Figure 46 presents the projected supply and demand on the NQGP for the Step Change scenario, comparing production between the 2024 and 2025 GSOOs (TJ/d). It highlights that:

[74] Utilisation of CGP for Mt Isa supply also limits gas to flow to other Queensland customers, when gas flows north from southern producers.

- There is sufficient committed and anticipated supply to residential, commercial, industrial and GPG customers on all days out to 2041.
- Demand for gas from residential, commercial, industrial users and GPG is forecast beyond 2041, indicating a long-term need for continued gas supplies on the NQGP. Alternatively, other electricity generation sources and development opportunities exist in North Queensland that might reduce the gas demand from this region.

Figure 46 Forecast supply and demand on the NQGP for the *Step Change* scenario, comparison production between the 2024 and 2025 GSOOs, 2025-44 (TJ/d)

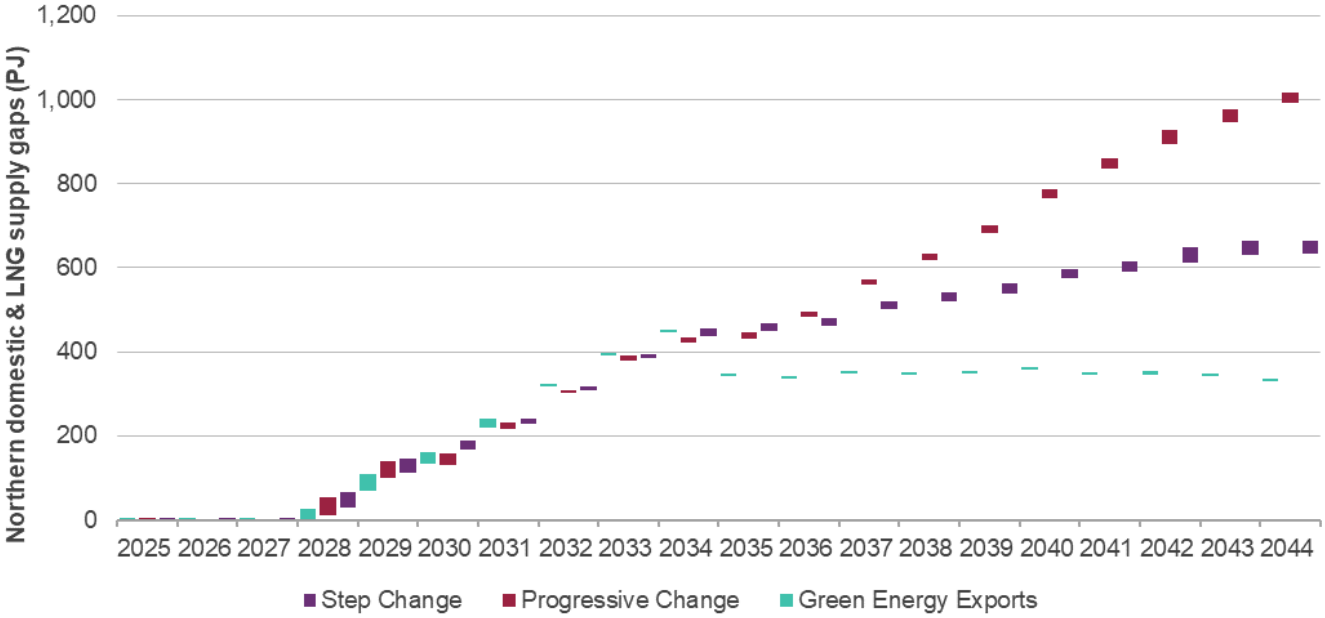


New supply is required in the north to address forecast annual supply gaps

To address annual supply gaps, new northern supply above what is considered committed and anticipated is required to be developed from 2028. In the longer term, as **Figure 47** shows, substantial annual supply gaps are forecast in Queensland as forecast production declines, depending on the scale of LNG export demand which is highly uncertain over that forecast horizon.

Continued drilling programs, pipeline augmentations, plant expansions, field or basin expansions, or the development of flexible injection capacity (such as storage), may need to be developed in Queensland from the mid-2030s to address emerging local transportation constraints affecting GPG.

Figure 47 Forecast domestic and LNG annual supply gaps in Queensland, assuming gas is made available to southern customers from northern producers and LNG producers as required, 2025-44 (PJ)



5 Options to address forecast supply challenges

As identified in Chapter 4, the ECGM requires new supply solutions to address the supply gaps and peak day supply shortfalls that are identified in the coming years. Various solutions are currently under consideration by market participants including transportation developments, LNG regasification terminals, new domestic gas supply sources (including renewable gases), and gas storages. A combination of these options is likely to be required to address supply issues in the long term.

As part of AEMO's physical assessment of gas adequacy to meet forecast demand, this chapter provides preliminary *what-if* analysis of gas adequacy with known potential additional future supply, transportation, and storage developments. The options are not exhaustive and are intended to provide guidance on the effectiveness of various options to address forecast supply challenges.

This analysis does not consider all factors such as costs, regulatory approvals, land use, social license, safety, or operational challenges of each option, and does not amount to a recommendation or representation regarding any projects or investments. It also does not examine the gas price impact of any of the options, or combination of options, that may impact gas consumers. As each assessed project is not committed or confirmed, the technical specifications of each reflect AEMO's best understanding of each project, informed by gas participant survey information where available, but these details may change as proponent's progress their projects.

Key insights

A range of proposed projects can provide sufficient supply to delay the forecast supply gaps to 2033 or 2034 and help to mitigate the risk of peak day shortfalls:

- **A combination of solutions, including new gas storage and additional northern supplies**, is required to address southern gas supply risks from 2034, as no single solution examined provides both sufficient peak production and annual supply to meet the forecast supply gaps over the long term.
- **Increased storage** to cater for increasing seasonal peaks is necessary to support all developments. The network injection capacity, location and timing of new storages will depend on the volume of new gas supplies that can be sourced locally in, or transported to, southern demand centres. Demand response mechanisms (either gas or electric) or on-site liquid storage for GPG will complement (and may reduce the need for) gas storage investment.

Investments in infrastructure from the mid-2030s will be highly dependent on the volume and rate at which gas is required for GPG, as forecast in Section 2.4.

5.1 Potential future supply, transportation, and storage projects

The supply, transportation and storage projects considered in this section have been proposed but are not sufficiently progressed to be classified as 'committed' or 'anticipated' and are therefore not included in the gas adequacy assessments in Chapter 4. The assessment in this chapter provides an indication of the impact of the development of several uncertain projects on addressing the physical gas adequacy risks identified across the GSOO horizon.

Table 11 details the challenges highlighted in Chapter 4 and explores the types of solutions that may be effective at resolving them.

Table 11 2025 GSOO supply challenges and options assessed

Supply challenge	Types of solutions for resolving
Annual and seasonal supply gaps	**Annual supply gaps require new supply** to be developed to provide sufficient volumes of gas domestically and for export: • Southern supply options include LNG regasification terminals, increased southern supply, infrastructure to transport gas produced in northern regions, or renewable gas projects. • Northern supply options include expansions or new supply from fields in the Surat and Bowen basins, or from new basins such as the Beetaloo sub-basin, the South Galilee or North Bowen basins, or from renewable gas projects. **Seasonal supply gaps require new flexible capacity** to support increased southern winter demand for heating and GPG. This may be addressed through a number of options, including: • New gas storage(s) in the south. • Upgrades to existing southern storage(s). • Regasification terminal(s) operated during winter. • Increased north to south pipeline capacity.
Daily or multi-day peak day shortfalls	**Increased injection capacity is required to satisfy extreme daily peaks** in demand. This risk is most observed in southern regions. For southern customers this supply challenge may be addressed by providing new southern supply and/or increased north-to-south pipeline transportation capacity. Depending on the magnitude of gas demand peaks and the capacity for injection from new solutions, southern storages may still be needed to adequately resolve peak day shortfall risks. Options therefore include: • New or expansion of existing storage(s), including shallow and deep facilities. • Onsite storage at gas generators to reduce peak withdrawal rates from the gas system at peak times. • Pipeline augmentations, including reversals of existing infrastructure to increase transportation flexibility. • Regasification terminal(s) to provide both additional supply and injection capacity. • Demand-side management mechanisms to reduce peak day demand.

Northern supply

Northern regions hold the most substantial reserves and resources, as described in Section 3.2.1. New northern supply from projects currently classified as uncertain is required in all options assessed, and may include expansions within existing basins (including development of new CSG wells), or developments in new basins such as the Beetaloo sub-basin, South Galilee, or North Bowen basins. The level of regional infrastructure investment required will depend on the proximity of the developments to existing processing and transportation infrastructure. The capacity to bring this gas south will also become more constrained by the capacity available along existing pipeline corridors (SWQP, MSP and MAPS).

North to south pipeline capacity

Increased north to south pipeline capacity provides southern demand centres with improved access to northern gas production, including existing, committed, anticipated and as yet undeveloped uncertain production (see Section 3.2.1). APA's ECGE Stage 3 expansions of the SWQP, MSP and the Bulloo Interlink (see Section 3.3.1) continue to be identified as development opportunities [75], and other projects such as Jemena's EGP reversal will also support improved north-south flow capabilities.

Additional pipeline capacity would provide improved capability to transport gas south throughout the year to the major load centres of Victoria, New South Wales and South Australia.

Southern supply

Southern (2C) contingent resources are known accumulations of gas that are not currently considered commercially recoverable. Projects are included in the Gunnedah, Otway, Gippsland, Cooper and Bass basins. Each of these uncertain 2C projects face a unique set of challenges including requirements for additional gas processing capacity and pipeline infrastructure to reach full delivery potential.

Additional renewable gas developments of green hydrogen or biomethane may also be available, with there being a small number of existing or committed renewable gas projects. Many of the proposed renewable gas supply projects identified to AEMO in the 2025 GSOO surveys are subject to a range of economic, regulatory and technical uncertainties. The timing and volumes of gas available from renewable sources is therefore challenging to forecast.

LNG regasification terminals

LNG regasification terminal projects are at various stages of development close to southern demand centres (at Port Kembla, Adelaide[76] and Geelong, see Section 3.3.4). LNG regasification terminals would provide significant peak day injection capability and could be operated seasonally during winter months when supply would be more available due to the northern hemisphere summer. During summer months when there is less demand, FSRUs could continue to supply domestic consumers or relocate to service alternative locations internationally during the northern hemisphere's winter, for example. In this analysis, AEMO has applied the expected year-round availability of FSRUs, as informed by proponent surveys, to receive and process cargoes that may support gas adequacy.

Regasification terminals will rely on existing or new pipeline infrastructure to enable delivery of its injection capacity to domestic consumers. This varies for each proposed development:

- **PKET** – Jemena plans to modify the EGP to enable bidirectional flow (providing north to south flow capability), and future expansion options exist to increase compression to increase transport capacity.
- **Venice's Outer Harbor LNG regasification terminal** – SEA Gas and Venice Energy have confirmed that the PCA can be reconfigured to support bidirectional flows from South Australia towards Victoria[77].
- **Viva and/or Vopak developments** – an LNG regasification terminal in Geelong would benefit from increased transport capacity along Victoria's SWP. The conversion of the WAG crude pipeline to a natural gas pipeline would increase the SWP transportation capacity.

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[75] Currently, APA has also committed to deliver two new projects (MSEP and MSP off-peak expansion) to upgrade the capacity of existing pipelines. See https://www.apa.com.au/news/asx-and-media-releases/apas-east-coast-gas-expansion-plan.

[76] This chapter focuses on options to address the structural supply gaps forecast from 2029. The Adelaide Energy Bridge project was not included in this options assessment, as the project only provides supply prior to the completion of the Venice Outer Harbor LNG regasification terminal and does not continue to supply gas beyond the end of 2028. See Table 10 for more detail on this project.

[77] See https://veniceenergy.com/2023/05/04/marketing-in-a-crowded-market/.

Storage

Gas storage capacity increases operational flexibility by providing load shifting of gas produced during summer to be used in winter when demand is higher. The ECGM currently relies on both deep and shallow storages to provide strategic reserves of gas for southern regions.

There are two storage projects in close proximity to southern load centres currently under consideration for development – the Golden Beach Storage Project and the HUGS Phase 2 project upgrading the Iona storage facility (see Section 3.3.2).

Gas storage capacity requirements are uncertain in the longer term. As demonstrated in Chapter 2 and Chapter 4, gas demand for residential and commercial customers is more variable daily and more uncertain seasonally while a growing role for GPG to firm the electricity system is forecast to put significant strain on gas demands in winter, as electrification of heating devices in particular puts more electrical load into the winter season. As forecast by the 2024 ISP, GPG is expected to have a key role in firming the NEM, which will increase the need for flexible gas supplies.

Pipelines (via linepack) and LNG regasification terminals (via the FSRU) provide storage capacity that can improve operational flexibility but do not represent a firm storage solution comparable to dedicated deep or shallow storage solutions (including on-site storage options at gas generators).

