

Gas Statement of Opportunities

March 2026

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 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 28 February 2026, 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.

This publication does not include all of the information that an investor, participant or potential participant might require, and does not amount to a recommendation of any investment.

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Executive summary

The 2026 *Gas Statement of Opportunities* (GSOO) forecasts the adequacy of gas¹ supplies in central and eastern Australia², based on information provided by gas industry participants, to meet households' and businesses' changing energy needs to 2045. 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).

This 2026 GSOO does not consider the impact of recent geopolitical events in the Middle East. AEMO will continue to monitor gas adequacy for this winter under its East Coast Gas System (ECGS) functions³, and will work with industry and governments to support ongoing supply should any risk or threat be identified.

As Australia transitions to a net zero emissions future, gas will remain essential for households, businesses and industry, and to support the operation of the electricity sector.

- New infrastructure investment commitments and improved short-term peak day supply expectations, and investments and actions in the National Electricity Market (NEM), have improved gas adequacy expectations since the 2025 GSOO. Risks to gas adequacy are now projected to occur one year later as declines in residential, commercial and industrial gas consumption are projected to continue. The 2026 GSOO forecasts gas shortfall risks during extreme peak day demand conditions from 2029 in southern⁴ Australia, with a need for additional supply in most scenarios from 2030.
 - The temporarily delayed retirement of Eraring Power Station and increasing developments in battery technologies in the NEM are expected to reduce the gas required to support gas-powered generation (GPG) of electricity in the short term, relative to previous forecasts.
 - Since the 2025 GSOO, more peak day supply is expected to be available to the south, including increased access to northern supply with APA's newly committed expansions to the north to south pipeline system. Timely completion of all committed and anticipated supply, storage and pipeline developments is vital to reduce peak day shortfall risks.
- From 2030, projected supply gaps under most weather conditions indicate a need for new supply in addition to that now classified as committed and anticipated, or more investment in demand-side opportunities to lower gas needs.
 - From 2032, supply gaps are projected to be smaller than in the 2025 GSOO due to a combination of higher forecast production from Longford Gas Plant during its final years of operation and lower forecast gas consumption for all gas users. Gas usage for electricity generation is lower due to a slower phase out of coal-fired power plants, consistent with the Draft 2026 *Integrated System Plan* (ISP).
 - Supply gap size will be materially influenced by weather conditions impacting both temperature-sensitive winter loads and the availability of renewable generation in the NEM to reduce GPG needs. More investment in renewable generation and electricity storage solutions in the NEM will lower GPG needs, reducing gas adequacy risk.
- Industry is considering various projects that may address these gaps. AEMO's technical assessment⁵ of potential combinations of future supply, storage and transportation projects demonstrates that all may delay the projected supply gaps and help mitigate the risk of peak day shortfalls, to varying degrees. A combination of projects will be required to address the supply gaps projected in this GSOO across the 20-year forecast horizon.

¹ The GSOO supply adequacy assessment considered all covered gases as defined in the National Gas Law, including natural gas, hydrogen and biomethane.

² 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>.

³ See <https://www.aemo.com.au/energy-systems/gas/east-coast-gas-system/about-the-east-coast-gas-system-ecgs>.

⁴ 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.

⁵ AEMO's technical assessment does not represent a merits or cost-benefit assessment of one project 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.

Key changes since the 2025 GSOO

Demand

- In forecasting GPG operation in the NEM, 11 historical weather patterns have been used (previously 10 patterns for the 2025 GSOO).
- The 2026 GSOO projections for GPG are based on the Draft 2026 ISP^A, while also incorporating known infrastructure and generation updates (as of the NEM October 2025 Generation Information) that have occurred since the Draft 2026 ISP inputs were finalised in the 2025 *Inputs, Assumptions and Scenarios Report* (IASR). This includes the recently announced delay of Eraring Power Station's retirement from 19 August 2027 to 30 April 2029.

Supply and transportation capacity

In the 2026 GSOO, southern producers expect to supply less gas annually than in the 2025 GSOO for three of the five years in the period to 2030, with the exceptions being 2027 and 2028. In the early 2030s, producers anticipate higher gas supply compared to their expectations in the 2025 GSOO. The variations are influenced by:

- **Gippsland Basin and Bass Basin:** higher production is forecast from the Gippsland Basin Joint Venture (GBJV) fields during Longford Gas Plant's final years of operations, and higher production is forecast from Orbost Gas Plant and Lang Lang Gas Plant.
- **Cooper Basin:** from the early 2030s, there is a forecast improvement in Cooper Basin reserves based on actual field performance and the latest project and development schedule.
- **Otway Basin:** Beach Energy has reported a downward reserves revision for the Thylacine West and Enterprise fields in the Otway Basin^B. The downward revisions are most pronounced in years 2029 to 2031, although with a small increase in expected supply for the years 2027 and 2028 only.
- Gas producers in northern regions have advised they expect higher levels of gas production from existing, committed and anticipated production:
 - Existing, committed and anticipated production from Queensland is projected to increase due to improved forecast supplies from liquefied natural gas (LNG) producers.
 - Tamboran's pilot development at **Shenandoah South** in the Beetaloo sub-basin in the Northern Territory has progressed from uncertain to committed status, and has an initial expected production of up to 40 terajoules per day (TJ/d) from mid-2026^C. APA's **Sturt Plateau Pipeline** project to transport this gas to the Amadeus Gas Pipeline is also considered committed. Construction on the pipeline started in November 2025^D and is scheduled to be completed in 2026^E.

The 2026 GSOO adequacy assessment includes higher north to south transportation capacity as APA Group's **East Coast Gas Grid (ECGG) Expansion Plan Stage 3A** is now considered committed^F. Stage 3A includes the following projects which are committed to be available from winter 2028:

- An additional compressor on the **South West Queensland Pipeline (SWQP)** is expected to provide an additional 58 TJ/d capacity from Wallumbilla to Moomba.
- An additional compressor on the mainline **Moomba Sydney Pipeline (MSP)** is expected to provide an additional 10 TJ/d capacity from Moomba. This is in addition to the relicensing of APA's **Moomba Sydney Ethane Pipeline (MSEP)** to a natural gas pipeline, which was already considered committed in the 2025 GSOO, and will provide an additional 25 TJ/d capacity on the MSP from mid-2026.
- An additional compressor on the **Young to Culcairn lateral of the MSP** is expected to provide an additional 39 TJ/d capacity towards Victoria.

Key project progress for supply already considered in the 2025 GSOO

Key infrastructure projects to increase storage and transportation capacity are under construction or have been completed. These projects were considered anticipated or committed in the 2025 GSOO and will contribute to additional supply capacity upon completion:

- APA Group's **Kurri Kurri Lateral Pipeline (KKLP)**^G project is a gas transmission pipeline and shallow storage facility near Newcastle. KKLP provides 72 TJ storage capacity for Hunter Power Station or 60 TJ/d peak day supply capacity into the ECGM. The pipeline was completed in June 2025.
- Senex Energy's **Roma North (Mimas) gas processing facility** came online in 2025^H, providing processing capacity of 28.5 TJ/d.
- 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. Work to complete the project is ongoing and is scheduled to complete by November 2026.
- Lochard Energy's **Heytesbury Underground Gas Storage (UGS)** expansion project (HUGS Project Phase 1)^I at Iona UGS will increase storage inventory capacity by 1.8 petajoules (PJ), and supply capacity by 45 TJ/d, from 2027.
- The **Carpentaria Pilot Project** in the Beetaloo sub-basin in the Northern Territory has reached final investment decision (FID)^J and changed from anticipated to committed status, with an initial expected production of 9.5 TJ/d from mid-2026 which will increase to 25 TJ/d, or 9.1 petajoules per year (PJ/y), from 2027.
- Construction has commenced at Arrow Energy's **Girraheewen Field Compression Station**, which will process gas from Surat Gas Project. The facility will have a processing capacity of 121 TJ/d and is expected to be online in 2027.

A. This includes that the timing of coal generation retirements in the 2026 GSOO are aligned with the Draft 2026 ISP.

B. Reported in 2026 GSOO surveys, based on 30 June 2025 assessment.

C. See <https://ir.tamboran.com/news-events/press-releases/detail/31/tamboran-reaches-final-investment-decision-on-its-shenandoah-south-pilot-project>.

D. See <https://apa.com.au/news/asx-and-media-releases/apa-commences-construction-of-the-sturt-plateau-pipeline>.

E. See <https://www.apa.com.au/operations-and-projects/gas/gas-transmission/sturt-plateau-pipeline-spp-project>.

F. See <https://www.apa.com.au/news/asx-and-media-releases/apa-to-deliver-pipeline-capacity-needed-to-solve-projected-east-coast-gas-shortfalls>.

G. See <https://www.apa.com.au/operations-and-projects/gas/gas-transmission/kurri-kurri-lateral-pipeline-kklp-project>.

H. See <https://senexenergy.com.au/wp-content/uploads/2025/12/End-of-year-update-2025.pdf>.

I. See <https://www.lochardenergy.com.au/our-projects/hugs/>.

J. See <https://app.sharelinktechnologies.com/announcement-preview/asx/68a9727d9a44fccc9538d38ddd85b10b>.

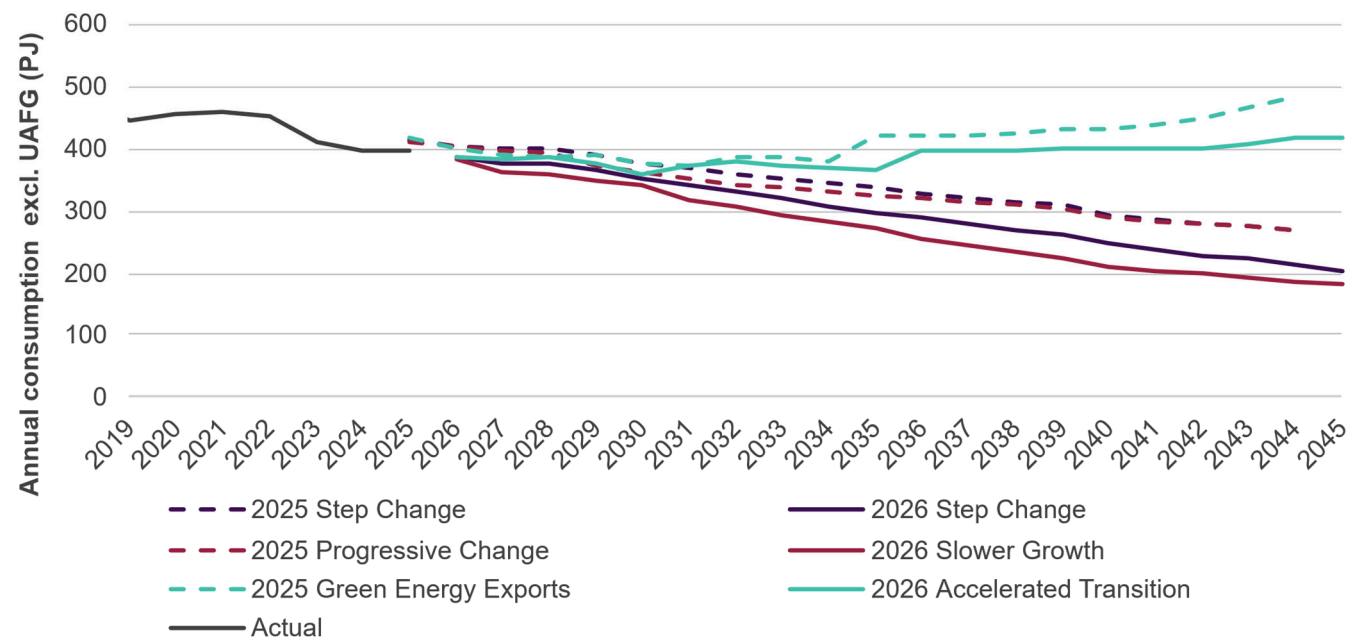
Consumer fuel-switching is contributing to lower forecast gas consumption

Gas plays a central role in the energy system, fuelling heating, cooking, industrial processes and electricity generation. In recent years, a declining trend in gas use has been observed, and this trend is expected to continue, yet uncertainties remain in terms of the pace and breadth of gas use across Australia’s economy. For this 2026 GSOO, AEMO used scenarios identified and defined in the 2025 *Inputs, Assumptions and Scenarios Report (IASR) – Step Change, Accelerated Transition, and Slower Growth*. These scenarios explore various uncertainties, including the degree of economic growth in Australia’s economy, the pace of decarbonisation of the energy sector, and the degree of investments made by energy consumers to contribute to the energy transition. From a gas sector perspective, these scenarios vary the level of economic activity, the pace of new gas connections and disconnections, and the opportunities for new gas use (such as, using hydrogen to produce green commodities). The *Step Change* scenario provides a central view of gas consumption, with *Accelerated Transition* featuring higher gas consumption from greater economic growth, a greater use of hydrogen, and more electrification, while *Slower Growth* has lower economic activity and less electrification.

The trend of declining gas consumption in this 2026 GSOO is steeper than what was projected in 2025, as electrification of the industrial sector is projected to gather pace as a preferred pathway to emissions reduction relative to alternatives. Consumption in the *Step Change* scenario is forecast to reduce to 203 petajoules per year (PJ/y) by 2045, which is almost half the volume consumed in 2025. In contrast, the *Accelerated Transition* scenario demonstrates that growth opportunities may exist through hydrogen use in a range of industrial applications.

Figure 1 shows actual and forecast domestic gas consumption in each of the three scenarios AEMO applied in the 2026 GSOO, excluding gas usage for electricity generation.

Figure 1 Actual and forecast domestic gas consumption, excluding GPG, all scenarios and compared to 2025 GSOO forecasts, 2019-45 (PJ)



Notes: the Northern Territory is included in actual gas consumption from 2020 onwards. The NGP, connecting the Northern Territory to Queensland, commenced in 2019. The first full year for which Northern Territory gas consumption data is available to AEMO is 2020. UAFG: unaccounted for gas, which is gas lost while being transported through the gas network.

While residential and small commercial users are forecast to reduce their gas needs across all scenarios, with greater availability of electric alternatives to traditional gas appliances in homes and businesses, gas consumption forecasts for

industrial and large commercial consumers are informed by surveys that reflect individual business decisions and capture more incremental electrification. In the *Step Change* scenario forecast, industrial consumption remains stable in the short term before declining from 2030 as electrification investments are assumed to reduce gas needs. Potential expansion of steelmaking and selected mineral processing and chemical industries that primarily use green hydrogen (also referred to as ‘green commodities’⁶) is incorporated into the *Accelerated Transition* scenario, providing a growth driver in gas consumption relative to other scenarios.

Annual gas-powered generation consumption is forecast to remain relatively stable, with demand expected to increasingly concentrate in winter

GPG plays a critical function in supporting the reliable and secure operation of the NEM. The Draft 2026 ISP⁷ reaffirms that renewable energy, firmed with storages⁸, backed up by gas-powered generation and connected by upgraded electricity networks, presents the least-cost way to supply secure and reliable electricity to consumers, while meeting government policies.

Analysis in the Draft 2026 ISP projects that annual gas usage for GPG in the NEM will remain broadly similar to today’s levels, but will become more peaky and seasonal. As GPG changes from regular mid-merit operations to a flexible back-up role, its output will increasingly be concentrated into shorter periods of high need. GPG is already playing a crucial role in maintaining electricity system reliability during infrequent periods of widespread low renewable generation – such as extended ‘dark and still’ events – as well as providing essential system security services that support overall grid stability.

The forecast shift to more GPG usage concentrated in winter months is driven by a number of factors, including:

- lower renewable generation availability in winter – shorter days and reduced solar irradiance, particularly in southern states, decrease solar output and increase reliance on GPG,
- higher winter electricity consumption as households transition to electric heating, and
- growing electric storage and solar capacity – increasing uptake of batteries, rooftop photovoltaics (PV) and utility-scale solar reduces the need for GPG to meet traditional summer peak day demand.

Figure 2 illustrates recent and forecast⁹ volumes of gas consumption for electricity generation across the NEM and the Northern Territory. While annual gas consumed by GPG is forecast to moderately decline in the short term as the installed capacity of electrical storages increases, upcoming coal retirements – including Victoria’s Yallourn Power Station and Eraring Power Station in New South Wales – are expected to generally increase GPG gas consumption. The extension of the operating life of Eraring Power Station to 30 April 2029¹⁰ temporarily lowers forecast gas consumption for power generation compared to the 2025 GSOO, which applied the previously advised closure date of August 2027. Consumers’ expected investments in electrifying existing appliances will increase the sensitivity of electricity demand to colder temperatures,

⁶ Green commodities included in the GSOO include iron and steel, ammonia, alumina, and methanol which are produced using green hydrogen (or with natural gas as a bridging fuel) as a feedstock or energy source to reduce emissions intensity compared with conventional production pathways.

⁷ See <https://www.aemo.com.au/consultations/current-and-closed-consultations/draft-2026-isp-consultation>.

⁸ In this context, storages refer to systems that can store electrical or potential energy for later use (such as batteries or pumped hydro energy systems)

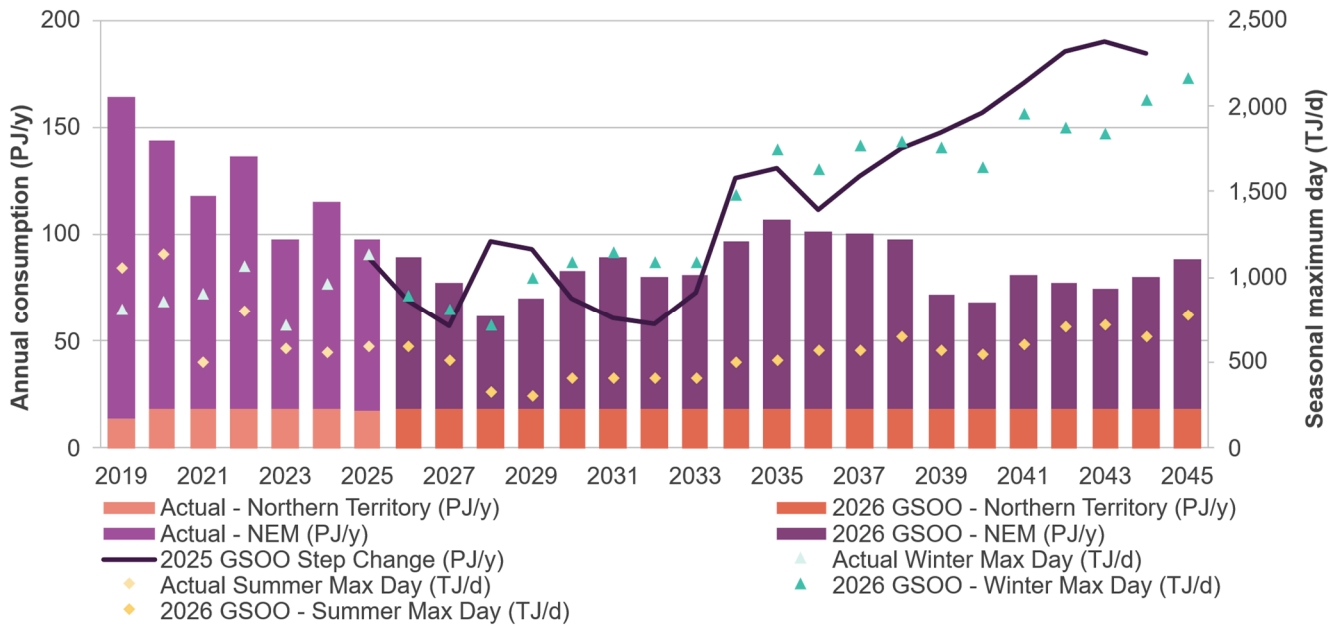
⁹ The GSOO GPG forecasts differ marginally to those presented in the Draft 2026 ISP, including those presented in Appendix 10: Gas Development Projections. The GSOO includes existing, committed and anticipated generation capacity information from NEM October 2025 Generation Information (see <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information>), including Eraring’s closure data in 2029, and 2025 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.

¹⁰ See <https://www.originenergy.com.au/about/investors-media/origin-extends-eraring-power-station-operations-to-2029/>.

resulting in winter peak GPG forecasts significantly exceeding summer peak forecasts over time under extreme weather conditions.

With GPG continuing to have a high need for gas during winter, gas infrastructure investments will need to cater for an increasingly seasonal and volatile demand profile.

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, 2019-45

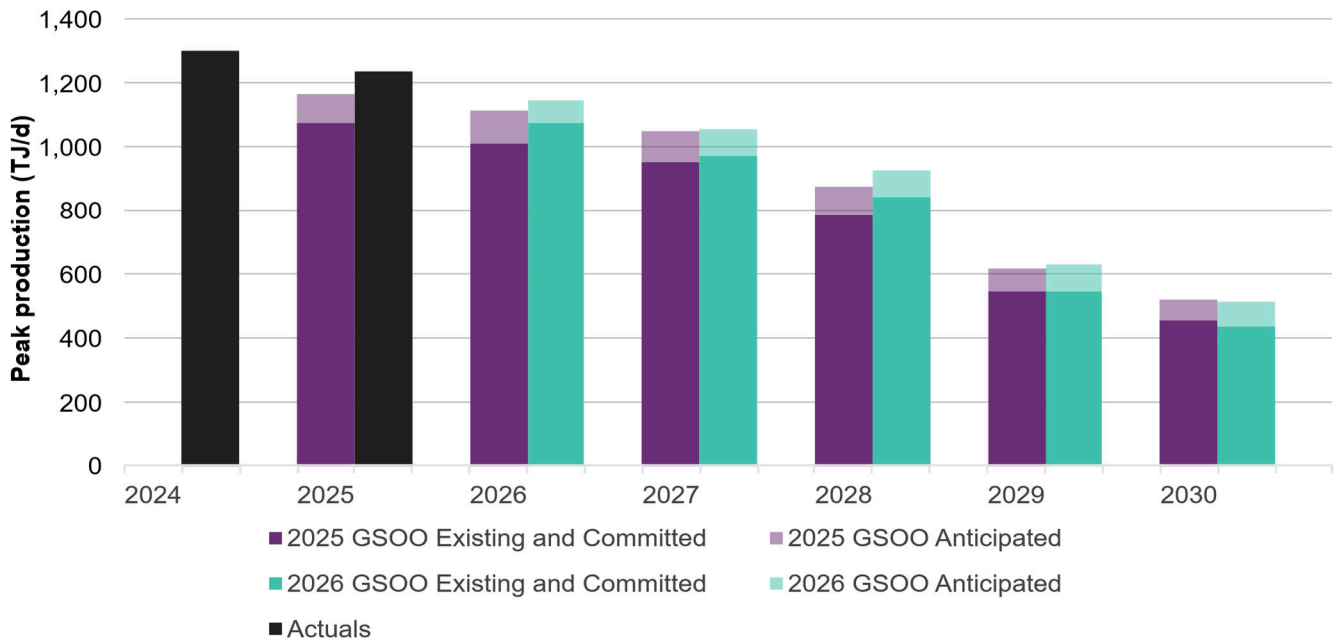


Risks of peak day shortfalls are forecast in southern regions from 2029 under extreme demand conditions

The peak day gas adequacy outlook has improved slightly compared to the 2025 GSOO. The 2026 GSOO reflects gas producers’ latest production profiles, with higher peak production capacity anticipated from southern gas producers until 2030. Additionally, the newly committed pipeline upgrades from APA’s East Coast Gas Grid (ECGG) Expansion Plan Stage 3A will increase the transportation capacity from north to south and improve pipeline capacity within the southern regions. The recently announced delay to the closure of Eraring Power Station in New South Wales is expected to temporarily reduce the need for GPG compared to the 2025 GSOO, lowering peak day gas adequacy risks if available and operating. This higher gas supply availability, in combination with lower forecast gas demand, results in a one-year delay to the potential timing of peak day shortfalls in southern regions, from winter 2028 reported in the 2025 GSOO, to winter 2029.

Figure 3 shows actual maximum daily gas production in 2024 and 2025 from southern gas fields and the advised daily maximum production capacity in winter each year to 2030. It shows that, until 2030, forecast production capacity is higher from existing, committed and anticipated facilities than was advised for the 2025 GSOO, but continues to represent a significantly declining trend as southern fields deplete. Producers continue to advise that southern production capacity will decline, which will increase reliance on southern storage facilities and gas produced and transported from northern regions to southern customers.

Figure 3 Actual and forecast maximum daily production capacity from southern gas fields in June, 2024-30 (TJ/d)



Note: the production capacity represents the maximum daily quantity in June each year; production capability in other months may vary.

Figure 4 below emphasises the seasonal gas supply and demand dynamics in the south, and the important role of storages and transportation to deliver gas from northern regions. This shows how southern production, pipeline and storage capacity met actual southern gas demand in 2024 and 2025, and the projected adequacy of existing, committed and anticipated southern production, pipeline capacity and storage facilities to meet gas demand until 2030 in the *Step Change* scenario¹¹.

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 teal line), plus
- expected capability to import gas from Queensland through the South West Queensland Pipeline (SWQP¹² – dashed teal line), including the impact of APA’s ECGG Expansion Plan Stage 3A, plus
- gas injection capacity into the market from deep storage at Iona Underground Gas Storage (UGS – dotted teal line), plus
- gas injection capacity into the market from shallow storages at Dandenong, Newcastle and Kurri Kurri Lateral Pipeline (KKLP – solid red line), plus
- anticipated gas supply capacity from southern regions (dashed red line).

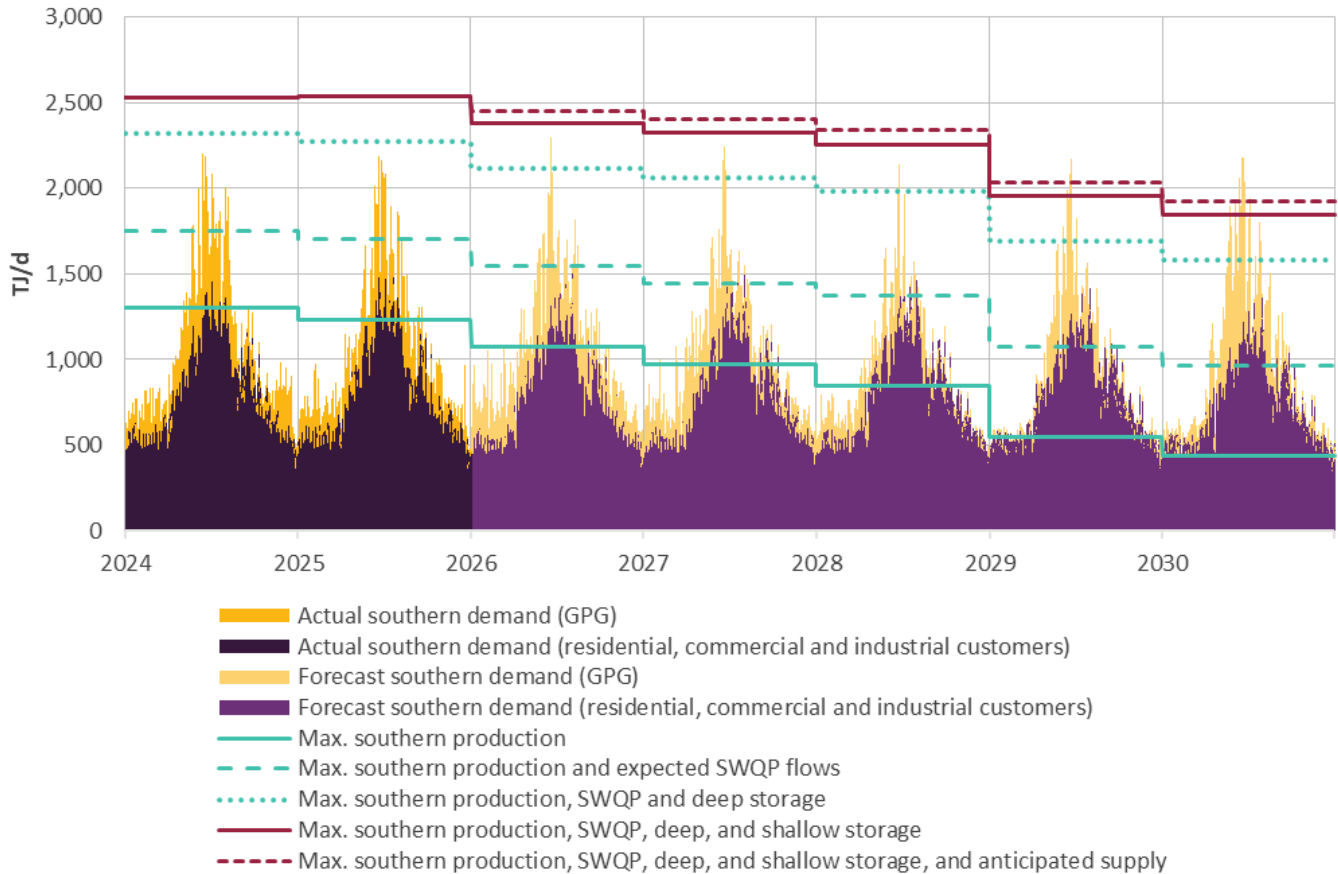
The seasonality and variability of the vertical lines in **Figure 4** demonstrate how weather conditions are a significant driver of peak gas demand for residential, commercial and industrial consumers and for electricity generation in the winter

¹¹ Extreme peak day demand is characterised by 1-in-20-year highs in daily demand from residential, commercial and industrial customers, reflects extreme weather conditions which is expected to be exceeded, on average, only once in 20 years, and 1-in-10-year high daily gas requirements for GPG, reflects extreme weather conditions which is expected to be exceeded, on average, only once in 10 years.

¹² The estimate of available SWQP flow accounts for modelled gas flow from the SWQP up the Carpentaria Gas Pipeline (CGP) to Mount Isa.

months. The GSOO assessment of gas supply and demand adequacy considered a range of weather patterns¹³ (Figure 4 reflects weather conditions consistent with those seen in 2024).

Figure 4 Actual daily southern gas system adequacy since January 2024, and forecast to 2030 using existing, committed and anticipated projects, reference year 2024 (TJ/d)



Notes:

- Actual maximum southern production and SWQP flow rates are shown for 2024 and 2025.
- Extreme peak day demand levels reflect weather conditions that drive 1-in-20 year gas demand, and 1-in-10 year electricity demand. The degree to which gas demand and electricity demand peaks coincide will influence gas supply adequacy.
- Expected SWQP flows include committed SWQP capacity increase from ECGG Expansion Plan Stage 3A.

Figure 4 shows that from 2029 onwards, peak day gas shortfall risks are forecast to emerge as southern production declines. While gas demand remains highly seasonal and volatile, the scale of maximum daily demand is not forecast to be dissimilar to historical levels of peak gas usage. The difference is that, as forecast southern production continues to decline over time, southern regions will rely more heavily on storage withdrawals and north to south pipeline flows to meet winter peaks. Recent investment commitments to increase north to south transport capacity improve the capability of the pipeline network to deliver gas to where it is needed, however the SWQP is expected to increasingly hit pipeline capacity as southern production declines without ongoing investments to reduce transport bottlenecks.