5.2 Proposed projects can delay shortfall risks and supply gaps to 2034

AEMO has assessed a range of development options currently under consideration by gas market participants to address potential future supply challenges. The capacities, timings, and individual effects on shortfalls of the options are presented in **Table 12** and shown graphically in **Figure 48**. It shows that most of the proposed projects by market participants can individually delay the annual supply gaps to 2033 or 2034. However, no single solution is forecast to be sufficient to resolve all forecast annual and seasonal supply gaps over the full horizon of the GSOO, and fully address the risk of daily peak shortfalls beyond 2034.

This assessment does not represent a 'best' or 'most economic' assessment of the options. Each project is presented individually, and may rely upon associated downstream pipeline augmentations to increase effectiveness. These augmentations are also currently classified as uncertain developments, and are not limited to integrated options from a single developer or gas market participant. The analysis does not examine customer pricing impacts of any particular solution.

Table 12 Future supply, transportation and storage options assessed

Option name	New southern supply		Transportation capacity (if relevant)		Southern annual supply gaps delayed to	Storage capacity (if relevant)	Additional northern supplies to the south (if relevant)
	Detail	Capacity	Detail	Capacity			
LNG regasification terminal	New South Wales (Port Kembla) from 2026	500 TJ/d, 130 PJ/y	• Eastern Gas Pipeline (EGP) reversal Stages 1 and 2	Stage 1: 2026 – 200 TJ/d Stage 2: 2027 – 325 TJ/d	2034	None	None
	South Australia (Outer Harbor) from 2027	405 TJ/d, 110 - 144 PJ/y	• Port Campbell to Adelaide (PCA) pipeline reversal, from 2028	250 TJ/d	2033	None	None
	Victoria (Geelong[A]) from 2028	750 – 778 TJ/d, 140 – 270 PJ/y	• WAG pipeline conversion project[E]	120 TJ/d[G]	2033	None	None
Pipeline expansions and upgrades	None	N/A	• ECGE Stages 3 and 4 • EGP reversal Stage 1 and 2 • Port Campbell to Adelaide (PCA) pipeline reversal, from 2028	800 TJ/d Bulloo Interlink 605 TJ/d SWQP 700 TJ/d MSP[B]	2034	Riverina Storage 200-500 TJ	100-150 PJ/y
Pipeline expansions and upgrades without northern supplies	As above	As above	As above	As above	2029	As above	None
Southern supply	2C Southern Supply[C] and renewable gas	Ramping to 200 PJ/y by 2030, then 100 PJ/y in the long term	• Hunter Gas Pipeline (Narrabri to Newcastle)[F] – by Q4 2028	200 TJ/d	2034	None	None

A. This could be either Viva's or Vopak's proposed LNG regasification terminal project.
B. Includes the relicensing of the Moomba Sydney Ethane Pipeline (MSEP) to transport natural gas, which is classified as an anticipated project.
C. A contingent (2C) resource is a best estimate of a quantity of gas that is less certain, and potentially less commercially viable, than 2P. This option only includes production profiles from southern 2C resources reported to AEMO via the GSOO surveys. Projects included in this additional southern supply include projects in the Gunnedah, Otway, Gippsland, Bass and Cooper basins.
D. If including additional northern supplies beyond committed and anticipated productions.
E. Only for Viva project.
F. Operation commencement is subject to project dependencies and main activities required to commence supply and key risks to the development that could affect the timing of FID or the commencement date. Project dependencies and key risks include a final investment decision for the Narrabri Gas Project, execution risk, regulatory approvals (including land access agreements, securing pipeline approval and Native Title determination) and assurance, and construction of the pipeline.
G. The capacity modelled is the increase to the SWP capacity that the WAG provides when the Viva Energy LNG regasification terminal injecting at maximum rate. See Chapter 5 of the VGPR for more detail on preliminary modelling for the WAG capacity and impact to the SWP.

Figure 48 Map of future supply, transportation and storage options assessed

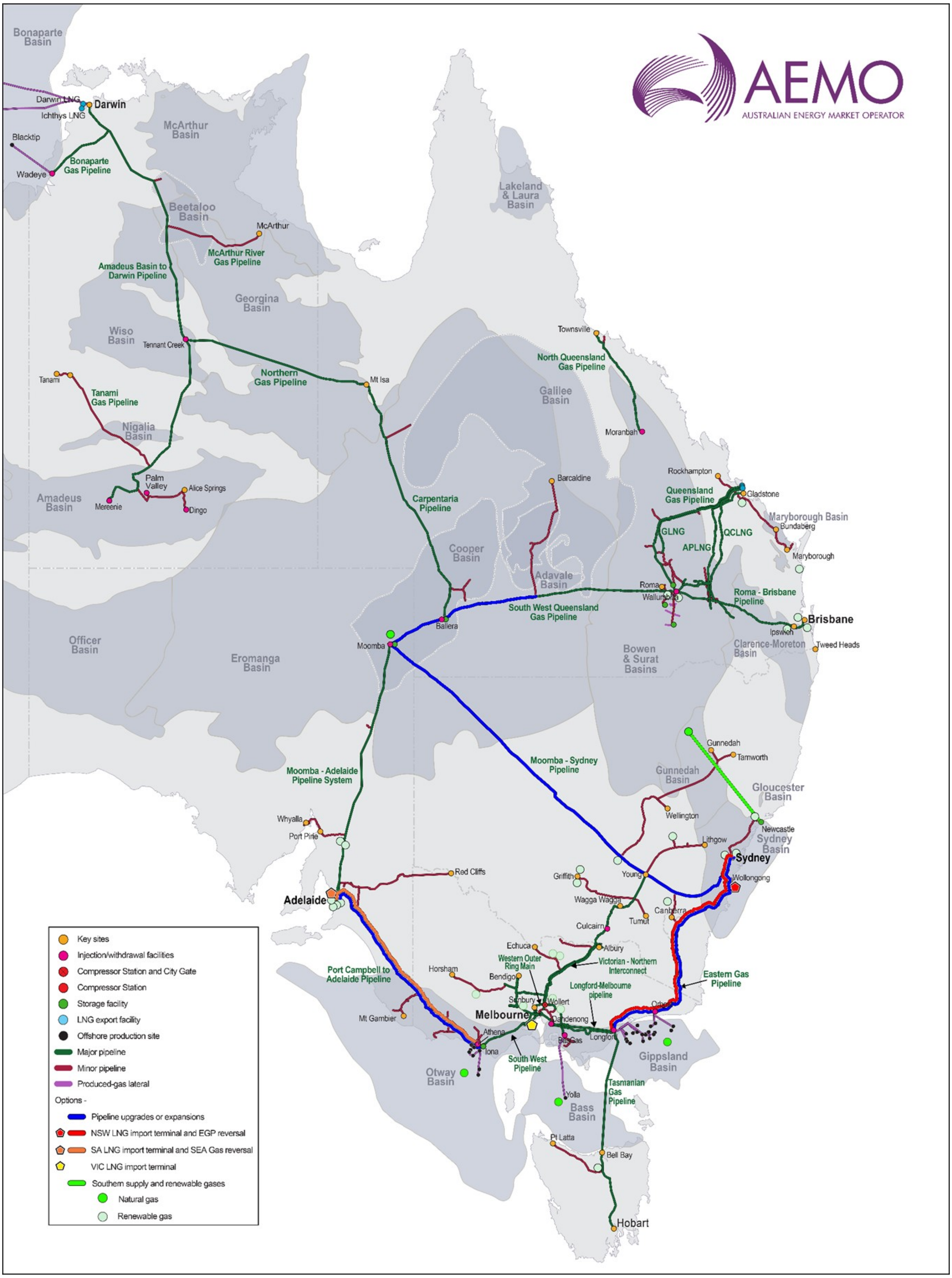


Figure 49 presents the forecast southern adequacy for each of the future potential options assessed and their individual impacts on addressing the structural annual supply gaps that are forecast with only existing, committed and anticipated projects. The figure shows that:

- **Pipeline expansions and upgrades to improve north to south flow capacity** may delay the forecast supply gaps to 2029 if the Bulloo Interlink (ECGE stage 3), Riverina storage (EGCE Stage 4), and reversal projects on EGP and PCA are implemented to enable effective transport capacity to all southern demand centres. To fully utilise this additional transportation capacity, new northern supplies beyond committed and anticipated developments, and in addition to that required to service northern supply gaps, are required in order for sufficient gas to be available to ensure effectiveness of this potential solution. With additional northern supplies, annual supply gaps can be delayed to 2034.
  - This chapter provides some analysis of the effectiveness of the solution without additional northern supply – in each instance, this is explicitly mentioned.
- **Development of currently uncertain southern supply** developments may delay annual supply gaps to 2034 and help mitigate peak day shortfall risks. This solution will require the Hunter Gas Pipeline by 2028 to transport 2C supplies from Narrabri to Newcastle.
- **An LNG regasification terminal** may delay supply gaps to 2033 or 2034 and help mitigate peak day shortfall risks, depending on the availability of LNG cargoes and the development of associated pipeline infrastructure to support deliverability (depending on the terminal). Additional infrastructure upgrades such as the EGP and PCA reversal are also required to effectively transport gas across southern states.

Figure 49 Range of annual shortfalls for each option assessed across various weather conditions, in comparison to the *Step Change* scenario, 2025-44 (PJ)

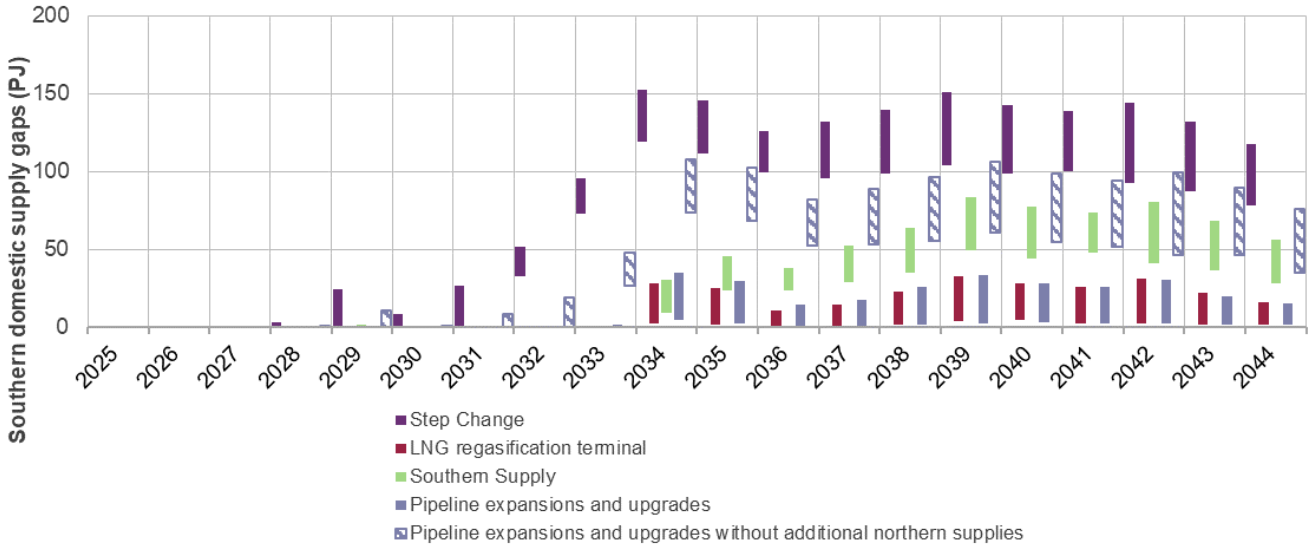
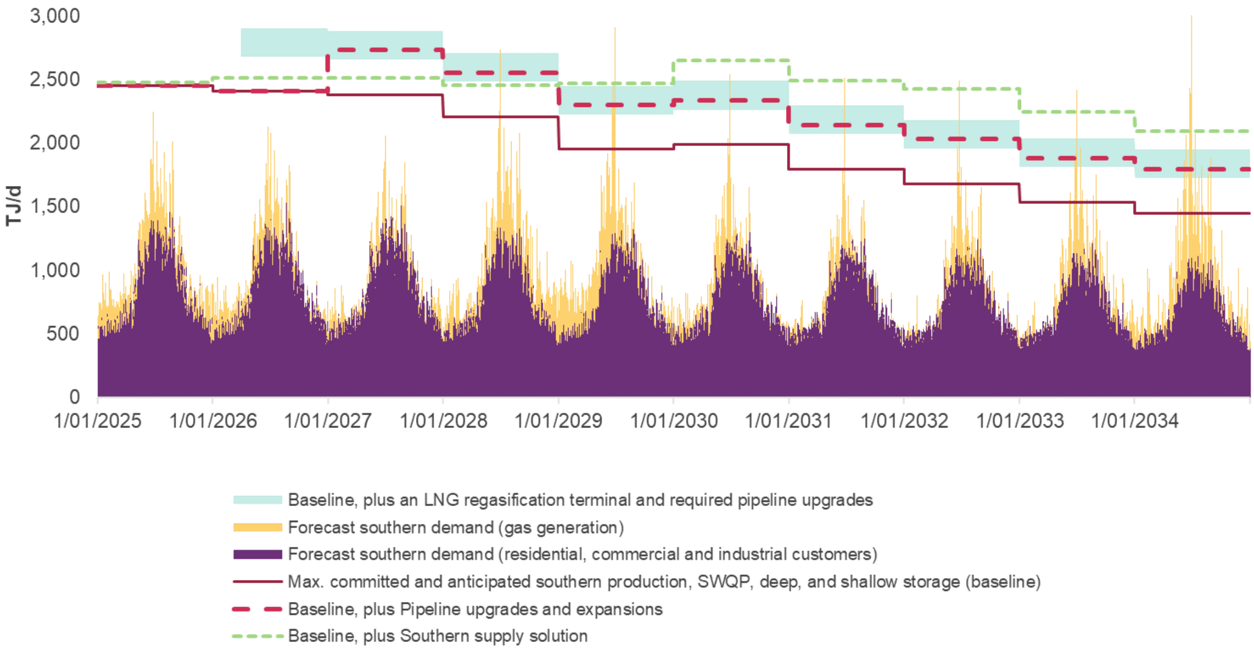


Figure 50 shows that while the risk of daily shortfalls under extreme peak demand conditions is reduced significantly in all options to 2033, additional investments above those assessed are still needed to fully address the risk of daily peak supply shortfalls from 2029 in some solutions (and later than 2029 in other solutions). This could be delivered by a combination of the options assessed, new capacity from storage or gas plants in the

south, or new pipelines which could provide alternative north to south transportation. Demand reduction measures, including alternative on-site fuel sources for gas generation or measures that reduce electricity peak demands to reduce GPG demand, may also assist in mitigating peak day gas shortfall risks.