This reliance on storage withdrawals and north to south pipeline flows increases the sensitivity of gas supply in the south to any disruption in supply or transportation. While the Turrum Phase 3 project¹⁴ at Longford Gas Plant and Heytesbury UGS

¹³ The weather patterns studied in the GSOO were based on real weather conditions observed between 2014 and 2024.

¹⁴ Already considered committed in the 2025 GSOO.

(HUGS) Project Phase 1¹⁴ at Iona UGS are projected to introduce new supply and expanded storage capacity, the southern regions still face exposure to shortfalls under extreme winter peak conditions.

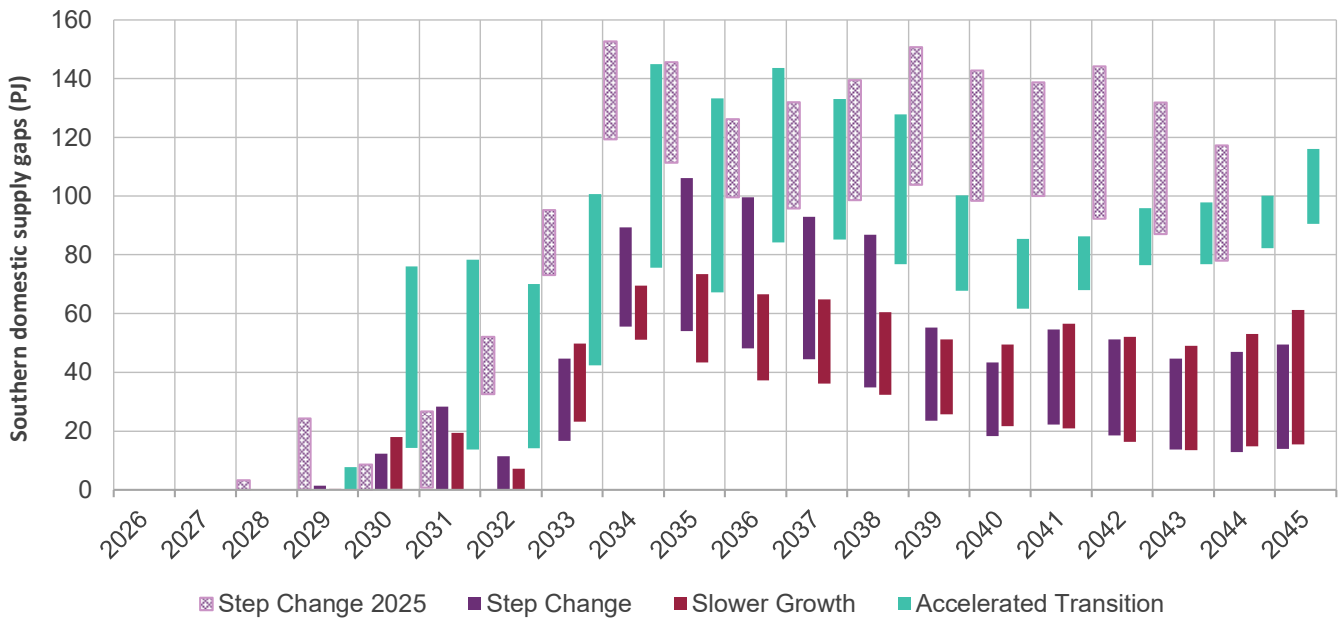
The 2026 GSOO forecasts lower winter peak day demand than the 2025 GSOO, as the committed and anticipated development of new battery capacity and the delayed retirement of Eraring Power Station offsets the gas required for GPG to provide firming generation in the NEM.

In extreme gas shortfall conditions, prudent use of secondary fuels to operate GPG for short periods and reduce gas use may reduce peak day gas shortfall risks without increasing risks to electricity reliability.

Without ongoing investment, supply gaps are forecast in southern Australia from 2030 in most weather conditions as production continues to decline

From 2030, supply gaps are projected in all AEMO’s scenarios under the majority of weather years simulated, even with the development of committed and anticipated gas supplies and expanded electricity developments that offset GPG needs. These supply gaps, which are most likely to occur during winter when gas consumption is highest, signal a need for structural investment from the gas industry. **Figure 5** shows the range of projected annual supply gaps forecast in southern regions, with the range representing the impact of different weather conditions if they were to occur in a given year.

Figure 5 Range of domestic annual supply gaps forecast in southern regions based on existing, committed, and anticipated developments, Step Change scenario, comparing 2026 GSOO and 2025 GSOO, 2026-45 (PJ)



As **Figure 5** shows, the projected structural supply gaps in this 2026 GSOO are projected one year later than the 2025 GSOO. The improved outlook forecast for 2029 is primarily due to:

- lower forecast residential, commercial and industrial consumption of gas,
- lower forecast GPG consumption, driven by increased battery build consistent with the Draft 2026 ISP and the extended operation of Eraring Power Station,

- increased transportation capacity from north to south and within the southern states, with APA’s ECGG Expansion Plan Stage 3A now committed to be available from 2028, and
- a forecast increase in expected Northern Territory production from mid-2026, allowing more Queensland gas to flow towards southern states. As Northern Territory gas increasingly meets demand at Mt Isa, more Queensland production can be sent to Moomba and on to southern customers.

While supply gaps emerge in all scenarios, **Figure 5** demonstrates that with existing, committed and anticipated gas supply, gas adequacy is plausible to 2032 in some scenarios, although some weather conditions may lead to supply gaps from 2030. **Table 1** shows the percentage of modelled weather conditions¹⁵ that show a supply gap risk.

Table 1 Percentage of modelled weather conditions with annual supply gaps

Scenario	2025	2026	2027	2028	2029	2030	2031	2032	2033+
<i>Step Change</i>	0%	0%	0%	0%	9%	59%	55%	36%	100%
<i>Slower Growth</i>	0%	0%	0%	0%	0%	91%	27%	27%	100%
<i>Accelerated Transition</i>	0%	0%	0%	0%	91%	100%	100%	100%	100%

Note: 0% means no supply gap occurred for any weather condition modelled in the year. 100% means all modelled weather conditions showed a supply gap.

In the next decade, as coal generators retire, the size of the supply gap is expected to increase, before settling on a lower ‘need’ in the longer term. The upper ends of the projected *Step Change* supply gaps are higher in 2030 and 2031 for the 2026 GSOO than in the 2025 GSOO, but lower across all other years in the horizon, with most years showing a wider range:

- To 2032, the possibility of supply gaps exists in some scenarios, and in most simulated weather conditions. If weather conditions are mild, inadequacy risks may not eventuate in these years.
- From 2032 to 2045, the supply gaps are lessened relative to the 2025 GSOO due to a combination of higher forecast production from Longford Gas Plant during its final years of operation and lower gas consumption forecast for all gas users, including lower gas usage for electricity generation due to a slower phase out of coal-fired power plants, consistent with the Draft 2026 ISP.
- For 2034 to 2038, the supply gap range is most sensitive to weather uncertainty and other conditions that affect gas demand (including availability of coal generation in the NEM).
- From 2039, once most coal generators are forecast to have retired by this period in the Draft 2026 ISP, continued investment in new electricity supplies (particularly solar, wind and electricity storages) required to maintain a reliable and secure low-emission power system, is expected to reduce the supply gaps over the longer term.

The year-to-year variability in supply gaps – and the trend towards these gaps narrowing over the longer term – highlights the ongoing investment uncertainty for new gas infrastructure. It also underscores the strong interdependencies with investment in the NEM, particularly if alternative sources of new dispatchable firm capacity could reduce the currently projected need for GPG.

¹⁵ The GSOO leveraged 11 historical years of weather conditions, to reasonably consider a range of weather patterns on GPG requirements.

Committed and anticipated investments are offsetting declining production, yet supply gaps remain in the longer term

The 2026 GSOO highlights that committed and anticipated supply and infrastructure projects remain essential to maintaining short-term supply adequacy. Despite these investments, declining southern production means the market faces a sustained gap between forecast consumption and available gas from the early 2030s. This gap is smaller than previous forecasts but remains as an opportunity for continued investment in supply, transport and/or storage solutions (or additional actions to reduce the gas consumption and peak day demand).

The supply-demand outlook shows:

- On-schedule development of committed and anticipated supply, storage and pipeline projects 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 domestic demand and established Queensland liquefied natural gas (LNG) export contracts¹⁶ from the end of 2026.
- Increased investment in pipeline infrastructure will improve the ability for northern supply to reach southern customers, so long as northern supplies are available. This scale of additional committed transportation and northern supply investment, however, is not yet sufficient to replace declining southern production or meet winter peak day demands of similar magnitude to historical peaks.
- Ensuring storages are at full capacity prior to winter remains critical to reducing peak day gas shortfall risks but cannot substitute for new supply. Winter gas supply from the north is also important in managing southern states' gas supply adequacy and mitigating the risk of southern storage depletion.
- The timely development of electricity transmission¹⁷, renewable energy, and electrical storage projects in the NEM will reduce gas adequacy risks by reducing reliance on GPG operations. Prior to closure, 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 help mitigate gas adequacy risks.
- The Draft 2026 ISP's proposed optimal development path includes around 27 gigawatts (GW) of grid-scale battery and pumped hydro storage by 2030. Currently, 32 GW of battery storage projects are progressing through various stages in the connections process¹⁸. This substantial increase in electrical storage capacity, projected in the Draft 2026 ISP, must be delivered in full and on schedule, to prevent GPG demand from exceeding the levels assumed in this 2026 GSOO.
- In extreme gas shortfall conditions, prudent use of secondary fuels to operate GPG for short periods and reduce gas use may reduce peak day gas shortfall risks without increasing risks to electricity reliability.
- Overall, while gas infrastructure projects presently identified as committed and anticipated projects help maintain short-term adequacy, they are not yet sufficient to provide a complete long-term solution.

¹⁶ The 2026 GSOO did not consider the impact of the Federal Government's announced domestic gas reservation scheme or any other consequences relating to this policy.

¹⁷ As reported in the Draft 2026 ISP, these electricity transmission developments include Project EnergyConnect, HumeLink, Hunter Central-Coast Renewable Energy Zone (REZ) Network Infrastructure Project, Central-West Orana REZ Network Infrastructure Project and Western Renewables Link.

¹⁸ As reported in AEMO's December 2025 Connections Scorecard. See <https://www.aemo.com.au/newsroom/media-release/strong-delivery-growing-energy-investment-pipeline-in-december-quarter>.

Timely delivery of northern producers' anticipated supplies is critical, and from 2030 more supply is required, to meet domestic demand and Queensland export agreements

Northern gas producers provide critical support to keep domestic users adequately supplied¹⁹. Queensland LNG producers control around 70% of total 2P reserves²⁰ in the ECGM, and volumes of gas exported 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:

- From 2030, uncertain supply developments will be required to satisfy northern demand and contracted volumes of LNG exports. Sufficient development of currently uncertain opportunities will also support southern demand.
- It remains critical that LNG producers continue to make additional supply, above what is contracted for export, available to domestic customers during winter in all years of the outlook period. This will support flows to southern regions and help mitigate the risk of southern supply shortfalls.
- Although recent commitments to increase north to south pipeline capacity will improve the outcomes for southern consumers, gas flow from the north to the south will continue to face transportation limits.

In December 2025, the Federal Government released its Gas Market Review Report²¹, which included a review of the Australian Domestic Gas Security Mechanism, Gas Market Code and Heads of Agreement, and potentially a domestic gas reservation scheme, which is aimed to come into effect from 2027²². As this policy is currently under consultation, this 2026 GSOO did not consider the impact of a domestic gas reservation scheme affecting the ECGM, or any other consequences relating to this policy.

Additional investments in gas infrastructure and supply can address peak day gas shortfall risks and supply gaps in the short and medium term

Given the identified supply gaps, the 2026 GSOO includes a collection of *what if* analyses to explore potential future supply, transportation, and storage projects that have been proposed for development within the next five years in addition to those that are already classified as committed and anticipated developments.

Table 2 shows collections of proposed projects (“project sets”) announced by market participants assessed in this GSOO, and their capacities, timings, and the individual effect of each project set on southern gas adequacy.

The project sets assessed are not exhaustive and are only intended to provide insights into the effectiveness of different individual project sets in addressing forecast supply challenges. This technical assessment did not consider all factors such as cost, market dynamics, regulatory approvals, land use, social license, safety, or operational challenges of each project, and does not amount to a recommendation or representation regarding any investment. It also did not assess whether adjustments to the timing or type of investment in the power system would reduce GPG demand and ameliorate some of the gas supply gaps at lower cost than investment in gas infrastructure. The project sets remain aligned with the gas development projections in the Draft 2026 ISP, with updated project information and improved representations of the

¹⁹ 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.

²⁰ 2P, or proved and probable, is widely accepted as the best estimate of reserves.

²¹ See <https://www.dcceew.gov.au/energy/markets/gas-markets/gas-market-review>.

²² See <https://minister.dcceew.gov.au/bowen/media-releases/joint-media-release-affordable-gas-australian-homes-and-businesses>.

Southern supply and Pipeline expansions with new northern supply project sets. The updated project sets will serve as the foundation for gas development projections in the final 2026 ISP.

Table 2 Future supply, transportation and storage project sets assessed

Project set	New supply	Transportation capacity and storage capacity (if relevant)	Impacts on southern adequacy	
			Peak day shortfalls delayed to	Annual supply gaps delayed to
LNG regasification terminal	New South Wales (Port Kembla)	Eastern Gas Pipeline (EGP) reversal Stages 1 and 2	2031	2034
	South Australia (Outer Harbor)	Port Campbell to Adelaide (PCA) pipeline reversal	2030	2034
	Victoria (Geelong ^A)	Westernport Altona Geelong (WAG) pipeline conversion project ^B	2031	2034
Pipeline expansions with new northern supply	Northern production developments ^C	Bulloo Interlink (ECGG Expansion Plan Stage 3B ^D) MSP to EGP compression South West Pipeline (SWP) expansion ^E EGP reversal Stages 1 and 2 PCA pipeline reversal Riverina Storage (ECGG future stage)	2030	2031
Southern supply	Southern backfill production ^F		2031	2034
	New southern production and additional backfill production ^G	Hunter Gas Pipeline (Narrabri to Newcastle)	2034	2035

A. This could be either Viva Energy’s or Vopak’s proposed LNG regasification terminal project.
 B. Only for Viva Energy’s proposed LNG regasification terminal project.
 C. Projects included in this additional northern supply included 2C resources from the Bowen and Surat basins and Beetaloo sub-basin. 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 project set only included production profiles from northern 2C resources reported to AEMO via the GSOO surveys.
 D. Includes the capacity increase of MSP Young to Culcairn by 39 TJ/d, MSP mainline to Wilton by 10 TJ/d and SWQP capacity by 58 TJ/d, which were considered committed in the 2026 GSOO and therefore were included in all analyses in this section.
 E. Expansion capacity based on APA’s Rule 80 application to expand the SWP. See <https://www.aer.gov.au/industry/registers/access-arrangements/apa-victorian-transmission-system-rule-80-application-expansion-south-west-pipeline/initiation#submissions>.
 F. Projects included in this additional southern supply included 2C resources from the Otway, Gippsland, Bass and Cooper basins that are capable of backfilling existing plants. This project set only included production profiles from southern 2C resources reported to AEMO via the GSOO surveys.
 G. Projects included in this additional southern supply include prospective resources from the Gunnedah, Otway, Gippsland, Bass and Cooper basins, and included contingent gas or renewable gas developments that require a new gas plant and prospective supply that can backfill existing plants. Prospective resources are estimated gas volumes from undiscovered accumulations that remain highly speculative, as they have not been confirmed through drilling or exploration activities. This project set included production profiles from southern contingent and prospective resources reported to AEMO via the GSOO surveys.

Figure 6 and Figure 7 present the forecast southern daily adequacy for each of the future potential project sets assessed and their individual impacts on addressing annual supply gaps and peak day shortfalls, showing that:

- **An LNG regasification terminal** is forecast to delay the forecast supply gaps to 2034, if the associated pipeline infrastructure and storages required to ensure effective delivery from the terminal are also developed. While all terminals assessed delay peak day shortfalls, the supply capacity of the different terminals and their supporting pipeline infrastructure varies resulting in a peak day shortfall delay to either 2030 or 2031.
- **Pipeline projects that increase north to south gas transfer capacity, combined with uncertain northern supply developments**, are forecast to delay the forecast peak day and seasonal shortfalls to 2030 and supply gaps to 2031. This project set depends on additional northern gas becoming available to be transported south, beyond currently committed and anticipated production. Additional investments in the north may materially improve the effectiveness of this project set. The 2026 GSOO has not attempted to examine future stages of APA Group’s ECGG Expansion Plan,

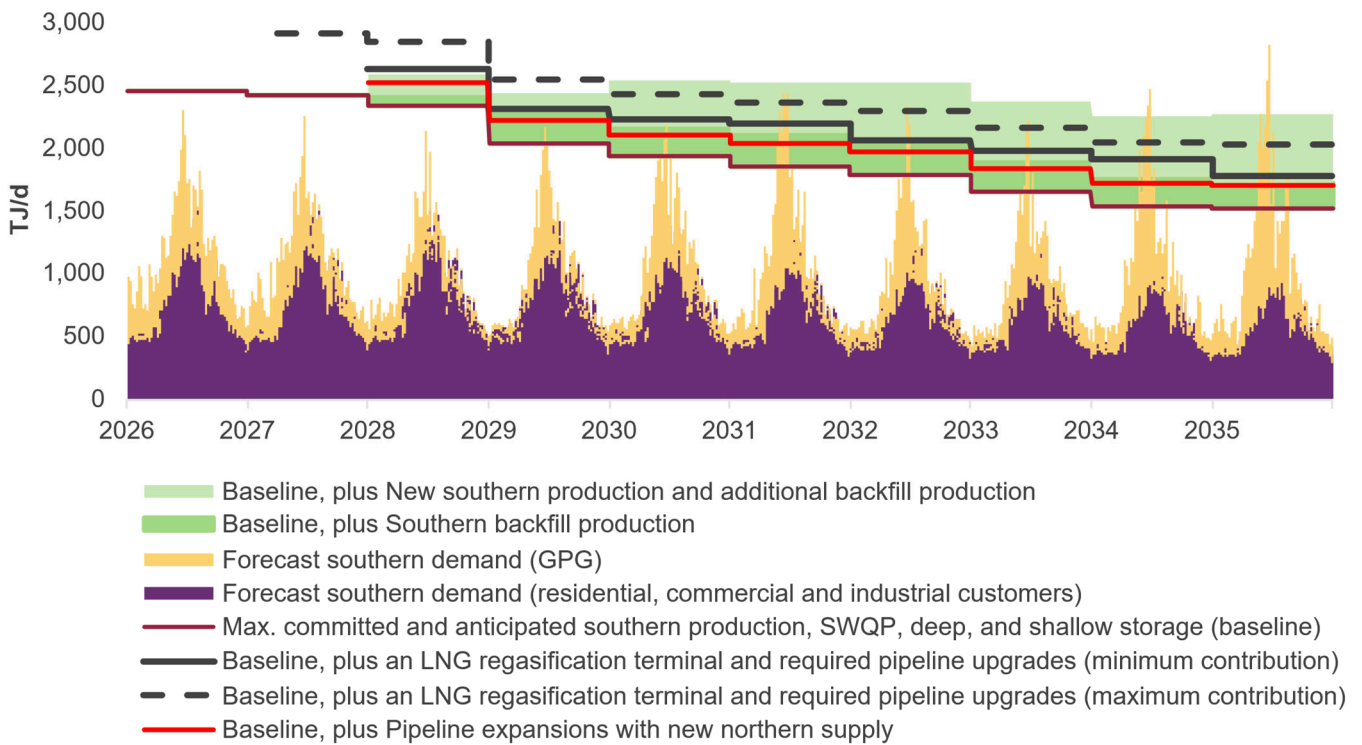
the North to East Australia Pipeline Project²³, or upgrades to the Northern Gas Pipeline (NGP) that would enable better access to proposed developments in the Northern Territory.

- The development of all **southern supply that could backfill the production capacity of existing plants** is forecast to defer forecast peak day shortfalls to 2031 and supply gaps to 2034. If additional southern supply is developed and production capacity increased, including the development of all currently uncertain **new gas plants and further backfill using prospective resources**, this could further delay the peak day shortfalls to 2034 and supply gaps to 2035. However, this is subject to much greater uncertainty given the less mature nature of prospective resources.

To close the supply gaps completely, the Draft 2026 ISP identified that future gas development projections are likely to require a combination of transport, gas storage and supply to meet consumer demand.

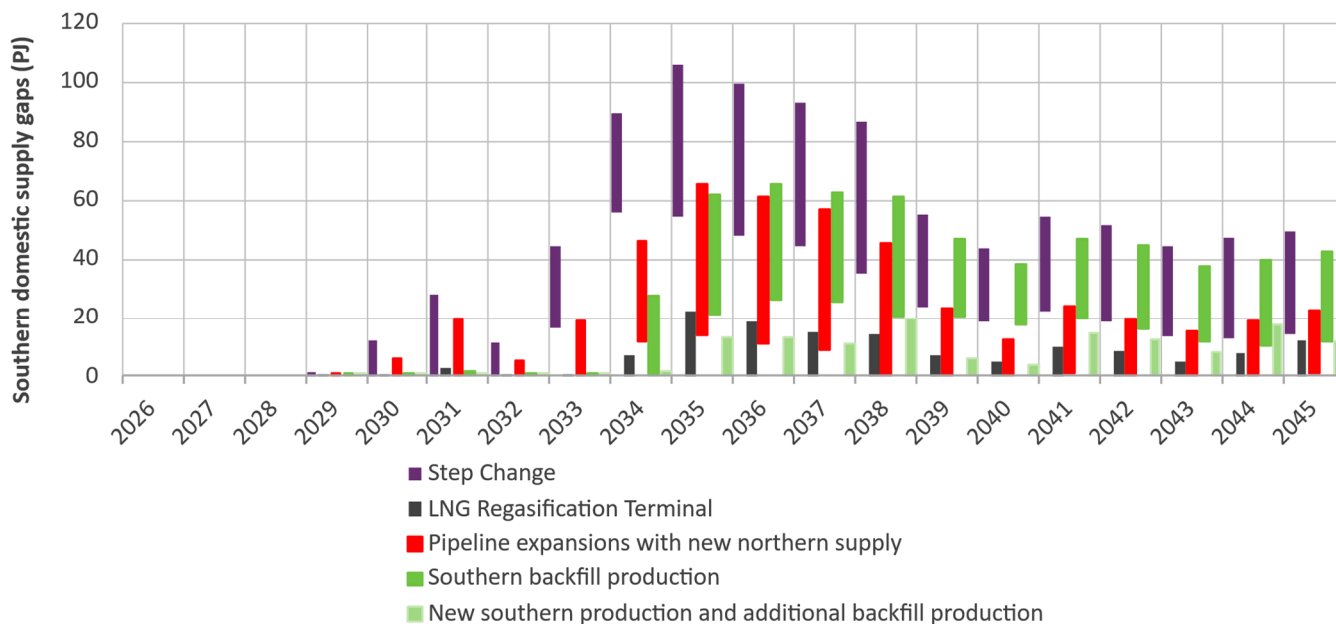
In addition to the future potential project sets that were explored to ensure supply adequacy in the southern regions, the development of increased northern supply is also required to support the export positions of Queensland LNG producers.

Figure 6 Projected southern daily adequacy for each of the project set assessed, reference year 2024, 2026-35 (TJ/d)



²³ See <https://www.apa.com.au/operations-and-projects/gas/gas-transmission/north-to-east-australia-pipeline-project>.

Figure 7 Range of annual supply gaps for each project set assessed across various weather conditions, in comparison to the Step Change scenario, 2026-45 (PJ)



Volatility in projected GPG requirements will drive long-term gas investment needs

Although project sets could delay the forecast supply gaps by a number of years, declining southern production and an increasing likelihood of peak GPG demand coinciding with high residential, commercial and industrial demand in winter is expected to place additional pressure on gas supply adequacy. Future gas investments will need to increasingly cater for concentrated periods of high gas demand, driven by volatile GPG requirements, particularly when electricity demands are high and renewable generation availability is low.

As a result of these demand-side dynamics, along with declining forecast residential, commercial and industrial gas consumption, the project sets reveal a need for supply flexibility to mitigate risks associated with peak day and seasonal shortfalls in extreme conditions. Gas storage is an effective solution to manage peak seasonal demands, if in locations that provide sufficient access to consumers and gas supply. Storage provides flexible injection capability, the ability to respond quickly to changes in demand, and potential relief of existing transportation constraints within the gas network.

Additional developments to complement the project sets may resolve the annual supply gaps and significantly reduce the risk of peak day shortfalls. From a whole-of-system perspective, greater investment in gas demand-side opportunities, or in NEM capacity that reduces GPG usage while maintaining reliability and system security, could also help close the supply gap cost-effectively. This is particularly relevant for the 2034 to 2038 period, when the expected supply gap is largest and most sensitivity to weather uncertainty.

The final 2026 ISP, and subsequent ISPs, will continue to explore efficient and effective sources of firming to support the NEM, while considering how those investments interact with fuel supply needs, including gas fuel.

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1 Introduction

The 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 forecast for use in generating electricity in the NEM and in the Northern Territory. The physical assessment focuses on the needs of domestic consumers, recognising the export commitments of LNG producers within the ECGM²⁴, and the capability for LNG producers to offer gas production surplus to export commitments to meet the needs of domestic consumers.

In conducting this assessment, the GSOO examines the limitations for gas 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, the method of assessment considers that all available gas supply will be utilised to meet the needs of gas consumers, subject to technical operating limits, transportation constraints, storage limitations, and the degree of certainty for new projects (assessed using defined classification statuses). If gas producers do not produce in accordance with their forecasts, or if the gas network has limitations not considered (such as unplanned outages), then the adequacy of the gas system may differ from the assessment in the GSOO.

The GSOO explores several potential planning scenarios, focusing on the adequacy of the system to meet changing gas needs from now until 2045. The GSOO must assess the adequacy of committed and anticipated supply and infrastructure to meet consumer needs. In addition, the 2026 GSOO explores developments that may improve gas adequacy in the longer term, beyond existing commitments. This is strongly linked to the gas infrastructure analysis in the 2026 ISP.

AEMO's 2026 VGPR Update²⁵ complements the GSOO by providing a focused assessment of the supply-demand balance to 2030 in Victoria's Declared Transmission System (DTS).

Definitions

The following definitions apply throughout this document when assessing peak day gas shortfall risks and annual supply gaps:

- **Peak day demand** is very high gas usage that may be driven by residential, commercial and industrial customers or gas demand for electricity generation. The degree to which gas demand and electricity demand peaks coincide will influence gas supply adequacy. AEMO forecasts maximum daily demand separately for each sector:
 - **Residential, commercial and industrial** maximum daily demand is forecast using a probability of exceedance (POE) measure, with the GSOO reporting on two demand levels: one level expected to be exceeded only once in 20 years (5% POE) and the other level once in two years (50% POE).
 - **GPG** maximum daily demand is forecast by applying a POE measure for electricity demand, with maximum operational electricity demand only expecting to be exceeded once on a 1-in-10-year (10% POE) basis. GPG demand is forecast using 11 weather reference years in the 2026 GSOO.

²⁴ The ECGM does not incorporate the Northern Territory's export facilities, so the GSOO did not consider LNG exports from the Northern Territory.

²⁵ At <https://www.aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/victorian-gas-planning-report>.

- **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.
- A **peak day shortfall** is driven by insufficient available gas production or transport capacity to meet extreme peaks in demand on a single day.
- A **seasonal or annual supply gap** is driven by insufficient gas production or transport capacity to meet total seasonal or yearly demand.

1.1 Scenarios

Considering the uncertainties in the speed and extent of gas sector transformation through the energy transition to net zero, AEMO uses scenarios and sensitivities to explore the needs of gas consumers and the adequacy of gas reserves, resources and infrastructure to meet those needs. For the 2026 GSOO, AEMO modelled the next 20 years using scenarios from the 2025 IASR²⁶ to forecast gas consumer needs in futures that generally achieve stated government energy and emissions policies, and assess gas adequacy in these futures. **Table 3** summarises key parameters for the scenarios used.

Table 3 Key parameters by scenario

Parameter	<i>Slower Growth</i>	<i>Step Change</i>	<i>Accelerated Transition</i>
National decarbonisation target	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	Slower economic growth, lesser coordination	Moderate economic growth, stronger coordination	High economic growth, stronger coordination
Australian economic and demographic drivers	Lower, with near-term economic growth calibrated with current economic conditions	Moderate economic growth, with near-term economic growth calibrated with current economic conditions	Higher, with near-term economic growth calibrated with current economic conditions
Electrification	Electrification tailored to meet existing emissions reduction commitments, with slower adoption given weaker economic circumstances	High electrification to meet emissions reduction commitments, with pace of adoption reflecting economic conditions	Higher electrification efforts to meet aggressive emissions reduction objectives, with faster pace of adoption
Energy efficiency	Moderate	High	Higher
Hydrogen use and availability	Low production for domestic use, with no export hydrogen	Moderate-low production for domestic use, with no export hydrogen	Moderate production for domestic industries and green commodities, with no export hydrogen
International Energy Agency (IEA) 2025 World Energy Outlook scenario alignment^A	Current Policies Scenario (CPS)	Stated Policies Scenario (STEPS)	Net Zero Emissions by 2050 (NZE)

A. Alignment with the International Energy Agency scenarios has been updated in the 2026 GSOO to reference the 2025 World Energy Outlook. The alignment in the 2025 IASR refers to the 2024 World Energy Outlook.

In the scenarios:

- **Step Change** achieves the objectives of Australia's government policies in transitioning to a low-emission energy system, and reflects a scale of global and domestic action that limits global temperature rise to below 2°C compared to pre-industrial levels. Consumers continue to embrace opportunities to support the transition through electrification

²⁶ See <https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/2025-26-inputs-assumptions-and-scenarios>.

(reducing gas demand by switching to electric alternatives), continued investment in energy efficiency and consumer energy resources (CER). Limited growth is expected from hydrogen used in production of green commodities.

- **Slower Growth**²⁷ achieves the objectives of Australia’s government policies in transitioning the energy system, and reflects domestic action to contribute to lesser global ambition to extend specific commitments to limit temperature rise. It is a future that is challenged by lesser economic growth and greater challenges than other scenarios, with electrification-driven reductions in gas demand, investments in energy efficiency and CER all lower due to the weaker economic circumstances, while domestic developments of green commodities do not proceed.
- **Accelerated Transition**²⁸ reflects very strong decarbonisation activities domestically and globally to limit temperature increase to 1.5°C. It involves rapid transformation of Australia’s energy sectors, utilising all available pathways to net zero including a strong use of electrification, and transformation of other sectors at pace, including action to reduce the emissions intensity of molecular forms of energy. Growth in hydrogen consumption fuels the expansion of green commodities production.

1.2 Gas market reform

A range of gas market reforms are being considered that build on the ECGS reliability and supply adequacy framework as well as seeking to address key gas market issues. The regulatory changes are at various stages, from early design through to detailed packages of work currently in consultation phases being progressed by either the Australian Energy Market Commission (AEMC) or the Federal Government Department of Climate Change, Energy, the Environment and Water (DCCEEW). **Table 4** summarises the key gas market reforms and provides a high-level overview of each reform, its purpose and its status at the time of publication. Except for the notice of closure for gas infrastructure rule change, none of these gas market reforms were considered in or otherwise influenced the 2026 GSOO.

Table 4 Ongoing market reforms

Gas market reform	Description	Status
ECGS Stage 2 Reliability and Supply Adequacy (RSA) reforms	<p>A package of reforms aimed at strengthening gas reliability and supply adequacy through changes to the National Gas Rules (NGR), building on the reforms introduced in 2023. The package includes:</p> <ul style="list-style-type: none"> • enhancing reliability and supply adequacy arrangements^a, • Projected Assessment of System Adequacy^b, • supplier of last resort mechanism^c, and • notice of closure for gas infrastructure^d. 	<p>The notice of closure rule change was implemented in February 2026 and is reflected in this GSOO.</p> <p>The remaining reforms are progressing through the AEMC’s rule change process and are expected to be progressively implemented over 2026 to 2027, dependent on final determinations that are expected in mid-2026.</p>
Proposed Extension of AEMO’s ECGS Reliability and Supply Adequacy Functions^e	<p>The Energy and Climate Change Ministerial Council (ECMC) is considering whether to extend AEMO’s functions to enable it to help address projected structural gas shortfalls in the ECGS. The two potential measures being considered are:</p> <ul style="list-style-type: none"> • extending the RSA framework to include a new last resort investment support tool that could be used to support supply-side investments, where it is required to address prolonged shortfalls of gas supply and the market is unable to deliver the investment in time. • extending the scope of the GSOO to include a detailed assessment of the investment options available to address gas shortfalls to reduce information barriers that may be impeding market-led investment. This is not intended to 	<p>The Federal Government completed consultation on the draft regulatory package in February 2026.</p> <p>Ministers are expected to make a decision on whether to proceed with this reform around mid-2026.</p>

²⁷ This scenario was referred to as *Progressive Change* in the 2025 GSOO. *Progressive Change* has been renamed to *Slower Growth* to more accurately reflect the settings that this scenario embodies.

²⁸ The scenario with the strongest decarbonisation activity has been redefined from *Green Energy Exports* in the 2025 GSOO to *Accelerated Transition*.

Gas market reform	Description	Status
	convert the GSOO into an integrated planning instrument or to impose investment obligations on gas market participants.	
Gas Market Review^F	The Federal Government has completed a Gas Market Review examining the effectiveness of existing regulatory instruments ^G with options to consolidate and streamline regulations and create a long-term stable regulatory environment to support investment certainty. A central recommendation of the Review is to establish a domestic gas reservation scheme, alongside consideration of removing the Australian Domestic Gas Security Mechanism, Heads of Agreement and the pricing provisions in the Code.	Further consultation and policy development on the design and implementation of reforms arising from the Review are expected to commence in 2026. The domestic gas reservation scheme is not considered in this GSOO.

A. See <https://www.aemc.gov.au/rule-changes/ecgs-enhancing-reliability-supply-adequacy-arrangements>.

B. See <https://www.aemc.gov.au/rule-changes/ecgs-projected-assessment-system-adequacy>.

C. See <https://www.aemc.gov.au/rule-changes/ecgs-supplier-last-resort-mechanism>.

D. See <https://www.aemc.gov.au/rule-changes/ecgs-notice-closure-gas-infrastructure>.

E. See <https://consult.dceew.gov.au/proposed-extension-aemo-ec-gas-system>.

F. See <https://www.dceew.gov.au/energy/markets/gas-markets/gas-market-review>.

G. The regulatory instruments reviewed were the Australian Domestic Gas Security Mechanism, the Gas Market Code, and the Heads of Agreement with east coast LNG exporters.

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 website²⁹, and some materials are listed in **Table 5**. Key supporting materials include:

- AEMO's **demand forecasting portal**³⁰ – interactive access to detailed forecasts of annual gas consumption and maximum gas demand, for each region and scenario included in this GSOO.
- **Supply input data files**²⁹ – information about pipelines, production facilities, storage facilities, field developments, and any new projects or known upgrades considered in this GSOO analysis, including capacity information. The files also provide an update of reserves and resources, and cost estimates used for GSOO modelling. The files will also include information related to the new notice of closure requirements for gas infrastructure.
- **2026 VGPR Update** – a focused assessment of the gas supply-demand balance in Victoria's DTS.

Table 5 Other relevant reference materials

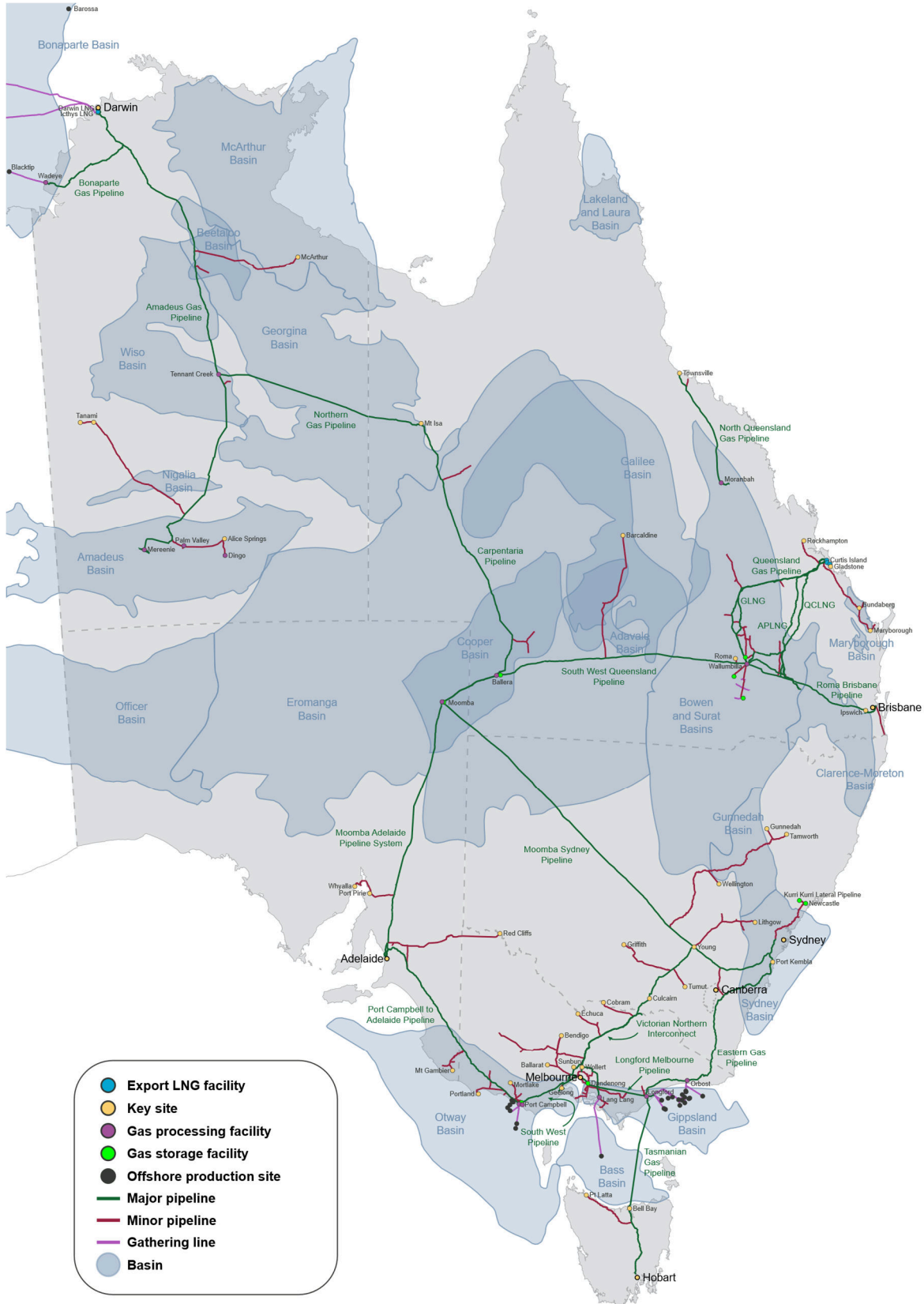
Information source	Website address and link
Gas Bulletin Board – Map and Reports	https://www.aemo.com.au/energy-systems/gas/gas-bulletin-board-gbb
2025 Inputs, Assumptions, Scenarios Report (IASR), and Excel Workbook	https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/2025-26-inputs-assumptions-and-scenarios
Deloitte Access Economics, Economic Forecasts 2024-25	https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr
CSIRO multi-sectoral energy modelling	https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/csiro-2024-multi-sectoral-modelling-report.pdf
ACIL Allen: 2025 Natural gas price forecast report	https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2026/2026-acil-allen-2025-projections.pdf
ACIL Allen: 2025 Natural gas price forecast workbook	https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2026/acil-allen-workbook

²⁹ At <https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo>.

³⁰ At <https://forecasting.aemo.com.au/>.

Figure 8 is a map of the basins, pipelines, and load centres across the ECGM.

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 consumer groups. The forecasts described are for the *Step Change* scenario, unless otherwise specified. The gas consumption and demand forecasts for all scenarios are also available on the AEMO Forecasting data portal³¹.

Key insights

- **Gas consumption declined in 2025**, reflecting milder weather conditions, continued lower industrial use, the ongoing impact of electrification, and lower LNG exports from Queensland.
- **Annual consumption is forecast to decline to 2045**, with electrification driving lower gas use across residential, commercial, and industrial consumers. Projected electrification of heating, cooking, and other traditional residential and commercial appliances is forecast to also **reduce peak day demands**, with reductions forecast to be greatest in Victoria, as the region has the highest gas penetration and has the most supportive policy environment for fuel-switching. AEMO surveys of large industrial gas users show lower levels of forecast consumption than in the 2025 GSOO. From 2031, industrial electrification is projected to be higher than in the 2025 GSOO as industrial facilities are projected to electrify to reduce emissions more effectively than other available alternatives to meet emissions policy targets.
- Annual gas consumption for the generation of electricity is forecast to modestly reduce in the short term before stabilising in the long term; however, **gas demand for GPG is forecast to be increasingly volatile** as it is expected to increasingly provide back-up support for renewable generation in the NEM, particularly in winter when solar availability is lower and electricity consumption for heating increases with electrification.

2.1 Total gas consumption forecasts

Figure 9 shows recent and forecast consumption, under the *Step Change* scenario over a 20-year period. Details of different consumer segments, trends, and key drivers of consumption are discussed in Section 2.2.

The 2026 GSOO forecasts declining annual gas consumption for the *Step Change* scenario, consistent with the 2025 GSOO. Forecasts commence at a lower point relative to the 2025 GSOO, reflecting reduced gas consumption observed in recent years. Exports of LNG from Queensland are forecast to remain the largest consuming customer segment, representing approximately three-quarters of total consumption in 2045.

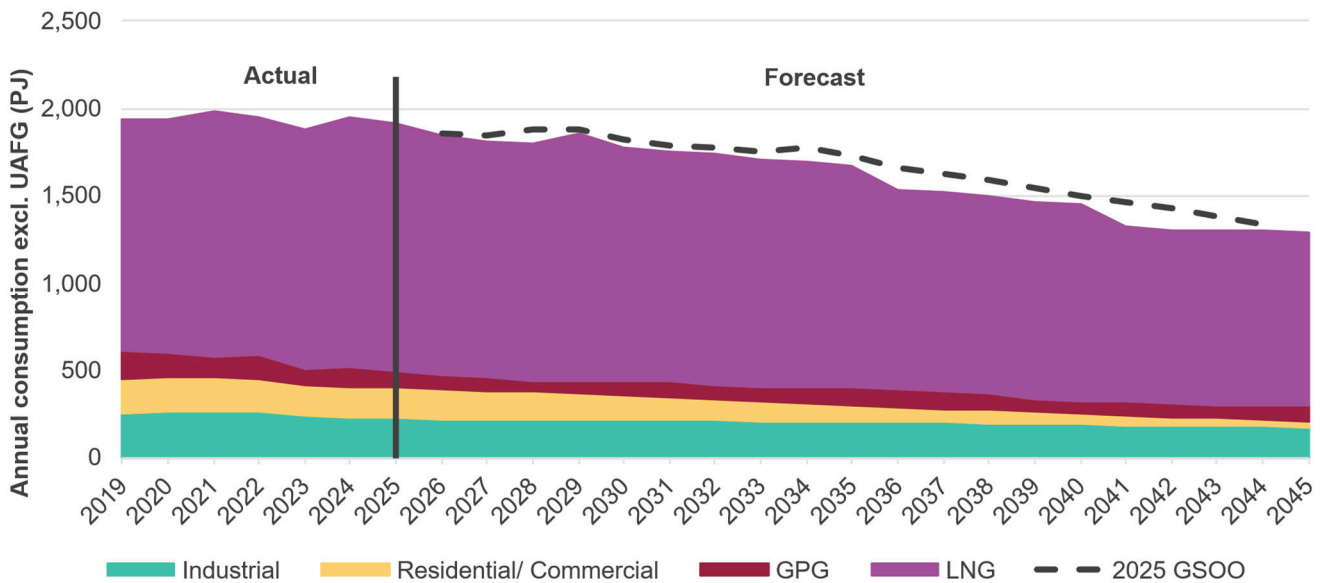
Gas consumption across the residential and small commercial sectors is forecast to decline steadily, reflecting fewer active connections and the impact of projected electrification in response to market and policy drivers. Bans on new gas connections in Victoria³² and the Australian Capital Territory³³ contribute to lower forecast gas use, despite growth in new dwellings and economic activity, with 65% of the decline projected to take place in Victoria.

³¹ At <https://forecasting.aemo.com.au/>. First select either **Gas/ Annual consumption** or **Gas/ Maximum Demand**, then select 'GSOO 2026' from the Publication drop-down.

³² See *Victoria's Gas Substitution Roadmap*, at <https://www.energy.vic.gov.au/renewable-energy/victorias-gas-substitution-roadmap>.

³³ See *Powering Canberra: Our Pathway to Electrification*, Australian Capital Territory Government Position Paper, at https://www.climatechoices.act.gov.au/_data/assets/pdf_file/0009/2052477/Powering-Canberra-Our-Pathway-to-Electrification-ACT-Government-Position-Paper.pdf.

Figure 9 Actual and forecast total annual gas consumption, all sectors, Step Change scenario, 2019-45 (PJ)



Note: Northern Territory industrial, residential and commercial gas consumption is included from 2020 onwards. The NGP, connecting the Northern Territory to Queensland, commenced in 2019. The first full year for which Northern Territory gas consumption data is available to AEMO is 2020. Northern Territory LNG forecasts are excluded.

Responses to AEMO’s survey of large industrial gas users show declining consumption. The consumption forecast includes gas-to-electricity fuel-switching to meet decarbonisation objectives.

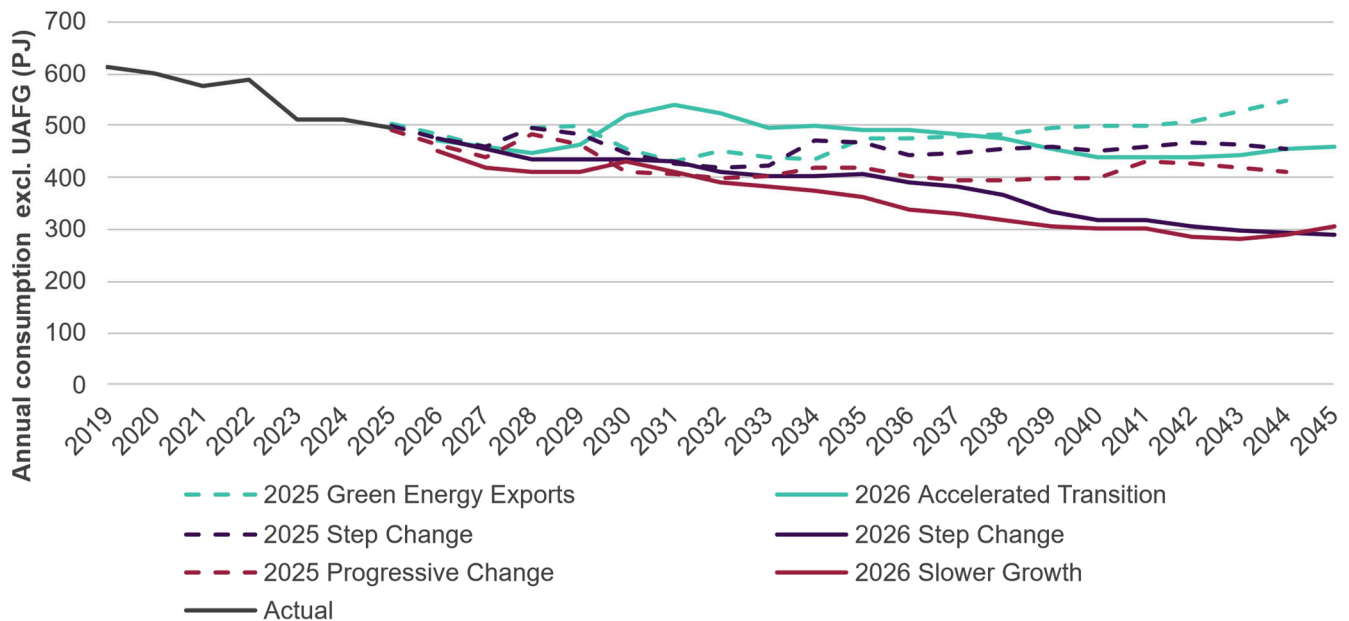
In the short term, gas consumption for GPG use is forecast to decline as the rapid rollout of electrical storage reduces the need for gas generation to meet peak electricity demand. At the same time, increasing renewable generation, including CER, is expected to supply more bulk energy, lowering the requirement for mid-merit GPG operation.

As coal generators retire and renewables provide a greater share of electricity, the role of GPG is starting to shift. Gas generation is becoming increasingly important for maintaining NEM reliability and security, even though its total annual gas consumption has declined. Over time, GPG is expected to contribute more during winter, when renewable output is typically lower and additional firming support may be required, even as annual gas demand stabilises.

The extended availability of Eraring Power Station to April 2029 has temporarily reduced the forecast demand for GPG for both peak electricity demand firming and winter electricity adequacy compared to the 2025 GSOO.

Figure 10 presents forecast domestic gas consumption for all three scenarios considered. Consumption in the *Step Change* and *Slower Growth* scenarios is forecast to decline, with both scenarios projecting lower consumption than the 2025 GSOO, driven by a lower GPG consumption forecast, consistent with the Draft 2026 ISP, and forecast reductions in consumption from large industrial loads (LILs) due to closures and other operational decisions. In the *Accelerated Transition* scenario, residential, commercial, and industrial gas consumption is forecast to be lower than the 2025 GSOO, although GPG consumption is projected to be higher from 2029 to 2039 due to the accelerated coal closures through this period in this scenario. The *Accelerated Transition* scenario also includes growth opportunities through hydrogen use in the production of green commodities.

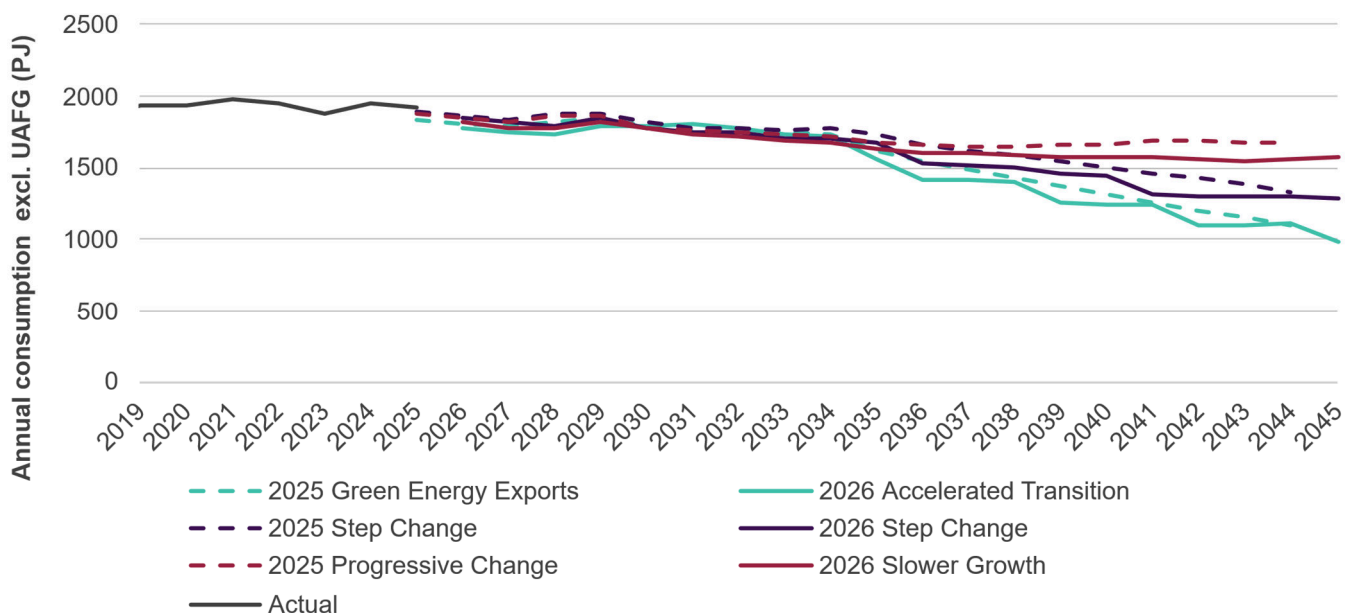
Figure 10 Actual and forecast domestic gas consumption, all scenarios, and compared to the 2025 GSOO, 2019-45 (PJ)



Note: Northern Territory industrial, residential and commercial gas consumption is included from 2020 onwards. The NGP, connecting the Northern Territory to Queensland, commenced in 2019. The first full year for which Northern Territory gas consumption data is available to AEMO is 2020.

Figure 11 includes the consumption impact from LNG exports from Queensland. LNG export forecasts, as described in Section 2.2.3, are informed by survey responses provided by the LNG producers through to 2035. Beyond 2035, higher long-term uncertainty is reflected by presenting a range of possible consumption outcomes across the scenarios.

Figure 11 Actual and forecast total annual gas consumption, all sectors, all scenarios, and compared to the 2025 GSOO, 2019-45 (PJ)



Note: Northern Territory industrial, residential and commercial gas consumption is included from 2020 onwards. The NGP, connecting the Northern Territory to Queensland, commenced in 2019. The first full year for which Northern Territory gas consumption data is available to AEMO is 2020. Northern Territory LNG forecasts are excluded.

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

2.1.1 Economic and population outlook

AEMO applied long-term state and territory-based economic and population forecasts, developed by Deloitte Access Economics (DAE)³⁴, in the preparation of gas consumption forecasts for the 2026 GSOO.

This GSOO applied insights provided by DAE in June 2025, presenting key state and national economic indicators that considered global political, economic and trade conditions on the Australian economy, as published in the 2025 IASR³⁵. These insights featured slightly stronger Gross Domestic Product (GDP) growth in the early years of the forecast relative to the 2025 GSOO, driven by better-than-expected domestic conditions.

Differences between the scenarios are as follows:

- *Step Change* adopts the central economic forecast, with an average annual growth rate in Australia's GDP of 1.8%. Economic activity shifts from hard-to-abate industries such as mining to the services and other sectors.
- *Slower Growth* incorporates the downside economic outlook, with lower population growth and labour productivity than the Step Change scenario. Annual average growth in Australia's GDP is lower, at 1.3%.
- *Accelerated Transition* incorporates the upside economic outlook and is driven by more favourable assumptions around growth in the population and economy relative to *Step Change*. This is because a combination of policy and technology drives a surge in clean energy. The average annual growth rate in Australian GDP is 2.5% in this scenario.

Under the *Step Change* scenario, DAE forecast Australia's population growth to slow across the forecast period, influenced by social, economic, and net migration. AEMO used the economic forecasts to derive future projections of gas consumption from forecast effective residential and small commercial connections.

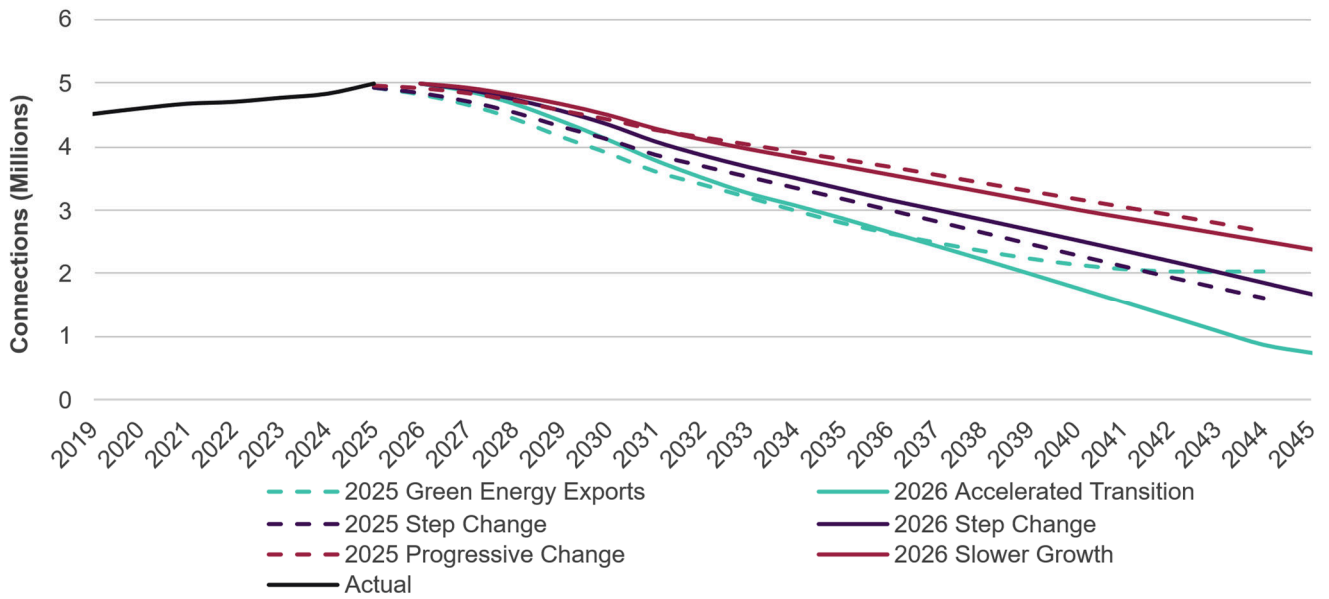
Figure 12 shows forecasts of effective connections for residential and small commercial businesses. The projections consider positive population and economic growth offset by reductions in gas use through appliance electrification and the effect of policies banning new gas connections (in Victoria and the Australian Capital Territory). In this figure, effective connections represent the equivalent number of connections if each connected dwelling or commercial premises retained the volume of gas use that has been observed historically. In reality, a material reduction in gas used per connection is forecast. That, coupled with slowing growth in new gas connections, results in a material decline in effective connections over time.

The *Slower Growth* scenario retains the highest number of effective connections, as it features the lowest amount of fuel switching to electricity. Greater levels of fuel-switching occur in the *Step Change* and *Accelerated Transition* scenarios, resulting in lower relative effective connections.

³⁴ At <https://www.aemo.com.au/-/media/files/major-publications/isp/2025/deloitte-access-economics-2024-economic-forecast.pdf>.

³⁵ For more information, see the 2025 IASR, at <https://www.aemo.com.au/consultations/current-and-closed-consultations/2025-iasr>.

Figure 12 Actual connections and forecast effective connections for residential and small commercial businesses, all scenarios, and compared to the 2025 GSOO, 2019-45



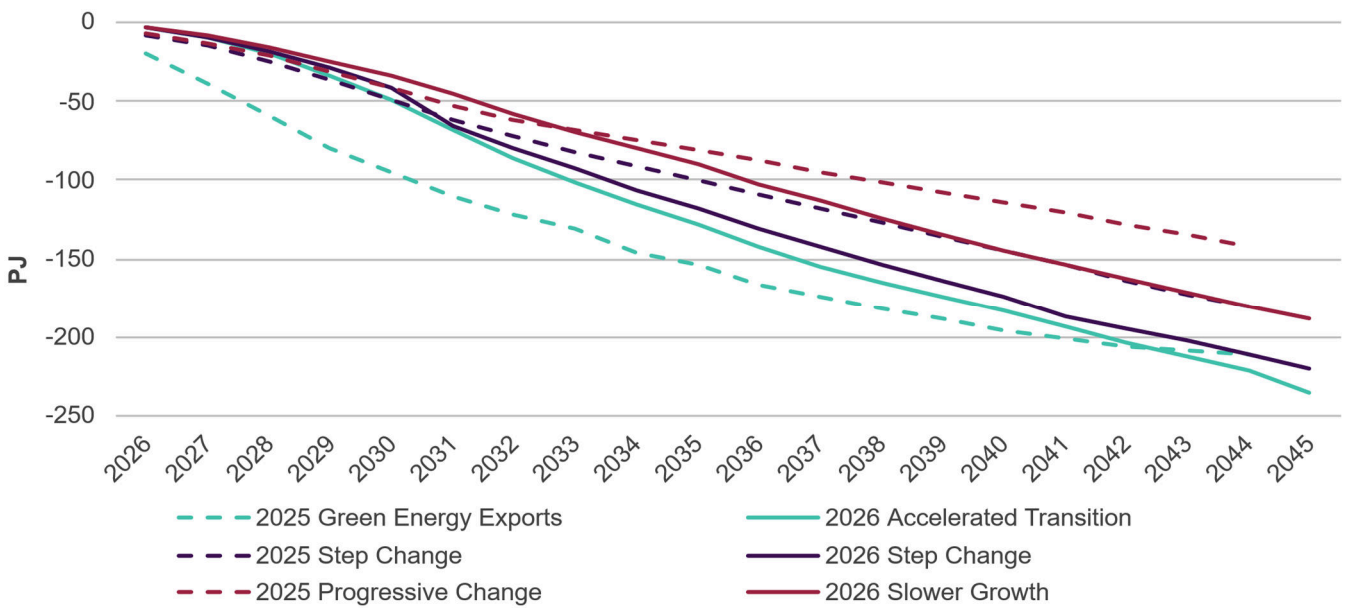
Note: 'Effective connections' represents the number of connections that would exist if residential and small commercial gas consumption remained at historical average levels per connection.