Figure 50 Forecast southern daily adequacy for each of the future options assessed, 2025-35 (TJ/d)



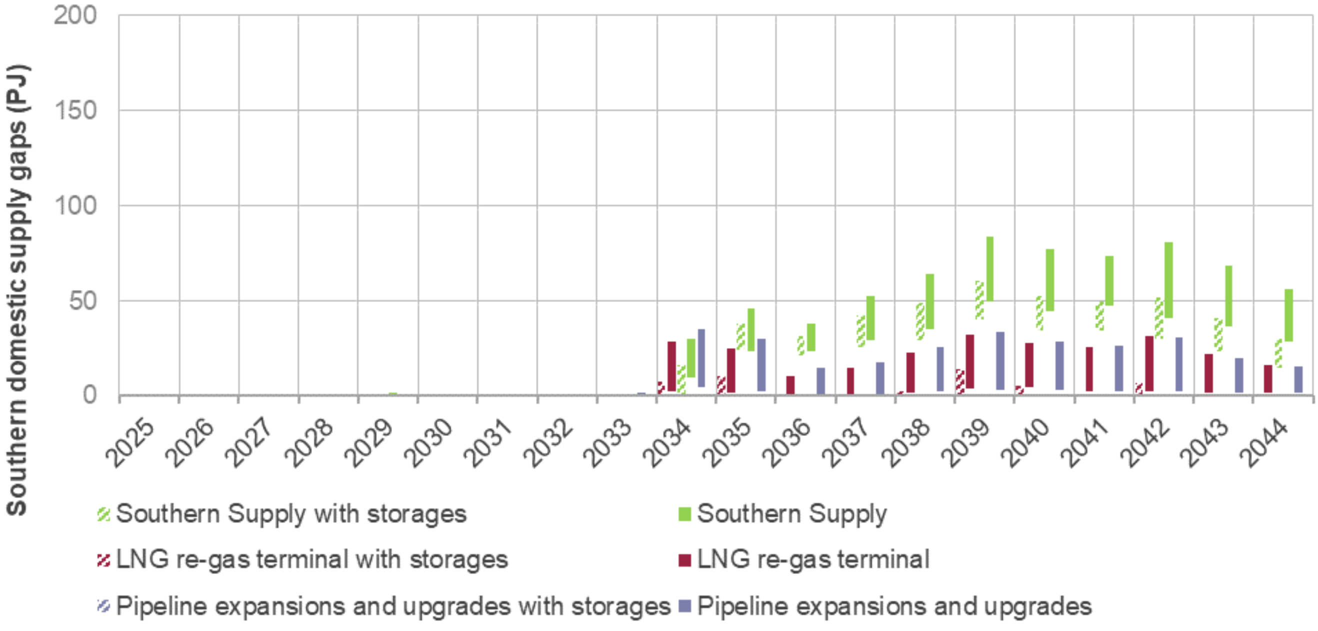
5.2.1 New storage developments are required to address southern gas supply risks after 2034

As coal generators that operate in the NEM retire, increasing the need for alternative dispatchable electricity generation sources, the use of gas for GPG is forecast to grow significantly and become more variable. To address the needs of annual, seasonal and peak day requirements of all gas users, a combination of different investments is needed over the longer term, particularly from the early 2030's, as no single solution examined provides sufficient peak production and annual supply to meet the forecast supply gaps.

In addition, increased storage to cater for peak seasonal loads is forecast to be necessary. Storage provides increased flexible injection capacity at peak times, the capability to rapidly ramp up and down, and the potential to relieve existing bottlenecks in network capacity. All forms of storage will be critical to address the seasonal adequacy challenges and winter peaks, including those forecast for GPG in the late-2020s and from the mid-2030s onwards (see Section 2.4).

Figure 51 presents the range of southern annual supply gaps from future supply options assessed, including additional storage build. It shows that all solutions can improve the way annual supply gaps can be addressed with additional storage developments. In the *Pipelines Expansions and Upgrades* option, for example, annual supply gaps may be fully addressed with sufficient additional storage capable of servicing demand centres effectively, as shown in the figure by the absence of a corresponding 'hatched' series. This highlights the important role of storages to provide flexible gas availability, particularly valuable to support the highly variable GPG demand in the future.

Figure 51 Range of southern annual supply gaps for future supply options assessed, including additional storage build, 2025-44 (PJ)



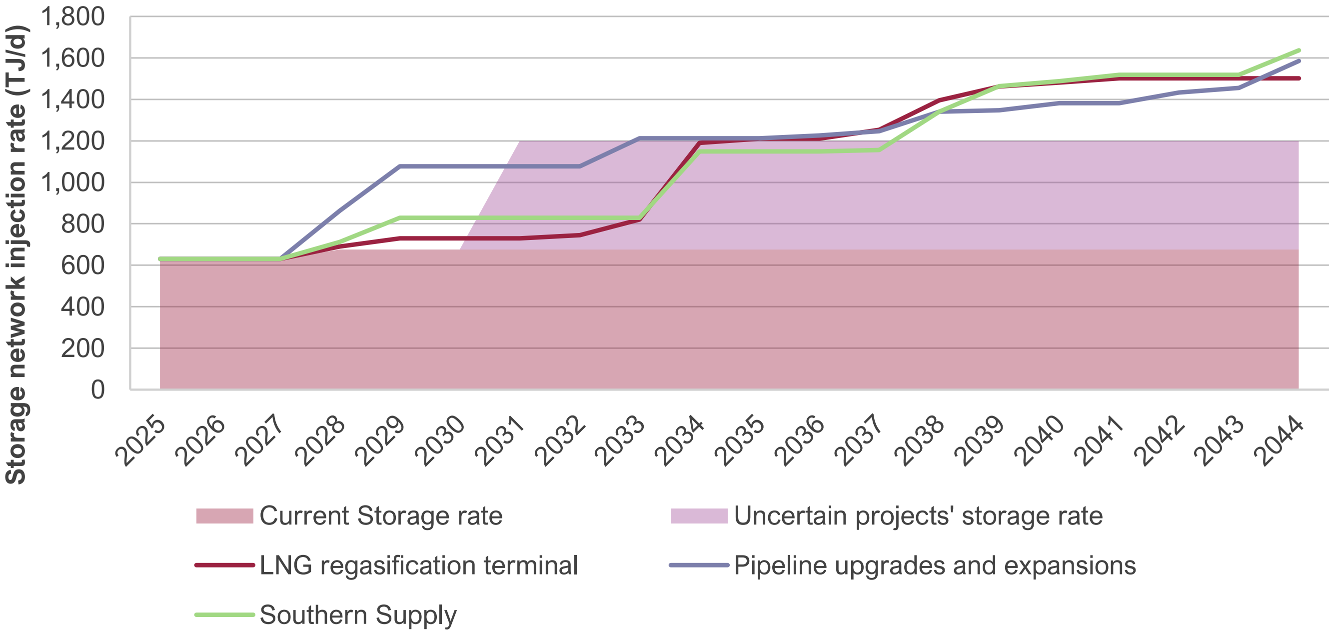
The necessary depth, network injection capacity and timing of new storages will depend on the volume of new gas supplies that can be sourced locally in, or transported to, the southern demand centres. The location for storages also depends on GPG requirements and the range of upstream supply and transportation options being developed.

Figure 52 shows the total required storage network injection capacity required for each option and to address the seasonal, peak day and annual supply gaps. It highlights that:

- Additional storage services are required in all options from 2028 to address flexible demand requirements.
- The network injection capacity and timing for new storage required by the system varies across each option assessed, due to individual options' supply capacity and capabilities for flexible operation and injection. The level of storage also varies according to the degree of transport capacity that is available across the options to bring new supplies to demand centres.
- The *Southern Supply* and *LNG Regasification Terminal* options will require similar storage injection capacity, as both options are able to supply gas to southern demand locally.
- *Pipeline Expansions and Upgrades* can provide year-round supplies to the south so more storage services are required to use off-peak refilling opportunities to enable appropriate support of southern winter demand.
- Toward the end of the 2030s, all options will require about 500-550 TJ/d of additional injection capacity from southern storages. For perspective of the scale of this need, two current uncertain projects, Golden Beach and the HUGS Phase 2 project, can provide up to 525 TJ/d in total.
- In the 2040s, the optimal amount of storage is highly uncertain, and is dependent on numerous factors, particularly the location of new entrant gas generators in the NEM. The 2026 ISP will examine GPG investment

needs with greater consideration of gas system capabilities, following the *Better integration of gas and community sentiment into the ISP* NER rule change[78], as determined in December 2024.

Figure 52 Total southern storage injection capacity, all options assessed, *Step Change*, 2025-44 (TJ/d)



5.2.2 Examining the operations of proposed options

The future year-round supply and demand balance will vary under each modelled development option. This section analyses the daily capability of all options to deliver gas during 2033, which is selected as an example year that is able to adequately meet annual and seasonal supply gaps in most individual solutions in *Step Change*.

Figure 53, Figure 54 and **Figure 55** show:

- Gas from the north will continue to be relied on to meet southern demand (including refilling storages), even if supplies are provided by a new *LNG Regasification Terminal* (**Figure 53**) and especially in the *Pipeline Upgrades and Expansions* option (**Figure 54**) in 2033. The volume of gas delivered by the SWQP is reduced during summer but is still crucial to refill Iona storage in preparation for winter.
- New uncertain *Southern supply* (**Figure 55**) would reduce reliance on gas from the north as compared to the other options. With expanded southern production, surplus southern gas is able to be transported north outside of winter periods up to 2033.
- Storage operations are critical in all options. Re-filling will occur frequently throughout the summer months and storages provide critical injections between June and September.
- While no annual supply gaps are found in all options (depending on the specific terminal in the *LNG Regasification Terminal* option, as outlined in Table 12) in this year, peak day shortfall risks still exist in winter periods. This highlights the needs for additional investments above those assessed to fully address gas supply inadequacy risks for gas consumers across the year.

[78] See https://www.aemc.gov.au/rule-changes/better-integration-gas-and-community-sentiment-isp-0.

These observations are specific to the presented options only. Development of alternative supply, transportation or storage options, or similar options of different capacities, may materially impact these examples.