2.1.2 Electrification

Electrification (fuel-switching from gas to electricity) is one of the pathways to decarbonise the Australian economy.

Figure 13 shows electrification projections across all scenarios.

Figure 13 Forecast changes in gas consumption from electrification, all scenarios, and compared to the 2025 GSOO, 2026-45 (PJ)



Electrification in the 2026 GSOO drew on modelling conducted by CSIRO for the 2025 IASR³⁶. For the *Step Change* and *Slower Growth* scenarios, electrification is higher than in the comparable 2025 GSOO *Step Change* and *Progressive Change* scenarios. The *Step Change* scenario is forecast to have a less-developed domestic hydrogen industry compared to the 2025 GSOO, further driving the need for electrification as a decarbonisation lever. Electrification in the *Accelerated Transition* scenario reflects a more gradual pathway than the 2025 GSOO *Green Energy Exports* scenario, reflecting updated AEMO survey responses from large industrial gas users. After 2035, the *Slower Growth* scenario features greater electrification from industrial users than the 2025 GSOO *Progressive Change* scenario.

Significant levels of electrification are projected in the residential and small commercial sectors, reflecting the potential to fuel-switch specific applications such as space heating and hot water heating.

2.1.3 Energy efficiency

Reduced gas consumption arising from changes in consumer behaviour, equipment efficiency, and building thermal performance is regarded as energy efficiency savings.

Various federal and state-based policy initiatives provide stimuli for gas consumers to improve their energy efficiency. Key policies include:

- the National Construction Code 2022 (NCC 2022), including “whole of home” provisions supporting lower household energy consumption and higher thermal performance standards for new buildings including new dwellings³⁷,
- the *Greenhouse and Energy Minimum Standards Act 2012* (GEMS Act), implemented via the Equipment Energy Efficiency (E3) Program, which sets minimum energy efficiency standards for appliances and equipment supplied in Australia,
- 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) – that subsidise upgrades across residential and business settings,
- the Commercial Building Disclosure (CBD) and National Australian Built Environment Rating System (NABERS), which drive performance improvements via disclosure, ratings, and benchmarking,
- the Household Energy Upgrade Fund (HEUF), delivered through the Clean Energy Finance Corporation (CEFC), which provides financial support for household energy performance upgrades,
- the Safeguard Mechanism reforms (April 2023), which create further incentives for Australia’s largest emitting facilities to implement within-fuel efficiency improvements as part of emissions reductions, and
- prospective policies including minimum energy performance standards (MEPS) for rental homes and universal mandatory disclosure (UMD) of energy ratings for existing homes with implementation scale varying across scenarios (expanding the Nationwide House Energy Rating Scheme (NatHERS) to existing builds will support UMD).

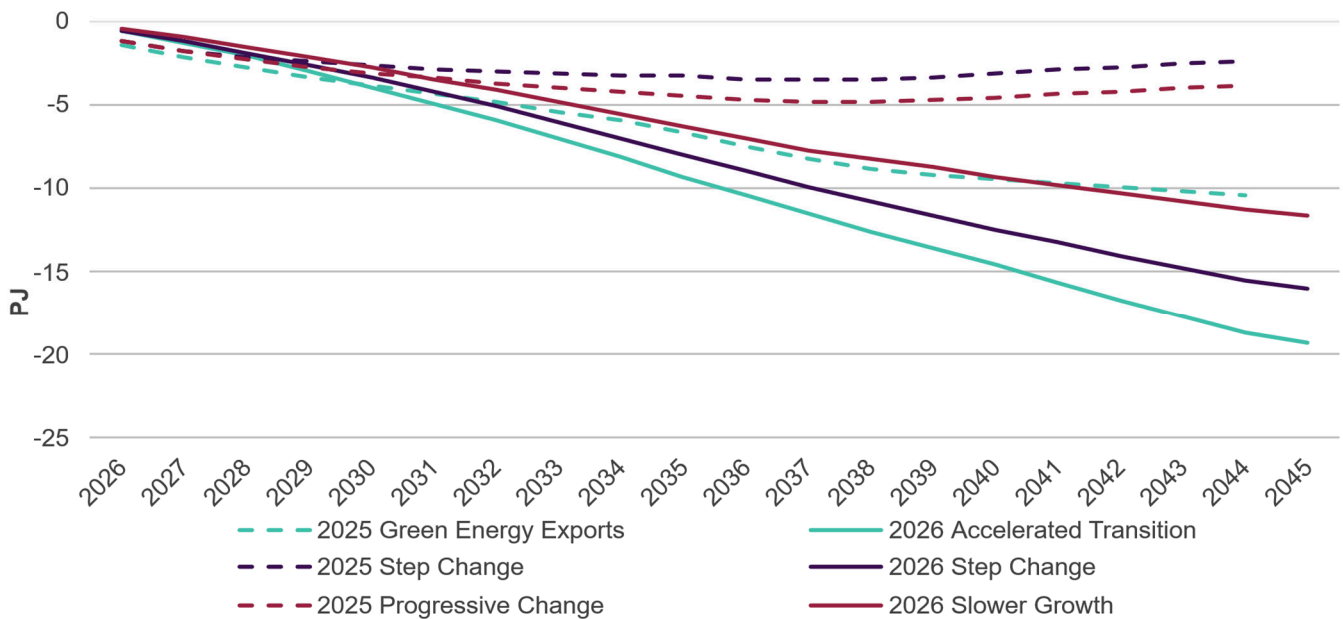
³⁶ See *Multi-Sectoral Modelling 2024*, at https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/csiro-2024-multi-sectoral-modelling-report.pdf.

³⁷ See *NCC 2022 residential energy efficiency Overview of provisions*, at <https://www.abcb.gov.au/sites/default/files/resources/2023/NCC-2022-residential-energy-efficiency-overview-of-provisions-transcript.pdf>.

These measures deliver the greatest additional energy efficiency savings in the *Accelerated Transition* scenario, reflecting stronger economic conditions and higher emissions reduction ambitions that economically enable and socially encourage energy savings; the *Slower Growth* scenario exhibits slower improvements.

Figure 14 illustrates energy efficiency savings forecasts for all scenarios. Energy efficiency savings forecasts are greater than in the 2025 GSOO from 2030, due to higher projections of market-led energy efficiency³⁸, introduction of the CBD expansion roadmap³⁹, and targeted extensions to the ESS and VEU.

Figure 14 Forecast reduction in gas consumption from energy efficiency, all scenarios, and compared to the 2025 GSOO, 2026-45 (PJ)



2.1.4 Wholesale and retail gas prices

AEMO engaged ACIL Allen to prepare wholesale gas price forecasts for the 2026 GSOO⁴⁰. These forecasts considered the influence of international market dynamics on gas prices across the ECGM, considering the impact of LNG netback pricing, costs associated with importing LNG, and other competitive factors.

Retail gas price forecasts, which drew on data from the Australian Energy Regulator (AER) and operators of gas infrastructure, influenced projected gas consumption through discretionary expenditure on fuel by consumers. While short-term price elasticity from retail and small commercial consumers is modest, in the longer term those consumers were assumed to seek lower exposure to gas prices through electrification and the adoption of more energy efficient practices and equipment.

Gas consumption patterns of large industrial consumers are less flexible to fluctuations in short-term gas prices than those of the residential market, as production processes are typically operated on a continuous basis.

³⁸ Market-led energy efficiency is that which is projected to occur in the absence of policy measures. See *2025 Energy Efficiency Forecasts Final Report* at <https://www.aemo.com.au/-/media/files/major-publications/isp/2025/stage-2/2025-energy-efficiency-forecasts-final-report.pdf> for more information.

³⁹ See Commercial Building Disclosure Program: Policy Roadmap to expand mandatory disclosure of commercial building energy performance ratings at https://www.cbd.gov.au/sites/default/files/2025-10/ENR325_0625%20CBD%20Roadmap%20v10.pdf.

⁴⁰ ACIL Allen, *2025 Natural gas price forecast report*, at https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2026/2026-acil-allen-2025-projections.pdf.

This 2026 GSOO does not consider the impact of recent geopolitical events in the Middle East. AEMO will continue to monitor gas adequacy for this winter under its East Coast Gas System (ECGS) functions⁴¹, and will work with industry and governments to support ongoing supply should any risk or threat be identified.

2.1.5 Hydrogen

The National Gas Law and National Gas Rules (NGR)⁴² require 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 exception to this is dedicated hydrogen, which is a subset of covered gas demand that can only be met by hydrogen and cannot be substituted by other gases. It may be used by specific industrial applications, including as a feedstock for green commodities⁴³ processing and as a substitute for coal in steel production. Further detail on dedicated hydrogen forecasts is provided in the 2026 *Gas Demand Forecasting Methodology Information Paper*⁴⁴.

Dedicated hydrogen consumption for green commodity production in the 2026 GSOO was based on modelling used in the 2025 IASR⁴⁵. The *Step Change* and *Slower Growth* scenarios did not include dedicated hydrogen.

Hydrogen that is produced at a remote facility, consistent with the NGR's definition of remote facilities, is excluded from the GSOO forecast, as it is not connected to the ECGM and therefore not appropriate to be included in the overall ECGM adequacy assessment. Further description of the treatment of dedicated hydrogen and remote facilities is in the 2026 *Gas Demand Forecasting Methodology Information Paper*.

Figure 15 shows the domestic gas consumption profile of the *Accelerated Transition* scenario in the 2026 GSOO, which replaced the *Green Energy Exports* scenario in the 2025 GSOO, and highlights the contribution of dedicated hydrogen demand.

The gas consumption profile was informed by results of the 2026 GSOO surveys of existing LILs and industry-level analysis in the 2025 IASR. Stronger economic activity, policy developments and renewable gases facilitate the growth of green commodities production and the decarbonisation of industry in the *Accelerated Transition* scenario.

Figure 16 shows the dedicated hydrogen consumption forecast across the scenarios. Hydrogen for green commodities is largely dominated by the iron and steel sector, with small amounts used in fertiliser and alumina production. Compared to the 2025 GSOO *Green Energy Exports* scenario, use of dedicated hydrogen in the *Accelerated Transition* scenario is higher from 2040, reflecting the prospects for green commodities. The higher growth prospects of green commodities in this scenario was an intentional design of the scenario, with greater focus on domestic economic prospects rather than hydrogen exports, as consulted upon with stakeholders in the 2025 IASR.

⁴¹ See <https://www.aemo.com.au/energy-systems/gas/east-coast-gas-system/about-the-east-coast-gas-system-ecgs>.

⁴² 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>.

⁴³ Green commodities included in the GSOO include iron and steel, ammonia, alumina, and methanol which are produced using green hydrogen (or with natural gas as a bridging fuel) as a feedstock or energy source to reduce emissions intensity compared with conventional production pathways.

⁴⁴ See AEMO's 2026 *Gas Demand Forecasting Methodology Information Paper*, at https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2026/2026-gsoo-methodology-demand-forecasting.pdf.

⁴⁵ See Section 3.3.6 of the 2025 IASR, at https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/2025-inputs-assumptions-and-scenarios-report.pdf.

Figure 15 Actual and forecast domestic covered gas consumption, excluding GPG, Accelerated Transition scenario with dedicated hydrogen consumption for green commodities, and compared to the 2025 GSOO, 2019-45 (PJ)

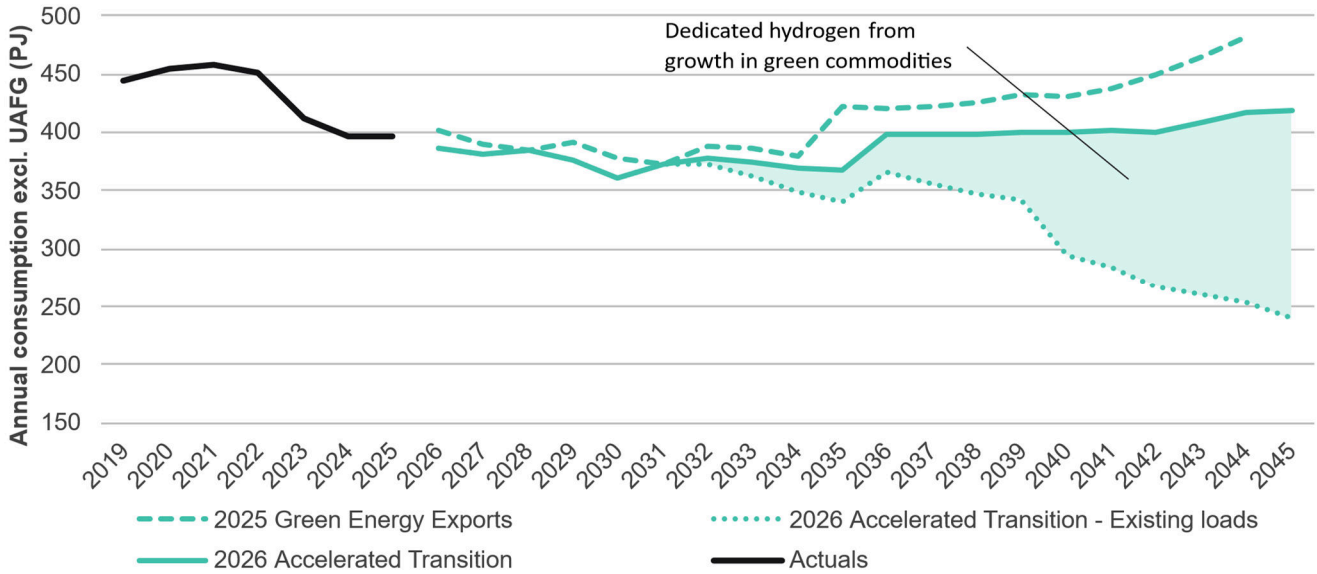
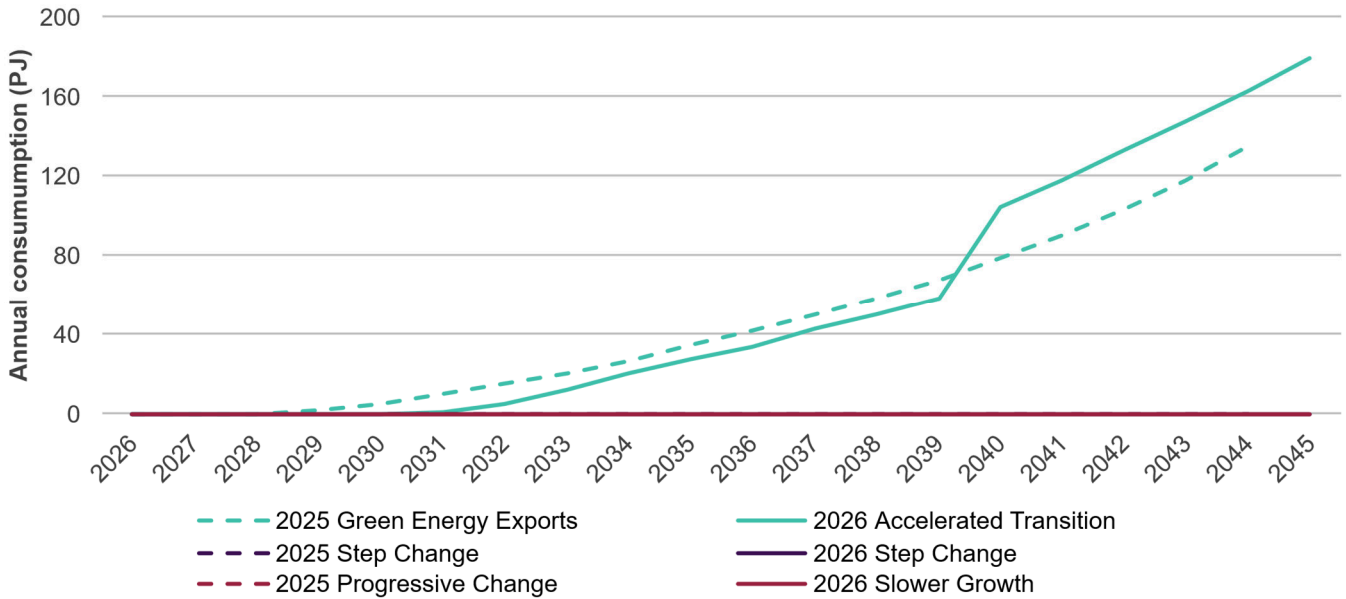


Figure 16 Forecast dedicated hydrogen demand from growth in green commodities, all scenarios, and compared to the 2025 GSOO, 2026-45 (PJ)



2.2 Consumption forecasts by sector

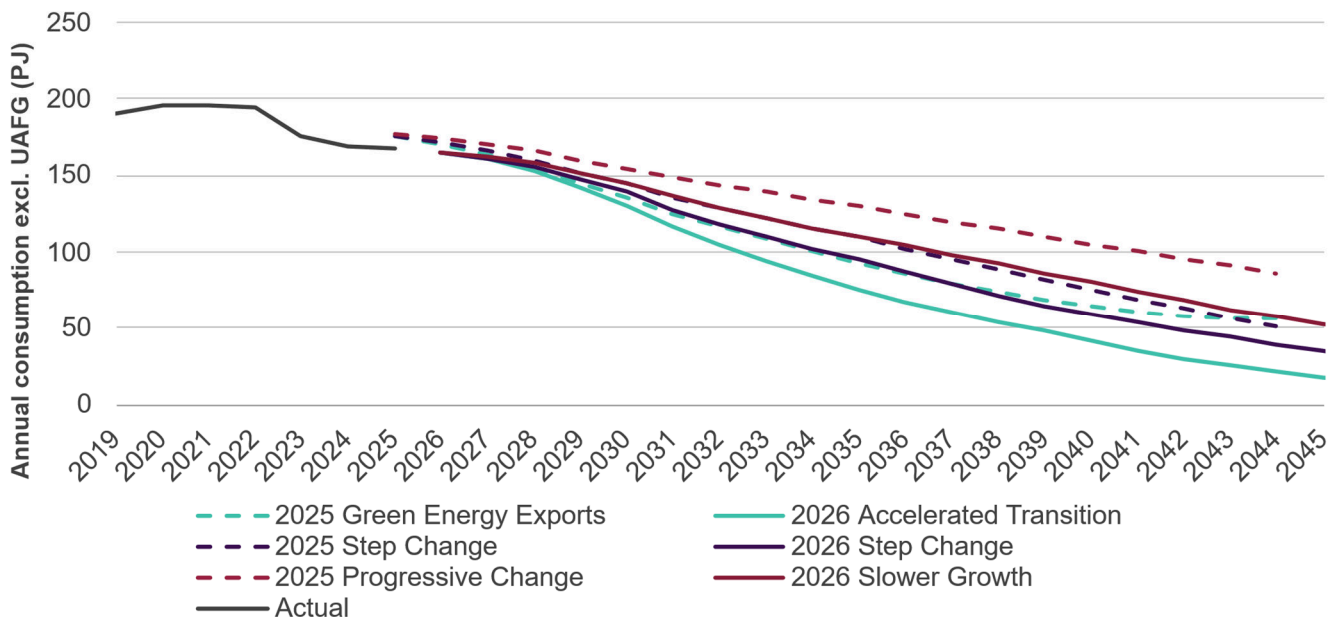
2.2.1 Residential and small commercial consumption

Residential and small commercial consumers are defined in the GSOO as those using less than 10 terajoules (TJ) of gas per year and equipped with a basic gas meter. Forecasts reflect recent trends and projected changes in the number of gas

connections, adjusted for fuel-switching to electricity⁴⁶, as well as energy efficiency improvements and behavioural responses to changes in gas price.

Figure 17 shows forecast residential and small commercial consumption for all scenarios. Forecast residential and small commercial consumption assumed average weather conditions⁴⁷. The weather in 2025 was nearer to long-term average conditions than that in 2024. The starting position of the 2026 GSOO forecast is closer to 2025 actual consumption, compared to the starting point of the 2025 GSOO forecast relative to 2024 actual consumption.

Figure 17 Actual and forecast residential and small commercial annual consumption, all scenarios, compared to the 2025 GSOO, 2019-45 (PJ)



Note: The Northern Territory is included in actual gas consumption from 2020 onwards. The NGP, connecting the Northern Territory to Queensland, commenced in 2019. The first full year for which Northern Territory gas consumption data is available to AEMO is 2020.

In the *Step Change* scenario:

- Electrification and, to a lesser extent, energy efficiency savings lead to reduced gas consumption across the sector over the forecast horizon, despite projected growth in population and dwellings. Residential electrification includes the projected impact of gas connections bans in Victoria and the Australian Capital Territory.
- Residential and small commercial gas consumption in 2045 is forecast to be close to 35 PJ, down by 130 PJ from the level of gas consumption in 2026.

In other scenarios:

- A more gradual decline in gas consumption from residential and small commercial consumers is forecast in the *Slower Growth* scenario, primarily due to relatively lower consumer investments in electrification and energy efficiency.
- Greater electrification in the *Accelerated Transition* scenario is required to achieve the strong decarbonisation objective of this scenario.

⁴⁶ See effective connections forecast in **Figure 12**. Further details about the calculation approach are in AEMO’s 2026 *Gas Demand Forecasting Methodology Information Paper*.

⁴⁷ As described in the 2026 *Gas Demand Forecasting Methodology Information Paper*, AEMO assumes historical average weather conditions in preparing residential and small commercial consumption forecasts.

2.2.2 Industrial consumption

Industrial gas consumers are defined as those using over 10 TJ per year (TJ/y), excluding NEM-connected GPG⁴⁸ and LNG export facilities. 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, as well as those that use gas as a backup fuel in the emerging data centre market.
- 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 and hydrogen), the *Accelerated Transition* 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 prospective consumers of dedicated hydrogen. Further information on dedicated hydrogen for growth in green commodities is described in Section 2.1.5.

For the *Step Change* scenario:

- Industrial consumption is forecast to decline from 229 PJ in 2026 to 168 PJ in 2045.
- Large industrial gas users show lower levels of forecast consumption than in the 2025 GSOO.
- Industrial electrification forecasts build on responses to AEMO’s surveys of LILs and CSIRO’s longer-term multi-sectoral modelling and are projected to be higher than in the 2025 GSOO to meet policy emissions targets.

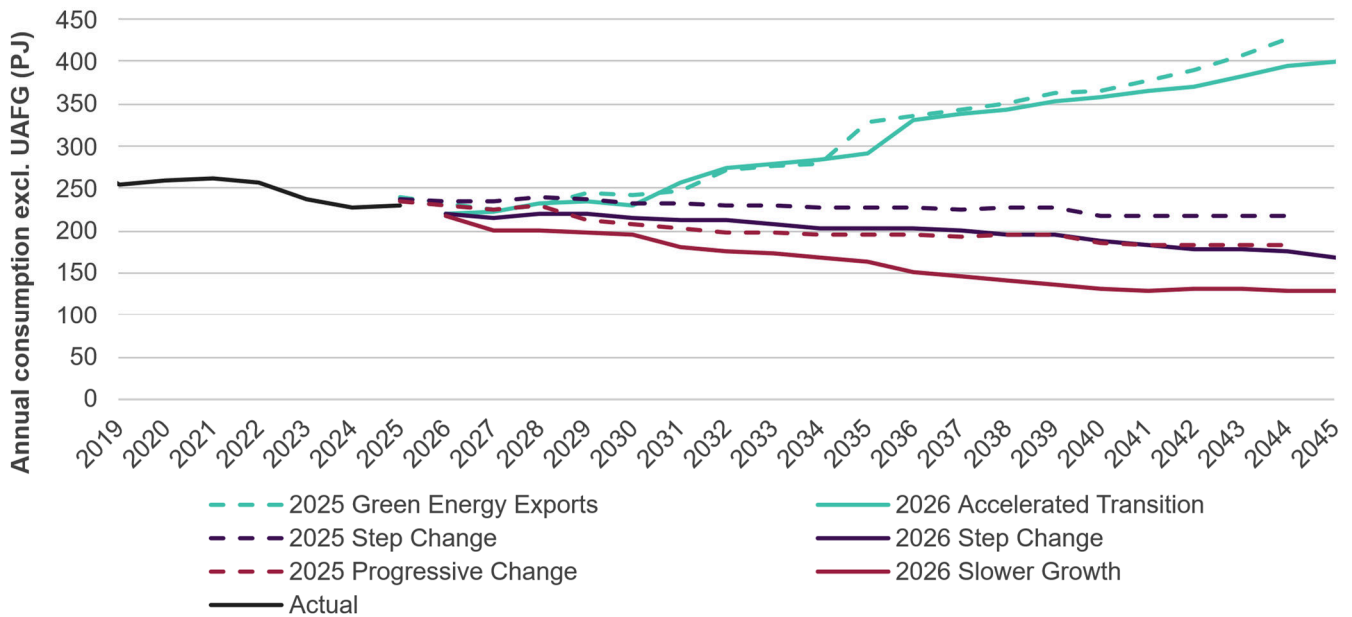
In other scenarios:

- Forecast consumption in *Slower Growth* declines faster due to weaker economic conditions compared to *Step Change*. LILs were assumed to consume gas for the duration of existing gas contracts where information is available. The trend of declining gas consumption in this scenario is steeper than what was projected in the 2025 GSOO *Progressive Change* scenario, as electrification of the industrial sector is projected to gather pace as an economically efficient pathway in many industrial applications to reduce emissions relative to alternatives.
- Forecast consumption in the *Accelerated Transition* scenario grows from 2030 until 2035, with further longer-term growth due to increasing demand for dedicated hydrogen in the production of green commodities. Total electrification is lower than in the *Step Change* scenario, as some industrial users were assumed to elect to incorporate renewable gas in production processes rather than electrify to meet emissions objectives.

Figure 18 shows actual and forecast industrial consumption in all scenarios. The forecasts start at a lower point compared to the 2025 GSOO, reflecting AEMO surveys of LILs.

⁴⁸ Industrial forecasts included facilities such as Yarwun GPG in Gladstone, Queensland, which supplies electricity to the Yarwun Alumina Refinery.

Figure 18 Actual and forecast industrial consumption, all scenarios, and compared to the 2025 GSOO, 2019-45 (PJ)



Note: The Northern Territory is included in actual gas consumption from 2020 onwards. The NGP, connecting the Northern Territory to Queensland, commenced in 2019. The first full year for which Northern Territory gas consumption data is available to AEMO is 2020.

2.2.3 LNG export

The forecasts for gas consumed by LNG producers before 2035 described in this section are underpinned by surveys⁴⁹ of contracted LNG exports⁵⁰, firm domestic supply contracts, expected contract variations, and expected spot LNG export sales provided to AEMO by the Queensland LNG producers⁵¹. Some LNG producers may use contract variations for years when they are forecast to have insufficient supply to meet contracted export demand, and this is reflected in the forecast.

Figure 19 shows recent and forecast LNG exports for each of the three scenarios, compared to the 2025 GSOO. These forecasts incorporate quantities provided by the Queensland LNG producers directly reported to AEMO to 2035, and beyond 2035 the scenarios are dispersed in line with trends estimated in IEA forecasts⁵².

Between now and 2035, the 2026 GSOO reflects a forecast level of LNG exports averaging 1,253 PJ under long-term contracts and 85 PJ in expected LNG export spot sales⁵³. The expected gas needed to service export contract positions is, on average, 56 PJ lower compared to the 2025 GSOO, but expected LNG export spot sales are 40 PJ higher on average.

Recognising that long-term forecasts are highly uncertain, the forecasts remain on a similar trajectory to the 2025 GSOO, although in scenarios where LNG exports were assumed to decline, the forecasts now assume an orderly shutdown of LNG processing trains, resulting in steps in the forecast.

In addition:

⁴⁹ Under the NGR, Northern Territory LNG facility operators and field owners are exempt from participation in the GSOO survey.

⁵⁰ Also referred to as long-term LNG sales and purchase agreements (SPAs).

⁵¹ LNG exporters in the Northern Territory are not considered participants of the ECGM and were not included in the GSOO.

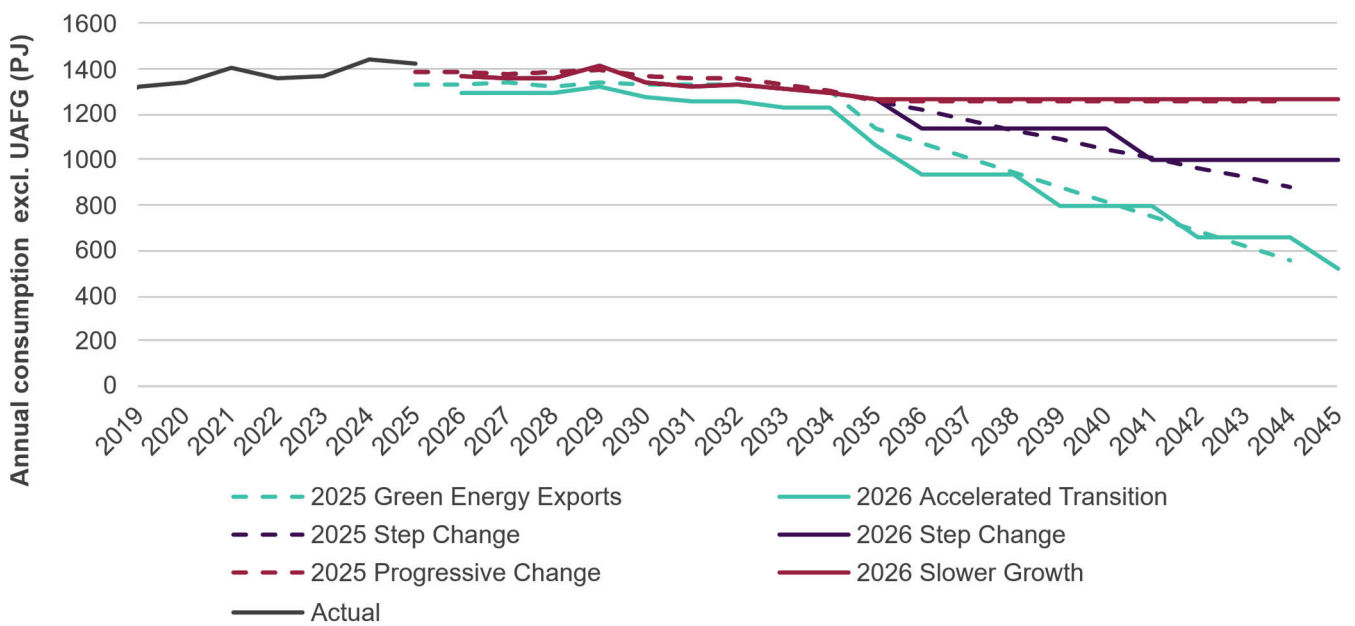
⁵² **Table 3** (in Section 1.1) shows the alignment between AEMO’s scenarios and the IEA’s scenarios. AEMO has aligned Queensland LNG export forecasts with the IEA’s forecasts of LNG demand from the 2025 World Energy Outlook (see <https://www.iea.org/reports/world-energy-outlook-2025>) where possible.

⁵³ 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.



- In the *Slower Growth* scenario, reduced action towards global decarbonisation means east coast LNG exports have been forecast to be flat across the horizon.
- The *Step Change* and *Accelerated Transition* scenarios applied increasing levels of decarbonisation action globally to lower energy sector emissions, so reducing levels of east coast LNG export are forecast.
- The significant spread in forecast east coast LNG export by 2045 reflects the strong uncertainty regarding the scale of east coast export demand across these scenarios.

Figure 19 Actual and forecast LNG consumption, all scenarios, and compared to the 2025 GSOO, 2019-45 (PJ)



Note: LNG exporters in the Northern Territory are not considered participants of the ECGM and were not included in the GSOO.

In December 2025, the Federal Government released its Gas Market Review Report⁵⁴, which included a review of the Australian Domestic Gas Security Mechanism, Gas Market Code and Heads of Agreement, and provided recommendations relating to the ECGM. The Federal Government immediately announced the uptake of one of these recommendations, a domestic gas reservation scheme, which is aimed to come into effect from 2027⁵⁵.

These forecasts did not consider the impact of the proposed domestic gas reservation scheme or any other consequences relating to this policy, as the policy is still under consultation. Nor do they consider potential changes in LNG export levels arising from recent geopolitical events in the Middle East.

For more information on the LNG forecast methodology, see AEMO’s 2026 *Gas Demand Forecasting Methodology Information Paper*⁵⁶.

⁵⁴ See <https://www.dcceew.gov.au/energy/markets/gas-markets/gas-market-review>.

⁵⁵ See <https://minister.dcceew.gov.au/bowen/media-releases/joint-media-release-affordable-gas-australian-homes-and-businesses>.

⁵⁶ At https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2026/2026-gsoo-methodology-demand-forecasting.pdf.

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, and
- GPG.

The following section discusses the seasonality of daily 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 gas demand for residential and small commercial consumers is strongly seasonal, with maximum demand occurring in winter driven by the demand for space heating, particularly in the southern regions. Customers in Queensland and the Northern Territory generally show less seasonality in demand due to lower heating requirements. Industrial consumption typically has less seasonal and daily variance owing to the continuous nature of most production processes.

Figure 20 below shows the historical volatility and strong seasonality of daily demand in the southern regions of New South Wales (including the Australian Capital Territory), South Australia, Tasmania and Victoria in 2024 and 2025.

Daily demand by residential, commercial and industrial consumers is shown as the dark purple area in the chart, and demonstrates that temperature sensitive load in the winter in southern regions results in daily peaks that may be two to three times higher than in summer.

Gas volumes required for GPG (yellow area in **Figure 20**) 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 the cold weather in winter that drives higher gas demand typically also leads to higher electricity demand. Winter months also typically experience lower electricity production from renewable resources, particularly solar with shorter days and the lower sun angle reducing PV output. **Figure 20** demonstrates that, for example, in June 2025, cold winter conditions combined with low wind availability led to high GPG demand⁵⁷ at a time when gas consumption was also coincidentally high.

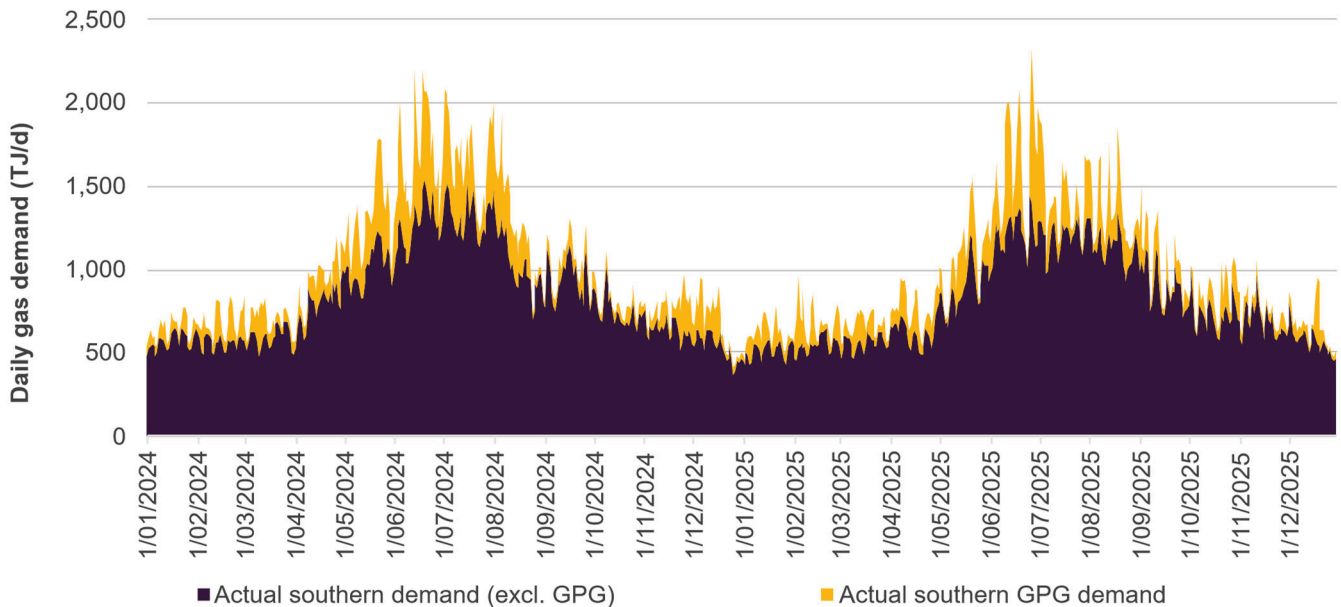
Daily demand by residential, commercial and industrial consumers is shown as the dark purple area in the chart, and demonstrates that temperature sensitive load in the winter in southern regions results in daily peaks that may be two to three times higher than in summer.

As outlined in Section 2.1, GPG demand depends on the availability of renewable generation, as well as battery and hydro storages. As electrification increases winter electricity consumption, winter GPG peaks continue to grow at a significantly faster pace than summer peaks. These increases exceed the reduced peakiness from the declining residential and small commercial sectors.

⁵⁷ For more information, see AEMO, *Quarterly Energy Dynamics Q2 2025*, at https://www.aemo.com.au/-/media/files/major-publications/ged/2025/ged-q2-2025.pdf?rev=8732b44ba628445da5883f92e84cd87d&sc_lang=en.

Demand for gas for LNG export is less volatile compared to other sectors, and changes in daily demand are more gradual, however do exhibit some seasonality, with summer exports typically higher than winter exports as the Australian summer corresponds to winter in key northern hemisphere Asian markets.

Figure 20 Actual domestic daily gas demand in southern regions from January 2024 to December 2025, showing seasonality and peakiness (TJ/d)



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

Table 6 and **Table 7** show recent observed maximum daily demands for each region and their seasonal 20-year forecasts for all sectors (excluding GPG) in the *Step Change* scenario. Maximum daily demand forecasts for both 50% POE and 5% POE levels are provided in these tables. These forecasts include unaccounted for gas (UAFG) that is lost while being transported through the gas network. Regional demand forecasts for all scenarios are available on AEMO’s Gas Forecasting Data Portal⁵⁸.

Maximum daily demand forecasts assume typical weather conditions, drawing on the distribution of observed weather conditions over the past 25 years. Given the mild weather in 2025, in terms of daily minimum temperatures, the peak day demand forecast for 2026 is higher than 2025 actuals, reflecting the historical average weather conditions.

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

- **Southern mainland regions (Victoria, New South Wales and South Australia)** are projected to have the greatest decline in peak day demand, with each of the three regions’ maximum daily demand forecasts reducing by approximately 30% or higher over the 20-year outlook. Policies that support electrification encourage this consistent projected decline over time.

⁵⁸ At <https://www.aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/gas-forecasting-data-portal>. 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.

- **Queensland** is projected to have a slow and steady decline in maximum daily demand, driven primarily by expected changes in industrial consumption indicated through LIL survey responses. After 2040, the forecast decline steepens, reflecting industrial electrification.
- **Tasmania** is forecast to maintain a steady level of gas demand across the outlook period, due to the fact that this region has a large proportion of relatively stable industrial gas consumption.
- **Northern Territory** demand forecasts are influenced by growth in industrial consumption in the late 2020s, with some forecast closures informed by AEMO surveys occurring toward the end of the outlook period.

Table 6 Total 1-in-2 and 1-in-20 forecast maximum demand, winter, all sectors excluding gas generation, including UAFG (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
2023	436		4,229		316		133		20		982		18	
2024	433		4,476		288		132		21		976		19	
2025	433		4,194		287		129		20		935		21	
<i>Step Change</i>														
2026	450	475	4,105	4,117	298	310	131	137	21	23	958	1,032	20	22
2030	417	442	4,007	4,018	278	289	127	133	22	23	836	900	25	28
2035	311	330	3,797	3,807	274	284	114	120	20	21	621	667	26	29
2040	240	254	3,411	3,422	261	272	102	107	17	18	440	469	17	19
2045	203	215	2,975	2,983	199	206	96	100	16	17	318	337	18	20

Table 7 Total 1-in-2 and 1-in-20 forecast maximum demand, summer, all sectors excluding gas generation, including UAFG (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
2023	263		4,669		328		87		20		420		18	
2024	255		4,695		306		84		19		312		20	
2025	252		4,573		301		84		21		318		20	
<i>Step Change</i>														
2026	269	296	4,577	4,589	314	326	84	89	20	22	407	484	20	23
2030	259	283	4,470	4,481	293	304	83	88	21	22	370	438	26	29
2035	204	222	4,235	4,246	290	301	78	83	19	20	294	339	26	30
2040	169	182	3,804	3,815	277	288	73	78	16	17	233	263	17	19
2045	153	165	3,319	3,327	210	218	70	75	15	17	191	209	17	19

2.4 Gas for electricity generation

GPG continues to play a crucial role in the NEM as a back-up source during periods of low coal or renewable generation availability and as the primary source of electricity generation in the Northern Territory. Some generators are also key providers of power system security services.

The Draft 2026 ISP reaffirms that renewable energy, firmed with storages (such as batteries or pumped hydro energy storage), backed up by GPG and connected by upgraded electricity networks, presents the least-cost way to supply secure and reliable electricity to consumers, while meeting government policies.

The 2026 GSOO leveraged the NEM's development trajectory in the Draft 2026 ISP^{59,60} to forecast GPG use in each scenario, given the forecast investments in electricity networks, CER, and utility-scale generation and storage technologies in the Draft 2026 ISP's optimal development path.

The extent to which GPG is required to operate in future will depend on several factors, most prominently the weather that influences the availability of renewable generation, and the availability and operation of coal generators and the extent of new investment in renewable generation, electrical storage and network infrastructure. These GPG forecasts were based on the weather conditions observed over recent history, from 2011 to 2024, to ensure real-world weather conditions are evaluated to determine the range of GPG outcomes. The range of potential GPG outcomes forecast is highly variable, particularly through the periods when coal generation is retiring.

Gas-fired peaking generators have historically been a critical generation source in meeting instantaneous electricity demand at peak demand periods, although much of the gas volumes used in producing electricity have been consumed by steam and combined-cycle gas turbines. The continuing evolution of the NEM generation mix – through the addition of longer duration storages, continued penetration of CER and flexible operation of coal – is seeing the volume of gas used in GPG decline, particularly in summer peaks. However, the significance of GPG to maintain reliability and security at times, and the increasingly likely role for GPG to provide energy during sustained periods of low renewable generation output, is increasing the importance of GPG's role for electricity consumers.

The impact of weather conditions on GPG requirements is highly dependent on the mix of generation and storage capacity available at the time. The GSOO leveraged 11 historical years of weather conditions, to reasonably consider a range of weather patterns on GPG requirements. Actual weather conditions may exceed or fall below the forecast outcomes.

2.4.1 Forecasts of gas use for electricity generation

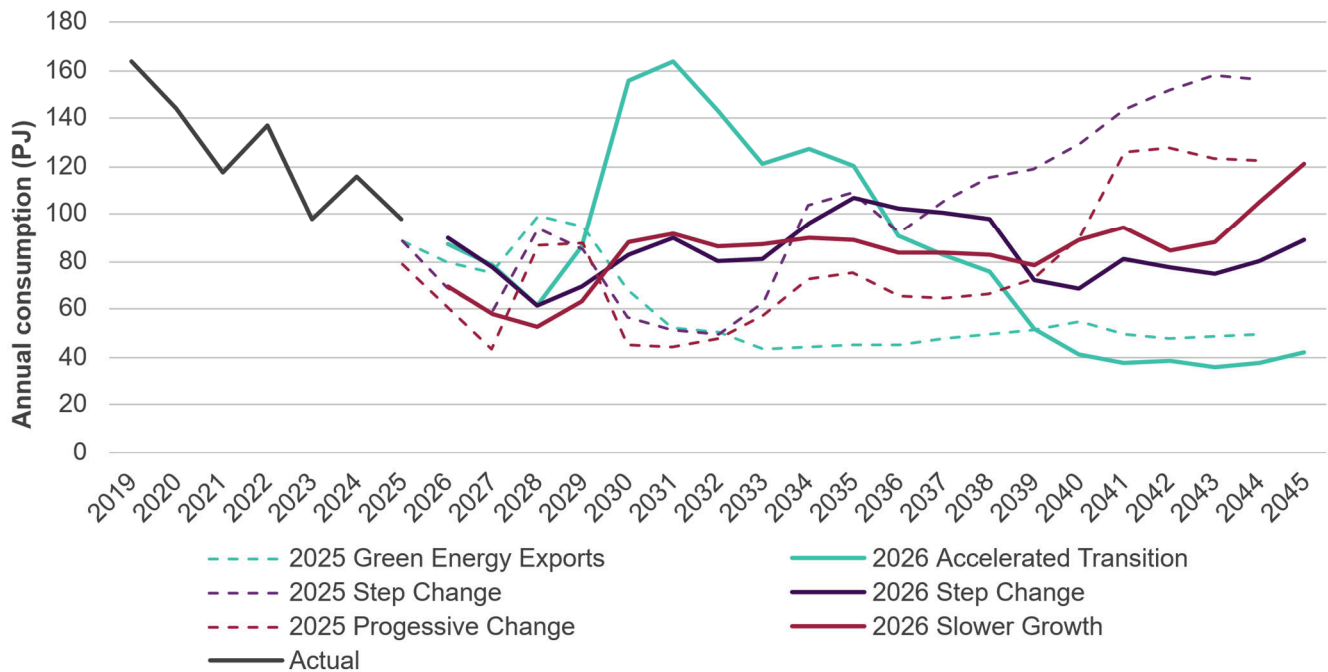
Annual GPG consumption has fallen in recent years as its role in the NEM has been changing. Under two of the three scenarios, it is now forecast to stabilise at around half of the 2019 level, with year-to-year fluctuations mainly driven by the

⁵⁹ The gas generation forecasts differ marginally to those presented in the Draft 2026 ISP, including those presented in Appendix 10 Gas Development Projections. The 2026 GSOO included existing, committed and anticipated generation capacity information from NEM October 2025 Generation Information (<https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information>), including Eraring's closure data in 2029, and 2025 ACIL Allen fuel price forecasts. Forecasts excluded the Yarwun (near Gladstone) and Diamantina (Mt Isa) power stations in Queensland and were averaged across different historical weather patterns. Yarwun and Diamantina were excluded because they were instead included in the industrial load forecast. While Yarwun is NEM connected, Diamantina is not. The forecasts in the GSOO are presented on a calendar year rather than a financial year basis.

⁶⁰ The GSOO applied delays to projects classified as either 'under construction' and as 'anticipated', consistent with the approach applied in the NEM Electricity Statement of Opportunities (ESOO) methodology, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2025/esoo-and-reliability-forecast-methodology.pdf.

timing of coal closures. **Figure 21** shows actual and forecast annual GPG usage for the three scenarios and compared to the 2025 GSOO.

Figure 21 Actual and forecast NEM and Northern Territory GPG consumption, by scenario, average of reference years 2014-2024, 2019-45 (PJ)



Compared to the 2026 GSOO’s *Step Change* scenario:

- The *Accelerated Transition* scenario is forecast to have higher GPG consumption in the mid-2030s as accelerated coal closures and electricity load growth increases the use of GPG, until greater renewable generation, transmission and electricity storage projects can be commissioned (aligned to the Draft 2026 ISP developments in this scenario).
- The *Slower Growth* scenario has similar GPG consumption to *Step Change* due to a similar level of coal capacity available (aligned to the Draft 2026 ISP developments in this scenario).

The timing of coal closures has a key influence on GPG needs. For this 2026 GSOO, AEMO applied coal closures:

- on the *closure date* when one has been provided by power station operators, or
- on a date after the winter peak period⁶¹ for generators when only a *closure year* has been provided by power station operators.

Where the Draft 2026 ISP forecasts the earlier closure of generators, that earlier closure has been applied, consistent with the Draft 2026 ISP.

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

⁶¹ If coal generators retire during the winter peak day demand period, greater GPG consumption is anticipated than if the coal generators remain operational over the season.

Figure 22 Actual and forecast NEM and Northern Territory GPG annual consumption (PJ/y) and seasonal maximum daily demand (TJ/d), Step Change scenario, 2019-45

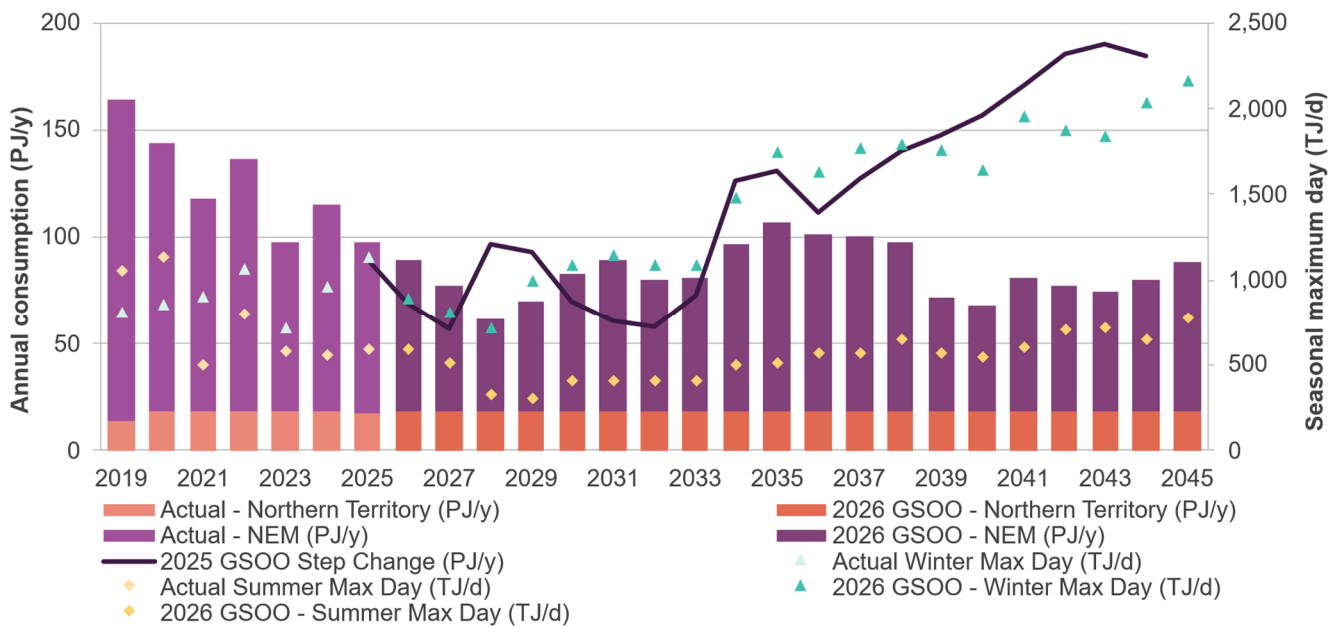


Figure 22 shows that in the short term, during the period to 2028:

- Annual GPG consumption is expected to decline as new electrical storage capacity continues to connect to the NEM, reducing the frequency of need for GPG to firm other electricity supplies. GPG is forecast to reach a low of 61 PJ/y in 2028 on an average weather year basis.
- The temporary extension of the operating life of the Eraring Power Station in New South Wales has materially contributed to a lower forecast for GPG compared to the 2025 GSOO. Eraring Power Station is now assumed to operate to its recently revised retirement date of April 2029 (previously August 2027)
- GPG is forecast to continue to peak in winter, which has been observed since 2021, with maximum winter demands ranging between 700 terajoules per day (TJ/d) and 900 TJ/d. Peak day demands are, however, projected to trend downwards in the short term as grid-scale batteries and hybrid renewable energy and storage systems continue to rapidly develop prior to the next announced coal generator closures of Yallourn and Eraring in 2028 and 2029 respectively. The commissioning of Snowy 2.0 is also expected to reduce reliance on GPG demand, providing new long-duration storage for the NEM.

In the medium term, between 2028 and 2038:

- GPG consumption is forecast on an average weather year basis to rise to between 60 PJ/y and 100 PJ/y, due to lower coal generation availability in the NEM after the retirement of Yallourn and Eraring power stations in 2028 and 2029 respectively, and the subsequent coal closures in the 2030s projected in the Draft 2026 ISP. While this coal generation capacity is expected to be replaced by investments in variable renewable energy (VRE) and electrical storage, GPG consumption is still forecast to increase to provide firming and security services for the NEM, and support rising electricity consumption and peak day demands.

- The forecast shows winter peak day demand rising to approximately 1,850 TJ/d in this period, due to the greater need for GPG in providing sustained electricity supply adequacy during longer periods of low VRE operation and/or coal unavailability, while the summer peak day demand remains at a similar level to previous years.

In the long term, beyond 2038:

- Annual GPG consumption is forecast to stabilise between 60 and 110 PJ/y, subject to prevailing weather patterns.
- Winter peak day demand is forecast to continue to gradually rise, with GPG continuing to provide firming generation as electricity demand increases with the electrification of heating loads.
- The forecast for this period is lower than the 2025 GSOO, driven by changes in the Draft 2026 ISP compared to the 2024 ISP used as the basis for the previous GSOO. The changes include:
 - longer assumed operation of coal generation capacity throughout the horizon, particularly in Queensland,
 - faster declines in the cost of new electricity storage, resulting in higher storage capacity which is expected to operate ahead of peaking GPG in the NEM's dispatch merit order (total electrical storage capacity in the Draft 2026 ISP is now expected to be approximately three times the GPG capacity, on a gigawatt basis, by 2035), and
 - an increased proportion of solar developments compared to wind in the VRE generation mix, which reduces the duration of GPG needs as the NEM is less exposed to prolonged wind droughts.

In summary, the major drivers of the GPG forecast in the NEM are:

- the rapidly changing role of GPG from a consistent mid-merit generator to a seasonal firming generator, and
- the evolving role of GPG in the context of other sources of firming generation.

More detailed discussion of these key drivers is in Appendix A2.

2.4.2 Forecast variance in GPG consumption and variability

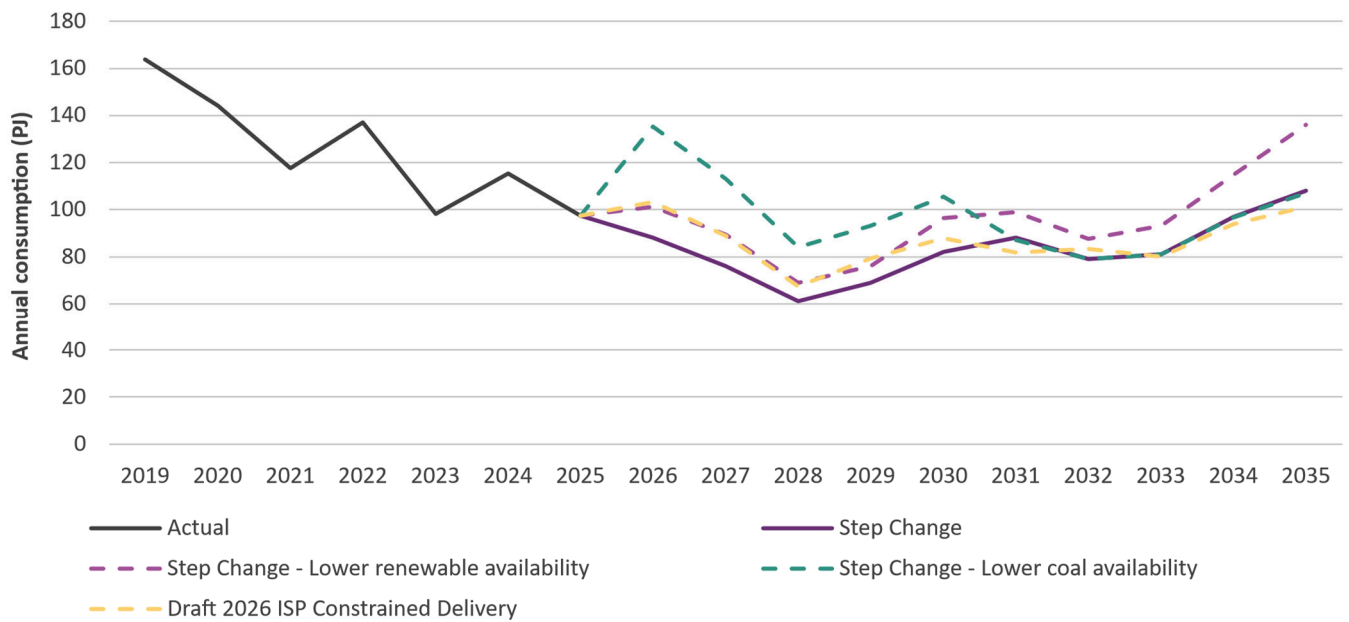
Impact of unforeseen events

GPG consumption has overall shown a declining trend since 2019, but several spikes in consumption have occurred as a result of unforeseen events in recent years, such as coal fuel supply disruptions, unplanned outages of coal generators and major electricity transmission lines, and low renewable energy production.

To demonstrate the resulting impact on gas supply needs for GPG under unforeseen events, AEMO has explored three sensitivities that explored plausible events. These sensitivities were designed and modelled prior to the recent geopolitical events in the Middle East, and in no way represent a projection of the impact this current situation may have on gas supply adequacy in the ECGM.

Figure 23 shows the higher volumes of gas that would be needed under the sensitivities explored to support electricity system operations, which may translate to gas sector risks if insufficient gas supply headroom is available. These events could occur in any year, though would not be expected to apply every year. The figure demonstrates the changing level of impact over time, with risk exposure typically reducing as the NEM develops more renewable generation with greater geographic and technical diversity.

Figure 23 Actual and forecast NEM and Northern Territory GPG consumption, sensitivities to Step Change scenario, 2019-35 (PJ)



In comparison to the *Step Change* scenario:

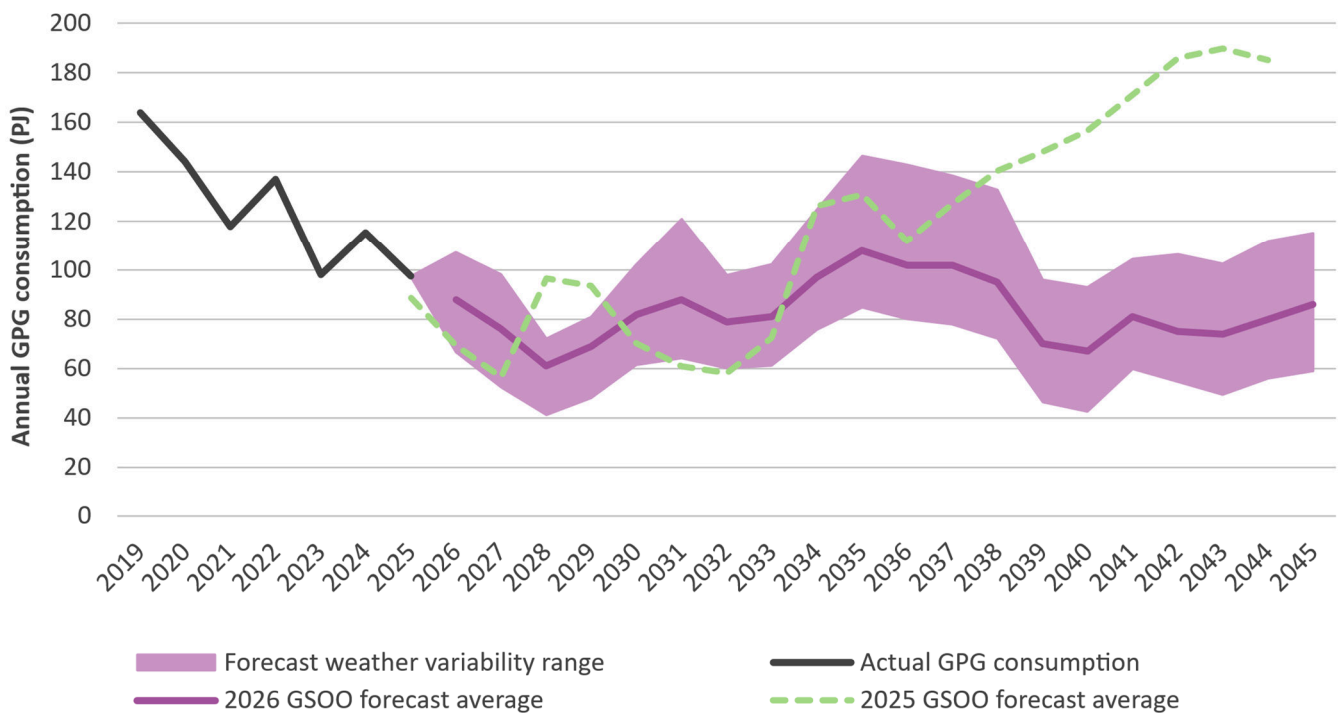
- Step Change – Lower renewable availability** assessed the impact of a prolonged rainfall drought similar to the Millennium Drought (2006-07) that resulted in approximately 45% lower inflow yield than an average year, in conjunction with the low VRE availability in winter observed in 2011⁶². Consequently, annual GPG is forecast to be up to 32% higher in weather events with similar features. While it is extremely unlikely that low water storage reservoir inflows will occur in all years, the sensitivity demonstrates the greater need for GPG in any year if reservoir inflows were at extremely low levels in conjunction with periods of very low VRE availability in winter.
- Step Change – Lower coal availability** assessed the impact of key coal power plant outages similar to those observed in 2022. In 2022, various conditions affected the availability of coal (see Appendix Section A1.5 for details). In such conditions, GPG demand could be up to 55% more than the forecast average consumption in *Step Change*. The impact of this sensitivity reduces later in the outlook period as coal generation is projected to retire and be replaced with alternative forms of generation and, as such, the availability of the remaining fleet has a lower impact on forecast GPG requirements.
- Draft 2026 ISP Constrained Delivery** is a sensitivity from the Draft 2026 ISP that explored the impact of supply chain or other constraints that may delay the delivery of electrical transmission, generation and storage projects in the NEM. More coal generation in this Draft 2026 ISP sensitivity is needed to operate for longer than the *Step Change* scenario (but not beyond any generator’s currently announced closure date), due to the slower delivery of new replacement generation from VRE. The impact of lower renewable generation development is greater than the higher temporary coal availability for most reference years, leading to GPG consumption to be up to 17% higher than in *Step Change*.