Figure 53 Supply-demand balance for the *LNG Regasification Terminal* option, 2033, *Step Change* (TJ/d)

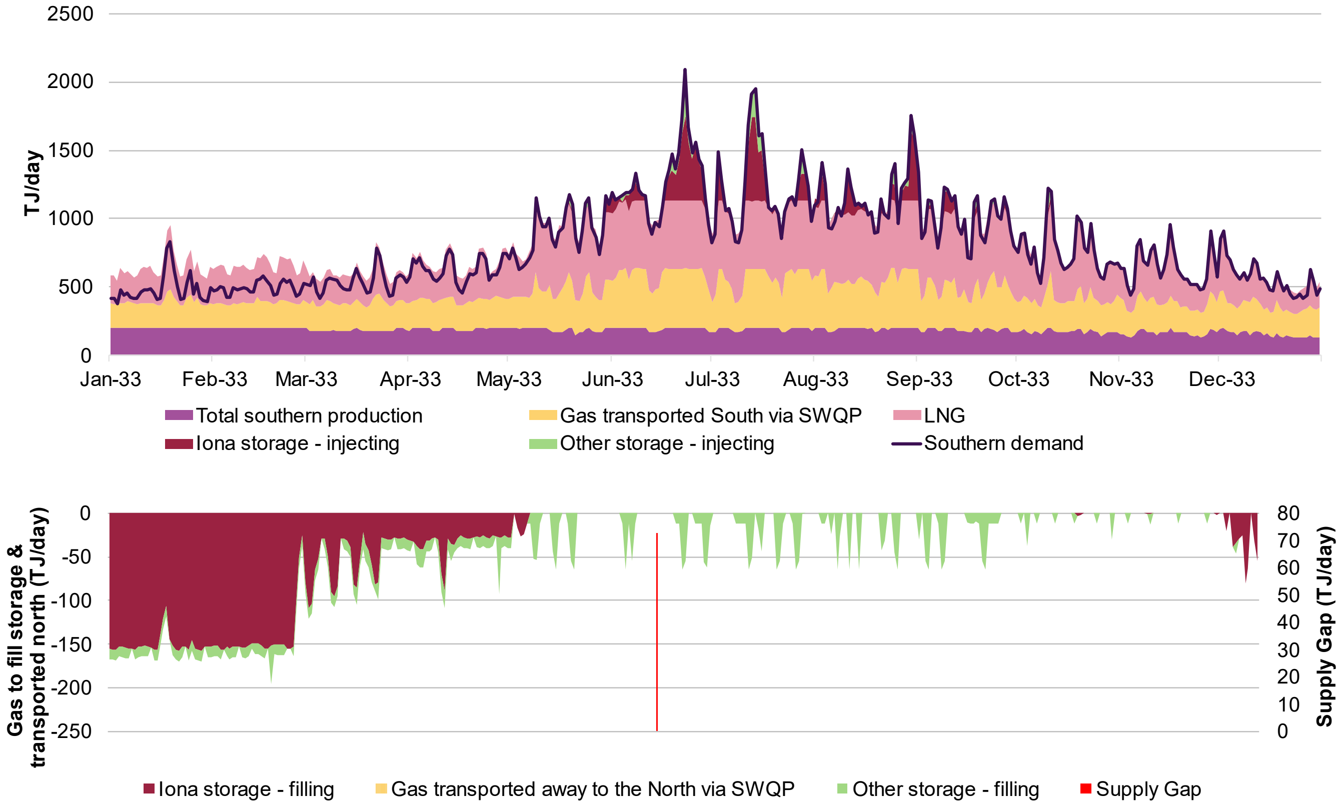


Figure 54 Supply-demand balance for the *Pipeline Upgrades and Expansions* option, 2033, *Step Change* (TJ/d)

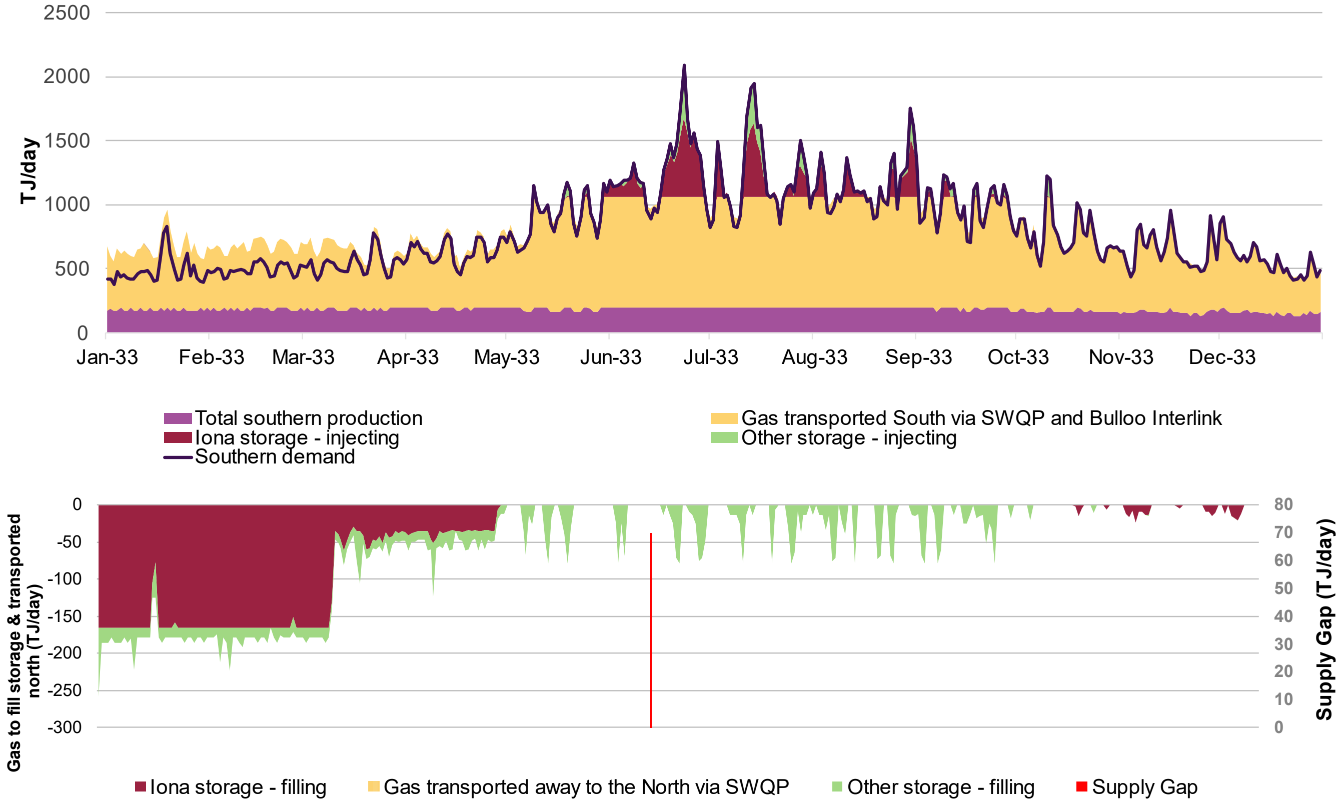
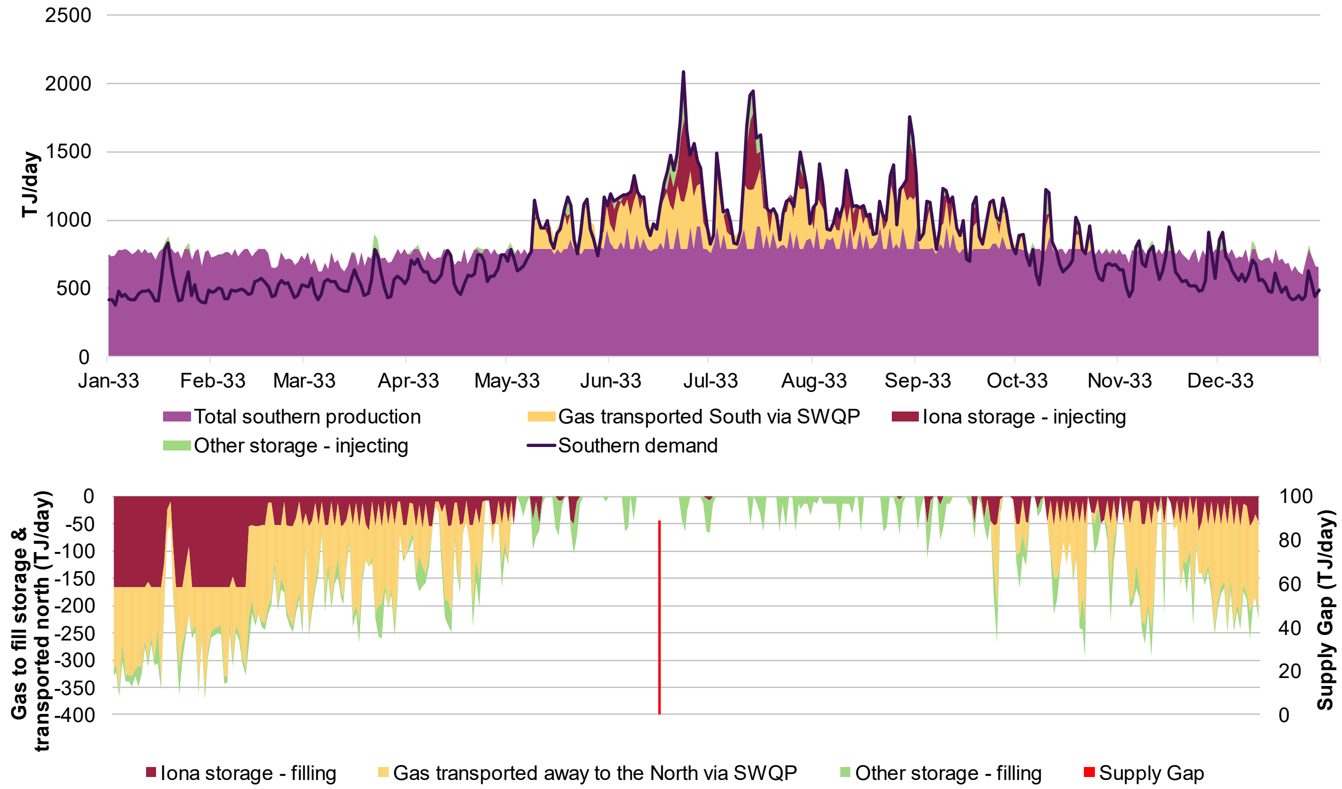


Figure 55 Supply-demand balance for the *Southern Supply* option, 2033, *Step Change* (TJ/d)

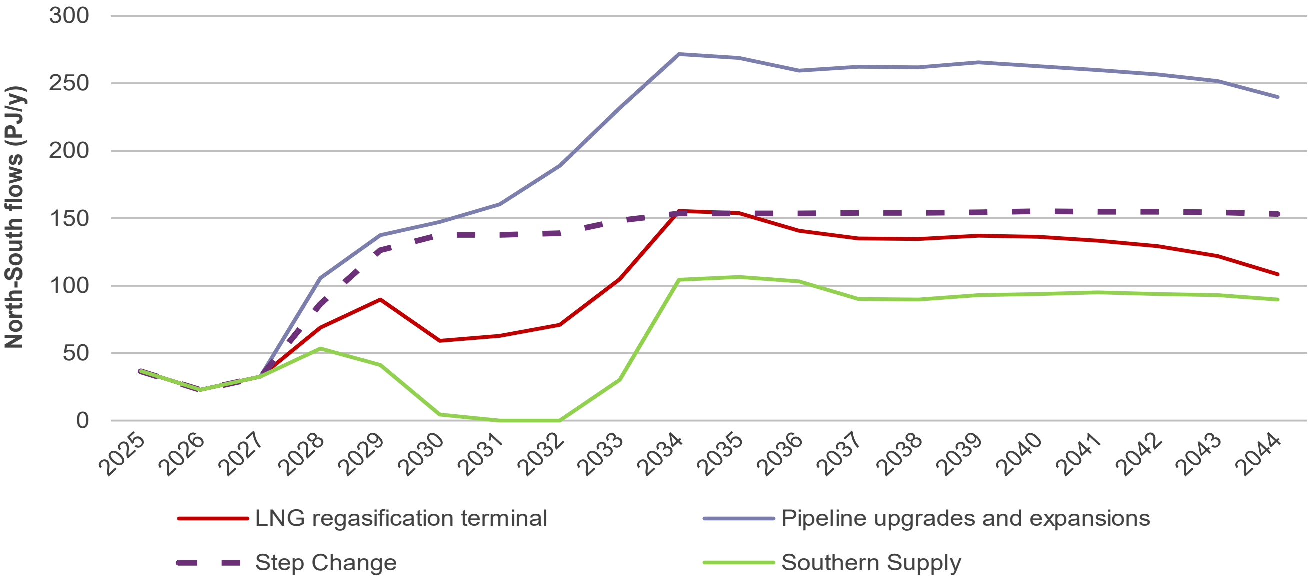


5.3 Significant new northern supply is required in all options assessed

Significant new northern supply is required across all options assessed to support forecast LNG export demand and domestic consumption in northern regions (Queensland and the Northern Territory). Opportunities for even greater northern supply development exist especially if northern gas is capable of meeting the southern supply structural supply gaps (either from increased transportation capabilities through pipelines, or LNG shipments). Without additional transportation capacity, southern production decline is expected to increase reliance on northern fields via the SWQP in all options without new supply developments in the south.

The primary driver for supply gaps in the north is the sustained medium-term commitments for LNG exports that exceed the level of committed and anticipated volumes of supply expected to be produced from the LNG producers' CSG operations. The supply required above committed and anticipated volumes is forecast to be approximately 500 PJ/y from the mid-2030s for the *Step Change* scenario (see Section 4.2). Some variation in the amount of northern supply required exists as southern demand is met to a varying extent by northern supply. Options which include more southern supply require less imported gas from the north, as shown in **Figure 56**.

Figure 56 Total gas transported from north to south for all options assessed, compared to flows with only existing, committed and anticipated developments, *Step Change*, 2025-44 (PJ)



In total, the 2025 GSOO indicates approximately 7,000 PJ of additional northern gas (above what AEMO considers committed and anticipated) will be required during the period to 2044 given committed and anticipated southern supply. The volume of supply classified as 'uncertain' through AEMO's 2025 GSOO survey responses is nearly equivalent to this requirement, and as identified in Figure 27 in Section 3.2.1, there are significant reserves and resources that could be accessed across the ECGM. Further exploration, development and appraisal in northern regions is likely to be required to prove and commercialise reserves and resources.