⁶² This sensitivity involved deliberately manipulating weather outcomes to explore extreme outcomes. To model this sensitivity, the weather patterns for multiple reference years were combined to achieve more impactful weather conditions on the GPG forecast than the individual reference years on their own.

Weather variability

AEMO used a range of different weather patterns⁶³ from a spread of historical weather conditions to generate the GPG forecast. **Figure 24** shows the range of projected annual GPG usage outcomes resulting from weather-driven variation affecting electricity demand, wind and solar availability, and inflows to hydro reservoirs. As this figure shows, material variation is possible each year, depending on the prevailing weather conditions and the availability of coal generation.

Figure 24 Actual GPG consumption and forecast variation in consumption due to weather conditions, Step Change scenario, 2019-45 (PJ)



The trends observed are:

- The forecast range of GPG outcomes increases in the 2030s, showing that the projected impact of weather variability increases as coal generation retires through this period. The figure demonstrates greater upside risk around the average than downside risk, indicating that extreme weather events require disproportionately more GPG usage than the average.
- The impact of weather variability on forecast GPG consumption stabilises in the 2040s as new generation, electrical transmission and storages continue to be built as outlined in the Draft 2026 ISP. Variability in the long term remains higher than the short term due to the increasingly VRE-dependent system, but the reduced volatility relative to the 2030s suggests that more NEM storage development and the continued development of CER will soften the volatility to some extent.

The weather pattern observed in 2024, consisting of protracted low wind conditions and low precipitation yields across the southern and eastern regions, is the primary contributor to the upper range of weather variability.

⁶³ AEMO simulated weather patterns from 2014 to 2024 for the 2026 GSOO.

3 Gas supply and infrastructure forecasts

This section provides an overview of 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

- The sum of reported reserves and resources from existing, committed and anticipated fields has increased since the 2025 GSOO, reflecting an increasing proportion of anticipated volumes in the north and greater potential resources from prospective and uncertain supply projects.
- Compared to the forecasts provided for the 2025 GSOO, from 2026 to 2030, southern producers now forecast that annual southern production from existing, committed and anticipated fields will be lower, except in 2027 and 2028. In 2030, producers anticipate 8 PJ less production than their expectations in the 2025 GSOO.
- Consistent with the downward trend outlined in the 2025 GSOO, southern production is still forecast by producers to decline significantly, from 318 PJ in 2026 to 170 PJ in 2030.
- Northern production is forecast by producers to be higher than the 2025 GSOO, driven by improved forecasts from the Queensland LNG producers and committed production from the Beetaloo sub-basin for domestic usage in the Northern Territory.

3.1 Changes since the 2025 GSOO

Infrastructure developments progress since the 2025 GSOO

Since the 2025 GSOO, additional investments are increasing the forecast supply and transport infrastructure expected to service the ECGM:

- Tamboran’s pilot development at **Shenandoah South** in the Beetaloo sub-basin in the Northern Territory has progressed from uncertain to committed status, with an initial expected production of up to 40 TJ/d from mid-2026⁶⁴. APA’s **Sturt Plateau Pipeline** project to transport this gas to the Amadeus Gas Pipeline is also considered committed. Construction on the pipeline started in November 2025⁶⁵ and is scheduled to be completed in 2026⁶⁶.
- APA Group’s **East Coast Gas Grid (ECGG) Expansion Plan Stage 3A** is now considered committed⁶⁷. This includes the following projects which are committed to be available from winter 2028:
 - An additional compressor on the **SWQP** is expected to provide an additional 58 TJ/d capacity from Wallumbilla to Moomba.
 - An additional compressor on the mainline **Moomba Sydney Pipeline (MSP)** is expected to provide an additional 10 TJ/d capacity from Moomba. This is in addition to the relicensing of APA’s **Moomba Sydney Ethane Pipeline**

⁶⁴ See <https://ir.tamboran.com/news-events/press-releases/detail/31/tamboran-reaches-final-investment-decision-on-its-shenandoah-south-pilot-project>.

⁶⁵ See <https://apa.com.au/news/asx-and-media-releases/apa-commences-construction-of-the-sturt-plateau-pipeline>.

⁶⁶ See <https://www.apa.com.au/operations-and-projects/gas/gas-transmission/sturt-plateau-pipeline-spp-project>.

⁶⁷ See <https://www.apa.com.au/news/asx-and-media-releases/apa-to-deliver-pipeline-capacity-needed-to-solve-projected-east-coast-gas-shortfalls>.

(MSEP) to a natural gas pipeline, which was already considered committed in the 2025 GSOO, and will provide an additional 25 TJ/d capacity on the MSP from mid-2026.

- An additional compressor on the **Young to Culcairn lateral of the MSP** is expected to provide an additional 39 TJ/d capacity towards Victoria.

Projects that are under construction or have recently completed construction

The following projects will contribute to additional supply capacity once construction is complete, and were already considered committed or anticipated in the 2025 GSOO:

- APA Group's **Kurri Kurri Lateral Pipeline (KKLP)**⁶⁸ project is a gas transmission and shallow storage facility near Newcastle. KKLP provides 72 TJ storage capacity for Hunter Power Station 60 TJ/d peak day supply capacity into the ECGM. The pipeline was completed in June 2025.
- Senex Energy's **Roma North (Mimas) gas processing facility** came online in 2025⁶⁹, providing processing capacity of 28.5 TJ/d.
- The **MSP off-peak capacity expansion project** will increase the MSP capacity in summer months by 80-120 TJ/d at times when pipeline maintenance is being undertaken in specific sections of the MSP. Work to complete the project is ongoing and is scheduled to complete by November 2026.
- Lochard Energy's **HUGS** expansion project (HUGS Project Phase 1)⁷⁰ at Iona UGS will increase storage inventory capacity by 1.8 PJ, and supply capacity by 45 TJ/d, from 2027.
- The **Carpentaria Pilot Project** in the Beetaloo sub-basin in the Northern Territory has reached final investment decision (FID)⁷¹ and changed from anticipated to committed status, with an initial expected production of 9.5 TJ/d from mid-2026 which will increase to 25 TJ/d, or 9.1 PJ/y, from 2027.
- Construction has commenced at Arrow Energy's **Girraheewen Field Compression Station**, which will process gas from Surat Gas Project. The facility will have a processing capacity of 121 TJ/d and is expected to be online in 2027.

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 2026 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 producers' current best estimates of their expected production capability, they remain exposed to technical and broader development risks, and the normal challenges of providing forecast accuracy over the short, medium and long term.

AEMO's GSOO forecasts of gas supply reflect the best advice and updated data provided to AEMO from producers. The surveys for the 2026 GSOO were conducted for most gas producers in September 2025. Any material changes that occurred

⁶⁸ See <https://www.apa.com.au/operations-and-projects/gas/gas-transmission/kurri-kurri-lateral-pipeline-kklp-project>.

⁶⁹ See <https://senexenergy.com.au/wp-content/uploads/2025/12/End-of-year-update-2025.pdf>.

⁷⁰ See <https://www.lochardenergy.com.au/our-projects/hugs/>.

⁷¹ See <https://app.sharelinktechnologies.com/announcement-preview/asx/68a9727d9a44fce9538d38ddd85b10b>.

after the survey responses and were provided to AEMO before the end of February 2026 have been reflected in this GSOO. Project proponents provide consideration of project development lead time in their survey advice.

AEMO applies the following project classifications, with gas field development projects also utilising the Petroleum Resources Management System (PRMS)⁷² to support the classification system. This allows consistent comparison of all projects within the gas supply chain (including field development, new supply projects, renewable gas opportunities, LNG regasification terminals, and infrastructure projects):

- **existing and committed** – gas fields and infrastructure that are already operating or have obtained all necessary approvals, with project 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 FID made, and
- **uncertain** – these projects are at earlier stages of development or face challenges in terms of commercial viability or approval.

For more information, refer to the 2026 *Gas Supply Adequacy Methodology Information Paper*⁷³.

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 resources 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.

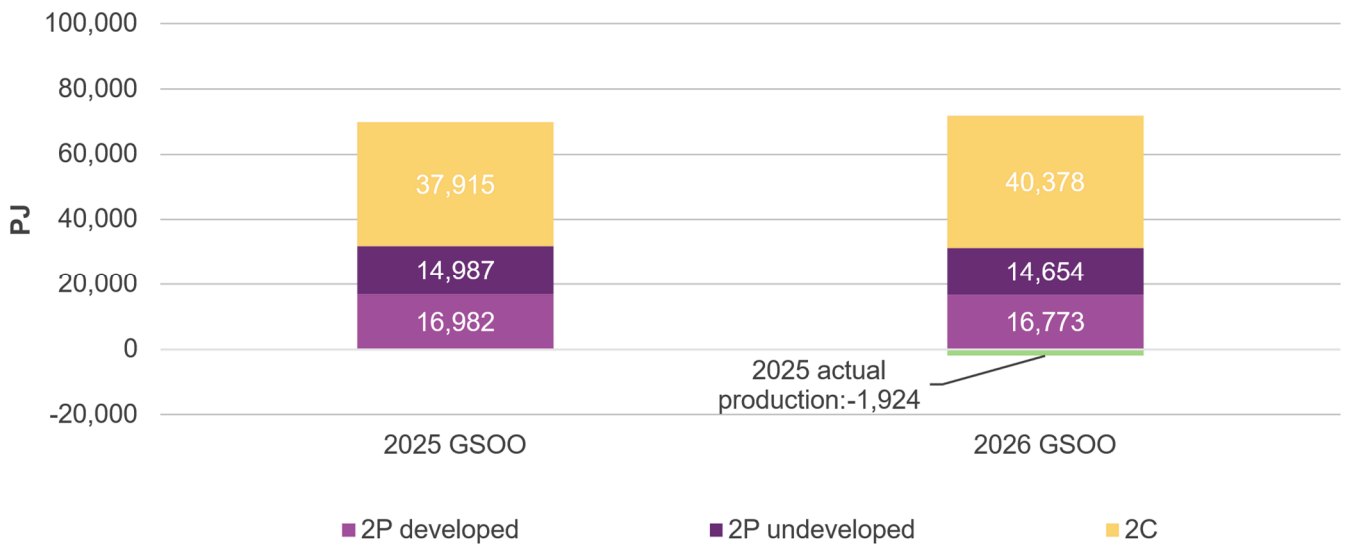
The reserves and resources estimate for the 2026 GSOO includes all major fields connected to the ECGM, excluding only the fields in the Northern Territory developed specifically for LNG export. The volume of the estimated reserves and resources may change over time as they are developed, reassessed, or depleted.

Figure 25 shows an uplift in total 2C volumes compared to the 2025 GSOO. Even though 1,924 PJ of gas was produced in 2025, 2P volumes have only declined by 542 PJ, indicating an underlying uplift in reported volumes after accounting for production.

⁷² The PRMS for defining reserves and resources was developed by an international group of reserves evaluation experts and endorsed by the World Petroleum Council, American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers, and Society of Exploration Geophysicists.

⁷³ See https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2026/2026-gsoo-methodology-supply-adequacy.pdf.

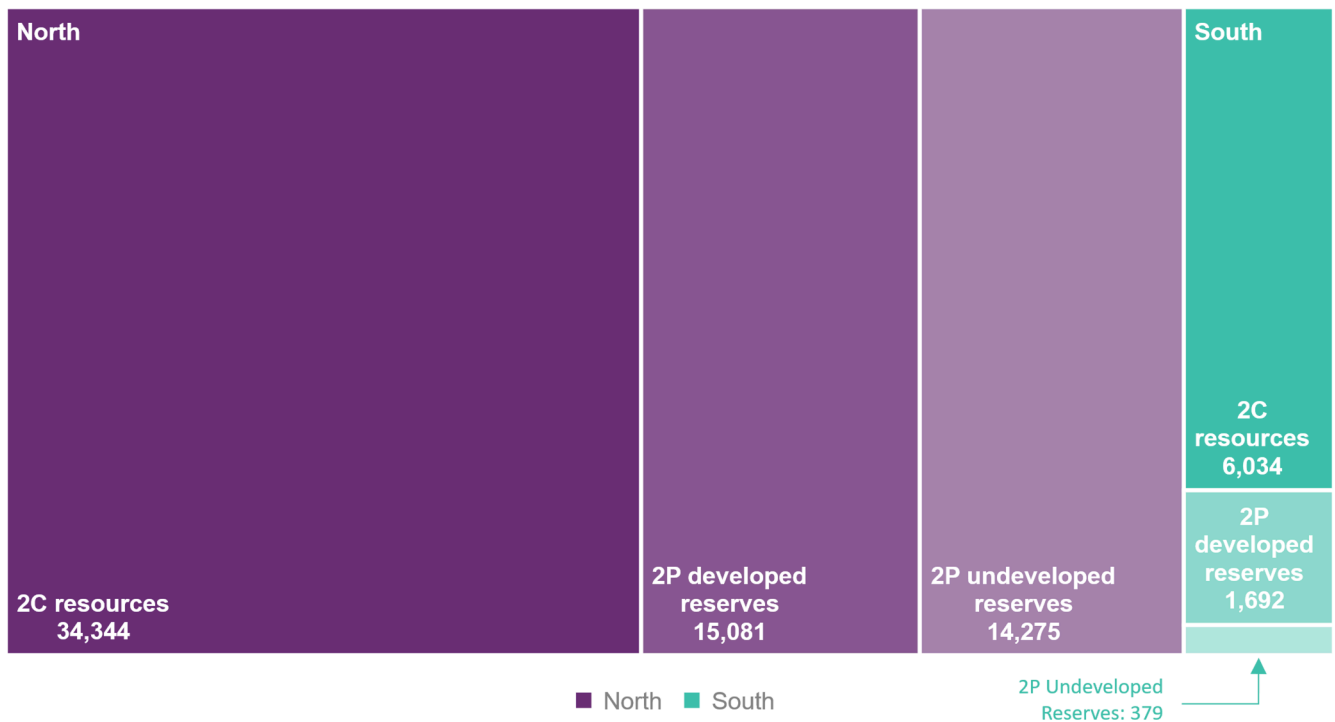
Figure 25 Reserves and resources reported in the 2025 GSOO compared to the 2026 GSOO (PJ)



Note: 2025 GSOO data in this chart represents Gas Bulletin Board (GBB) data extracted on 27 January 2025. 2026 GSOO data in this chart represents GBB data extracted on 2 March 2026.

Figure 26 shows that the majority of 2P reserves and 2C resources are in the north, with around 70% of 2P developed and undeveloped reserves in the ECGM controlled by Queensland’s LNG producers, while southern regions are experiencing a continued decline in reserves and resources.

Figure 26 Split of reserves and resources across northern and southern regions for the 2026 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 CO₂),
- 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), and
- the quality of the gas, particularly in terms of the need for additional processing.

Table 8 shows the annual production forecast from existing, committed and anticipated fields from 2026 to 2030, as advised to AEMO by gas producers.

Table 8 Forecast of available annual production as advised by gas producers, 2026-30 (PJ)

	Commitment criteria	2026	2027	2028	2029	2030
North (NT ^A and QLD)	Existing and committed	1,549	1,523	1,434	1,347	1,213
	Anticipated	35	69	163	239	287
	Total	1,584	1,592	1,597	1,585	1,500
	Difference from 2025 GSOO ^B	-17	25	33	54	28
South (VIC, NSW, SA ^C)	Existing and committed	292	290	252	179	142
	Anticipated	26	29	31	29	28
	Total	318	319	283	208	170
	Difference from 2025 GSOO ^B	-12	13	5	-11	-8
Total gas production in the ECGM		1,903	1,912	1,880	1,793	1,670
Total difference from 2025 GSOO		-30	38	39	43	19

A. Northern Territory supply excludes gas production from LNG export facilities in Darwin.

B. Annual volume figures in the north and south, as published in the 2025 GSOO, have been adjusted due to a data input error. This correction has minimal impact on the supply adequacy assessment as volumes remain constrained by the maximum daily quantity.

C. The Queensland component of the Cooper Eromanga basin appears in the South Australia category.

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 2025 GSOO. This production figure is in close alignment with that published by the Australian Competition and Consumer Commission (ACCC) in its December 2025 Gas Inquiry 2017-2030 Interim Report⁷⁴.

⁷⁴ ACCC. Gas Inquiry December 2025 interim report, at <https://www.accc.gov.au/system/files/gas-inquiry-december-2025-interim-report.pdf>.

- Southern⁷⁵ gas production is forecast to decrease by over 46% over the next five years (from 318 PJ to 170 PJ), driven by depleting legacy gas fields in the Gippsland region. Compared to the 2025 GSOO, southern producers expect to supply less gas for all years in this period except 2027 and 2028.
- In the north, gas producers’ production estimates from existing, committed and anticipated sources are higher from 2027 onwards compared to the 2025 GSOO (also shown in **Figure 28**). The total existing and committed, and anticipated volumes holds steady over the five-year period, with an increasing proportion of anticipated volumes.

Figure 27 shows that in the early 2030s, southern producers are expecting to produce higher quantities of gas from existing, committed and anticipated facilities compared to their previous expectations in the 2025 GSOO. The variations from last year’s forecast through to the mid-2030s are influenced by:

- higher production from the GBJV fields during Longford Gas Plants’s final years of operation and higher production forecast from the Orbost Gas Plant and Lang Lang Gas Plant,
- a forecast improvement in Cooper Basin reserves and resources from the early 2030s based on actual field performance and the latest project and development schedule, and
- Beach Energy’s downward revision of the reserves estimates for the Thylacine West and Enterprise fields in the Otway basin. The lower production estimates resulting from lower reserve quantities are most pronounced in years 2029 to 2031, although with a small increase in expected supply for the years 2027 and 2028 only.

Figure 27 Actual and forecast annual production from southern gas fields (excluding potential supply from LNG regasification terminals), 2022-45 (PJ)



Figure 28 shows that northern producers have reported higher expectations for existing, committed and anticipated production compared to the 2025 GSOO due to improved forecast supplies from the LNG producers. Higher quantities of

⁷⁵ Southern gas production refers to fields and plants located downstream of the Southwest Queensland Pipeline (SWQP) and includes gas supply from the Cooper Eromanga basin.

uncertain northern gas in the 2030s are included in the 2026 GSOO with the new inclusion of contingent resources in the Taroom Trough (located in the Bowen Basin).

Figure 28 Actual and forecast annual production from northern gas fields, 2022-45 (PJ)



3.2.3 Annual contracted supply

Annual contracted supply volumes provided by gas producers via the GSOO surveys provides a view of current firm gas commitments in the ECGM.

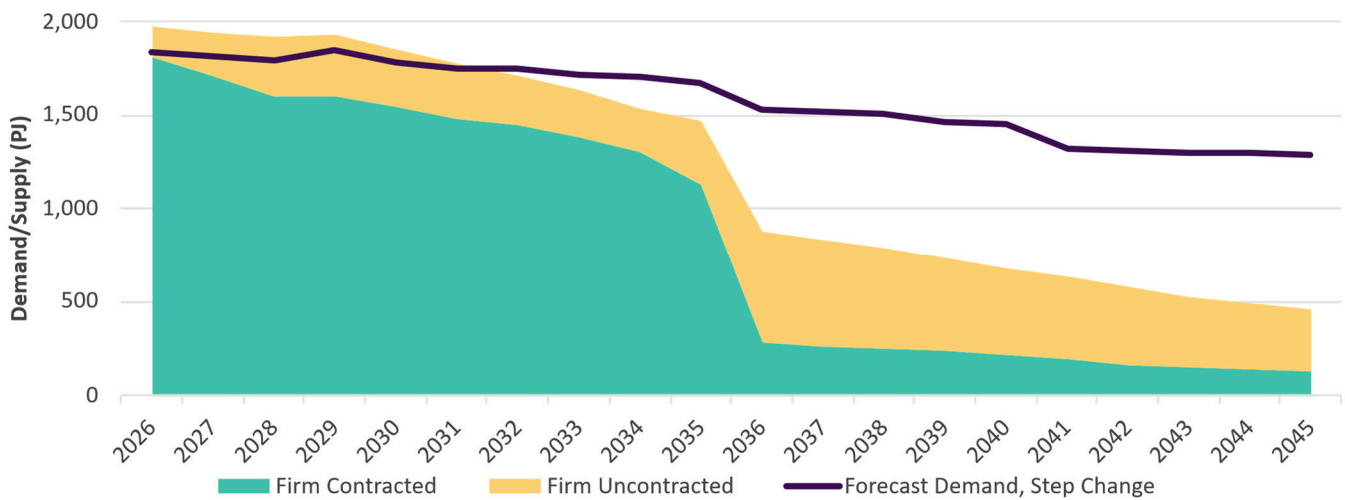
A contract for firm supply of gas between a user and a producer (firm contracted supply) means supply must be made available according to the terms of the contract. Firm contracted supply from each producer is not necessarily equal to their production forecast, so the analysis in this section alone does not provide a definitive overall assessment of domestic supply adequacy, and these contracts were not used for the physical gas adequacy assessment in Section 4.

When supply is firm, but no contract exists for the corresponding production (firm uncontracted supply), supply is assumed to be available. Firm uncontracted supply may be sold on domestic spot markets or supply hubs or sold to LNG exporters and sold overseas. Gas sold on domestic spot markets or supply hubs will tend to attract a higher price at times of high demand or constrained supply. Alternatively, for some facilities that have the capability to do so, uncontracted supply may remain unproduced and the production of reserves delayed to a later time.

Figure 29 shows most supply is subject to firm contracts in 2026, with further uncontracted supply available to meet forecast demand, followed by a growing gap between contracted supply and forecast consumption. Producers generally need firm contracts or gas supply agreements (GSAs)⁷⁶ with customers to lower investment risks and bring new gas supply to market. Without firm contracted customers, supply uncertainty remains, which presents a significant challenge to de-risking new upstream supply projects.

⁷⁶ A GSA means an agreement under which one party agrees to sell and supply and another party agrees to purchase and take delivery of gas, and may include any arrangements for quantity, delivery point(s), nominations/scheduling, pricing and payment.

Figure 29 Firm contracted and firm uncontracted contract quantities for all producers (including LNG producers) in comparison to forecast demand, Step Change scenario, 2026-45 (PJ)



Contract information in this chart is based on information provided to AEMO as part of 2026 GSOO survey submission, collected by 30 September 2025. It does not include contracts entered outside of the official survey submission cycle, such as the contract between Santos and the South Australian Government for 20 PJ/y of gas from 2030 to be supplied into the domestic market⁷⁷, although this contract quantity was considered in the supply adequacy assessment as available production at Moomba Gas Plant.

The chart also shows a large step in firm contract quantities between 2035 and 2036. This reflects the conclusion of the foundational LNG export contracts and, as discussed in Section 2.2.3, is followed by a period of higher uncertainty. **Contract quantities in this GSOO do not consider the impact of the domestic gas reservation scheme or any other consequences relating to this policy.**

3.2.4 Maximum daily production capacity

Maximum daily production capacity defines the quantity of 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 often 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 midstream infrastructure to deliver this gas to demand or storage facilities is the other major factor in determining the gas supply adequacy assessments in Section 4.

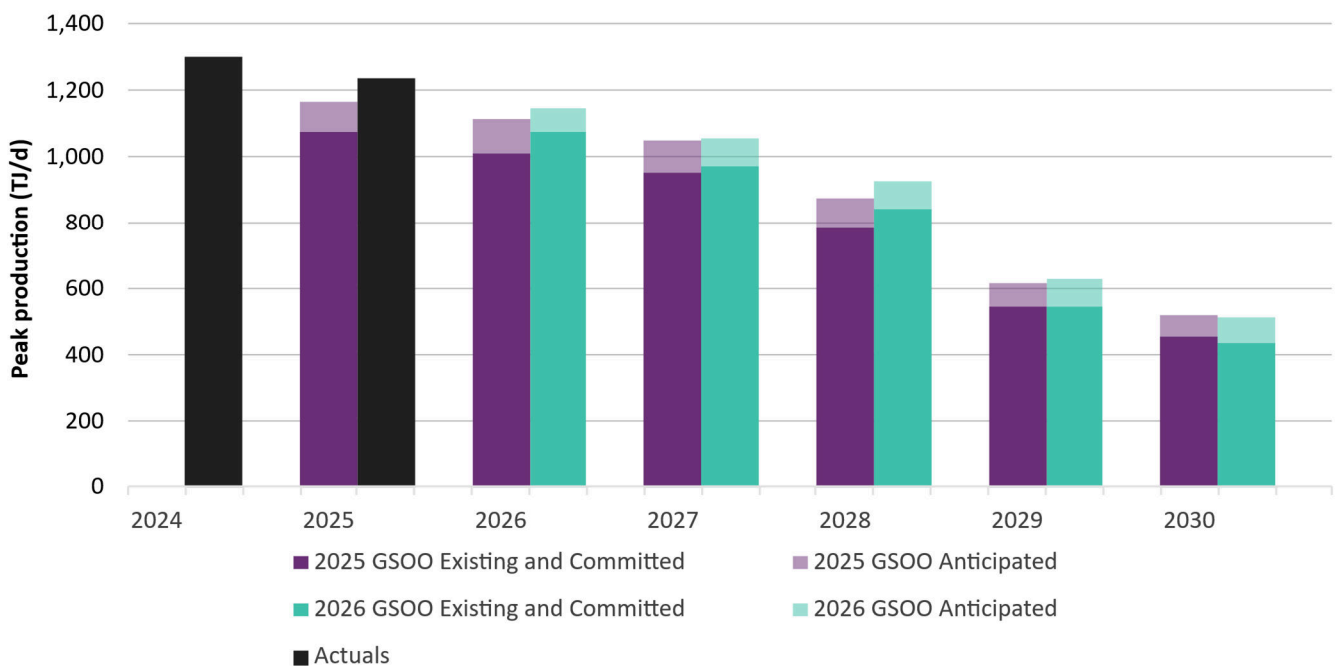
Southern daily production capacity

Figure 30 shows actual maximum daily gas production in 2024 and 2025 from southern gas fields and the advised daily maximum production capacity in winter forecast by producers for each year to 2030:

⁷⁷ See <https://www.santos.com/news/santos-agrees-key-terms-with-south-australian-government-for-200pj-of-gas-over-10-years-from-2030/>.

- The maximum daily production capacity⁷⁸ from existing, committed and anticipated southern fields is projected to decrease by 55% from 1,146 TJ/d in 2026 to 517 TJ/d in 2030. This reflects a continuing and significant declining trend in both annual and daily production as southern fields deplete.
- In the short term, forecast maximum daily production capacity from existing, committed and anticipated southern supplies is slightly higher than expected in the 2025 GSOO, due to field performance and production facility operational assumption changes.

Figure 30 Actual and forecast maximum daily production capacity from southern gas fields in June, 2024-30 (TJ/d)



The maximum daily production capacity can be constrained by outages or operational issues. As southern production tightens, redundancy in plant capacity is increasingly important for supply resilience.

One of the key southern production facilities, Longford Gas Plant, historically operated with three gas plants until the shutdown of Gas Plant 1 in 2024. GBJV informed AEMO that operation of one of the two remaining plants, Gas Plant 3, is now expected to continue beyond December 2028 and planned to be in operation until 2033, increasing onshore redundancy compared to the 2025 GSOO. For 2029 to 2033, the increase in plant nameplate capacity⁷⁹ will not be reflected in the available production capacity because the plant will be limited by offshore field capacity.

More information on Longford Gas Plant operations is in Section 3 of the 2026 VGPR Update.

⁷⁸ 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.

⁷⁹ The extension of Gas Plant 3 results in Longford’s nameplate capacity increasing from 420 TJ/d to 720 TJ/d from 2029 until 2033. If either of the two 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, daily 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 broadly proportional to annual production. Northern gas fields are currently operated predominantly for LNG export demand and domestic demand from local northern customers does not vary seasonally.

3.2.5 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, and
- **development wells**, which facilitate gas extraction through optimised reservoir management.

As part of the 2026 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:

- an expected decline in drilling activity for development wells in 2026 and the first half of 2027 compared to previous years, and
- the Surat and Bowen basins remaining 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 than conventional gas fields.

Figure 31 Historical and forecast number of development wells drilled, 2024 to June 2027

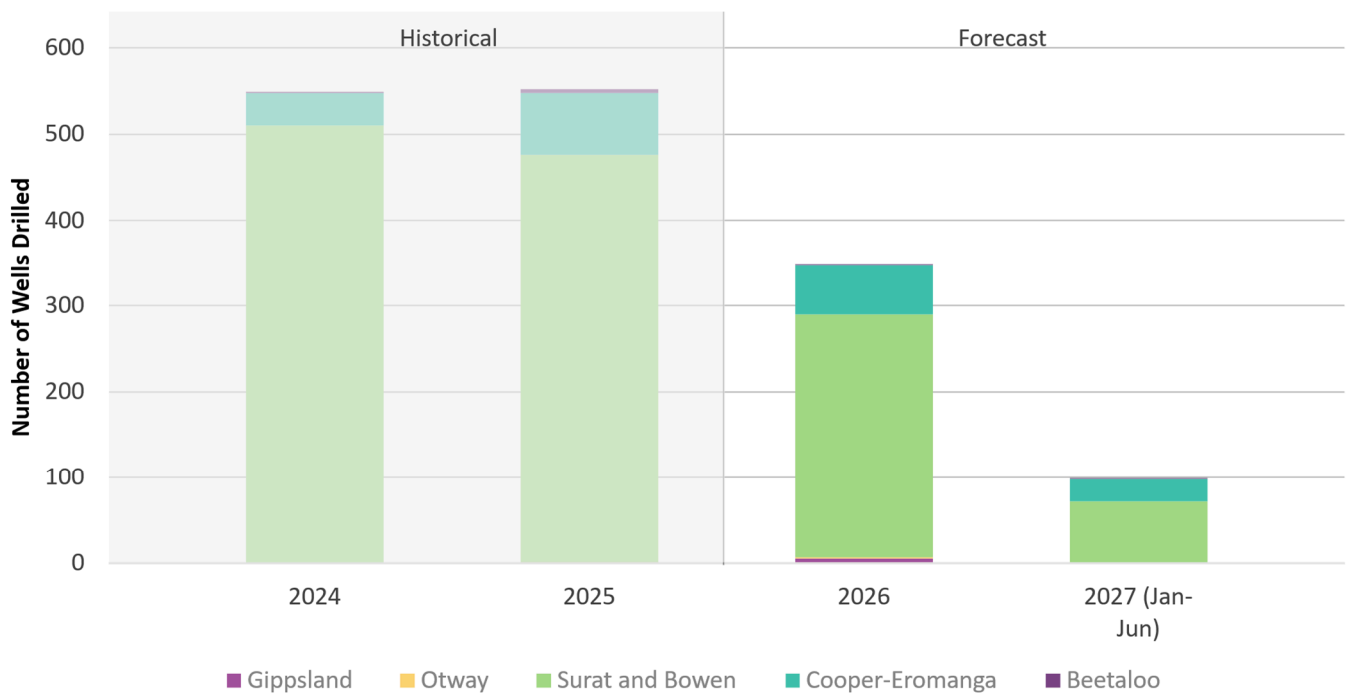
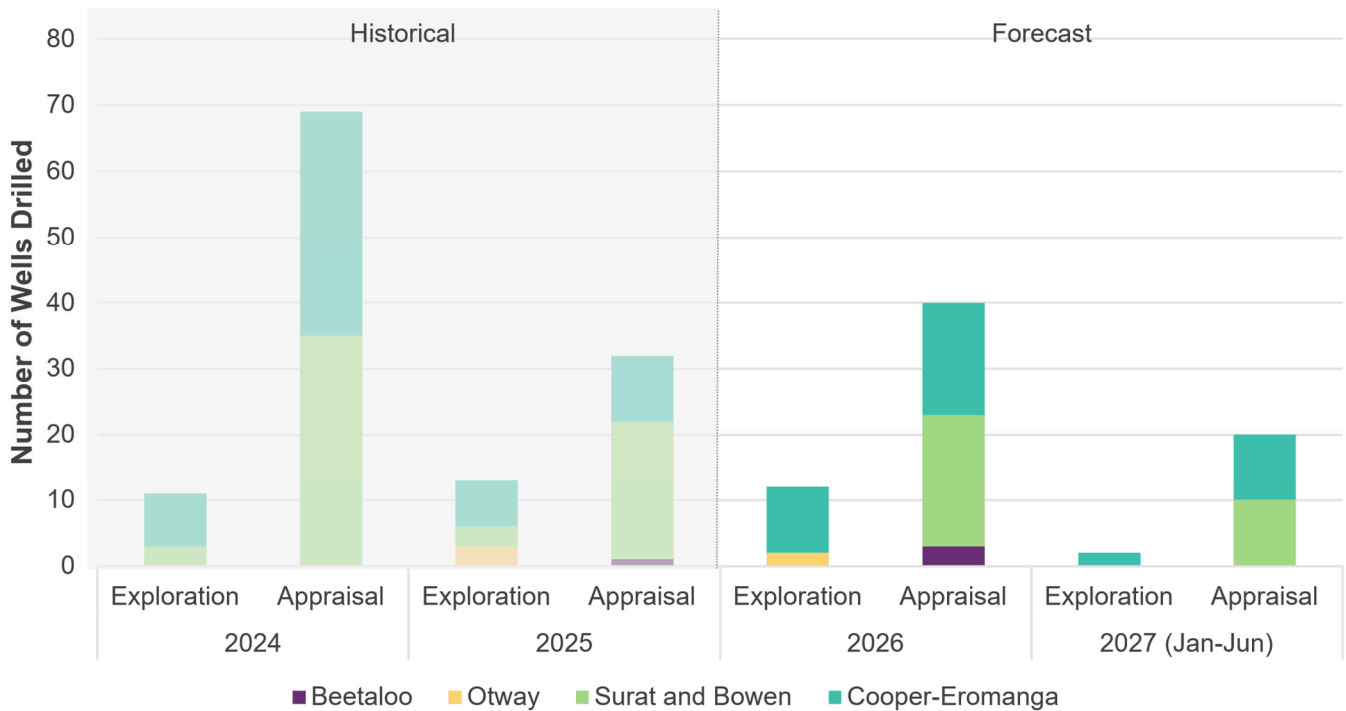




Figure 32 shows the historical and forecast year-on-year exploration and appraisal activity for all basins in the ECGM. Appraisal activity in 2026 is forecast to increase relative to 2025, whereas exploration activity is expected to slightly decrease.

Figure 32 Historical and forecast number of exploration and appraisal wells drilled, 2024 to June 2027



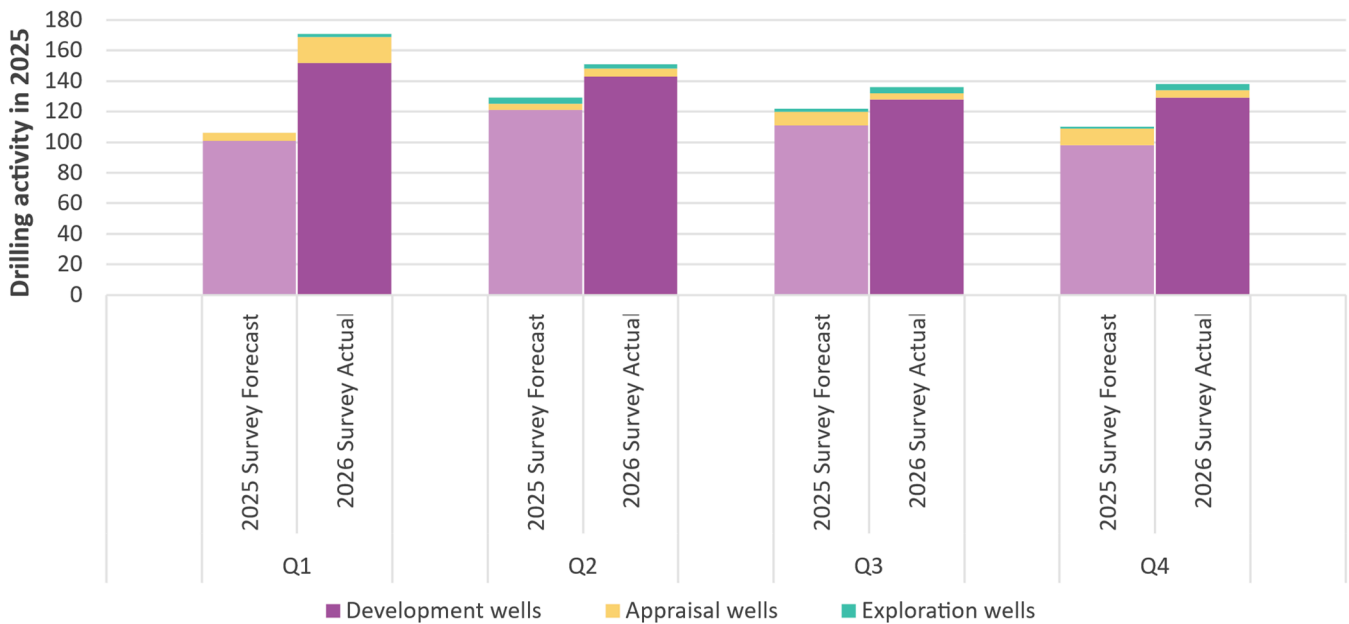
There is an ongoing drilling campaign at Otway Basin in which a consortium of gas producers (ConocoPhillips, Amplitude Energy and Beach Energy) contracted the Transocean Equinox drill rig to carry out their own or joint venture exploration drilling campaigns. If successful, the wells could connect to existing gas infrastructure near Port Campbell and help supply gas to the southern market later in the decade. For more information, see Section 5 of the 2026 VGPR Update.

On 20 February 2026, the South Australian Department of Energy and Mining announced grants for successful gas exploration projects under the 2025 SA Gas Initiative⁸⁰. The initiative aims to accelerate investment in gas projects in South Australia. These exploration projects were not included in the 2026 GSOO.

Figure 33 shows that the total number of actual wells drilled in 2025 (reported to AEMO in the 2026 GSOO survey process) was higher than the forecasts reported to AEMO in the 2025 GSOO survey process. Upstream development programs are dynamic and subject to change due to factors such as regulatory timing, capital allocation, supply chain constraints, workforce availability and weather. These factors could contribute to drilling activities being deferred or scaled back in 2024, as evidenced in the 2025 GSOO, with a portion of this activity shifting into 2025.

⁸⁰ See <https://energymining.sa.gov.au/industry/energy-resources/industry-activity/2025-sa-gas-initiative-grant-scheme>.

Figure 33 2025 GSOO survey forecast compared to 2026 GSOO survey actual number of wells drilled, 2025



3.2.6 Renewable gas opportunities

Renewable gas in the GSOO refers to:

- biomethane, which is methane produced by the anaerobic decomposition of organic matter and processed so it can be transported in existing gas networks (biomethane can be produced from multiple feedstocks, including agricultural and municipal waste streams, wastewater treatment facilities and forestry residues), and
- hydrogen produced via electrolysis using renewable energy (often referred to as green hydrogen).

While biomethane is a proven technology widely used in Europe⁸¹ 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 use⁸². As such, it would provide a decarbonisation alternative to electricity for industries that cannot easily electrify their industrial processes, should production be available.

The 2026 GSOO includes current and future supply from a small number of existing, committed or anticipated biomethane and hydrogen⁸³ projects. Examples of biomethane projects include Jemena’s Malabar biomethane project in New South Wales⁸⁴ and Delorean’s Edinburgh Parks in South Australia, while examples of hydrogen projects include Hydrogen Park, South Australia⁸⁵ and Hydrogen Park, Murray Valley in Victoria⁸⁶. Many of the additional proposed renewable gas supply projects identified in AEMO’s 2026 GSOO surveys still face various economic, regulatory, and technical uncertainties, so

⁸¹ See [https://energy.ec.europa.eu/topics/renewable-energy/bioenergy/biomethane_en#:~:text=The%20Biomethane%20Industrial%20Partnership%20\(BIP,of%20its%20potential%20by%202050](https://energy.ec.europa.eu/topics/renewable-energy/bioenergy/biomethane_en#:~:text=The%20Biomethane%20Industrial%20Partnership%20(BIP,of%20its%20potential%20by%202050).

⁸² See <https://www.dceew.gov.au/sites/default/files/documents/national-greenhouse-account-factors-2025.pdf>, page 19.

⁸³ Any behind-the-meter (distribution) hydrogen is subtracted from the covered gas forecast, that is, the forecast is net of this hydrogen production. Consumption directly connected to the ECGM has been included in the demand forecasts. Refer to the 2026 *Gas Demand Forecasting Methodology Information Paper* for more information.

⁸⁴ See <https://www.jemena.com.au/future-energy/future-gas/Malabar-Biomethane-Injection-Plant/>.

⁸⁵ See <https://www.agig.com.au/hydrogen-park-south-australia>.

⁸⁶ See <https://www.agig.com.au/hydrogen-park-murray-valley>.

accurately forecasting the timing and volumes of gas available from renewable sources is challenging. As an example, if the proposed projects overcame these challenges, the total biomethane volume across the ECGM would add up to approximately 12 PJ by 2030.

AEMO's 2025 IASR includes insights provided by ACIL Allen to forecast biomethane available volumes by feedstock type, state, and scenario. The supply adequacy assessment or extended analysis in Section 5 of the 2026 GSOO did not consider the ACIL Allen forecast volumes, as these forecasts represent only potential opportunities. They are not linked to any project proponent and therefore cannot be treated as committed, anticipated or uncertain developments. This ACIL Allen analysis⁸⁷ identified that over half of the biomethane potential supply may be developed from crop residues, while waste products offer another potential primary source. While survey responses for the 2026 GSOO included about 19 PJ/y of existing, committed, anticipated and uncertain biomethane production projects by 2032, ACIL considered that between approximately 100 PJ and 200 PJ of potential production in the ECGM may be feasible per annum, 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 terminals⁸⁸.

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 2026 GSOO.

3.3.1 Major gas transmission pipelines

This section highlights key pipelines that facilitate the transport of gas between the north and south as well as within southern regions and are integral to the supply adequacy assessment in Section 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. As part of APA's ECGG Expansion Plan Stage 3A, an additional compressor on the SWQP is expected to provide an increase of 58 TJ/d in capacity from Wallumbilla to Moomba from winter 2028. This part of APA's expansion project is considered to be committed in this GSOO.

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

⁸⁷ See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/2025-inputs-assumptions-and-scenarios-report.pdf?rev=63268acd3f044adb9f5f3a32b6880c27&sc_lang=en.

⁸⁸ LNG export terminals are considered consumers.

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.

At times, particularly in winter, the MSP will be flowing simultaneously towards Sydney via the mainline and towards Victoria via the VNI lateral. During simultaneous flows to Sydney and Victoria, the overall transport capacity of the MSP depends on the distribution of flow between Sydney and Victoria. In general, the total MSP capacity is higher when the quantities delivered via the mainline towards Sydney are higher.

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. The under-construction 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. Work is ongoing and is scheduled to be completed by November 2026. This project is expected to increase the off-peak capacity of the MSP by 80-120 TJ/d.

The conversion of APA's MSEP to a natural gas pipeline will add an additional 25 TJ/d capacity to the MSP from mid-2026. In addition, as part of APA's ECGG Expansion Plan Stage 3A, the following expansions are expected from winter 2028:

- an additional compressor on the mainline MSP which will provide an additional 10 TJ/d capacity from Moomba, and
- an additional compressor on the Young to Culcairn section of the VNI lateral which will provide an additional 39 TJ/d capacity towards Victoria.

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 used for transporting gas from Port Campbell and the Iona UGS facilities towards Melbourne, as well as supporting the refilling of the Iona UGS reservoir. It also 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 capacity of the SWP for transporting gas from Port Campbell to Melbourne varies depending on system demand, reaching its peak capacity on a 1-in-20 system demand day. The capacity for flow from Melbourne to Port Campbell is maximised on days of low demand.

Northern Gas Pipeline (NGP)

The NGP 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 supply gas to Mount Isa and eastern Australia, when Northern Territory production exceeds local demand. The NGP also has the capability to flow gas into the Northern Territory from Queensland (from Mt Isa to Phillip Creek) if required.

Moomba to Adelaide Pipeline System (MAPS)

The MAPS connects the Moomba Gas Hub 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 Riverland Transmission Pipeline. The MAPS supports limited northerly flow, receiving gas in Adelaide via a receipt point with the PCA pipeline; it does not flow into the PCA.

Eastern Gas Pipeline (EGP)

The EGP runs from Longford in Victoria to Sydney, and is also receives supply from the Orbest Gas Plant in Victoria. The EGP has a lateral at Hoskinstown to supply Canberra and an interconnection with the MSP at Wilton. The Port Kembla Lateral pipeline⁸⁹ is a dedicated lateral connecting Port Kembla Energy Terminal (PKET) to the EGP. The construction and connection of this lateral 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 PCA pipeline connects Adelaide 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 without the installation of compression. The PCA is the sole source of supply to the Ladbroke Grove Power Station, via the 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 9 lists other major midstream infrastructure servicing domestic consumers.

Table 9 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. The Sturt Plateau Pipeline that will connect the AGP to Tamboran's Beetaloo gas developments is currently under construction by APA.
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 transmission ring) to New South Wales, intersecting with the MSP at Culcairn. This pipeline is bidirectional.
Brooklyn Lara Pipeline (BLP)	Connects supply from the SWP at Lara to Brooklyn. This pipeline is bidirectional.
Longford Melbourne Pipeline (LMP)	Connects Melbourne to supply from Longford Gas Plant. Does not directly provide access to the Orbest 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.
Queensland Gas Pipeline (QGP)	Connects Gladstone and Rockhampton from Wallumbilla Gas Hub.
Jemena Gas Network's Northern Trunkline	Transports gas from the EGP and MSP south of Sydney to Newcastle, and connects the Newcastle Gas Storage Facility (NGSF). Presently this is not considered to be a transmission pipeline but is a large full regulation distribution pipeline.

⁸⁹ See <https://www.jemena.com.au/gas/pipelines/Eastern-Gas-Pipeline/port-Kembla-pipeline-project/>.

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. The following projects are examples.

Further expansion of the East Coast Gas Grid (ECGG)

APA Group is proposing further staged upgrades and expansions⁹⁰ beyond the recently committed Stage 3A, as part of its ECGG Expansion Plan. These developments, if delivered, would continue to expand gas transportation capacity on the APA pipelines, especially those that link the north with southern regions.

Stage 3B includes the proposed delivery of the Bulloo Interlink, a new 342 km pipeline connecting the SWQP to 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, among others. Other potential future stages include the proposed Riverina Storage Pipeline in New South Wales, along with new compression and pipeline infrastructure, which includes a proposed storage pipeline that would provide up to 500 TJ of flexible storage. This storage could be used to supply gas to Uranquinty Power Station, meet nearby demand in New South Wales, or be transported south to Victoria.

MSP to EGP compressor

This proposed project involves adding a new compressor at Wilton to support around 100 TJ/d of capacity from the MSP into the EGP. The MSP is currently incapable of flowing into the EGP due to the higher pressure operation of the EGP.

EGP Reversal Project and VicHub Expansion

The EGP is presently configured for unidirectional flow from Longford towards Sydney. Jemena has commenced work on Stage 1 to reconfigure the EGP to allow for bidirectional flow and staged upgrades to the EGP capacity. Stage 1 of the reversal project, which allows 200 TJ/d of supply to Victoria, was considered anticipated in this GS00, but this reverse flow capacity is contingent on the commencement of supply from the uncertain PKET regasification terminal. Jemena has advised Stage 1 is targeting completion by June 2026.

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 bidirectional flow. This uncertain project would allow PCA to receive gas from the proposed LNG regasification terminal at Outer Harbor, South Australia, or from the MAPS for west to 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 is in Section 5 of the 2026 VGPR Update.

SWP expansion

APA Group has proposed an expansion of the SWP to increase the Port Campbell to Melbourne capacity up to 615 TJ/d through the addition of two new compressor stations. More details on SWP expansion are in Section 5 of the 2026 VGPR Update.

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 rates into the market.

Table 10 lists existing market-facing storage facilities and proposed upgrades or facilities.

Shallow storage facilities – Dandenong LNG and Newcastle Gas Storage Facility (NGSF) – need to have inventories ready to provide operational flexibility and help mitigate risks of shortfalls. These storages hold limited volumes so they are unable to sustain high delivery rates into the market for extended periods. The newest shallow storage at Newcastle, KKLP, will primarily store gas to fuel the Hunter Power Station.

Figure 34 illustrates the distribution of storage behaviour at Iona UGS across historical different years. From the left side of the chart, between 0% and 10%, the distribution shows days with strongest supply to the market from storage, which typically occurs during the peak winter demand period. Days with very high deliveries from storage (above 400 TJ/d) occurred more frequently in 2025 than all other years shown on the chart. Iona UGS was heavy utilised⁹¹ during winter 2025, reaching up to 480 TJ/d of daily supply into the market to support overall gas usage including GPG.

Table 10 Key existing market-facing and proposed storage infrastructure

Name	Maximum storage capacity (PJ) ^A	Maximum delivery rate (TJ/d)	Connecting location
Silver Springs	45	10	Wallumbilla, Queensland
Iona UGS			Otway Basin, Victoria
• Existing	24.4	570	
• Upgrade (HUGS Phase 1 – Committed – expected to be online from 2027)	26.2	Up to 615	
• Upgrade (HUGS Phase 2 – Uncertain)	Up to 32.6	Up to 765	
Newcastle Gas Storage Facility (NGSF)	1.5	120	Newcastle, New South Wales
Dandenong LNG Storage	0.68	87 ^B	Melbourne, Victoria
Kurri Kurri Lateral Pipeline (KKLP)	0.072	60 ^C	Newcastle, New South Wales
Golden Beach Storage (Uncertain)	42	375	Gippsland Basin, Victoria

A. The maximum storage capacity includes buffer gas, excluding cushion gas.

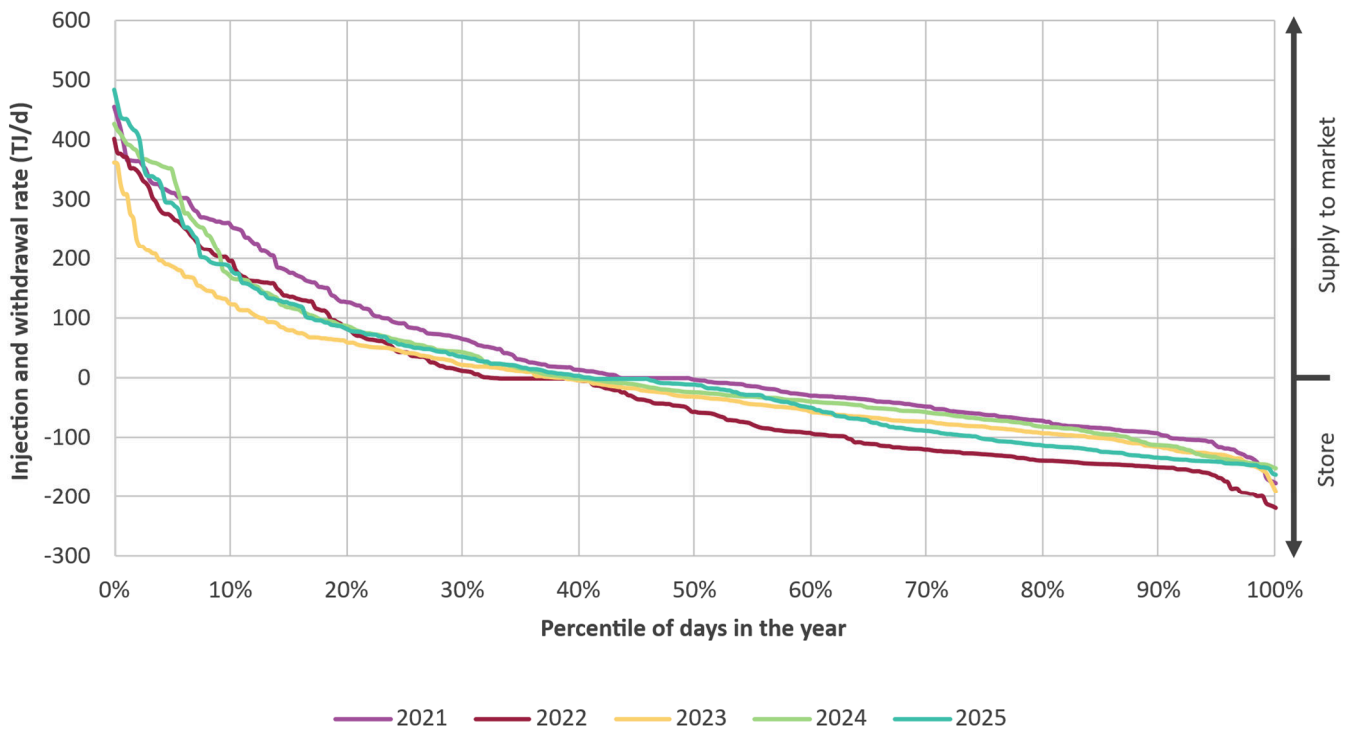
B. This storage can supply at faster rates for short periods of time, but that is non-firm supply and not able to be supported across a 24-hour period.

C. This maximum delivery rate is into Sydney Short Term Trading Market.

⁹⁰ See <https://www.apa.com.au/news/asx-and-media-releases/apa-to-deliver-pipeline-capacity-needed-to-solve-projected-east-coast-gas-shortfalls>.

⁹¹ For more details on heavy Iona UGS usage in winter 2025, see AEMO’s Q2 2025 *Quarterly Energy Dynamics*, at https://www.aemo.com.au/-/media/files/major-publications/qed/2025/qed-q2-2025.pdf?rev=8732b44ba628445da5883f92e84cd87d&sc_lang=en.

Figure 34 Distribution of change in storage level for Iona UGS for each year, 1 January 2021 to 31 December 2025 (TJ/d)



Additional uncertain storage developments

A number of potential new storage projects have been announced by developers, but have provided only sufficient evidence of commitment to classify these potential developments as uncertain. The following projects are examples.

Golden Beach Energy Storage Project

GB Energy is proposing a gas production and energy storage project within the Gippsland Basin, approximately 3 km offshore from the township of Golden Beach in Victoria. 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 42 PJ of gas. If developed, the uncertain project would provide up to 375 TJ/d to southern demand centres.

HUGS Project Phase 1 (committed) and 2 (uncertain)

Lochard Energy is progressing upgrades to the Iona UGS storage facility at Port Campbell, Victoria. Phase 1 of the project is committed and will increase storage inventory capacity from 24.4 PJ to 26.2 PJ, and the delivery capacity into the market by up to 45 TJ/d, from 2027. As advised by Lochard Energy, Phase 2 is still uncertain and under planning for 2029 to early 2030s. HUGS Phase 2 is proposed to expand the total storage inventory capacity of Iona UGS up to 32.6 PJ, and increase the maximum delivery 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.

There are a total of 42 existing gas processing facilities in the ECGM. **Table 11** lists the committed, anticipated and uncertain gas processing plant facilities that may be developed in the future, as advised by project proponents.

Table 11 Committed, and proposed gas processing plants

Name	Status	Purpose	Region
Girraheewen	Committed (expected to be online from 2027)	To support production from Arrow's Surat Gas Project	Queensland
Carpentaria Gas Plant	Committed (expected to be online from mid-2026)	To process gas from Beetaloo Energy's Carpentaria gas field	Northern Territory
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

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)⁹² 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 12**. No regasification terminal projects were considered committed or anticipated in the 2026 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.

⁹² An FSRU stores and regasifies LNG, before it is injected into a transmission system.

Table 12 Proposed LNG regasification terminals

Name	Region	Timing	Capacity	Additional considerations
Port Kembla Energy Terminal (PKET)^A	New South Wales	2027 ^A	500 TJ/d ^B 130 PJ/y	<ul style="list-style-type: none"> • Timing pushed back from 2026 to 2027. • Construction of the onshore infrastructure associated with PKET is completed. • 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. • The existing EGP capacity is available to transport gas from PKET to Sydney. • If supply from PKET commences, Jemena’s EGP reversal Stage 1 is anticipated to initially deliver the capacity for 200 TJ/d in reverse flows south to Victoria and could be further upgraded.
Outer Harbor LNG Project^C Port Adelaide	South Australia	2028	405 TJ/d 110 PJ/y	<ul style="list-style-type: none"> • Timing pushed back from 2027 to 2028. • Pending FID. • All necessary approvals acquired. • 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	<ul style="list-style-type: none"> • Pending FID. • Located adjacent to the Geelong Oil Refinery. • Viva Energy is currently in the process of securing an FSRU for the project. • Victorian Government supplementary EES has progressed to approved status^E. • The WAG pipeline (owned by joint venture between Viva Energy and Exxon Mobil) conversion could increase the capacity of delivery from the west of Melbourne.
Vopak Victoria Energy Terminal^F Port Phillip Bay	Victoria	2029	778 TJ/d 270 PJ/y	<ul style="list-style-type: none"> • Timing pushed back from 2028 to 2029. • Pending FID. • Ongoing EES preparation and review^G.

Note: Timing and capacity have been advised by project proponents in 2026 GSOO surveys and could be different from that reported in 2025 GSOO.

A. For more, see <https://www.squadronenergy.com/our-projects/port-kembla-energy-terminal>.

B. AEMO has been advised by the project proponent, Squadron Energy, that the latest maximum capacity of this project is up to 520 TJ/d. This was advised after 28 February 2026 so was not included in the 2026 GSOO modelling.

C. For more, see <https://veniceenergy.com/outer-harbor-lng-project/>. In 2024, AG&P LNG acquired Venice Energy. The acquisition was formalised in 2025.

D. For more, see <https://www.vivaenergy.com.au/energy-hub/gas-terminal-project/about-our-project>.

E. For more, see <https://www.planning.vic.gov.au/environmental-assessments/browse-projects/viva-energy-gas-terminal>.

F. For more, see <https://victoriaenergyterminal.com.au/>.

G. For more, see <https://www.planning.vic.gov.au/environmental-assessments/browse-projects/referrals/Vopak-Victoria-Energy-Terminal>.

4 Gas supply adequacy assessment

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

Key insights

In the south:

- As southern production continues to decline, peak day gas shortfall risks are forecast from 2029 under peak day demand conditions. Despite falling gas consumption, forecast peak day gas usage remains highly seasonal and volatile, and the scale of forecast extreme peak day demand is similar to historical levels of peak gas usage.
- Peak day shortfall risk is forecast one year later than in the 2025 GSOO, due to increased access to supply from the north with APA's newly committed expansions to the north to south pipeline system, lower forecast residential, commercial and industrial peak day consumption of gas, and lower gas projected to support GPG with the delayed retirement of Eraring Power Station and increasing developments in battery technologies in the NEM.
- Gas storages are critical providers of flexible peak day production, and the availability of all southern gas storage facilities and stored gas ahead of winter continues to be very important to mitigate future peak day adequacy risk.

In the north:

- Forecast increases in Northern Territory gas production are expected to meet local gas consumption needs, providing more supply headroom to meet southern demand subject to transport capabilities. The Northern Territory may need to continue to rely on alternative and interim gas supply arrangements, when existing gas supply is unable to meet demand, until additional production from committed and anticipated supplies is available.
- Given declining southern production, and in the absence of new investments, continued winter availability of northern supply remains critical to support flows to the southern regions to mitigate the risk of southern supply shortfalls.
- Timely delivery of northern producers' anticipated supplies is critical, and beyond 2030 more uncertain supply will be required, to meet all domestic supply and LNG export agreements.

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, and
- did not consider gas stored in pipeline linepack as an available source of supply⁹³, except in the case of the KKLP⁹⁴.

⁹³ 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 were not modelled.

⁹⁴ KKLP is equipped with its own compressors to boost the pressure of stored gas, and can be used as a flexible supply source for the ECGM.

Use of scenarios for the adequacy assessment

This 2026 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 the ability of 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.

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.
- UAFG⁹⁵ – typically between 3% and 5% of total gas usage results from gas leakage, or inaccuracies in gas measurement or heating values.

Use of data in charts

Unless otherwise specified, charts for peak day adequacy modelling refer to **extreme peak day demand conditions** using:

- 1-in-20 year peak day demand conditions for residential, commercial and industrial customers, and
- the 2024 reference year, which has very high daily gas requirements for GPG coinciding with high demand conditions for residential, commercial and industrial customers.

The charts therefore present an outcome that is akin to a ‘worst-case’ 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 to occur in winter during extreme cold temperatures that increase temperature-sensitive residential and business heating loads, on days which coincide with a period of low renewable generation or coal availability and high electricity demand driving high levels of GPG.