Current LNG export contracts are due to expire during the mid-2030s, meaning the level of export demand and residual gas available to support domestic customers is uncertain. The volume of northern supply that may support domestic consumers (in both northern and southern regions) will be largely dependent on the future export volumes and the expansion of supply that the LNG producers commit to over the medium and long term.

A1. Forecast accuracy

AEMO publishes data on the accuracy of its previous forecasts to build confidence in the forecasts it produces and to help inform its approach to continuous improvement. Assessing the historical performance of the forecasts can help identify any bias in recent forecasts and improve the understanding of forecast risks.

The following charts show AEMO's gas consumption forecasts since 2020, compared to actual recorded consumption in the ECGM. These charts can be used to assess the performance of the forecasts by comparing actual consumption against forecasts in each year. Only the historical central scenario forecasts are presented (which since 2022 has often been labelled with a *Step Change* naming convention).

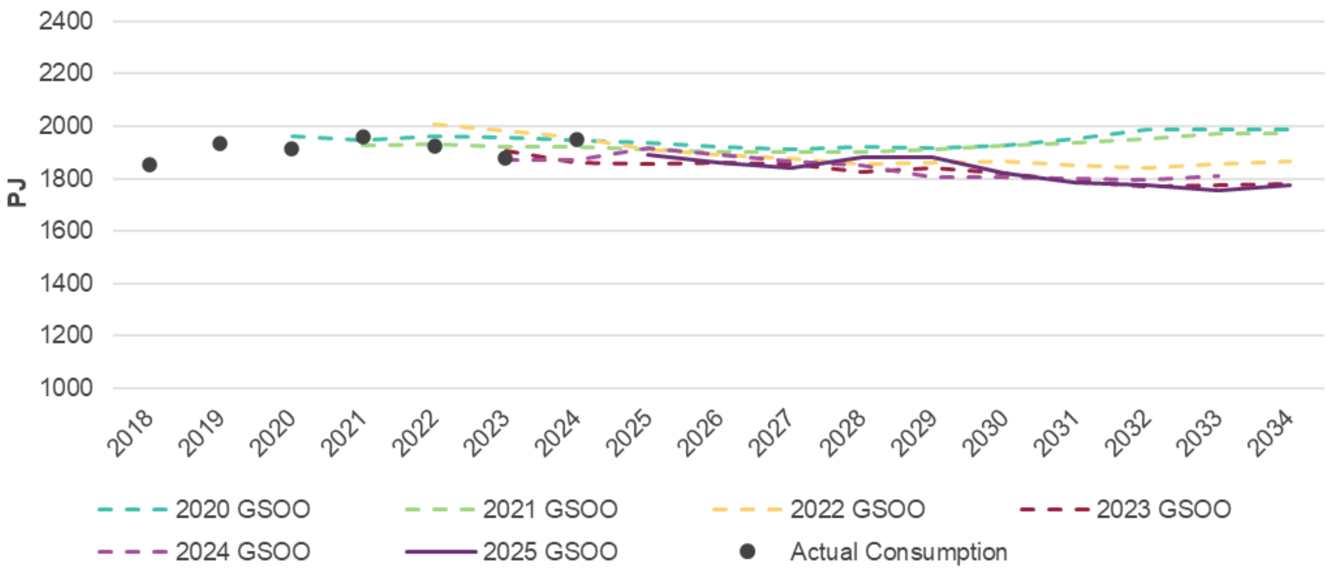
Actual annual gas consumption is partly driven by weather. For example, in a very cold year, gas consumption will be higher due to increased use of space heating. As AEMO's forecasts are developed on a weather-normalised basis (with typical weather conditions) some difference between forecast and actual consumption is expected in particularly hot or cold years.

As outlined in AEMO's *2025 Gas Demand Forecasting Methodology*, the gas forecasting approach applies long-term average weather patterns to the component drivers, meaning forecast error will likely exist when actual weather conditions materially deviate from historical averages. Where practical to estimate, AEMO's forecast accuracy assessment provides estimated 'weather normalised' equivalents for the most recent forecast year. More information on this approach is in AEMO's 2025 Gas Demand Forecasting Methodology.

A1.1 Total gas consumption forecasts

Figure 57 shows total gas consumption forecasts, including consumption for LNG export, over successive GSOO publications.

Figure 57 Actual gas consumption forecast comparison to actuals in the ECGM (PJ)



Note: The Northern Territory was included as a participating GSOO jurisdiction from the 2023 GSOO. Accordingly, this chart includes the Northern Territory in actual gas consumption from 2023 onwards to assess forecast accuracy.

Key observations:

- The 2020 GSOO and 2022 GSOO both over-estimated gas consumption for the corresponding calendar year, mainly driven by lower than forecast LNG consumption.
- The 2021 GSOO under-estimated consumption in that calendar year, mainly due to two major power system events which increased consumption of gas for gas generation in Queensland, New South Wales and Victoria.
- The 2023 GSOO over-estimated consumption in the 2023 calendar year. The variance mainly came from the lower than forecast consumption from GPG generation and residential and commercial sectors.
- The 2024 GSOO considerably under-estimated consumption for the 2024 calendar year. This was due to higher than forecast LNG and GPG consumption despite lower than forecast residential, commercial and industrial consumption. This reflects the relative size of LNG and GPG consumption.

Table 13 provides an overview of the forecast accuracy of the calendar year immediately following the forecast. Forecast accuracy in this case is measured as the percentage error, calculated as:

Percentage error = (Forecast - Actual) / Actual

A positive number represents an over-forecast; that is, where the forecast was higher than the actual consumption. Due to the large size of the LNG sector (which represents approximately 75% of total gas consumption), inaccuracies in this sector will make a large contribution to forecast error.

Table 13 Year ahead historical forecast accuracy, total consumption (PJ)

	2020	2021	2022	2023	2024
Year ahead forecast	1,961	1,928	2,009	1,904	1,869
Actual consumption	1,913	1,959	1,923	1,880	1,951
Forecast accuracy	2.5%	-1.6%	4.5%	1.3%	-4.2%
Source	GSOO 2020	GSOO 2021	GSOO 2022	GSOO 2023	GSOO 2024

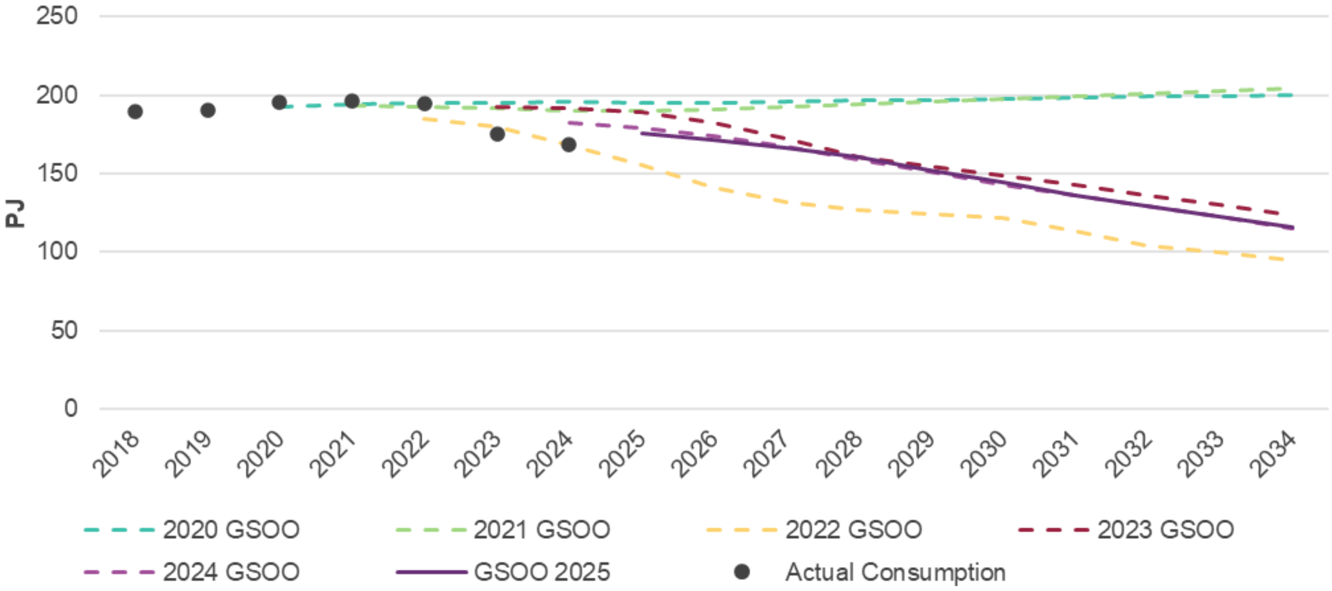
Note: Minor variations in historical consumption reported in previous GSOO reports may occur due to refinements to connection point mapping and updates of estimates with actual information.

The forecast accuracy of individual sectors is discussed in the following sections.

A1.2 Residential and commercial gas consumption forecasts

Figure 58 shows AEMO's residential and commercial gas consumption forecasts over successive GSOO reports compared to actual outcomes. AEMO's forecasts are driven by various components including growth of connections and population, growth and the impacts of investments in energy efficiency, gas fuel-switching such as electrification, and other factors including gas prices and economic activity. These factors are described in more detail in Section 2.2.1.

Figure 58 Actual gas consumption forecast comparison to actuals in the residential and commercial sectors (PJ)



Note: The Northern Territory was included as a participating GSOO jurisdiction from the 2023 GSOO. Accordingly, this chart includes the Northern Territory in actual gas consumption from 2023 onwards to assess forecast accuracy.

Table 14 provides an overview of the residential and commercial gas consumption forecast accuracy of the calendar year immediately following the forecast. AEMO's 2024 GSOO residential and commercial projection was 8% higher than actual consumption levels in calendar year 2024. The 2024 winter across much of the ECGM was one of the warmest winters on record[79]. A typical weather resulted in a 13 PJ reduction in gas consumption compared to a standard weather year for residential and commercial users[80]. Excluding the weather impact, AEMO's 2024 GSOO residential and commercial forecast is estimated to be over-forecast by just 0.4% compared to weather-normalised actual consumption.

Table 14 Year ahead historical forecast accuracy, residential and commercial total consumption (PJ)

	2020	2021	2022	2023	2024
Year ahead forecast	192	194	185	193	182
Actual consumption	195	196	194	175	169
Forecast accuracy	-1.6%	-1.2%	-4.6%	10.1%	8.0%
Source	GSOO 2020	GSOO 2021	GSOO 2022	GSOO 2023	GSOO 2024

A1.3 Industrial gas consumption forecasts

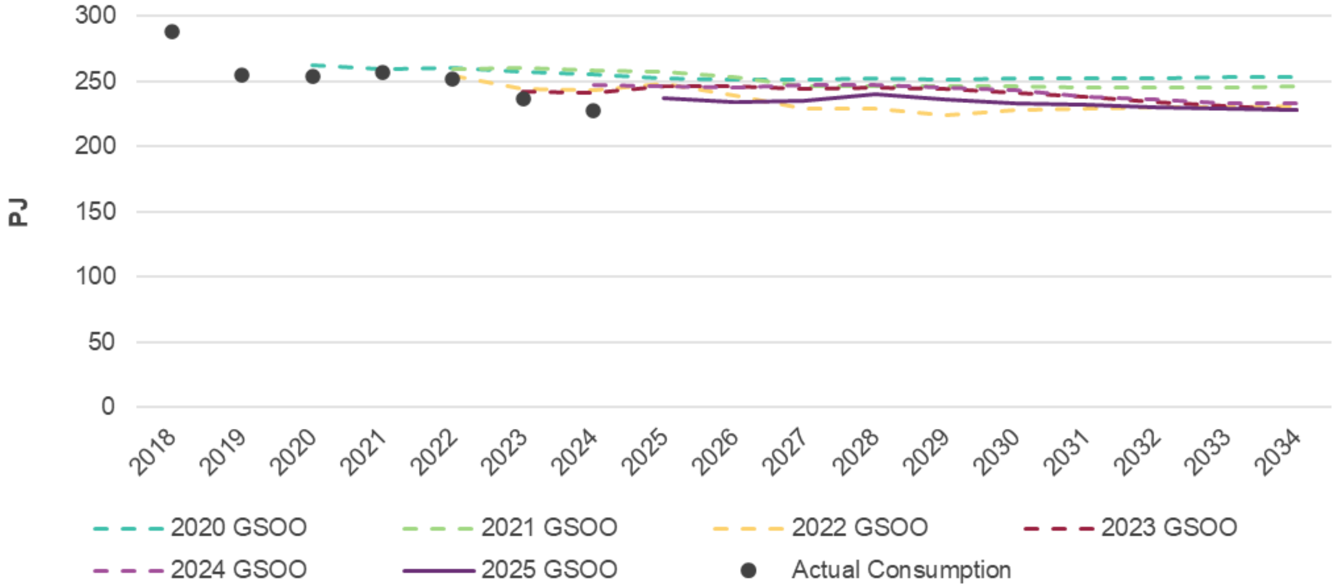
Figure 59 shows AEMO's industrial gas consumption forecasts. AEMO's industrial consumption projections are based on two categories – large industrial loads (LIL) and small to medium industrial loads (SMIL). Operators of

[79] Mean winter temperatures in 2023 were the warmest on record for Queensland, New South Wales and Tasmania, and second warmest for Victoria and South Australia. See http://www.bom.gov.au/clim_data/IDCKGC2AR0/202308.summary.shtml for further details.

[80] AEMO uses an EDD weather standard for Victoria and a Heating Degree Days (HDD) weather standard for other states. Refer to the AEMO Gas Methodology Paper at https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo for details on EDD and HDD formulation, historical climate change adjustment, and use as a weather standard.

large industrial loads are surveyed to ensure their best estimates of forecast gas consumption inform AEMO's LIL forecast, while the SMIL sub-sector is forecast using assumptions associated with economic drivers and historically observed trends. Industrial forecasts and forecast drivers are described in more detail in Section 2.2.2.

Figure 59 Actual gas consumption forecast comparison to actuals in industrial sector (PJ)



Note: The Northern Territory was included as a participating GSOO jurisdiction from the 2023 GSOO. Accordingly, this chart includes the Northern Territory in actual gas consumption from 2023 onwards to assess forecast accuracy.

Table 15 provides an overview of the industrial gas consumption forecast accuracy of the calendar year immediately following the forecast.

Table 15 Year ahead historical forecast accuracy, industrial total consumption (PJ)

	2020	2021	2022	2023	2024
Year ahead forecast	262	260	254	242	247
Actual consumption	254	256	252	237	227
Forecast accuracy	3.0%	1.2%	1.1%	2.1%	8.5%
Source	GSOO 2020	GSOO 2021	GSOO 2022	GSOO 2023	GSOO 2024

Over 90% of large industrial gas-consuming customers were surveyed (by volume) for the 2024 GSOO. Consistent with the methodology, AEMO adopts an econometric modelling approach to forecast the remaining in aggregate[81], which includes an allowance for the potential fuel-switching of industrial consumers to electricity and other gases[82].

Forecast industrial gas consumption continues to follow a long-term flattening trend. Variations from forecasts to actual industrial consumption arise primarily due to unpredictable factors such as weather variations, market

[81] Refer to the AEMO Gas Methodology Paper at https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo for details on AEMO's econometric modelling.

[82] Consumption impacts of potential fuel-switching to electricity and hydrogen from gas are based on multi-sectoral modelling conducted by consultants CSIRO and ClimateWorks.

shocks, or operational issues that result in unforeseen changes in industrial loads, both temporary and permanent.

AEMO's 2024 GSOO industrial projection was 8.5% higher than actual consumption in the 2024 calendar year. The difference can be attributed to these factors. In the SMIL sector, reduced consumption levels are estimated to have been driven by milder winter conditions and lower LIL consumption following the early closure of facilities in Victoria and New South Wales[83].

A1.4 LNG export segment consumption forecasts

In 2024, gas consumption by LNG export facilities in Queensland represented 75% of total gas consumption across the ECGM. The GSOO does not include any LNG export quantities produced within and exported from the Northern Territory.

LNG export consumption is driven by factors including:

- Operational considerations affecting CSG production.
- Operational considerations affecting LNG operations at Gladstone.
- Global market dynamics impacting the price and competitiveness of Australian LNG relative to other supplies of LNG globally (including from within each facility operator's global portfolio).
- Global market dynamics impacting the demand for energy and supply of alternative forms of energy, particularly in America, Europe and Asia.
- Contractual considerations affecting local production.

Near-term forecasts of LNG export consumption are advised by LNG producers via the GSOO survey process, like LIL consumption, in accordance with the gas forecasting methodology. Prior to the 2024 GSOO, information was provided to AEMO on a voluntary basis, however from February 2023 the *Gas Transparency Measures* package of reforms has mandated that gas production information be provided under the NGR.

Figure 60 and **Table 16** compare LNG export forecasts against actual LNG exports from Curtis Island in Queensland.

[83] e.g. refer to Qenos voluntary administration https://www.aigroup.com.au/news/media-centre/2024/imminent-qenos-closure-has-massive-implications-for-industry/.

Figure 60 Annual gas consumption forecast comparison, Queensland LNG (PJ)

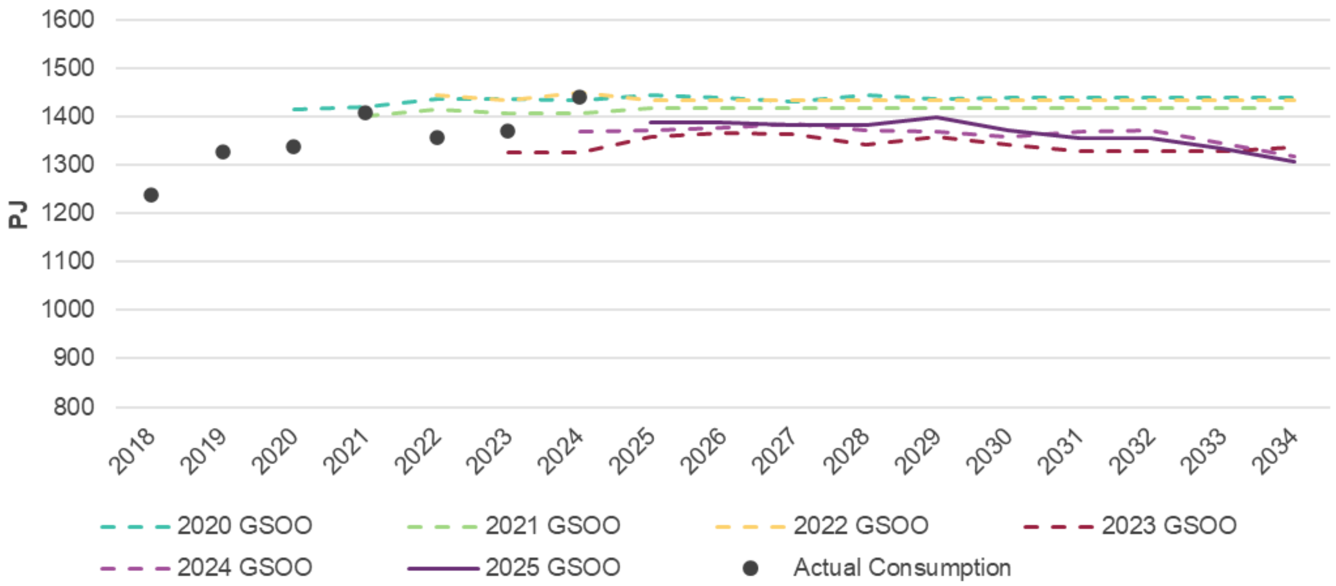


Table 16 Year ahead historical forecast accuracy, all Queensland LNG facilities total consumption (PJ)

	2020	2021	2022	2023	2024
Year ahead forecast	1,415	1,401	1,444	1,326	1,369
Actual consumption	1,338	1,407	1,358	1,371	1,439
Forecast accuracy	5.8%	-0.5%	6.4%	-3.3%	-4.9%
Source	2020 GSOO	2021 GSOO	2022 GSOO	2023 GSOO	2024 GSOO

Table 16 shows that the year-ahead forecast produced in each GSOO represent a combination of under- and over-forecast errors. These forecast errors may be in part attributable to the following dynamics:

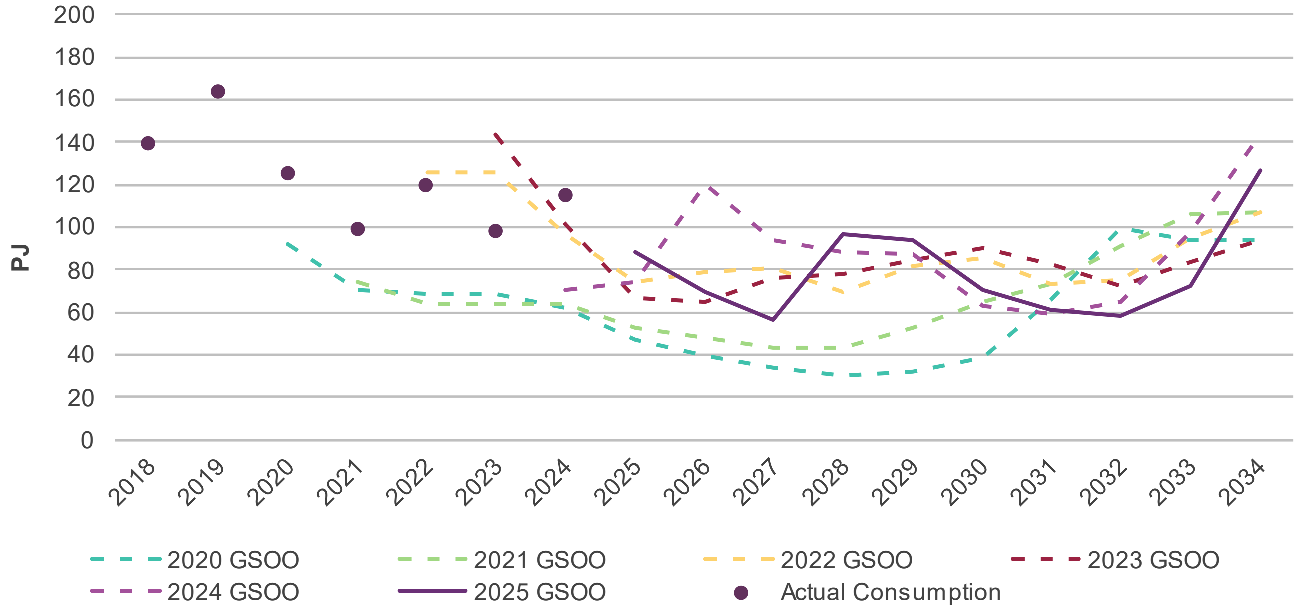
- In 2020, the COVID-19 pandemic led to reduced global economic activity.
- In 2022, despite strong Asian LNG demand and high international energy prices incurred by sanctions against Russia in response to the Russian-Ukraine conflict, domestic demand for natural gas was strong, and there was an appreciable decrease in Queensland LNG export. QCLNG also experienced multiple unplanned outages in Q4 2022.
- In 2023, production issues at QCLNG's facilities were resolved by late March, allowing a rebound in exports for the remainder of the year. Lower domestic gas demand over winter also enabled greater LNG winter exports, with the highest on record at 331 PJ.
- In 2024, Queensland LNG winter exports reached another record of 337 PJ, and exports continued following winter at high levels, with exports across October to December 2024 reaching 383 PJ, a record quarterly export level.

A1.5 Gas-powered generation consumption forecasts

Forecasting gas consumption for electricity generation is a complex challenge, as GPG utilisation is sensitive to a variety of events that impact the electricity sector, such as extreme weather conditions, outages at major coal-fired generators, and variations in renewable energy output.

A review of historical forecast accuracy is presented in **Figure 61** and **Table 17**, which highlight discrepancies between projected and actual gas usage. Forecasts produced prior to the 2022 GSOO generally underestimated gas consumption, while the 2022 and 2023 GSOOs overestimated demand. The 2024 GSOO, however, underestimated annual consumption by 37%.

Figure 61 Annual gas consumption forecast comparison to actuals for gas generation (PJ)



Note: The Northern Territory was included as a participating GSOO jurisdiction from the 2023 GSOO. Accordingly, this chart includes the Northern Territory in actual gas consumption from 2023 onwards to assess forecast accuracy.

Table 17 Year ahead historical forecast accuracy, gas generation in the NEM and Northern Territory, total consumption (PJ)

	2020	2021	2022	2023	2024
Year ahead forecast	92	74	125	143	71
Actual consumption	126	99	119	98	115
Forecast accuracy	-27%	-26%	5%	46%	-39%
Source	2020 GSOO	2021 GSOO	2022 GSOO	2023 GSOO	2024 GSOO

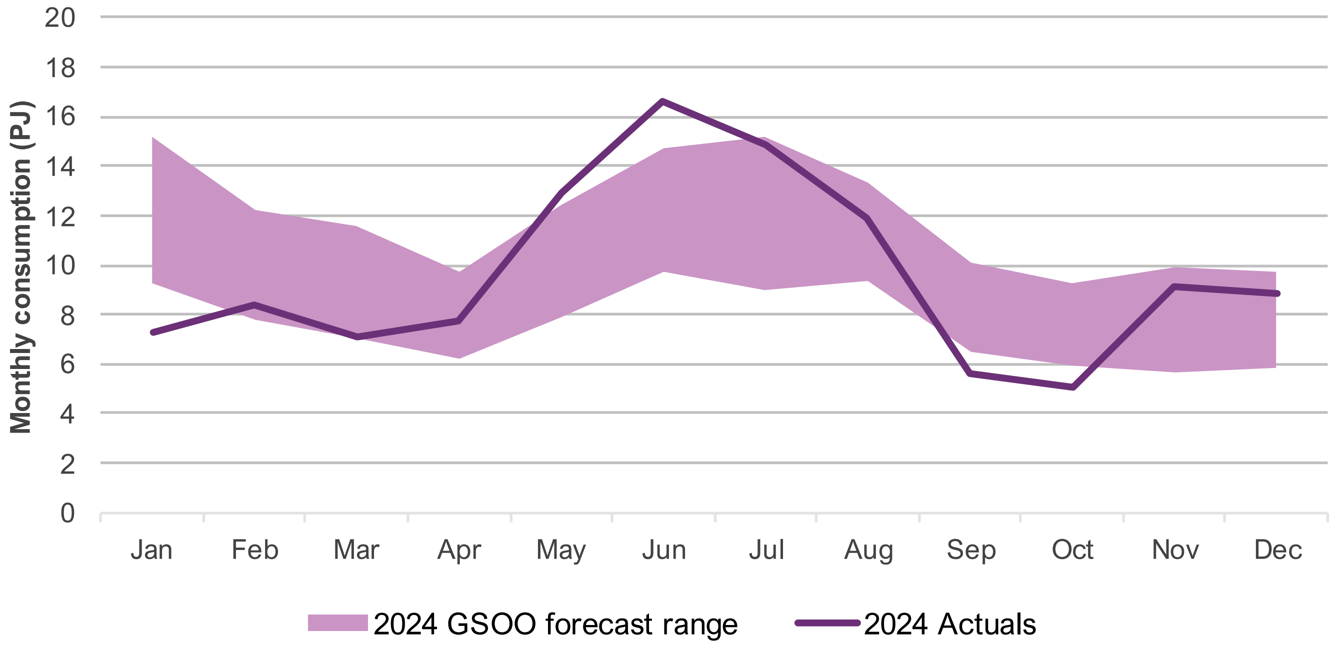
Gas consumption for electricity generation has exhibited an overall decline in recent years, with intermittent spikes attributed to major system disruptions or key events, such as:

- In 2019, prolonged high temperatures and bushfires affected New South Wales and Victoria with outages at Victorian coal generators, and fuel supply shortages affected coal generators in New South Wales.

- In 2020, the collapse of transmission towers affected the Heywood interconnector (connecting South Australia and Victoria) and extended outages for coal-fired power stations in Queensland.
- In 2021, flooding at the Yallourn coal mine affected coal generation in Victoria and the unexpected explosion at the Callide power station in Queensland (the impacted unit returned to service in August 2024, returning to full capacity in November 2024).
- In 2022, the war in Ukraine increased international prices for both gas and coal. This coincided with flooding events affecting coal production and an extended period of low renewable output. This increased the requirement for gas generators to purchase gas at short notice. However, on a yearly basis during 2022, the increased consumption by GPG during winter was offset by a mild summer resulting in lower than forecast GPG in that period.

The 2024 GSOO GPG forecast was 71 PJ (37%) lower than the actual 2024 total GPG consumption. While AEMO provides a GPG consumption forecast that reflects average conditions, a range of historical weather patterns are simulated to assess daily, seasonal and annual gas adequacy. **Figure 62** shows the 2024 GSOO GPG forecast's monthly consumption range across the range of weather conditions that were forecast for the 2024 GSOO, demonstrating that much of the year was broadly within the uncertainty range, despite the total annual consumption being inaccurate.

Figure 62 Actual and 2024 GSOO forecast monthly consumption from gas generators in the NEM and Northern Territory in 2024 (PJ per month [PJ/m])



In 2024, higher actual output levels of GPG were attributable to two primary factors:

- The NEM experienced very low wind speeds and below average rainfall across the southern regions, leading to a significant drop in wind and hydro generation in Q2 2024.

- The availability of coal generators also was relatively low, with October to December 2024 reflecting the lowest seasonal black-coal generation availability on record[84].

Beyond these trends, unexpected system events further impacted GPG consumption, with transmission line failures in Victoria and New South Wales in separate incidents. In addition, several planned outages on critical interconnector infrastructure in New South Wales coincided with low wind conditions outside daylight hours, resulting in a notable increase in the dispatch of GPG for firming support[85].

[84] See the Quarterly Energy Dynamics Q4 2024 report for more detail: https://aemo.com.au/-/media/files/major-publications/qed/2024/qed-q4-2024.pdf?la=en&hash=4962B271805C9472CA0B1CEEF80E051C.

[85] See The Quarterly Energy Dynamics Q2 2024 report for more detail: https://aemo.com.au/-/media/files/major-publications/qed/2024/qed-q2-2024.pdf?la=en

A2. Monthly demand forecast

Table 18 details the monthly demand forecast by region and sector for 2025. Forecast are provided for the *Step Change* scenario, 2019 reference year, with potential variation due to weather shown in brackets.

Table 18 Forecast monthly demand by region and sector (GPG and residential, commercial and industrial [RC&I]) for each month in 2025 (PJ)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Northern Territory	GPG	1.6 [+0,-2]	1.5 [+0,-1]	1.6 [+0,-2]	1.4 [+0,-1]	1.4 [+0,-1]	1.3 [+0,-1]	1.3 [+0,-1]	1.3 [+0,-1]	1.6 [+0,-2]	1.6 [+0,-2]	1.7 [+0,-2]	1.7 [+0,-2]
	RC&I	0.6 [+0,-0]	0.5 [+0,-0]	0.5 [+0,-0]	0.5 [+0,-0]	0.5 [+0,-0]	0.5 [+0,-0]	0.4 [+0,-0]	0.5 [+0,-0]	0.5 [+0,-0]	0.5 [+0,-0]	0.5 [+0,-0]	0.5 [+0,-0]
Queensland	GPG	1.2 [+2,-1]	1.3 [+1,-1]	1.4 [+1,-1]	0.2 [+1,-0]	0.8 [+1,-0]	2.8 [+0,-2]	2.7 [+1,-1]	1.7 [+1,-1]	0.3 [+1,-0]	0.7 [+0,-1]	0.6 [+0,-0]	1.2 [+1,-1]
	RC&I	9.1 [+0,-1]	7.8 [+0,-0]	8.4 [+1,-1]	8.4 [+1,-0]	9.1 [+1,-0]	8.9 [+0,-1]	8.5 [+1,-0]	8.3 [+1,-0]	8.5 [+1,-0]	9.2 [+1,-1]	8.9 [+0,-1]	9.0 [+0,-1]
Total Northern		**12.5 [+1,-2]**	**11.1 [+1,-1]**	**11.9 [+1,-2]**	**10.5 [+2,-2]**	**11.8 [+1,-1]**	**13.5 [+0,-3]**	**12.9 [+2,-1]**	**11.8 [+2,-1]**	**10.9 [+2,-1]**	**12.1 [+1,-2]**	**11.7 [+0,-3]**	**12.5 [+0,-2]**
New South Wales	GPG	2.3 [+0,-1]	1.0 [+1,-1]	1.3 [+1,-1]	0.5 [+2,-0]	1.5 [+1,-0]	3.9 [+0,-2]	2.9 [+2,-1]	2.4 [+1,-2]	0.5 [+2,-0]	0.4 [+0,-0]	0.4 [+1,-0]	0.9 [+1,-1]
	RC&I	7.0 [+0,-1]	6.7 [+0,-1]	7.8 [+0,-1]	8.4 [+0,-1]	11.2 [+0,-2]	11.1 [+0,-0]	11.2 [+1,-0]	11.3 [+1,-1]	9.8 [+1,-0]	8.3 [+1,-1]	6.9 [+1,-0]	6.6 [+1,-0]
Victoria	GPG	0.7 [+0,-0]	0.4 [+0,-0]	0.2 [+0,-0]	0.1 [+0,-0]	0.4 [+0,-0]	1.4 [+0,-1]	1.2 [+0,-1]	0.7 [+0,-0]	0.6 [+0,-0]	0.2 [+0,-0]	0.0 [+0,-0]	0.3 [+0,-0]
	RC&I	7.3 [+1,-0]	7.5 [+1,-0]	8.9 [+1,-1]	10.6 [+2,-0]	17.7 [+3,-3]	22.6 [+2,-2]	23.5 [+2,-0]	24.1 [+0,-4]	17.4 [+2,-2]	13.1 [+3,-3]	11.4 [+0,-3]	8.5 [+1,-1]
South Australia	GPG	2.7 [+0,-1]	2.1 [+1,-1]	2.3 [+1,-1]	1.7 [+2,-0]	2.4 [+1,-1]	4.1 [+1,-2]	3.5 [+1,-1]	2.6 [+1,-1]	2.8 [+0,-1]	2.1 [+0,-1]	1.8 [+1,-1]	2.1 [+0,-1]
	RC&I	2.0 [+0,-0]	2.1 [+0,-0]	2.4 [+0,-0]	2.9 [+0,-0]	3.7 [+0,-1]	3.4 [+0,-0]	3.4 [+0,-0]	3.4 [+0,-0]	3.2 [+0,-0]	3.0 [+0,-0]	2.4 [+0,-0]	2.2 [+0,-0]
Tasmania	GPG	0.1 [+0,-0]	0.0 [+0,-0]	0.0 [+0,-0]	0.0 [+0,-0]	0.1 [+0,-0]	0.1 [+0,-0]	0.1 [+0,-0]	0.1 [+0,-0]	0.1 [+0,-0]	0.2 [+0,-0]	0.0 [+0,-0]	0.0 [+0,-0]
	RC&I	0.4 [+0,-0]	0.5 [+0,-0]	0.4 [+0,-0]	0.4 [+0,-0]	0.5 [+0,-0]	0.6 [+0,-0]	0.6 [+0,-0]	0.5 [+0,-0]	0.5 [+0,-0]	0.6 [+0,-0]	0.6 [+0,-0]	0.5 [+0,-0]
Total Southern		**22.4 [+1,-3]**	**20.2 [+2,-2]**	**23.4 [+1,-3]**	**24.6 [+5,-1]**	**37.5 [+4,-6]**	**47.2 [+1,-7]**	**46.4 [+4,-1]**	**45.1 [+1,-5]**	**34.9 [+4,-3]**	**27.9 [+4,-3]**	**23.5 [+3,-3]**	**21.2 [+2,-1]**
Total Domestic		**34.9 [+2,-3]**	**31.3 [+2,-3]**	**35.3 [+1,-3]**	**35.2 [+7,-2]**	**49.3 [+5,-6]**	**60.7 [+0,-9]**	**59.3 [+6,-1]**	**56.9 [+3,-6]**	**45.8 [+5,-3]**	**40.1 [+3,-5]**	**35.3 [+3,-4]**	**33.7 [+2,-2]**
Queensland	LNG	119.2 [+4,-4]	108.1 [+3,-3]	118.1 [+5,-7]	115.9 [+10,-0]	113.8 [+10,-5]	108.2 [+1,-7]	112.2 [+0,-7]	111.9 [+3,-5]	115.2 [+5,-0]	125.1 [+2,-4]	117.6 [+5,-2]	122.3 [+6,-11]
Total		**154.1 [+4,-6]**	**139.3 [+6,-4]**	**153.4 [+3,-9]**	**151.1 [+11,-0]**	**163.0 [+9,-8]**	**168.9 [+0,-12]**	**171.5 [+3,-4]**	**168.9 [+4,-11]**	**161.0 [+10,-1]**	**165.2 [+1,-7]**	**152.8 [+6,-5]**	**155.9 [+7,-12]**

Note: Data is shown for the 2019 reference year. Data in the brackets represents differences in forecast demand for that component of demand due to weather variation. Totals may not add up due to rounding. Variation due to weather for total rows (for example, Total Northern), may not necessarily equal the sum of the variation of the individual components (for example, the lower bound for Total Northern demand may not equal the sum of lower bounds for GPG and RC&I for Queensland and Northern Territory), because these values may not occur in the same reference year.

Figure 63 and **Figure 64** show forecast monthly demand in petajoules a month (PJ/m) for 2025, for the 2019 reference year, by region and by sector respectively.

Figure 63 Forecast monthly domestic demand by region for 2025, *Step Change*, reference year 2019 (PJ/m)

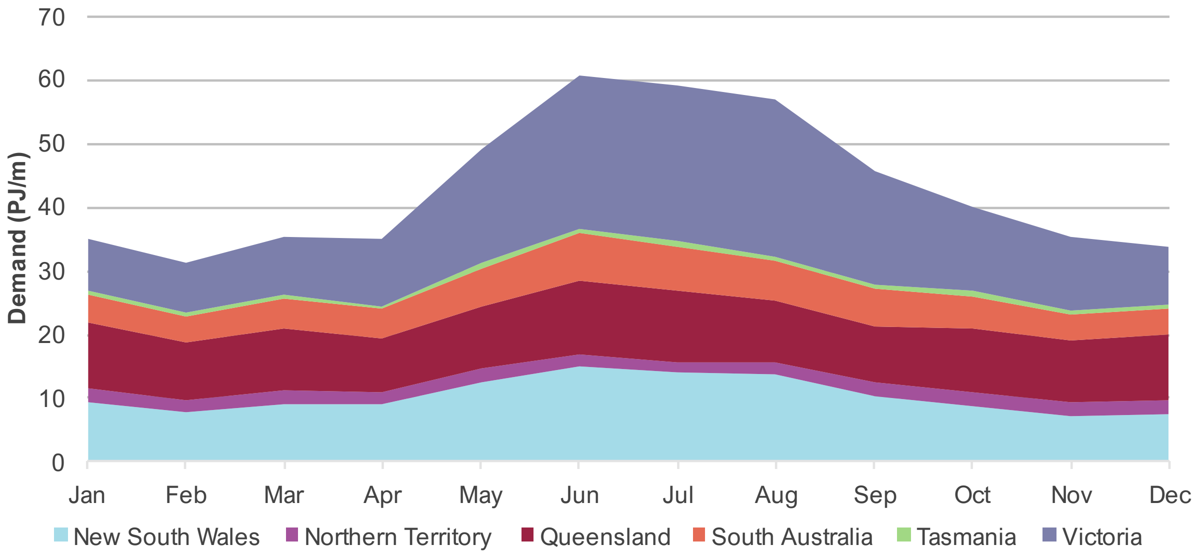
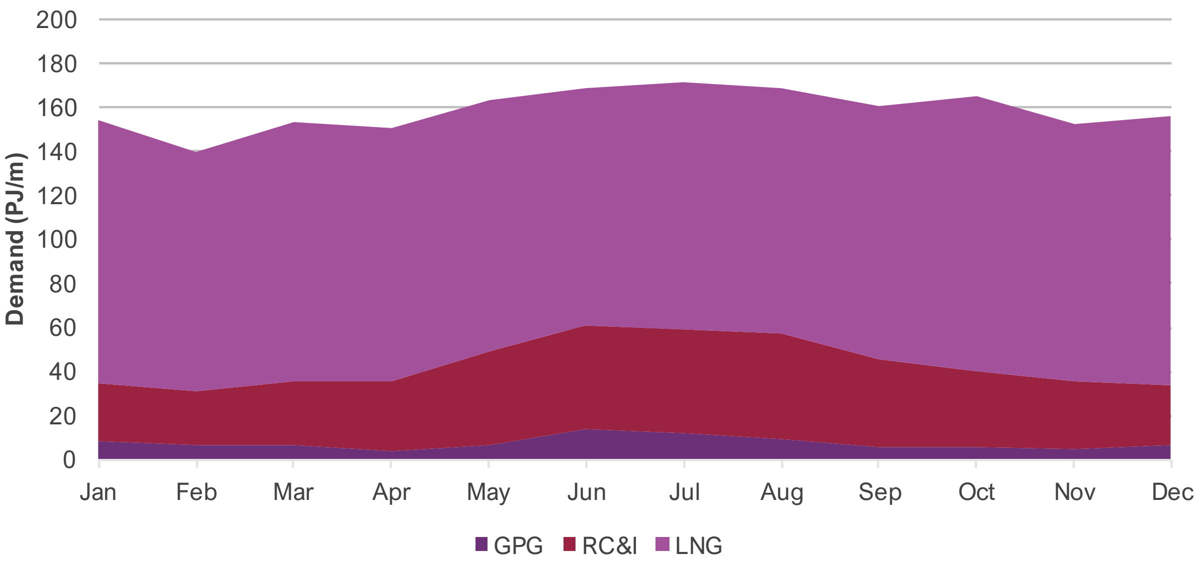


Figure 64 Forecast monthly demand by sector for 2025, *Step Change*, reference year 2019 (PJ/m)



List of tables and figures

Tables

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Glossary, measures and abbreviations

Units of measure

Term	Definition
EDD	effective degree day/s
GJ	gigajoule/s
PJ	petajoule/s
PJ/m	petajoules per month
PJ/y	petajoules per year
TJ	terajoule/s
TJ/d	terajoules per day

Abbreviations

Term	Definition
2C	best estimate of contingent resources
2P	proved and probable
ACCC	Australian Competition and Consumer Commission
ADGSM	Australian Domestic Gas Security Mechanism
AEMO	Australian Energy Market Operator
AGP	Amadeus Gas Pipeline
APLNG	Australia Pacific LNG Pty Ltd.
BLP	Brooklyn–Lara Pipeline
BGP	Bonaparte Gas Pipeline
CCS	carbon capture and storage
CGP	Carpentaria Gas Pipeline
CSG	coal seam gas
DTS	Declared Transmission System
DWGM	Declared Wholesale Gas Market
ECGM	East Coast Gas Market
EES	Environmental Effects Statement
EGP	Eastern Gas Pipeline
ESG	Environment, Social and Governance
FID	final investment decision
FSRU	floating storage regasification unit
GDP	Gross Domestic Product
GLNG	Gladstone LNG
GSOO	*Gas Statement of Opportunities*
IASR	*Inputs, Assumptions and Scenarios Report*
IEA	International Energy Agency
ISP	*Integrated System Plan*

Term	Definition
LIL	large industrial load
LMP	Longford Melbourne Pipeline
LNG	liquefied natural gas
MAPS	Moomba Adelaide Pipeline System
MMLI	Mass market large industrial
MSP	Moomba Sydney Pipeline
NEM	National Electricity Market
NIM	net interstate migration
NGP	Northern Gas Pipeline
NGR	National Gas Rules
NGSF	Newcastle Gas Storage Facility
NQGP	North Queensland Gas Pipeline
ODP	optimal development path
PCA	Port Campbell to Adelaide pipeline
PKET	Port Kembla Energy Terminal
POE	probability of exceedance
PRMS	Petroleum Resources Management System
PV	photovoltaic/s
QCLNG	Queensland Curtis LNG
QHGP	Queensland – Hunter Gas Pipeline
RBP	Roma – Brisbane Pipeline
RERT	Reliability and Emergency Reserve Trader
SEA Gas	South East Australia Gas (pipeline)
SMIL	small to medium industrial load
SMR	steam methane reforming
SNP	Sydney – Newcastle Pipeline
STTM	Short Term Trading Market
SWP	South West Pipeline
SWQP	South West Queensland Pipeline
TGP	Tasmanian Gas Pipeline
UAFG	unaccounted for gas
UGS	underground gas storage
VGPR	*Victorian Gas Planning Report*
VNI	Victorian Northern Interconnect
VRE	variable renewable energy
WEO	World Economic Outlook
WORM	Western Outer Ring Main

Glossary

This document uses many terms that have meanings defined in the NGR. The NGR meanings are adopted unless otherwise specified.

Term	Definition
1-in-2 peak day	The 1-in-2 peak day demand projection has a 50% probability of exceedance (POE). This projected level of demand is expected, on average, to be exceeded once in two years.
1-in-20 peak day	The 1-in-20 peak day demand projection (for severe weather conditions) has a 5% probability of exceedance (POE). This is expected, on average, to be exceeded once in 20 years.
anticipated projects	Gas field and production facility projects that developers consider justified on the basis of a reasonable forecast of commercial conditions at the time of reporting, and reasonable expectations that all necessary approvals (such as regulatory approvals) will be obtained and final investment decision (FID) made.
augmentation	The process of upgrading the capacity or service potential of a transmission (or a distribution) pipeline.
biomethane	Methane captured from biological processes such as wastewater treatment, landfill or biodigesters (also known as biogas) and purified to meet gas quality standards. Can be used interchangeably with natural gas.
commercial customers	See residential and commercial customers.
committed projects	Gas field and production facility projects that have obtained all necessary approvals, with implementation ready to commence or already underway.
consumption	Gas consumed over a period of time, usually a year but sometimes a month.
covered gas	An aggregation of natural gas, biomethane and hydrogen
curtailment	The interruption of a customer's supply of gas at the customer's delivery point, which occurs when a system operator intervenes, or an emergency direction is issued.
customer	Any party who purchases and consumes gas at particular premises. Customers can deal through retailers (who are registered market customers in the Declared Wholesale Gas Market [DWGM]) or may be registered as market participants in their own right.
Declared Transmission System (DTS)	Refers to the principal gas transmission pipeline system identified under the *National Gas (Victoria) Act*, including augmentations to that system. Owned by APA Group and operated by AEMO, the DTS serves Gippsland, Melbourne, Central and Northern Victoria, Albury, the Murray Valley region, and Geelong, and extends to Port Campbell.
Declared Transmission System constraint	A constraint on the gas Declared Transmission System.
Declared Wholesale Gas Market	The market administered by AEMO under Part 19 of the NGR for the injection of gas into, and the withdrawal of gas from, the DTS and the balancing of gas flows in or through the DTS.
demand	The amount of gas used on a daily basis. The maximum across a season is referred to as maximum demand or peak day demand.
distribution	The transport of gas over a combination of high-pressure and low-pressure pipelines from a city gate to customer delivery points.
Eastern Gas Pipeline (EGP)	The east coast pipeline from Longford to Sydney.
effective degree day (EDD)	A measure of coldness that includes temperature, sunshine hours, wind chill and seasonality. The higher the number, the colder it appears to be and the more energy that will be used for area heating purposes. The EDD is used to model the daily relationship between weather and gas demand.
extreme peak day demand	Extreme peak day demand is characterised by coincident very high daily demand from residential, commercial and industrial customers and high daily gas requirements for GPG.
facility operator	Operator of a gas production facility, storage facility, or pipeline.
gas generation	Electricity generated from gas turbines (combined cycle gas turbine [CCGT] or open cycle gas turbine [OCGT]).
Gas Statement of Opportunities	Demand forecasts (over a 20-year horizon) and supply adequacy assessment for eastern and south-eastern Australia published annually by AEMO.
industrial customers (Tariff D)	Gas transportation tariff applying to daily metered sites with annual consumption greater than 10,000 GJ or maximum hourly quantity (MHQ) greater than 10 GJ and that are assigned as being on demand tariffs (Tariff D) in the AEMO meter installation register. Each site has a unique Metering Identity Registration Number (MIRN).
injection	The physical injection of gas into the transmission system.

Term	Definition
lateral	A pipeline branch.
linepack	The pressurised volume of gas stored in the pipeline system. Linepack is essential for gas transportation through the pipeline network throughout each day, and is required as a buffer for within-day balancing.
liquefied natural gas (LNG)	Natural gas that has been converted to liquid for ease of storage or transport. The Melbourne LNG storage facility is at Dandenong.
LNG regasification terminal	A facility that receives, stores, and processes LNG back into its gaseous state before injecting it into the gas transmission pipeline network.
natural gas	A naturally occurring hydrocarbon comprising methane (CH_4) (between 95% and 99%) and ethane (C_2H_6).
participant	A person registered with AEMO in accordance with the National Gas Rules (NGR).
peak day shortfall	A peak day shortfall is driven by insufficient available gas production or transport capacity to meet extreme peaks in demand on a single day.
petajoule	An International System of Units (SI) unit. One PJ equals 1×10^{15} joules.
pipeline	A pipe or system of pipes for or incidental to the conveyance of gas, including part of such a pipe or system.
prospective resources	Estimated volumes associated with undiscovered accumulations of gas, highly speculative and not yet proven by drilling.
probability of exceedance (POE)	The statistical likelihood that a peak demand forecast will be met or exceeded.
renewable gases	Carbon-neutral natural gas substitutes that do not generate additional greenhouse gas emissions when burnt. Renewable gases include biomethane and hydrogen.
reserves	Quantities of gas expected to be commercially recovered from known accumulations.
residential and commercial customers (Tariff V)	Gas transportation tariff applying to consumers on volume-based tariffs (Tariff V). This includes residential and small to medium sized commercial gas consumers.
resources	Less certain, and potentially less commercially viable sources of gas, than reserves.
retailer	A seller of bundled energy service products to a customer.
seasonal or annual supply gap	A seasonal or annual supply gap is driven by insufficient gas production or transport capacity to meet total seasonal or yearly demand.
shoulder season	The period between low (summer) and high (winter) gas demand. It includes the calendar months of March, April, May, September, October, and November.
South West Pipeline	The 500 mm pipeline from Lara (Geelong) to Iona.
storage facility	A facility for storing gas, including the Dandenong LNG storage facility and Iona Underground Gas Storage (UGS) in Victoria, and Newcastle Gas Storage Facility (NGSF) in New South Wales.
summer	December to February.
system demand	Demand from Tariff V (residential, small commercial and industrial customers nominally consuming less than 10 TJ of gas per annum) and Tariff D (large commercial and industrial customers nominally consuming more than 10 TJ of gas per annum). Excludes gas generation demand, exports, and gas withdrawn at Iona.
Tasmanian Gas Pipeline (TGP)	The pipeline from VicHub (Longford) to Tasmania.
terajoule	An International System of Units (SI) unit. One TJ equals 1×10^{12} joules.
unaccounted for gas (UAFG)	The difference between metered injected gas supply and metered and allocated gas at delivery points, comprising gas losses, metering errors, timing, heating value error, allocation error, and other factors.
uncertain projects	Gas field and production facility projects that are at earlier stages of development or face challenges in terms of commercial viability or approval.
Underground Gas Storage (UGS)	A storage facility which reinjects gas into depleted gas reservoirs, which can be withdrawn out at a later date.
VicHub	The interconnection between the Eastern Gas Pipeline (EGP) and the gas DTS at Longford, facilitating gas trading at the Longford hub.
winter	June to August.