⁹⁵ AEMO’s demand forecasts in Section 2 and applied to the adequacy assessments in Section 4 included estimates of losses associated with UAFG.

Figure 35 emphasises the seasonal gas supply and demand dynamics in the south, and the important role of storages and transportation to deliver gas from northern regions. This shows how southern production, pipeline and storage capacity met actual southern gas demand in 2024 and 2025, and the projected adequacy of existing, committed and anticipated southern production, pipeline capacity and storage facilities to meet gas demand for the period shown to 2030 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 meet daily gas demand, from each of the following sources cumulatively:

- existing and committed gas production capacity from southern regions only (solid teal line), plus
- expected capability to import from Queensland through the SWQP⁹⁶ (dashed teal line), including the impact of APA’s ECGG Expansion Plan Stage 3A, plus
- gas injection capacity into the market from deep storage at Iona UGS (dotted teal line), plus
- gas injection capacity into the market from shallow storages at Dandenong, Newcastle and KKLP (solid red line), plus
- anticipated gas supply capacity from southern regions (dashed red line).

The seasonality and variability of the vertical lines in **Figure 35** demonstrate how weather conditions are a significant driver of peak gas demand for residential, commercial and industrial consumers and for electricity generation in the winter months (see Section 2.4.2 for discussion on weather-driven GPG demand). Periods of low renewable output can increase GPG requirements (in the absence of coal generation or other dispatchable capacity such as electricity storages), and have the potential to occur in winter when residential and commercial heating gas demand is also peaking. The GSOO assessment of gas supply and demand adequacy considered a range of weather patterns⁹⁷ (with **Figure 35** reflecting weather conditions consistent with those seen in 2024).

As **Figure 35** shows:

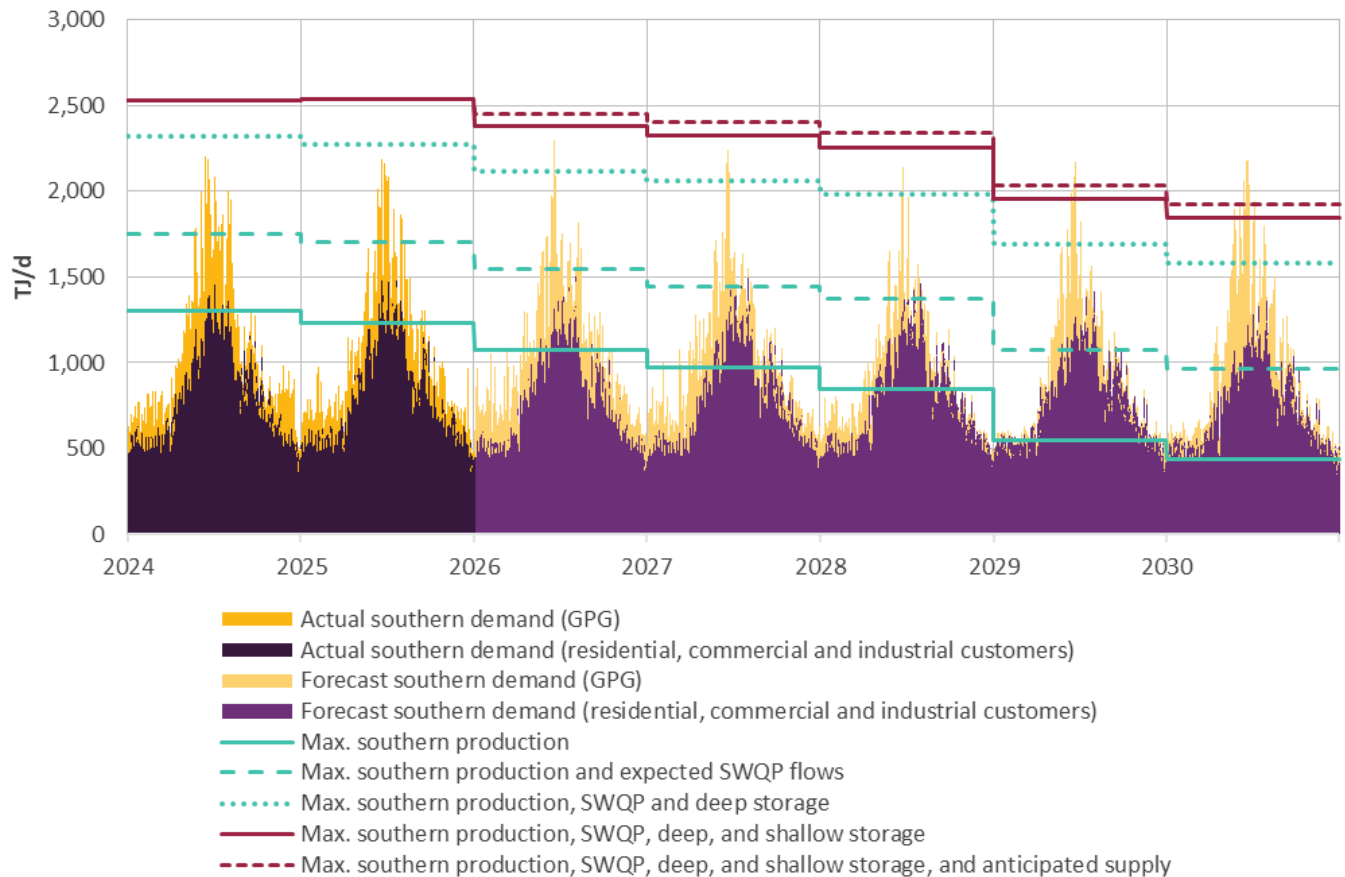
- **The risk of peak day shortfalls are forecast from 2029.** This is one year later than in the 2025 GSOO assessment, with lower winter peak day demand in this 2026 GSOO, due to:
 - lower projected peak use of GPG as the commissioning of new battery capacity and the delayed retirement of Eraring Power Station reduces the gas required to provide firming generation in the NEM,
 - lower forecast residential, commercial and industrial gas demand, and
 - additional north to south pipeline capacity from APA’s committed ECGG Expansion Plan Stage 3A project.
- Peak day gas shortfall risks are forecast due to declining southern production:
 - The peak day gas demands forecast for 2029, when peak day shortfall risks emerge, are of a similar magnitude to actual maximum demands reached in recent history. This indicates that the decline in southern production capacity is the primary driver of the peak day shortfall risk.
 - Prior to 2029, gas supply could become inadequate if tight supply-demand conditions are disrupted. This could occur if there are unexpected production outages in southern regions that reduce the output of existing, committed

⁹⁶ The estimate of available SWQP flow accounts for modelled gas flow from the SWQP up the Carpentaria Gas Pipeline (CGP) to Mount Isa.

⁹⁷ The weather patterns studied in the GSOO were based on real weather conditions observed between 2014 and 2024.

or anticipated facilities, or if electricity system conditions require more GPG than forecast at the same time as high gas demand. This highlights the crucial role of gas storage and the support from gas transported from the north in winter to help mitigate adequacy risks.

Figure 35 Actual daily southern gas system adequacy since January 2024, and forecast to 2030 using existing, committed and anticipated projects, reference year 2024 (TJ/d)



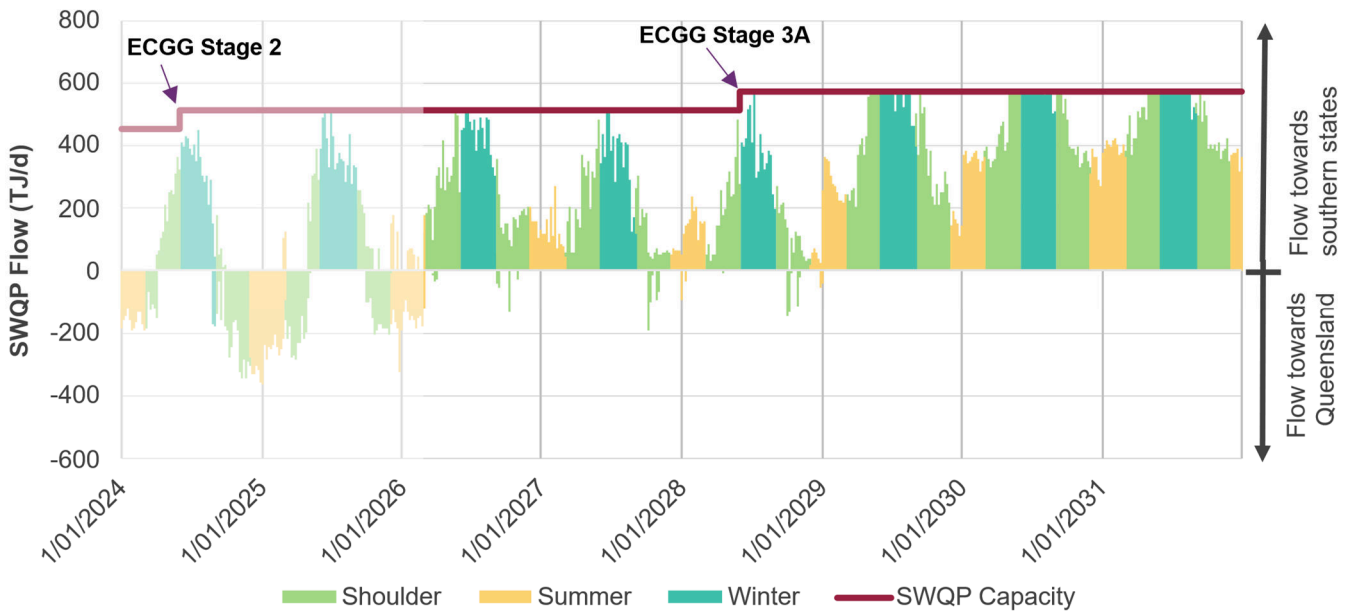
Note: Actual maximum southern production and SWQP flow rates are shown for 2024 and 2025.

Figure 36 shows an increasing historical and forecast trend for higher utilisation of SWQP to support southerly flow to the southern states. The committed SWQP capacity increase from APA’s ECGG Expansion Plan Stage 3A⁹⁸ allows more gas to flow south from winter 2028, reducing the risk of peak day shortfalls in that year. From 2029, flows on SWQP are forecast to reach flow limits around 25% of the year. SWQP has historically flowed at capacity for around 3% of the time as southern production used to be sufficient to meet southern demand.

This greater reliance on gas transported from northern fields via the SWQP is due to the decline in southern production, and is needed to both meet winter peak demands in south and refill southern storages ahead of these winter peak demand periods. This is demonstrated by increasingly higher flows from the SWQP southbound outside of winter in the shoulder and summer periods.

⁹⁸ See https://admin.apa.com.au/media/xc3hv0ud/260219_asx_release_ap_to_deliver_pipeline_capacity_needed_to_solve_projected_east_coast_gas_shortfalls.pdf.

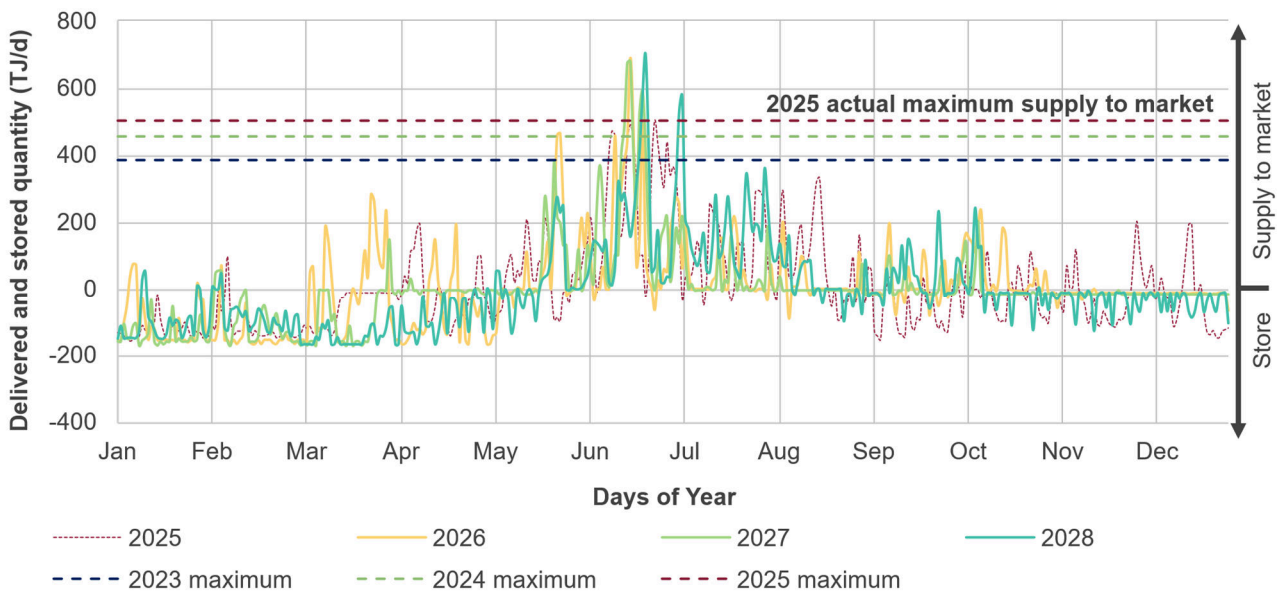
Figure 36 Actual (2024 to 2025) and projected (2026 to 2031, reference year 2024, Step Change) gas flows along the SWQP (TJ/d) – positive flows are southbound



Note: This chart shows the modelled outcomes of pipeline flows to demonstrate how the SWQP will reach capacity under forecast conditions during a particular reference year. The modelling does not account for contracting arrangements, such as time-swaps, and may not be an effective prediction of flows when the system is unconstrained.

Figure 37 demonstrates the potential for high reliance on large quantities of gas supplied from southern storages, with horizontal lines showing the actual maximum daily supply to market reached in the last three years for comparison.

Figure 37 Daily actual (2025) and projected (2026 to 2028, existing and committed only, Step Change, reference year 2024) storage deliveries and stored quantities for deep and shallow storages, compared to actual maximum deliveries for 2023 to 2025 (TJ/d)



The maximum historical delivery rate has occurred in winter each year. This shows how actual maximum daily deliveries into the market have been increasing each year and are forecast to reach even higher daily deliveries during projected peak

winter demand periods. Deep and shallow gas storages are forecast to continue to provide critical supply close to large demand centres, as southern production declines, in particular from Gippsland, which has no committed or anticipated supply forecast beyond 2033. Gas storages will require appropriate management to ensure stored gas is available on peaks days including, if necessary, sustained deliveries across multiple high demand days.

4.1.2 Annual and seasonal adequacy

From 2030, annual supply gaps are projected in each of AEMO's scenarios under the majority of weather years simulated, even with the development of committed and anticipated gas supplies and expanded electricity developments that offset GPG needs. These gaps, which are most likely to materialise during winter when gas consumption is highest, signal a need for further investment from the gas industry. The projected supply gaps in this 2026 GSOO are one year later than the 2025 GSOO, with the improved outlook forecast for 2029 primarily due to:

- further decreases in forecast residential, commercial and industrial consumption of gas, reflecting continued projected declines in actual gas consumption for these sectors,
- the reduction in forecast GPG consumption driven by the extended operation of Eraring Power Station and increased battery build consistent with the Draft 2026 ISP,
- increased transportation capacity from north to south and within the southern states with APA's ECGG Expansion Plan Stage 3A now committed to be available from winter 2028⁹⁹, and
- a forecast increase in expected Northern Territory production from mid-2026 allowing more Queensland gas to flow towards southern states. As gas from the Northern Territory is increasingly able to meet gas demand at Mt Isa, more Queensland production can be sent to Moomba and on to southern customers. More information on Northern Territory production is in Section 3.2.2.

This adequacy assessment assumed that committed and anticipated gas supply projects are delivered on time, and that planned electricity sector developments proceed as expected to reduce GPG requirements. Although supply adequacy has improved compared with the 2025 GSOO, forecasts still indicate a need for additional gas supply and new infrastructure.

The magnitude of forecast supply gaps is influenced by the volume of gas needed to support the NEM, which is dependent on the availability of NEM coal generators and the scale, type, and location of capacity that is developed to replace coal.

Figure 38 presents a range of projected annual supply gaps forecast in southern regions. The range reflects variations that are forecast across multiple weather patterns, influencing seasonal variations in forecasting demand (including the forecasting of demand for GPG). The forecast supply adequacy assessment included all existing, committed and anticipated supply, storage and infrastructure developments.

While supply gaps emerge in all scenarios, if relatively mild winters are encountered, it is possible that gas supply from existing, committed and anticipated projects would be sufficient to meet demand through to 2032. **Table 13** shows the percentage of modelled weather conditions that show a supply gap in each year.

⁹⁹ See <https://www.apa.com.au/news/asx-and-media-releases/apa-to-deliver-pipeline-capacity-needed-to-solve-projected-east-coast-gas-shortfalls>.

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, 2026-45 (PJ)

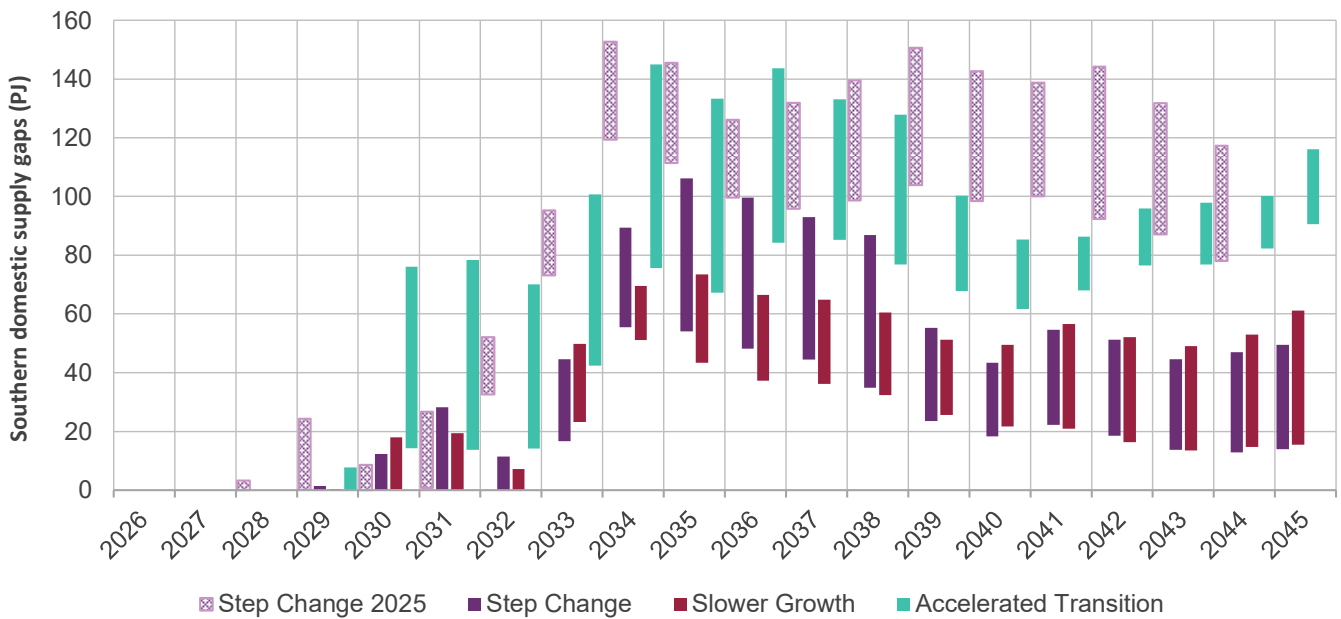


Table 13 Percentage of modelled weather conditions with annual supply gaps

	2025	2026	2027	2028	2029	2030	2031	2032	2033+
<i>Step Change</i>	0%	0%	0%	0%	9%	59%	55%	36%	100%
<i>Slower Growth</i>	0%	0%	0%	0%	0%	91%	27%	27%	100%
<i>Accelerated Transition</i>	0%	0%	0%	0%	91%	100%	100%	100%	100%

Note: 0% means no supply gap occurred for any weather condition modelled in the year. 100% means all modelled weather conditions showed a supply gap.

As **Figure 38** shows, in the next decade, as coal generators are forecast to retire, the size of the supply gap is projected to increase, before settling at a lower level in the longer term. The upper ends of the projected *Step Change* supply gaps are higher in 2030 and 2031 for the 2026 GSOO than in the 2025 GSOO, but lower across all other years in the horizon, with most years showing a wider range:

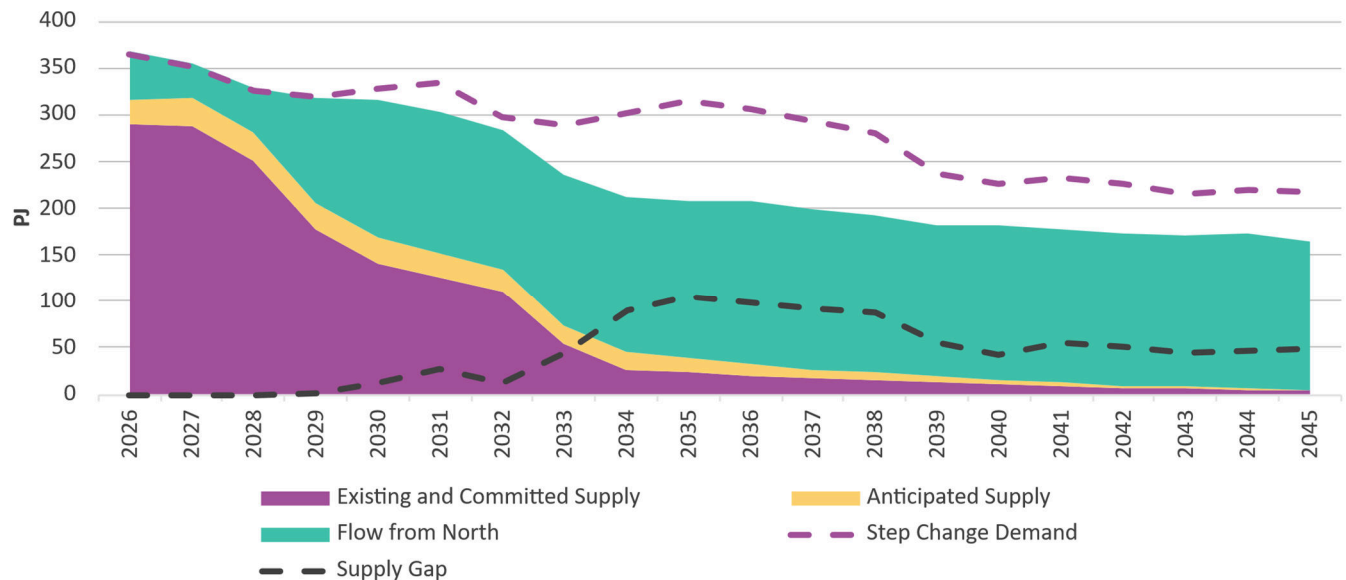
- To 2032, the possibility of supply gaps exists in some scenarios, and in most simulated weather conditions. If weather conditions are mild, inadequacy risks may not eventuate in these years.
- From 2032 to 2045, the supply gaps are smaller than in the 2025 GSOO. This is due to a combination of higher forecast production from Longford Gas Plant during its final years of operation and lower forecast gas consumption across all users, including lower gas usage for electricity generation due to a slower phase out of coal-fired power plants, consistent with the Draft 2026 ISP.
- From 2034 to 2038, the wide range is a result of a greater variance in the consumption forecasts under different weather conditions, primarily driven by GPG demand and the inclusion of the 2024 weather year in the modelling (see Section 2.4.2). This 2024 weather year includes an extended period of low renewable availability in southern states in autumn and winter, as well as lower than average rainfall, which results in higher reliance on GPG.
- From 2039, once most coal generators are forecast to have retired by this period in the Draft 2026 ISP, continued investment in new generation and storage required to maintain a reliable and secure low-emission power system is expected to reduce the supply gaps over the longer term.

The *Slower Growth* scenario exhibits a broadly similar trend in annual supply gaps to *Step Change*, but a slightly lower medium-term supply gap due to lower electricity demand forecast in this scenario resulting in lower GPG demand. For *Accelerated Transition*, the volume and range of supply gaps forecast to 2035 are higher and wider compared to the *Step Change* scenario, driven by rapid coal closures. From the late 2030s, annual supply gaps are forecast to be higher than the *Step Change* scenario, mostly due to increased demand for hydrogen to produce green commodities.

Figure 39 illustrates the growing forecast annual gas supply gaps in southern regions with existing, committed, and anticipated supplies in the *Step Change* scenario, compared to forecast annual consumption for the 2024 reference year. From 2029 there is forecast to be a small gap, reflecting the peak day shortfall risk, which increases to an annual supply gap from 2030 that will require a greater structural response.

As existing, committed and anticipated southern supply declines, an increasing proportion of supply in the south will need to be met by flow from the north, however this remains limited by the north to south transportation capacity.

Figure 39 Projected annual adequacy in southern regions, *Step Change* scenario, with existing, committed and anticipated developments, reference year 2024, 2026-45 (PJ)



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

Based on current production forecasts, **Figure 40** and **Figure 41** demonstrate the forecast utilisation of existing, committed, and anticipated supplies to meet southern demand in 2026 and 2030 in the *Step Change* scenario. The lower chart in each figure highlights how refilling of storage facilities during the warmer months is essential to establish sufficient reserves for winter withdrawals. Maintaining adequate storage levels ahead of winter ensures maximum withdrawal capacity is available to meet demand on winter peak days and to support sustained supply across consecutive high demand periods.

The two figures show that:

- In 2026, AEMO forecasts indicate southern gas production, northern supplies via the SWQP, and southern storage facilities will likely meet forecast southern demand under weather conditions observed in recent history.
- During winter 2030, a risk of multiple peak day shortfalls exist (shown by the unshaded area below the ‘Southern demand’ line series) if very high peaks in demand for GPG were to occur (as projected based on the 2024 weather

reference year). These may be due to very extreme weather conditions that lead to extreme electrical demand, or low renewable generation outputs that lead to more GPG operation in the NEM. As highlighted in **Table 13**, of the two residential, commercial and industrial peak day demand conditions and 11 weather reference years modelled in *Step Change*, 13 (59%) projected supply gaps in 2030 (see Section 2.4.2 for more information about different extreme GPG forecasts).

- In addition to peak day shortfall risks, **Figure 41** shows frequent shortfall risks across the winter. The frequency of the daily shortfalls shows a more structured supply gap that is forecast across the winter, with smaller gaps in the shoulder periods. Forecast southern production in 2030 is approximately half of what is expected to be available in 2026, and there is limited supply that can be transported from the north up to the capacity of the SWQP. There is also no committed or anticipated southern storage that could increase operational flexibility of southern production and transportation assets to mitigate the supply gap.

Figure 40 Forecast gas supply sources to meet southern daily demand, *Step Change* scenario, 2026 (TJ/d) (2024 reference year)

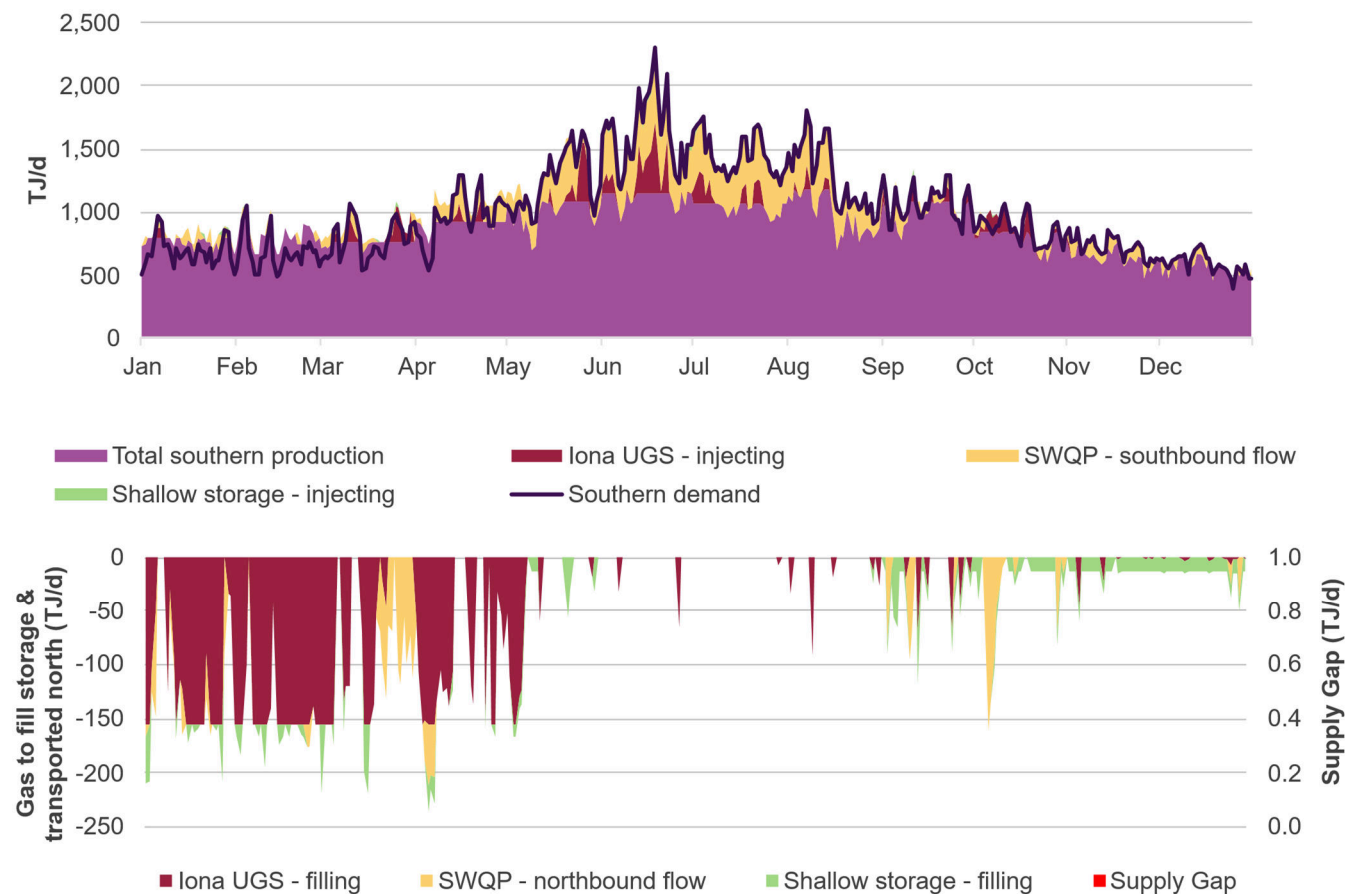
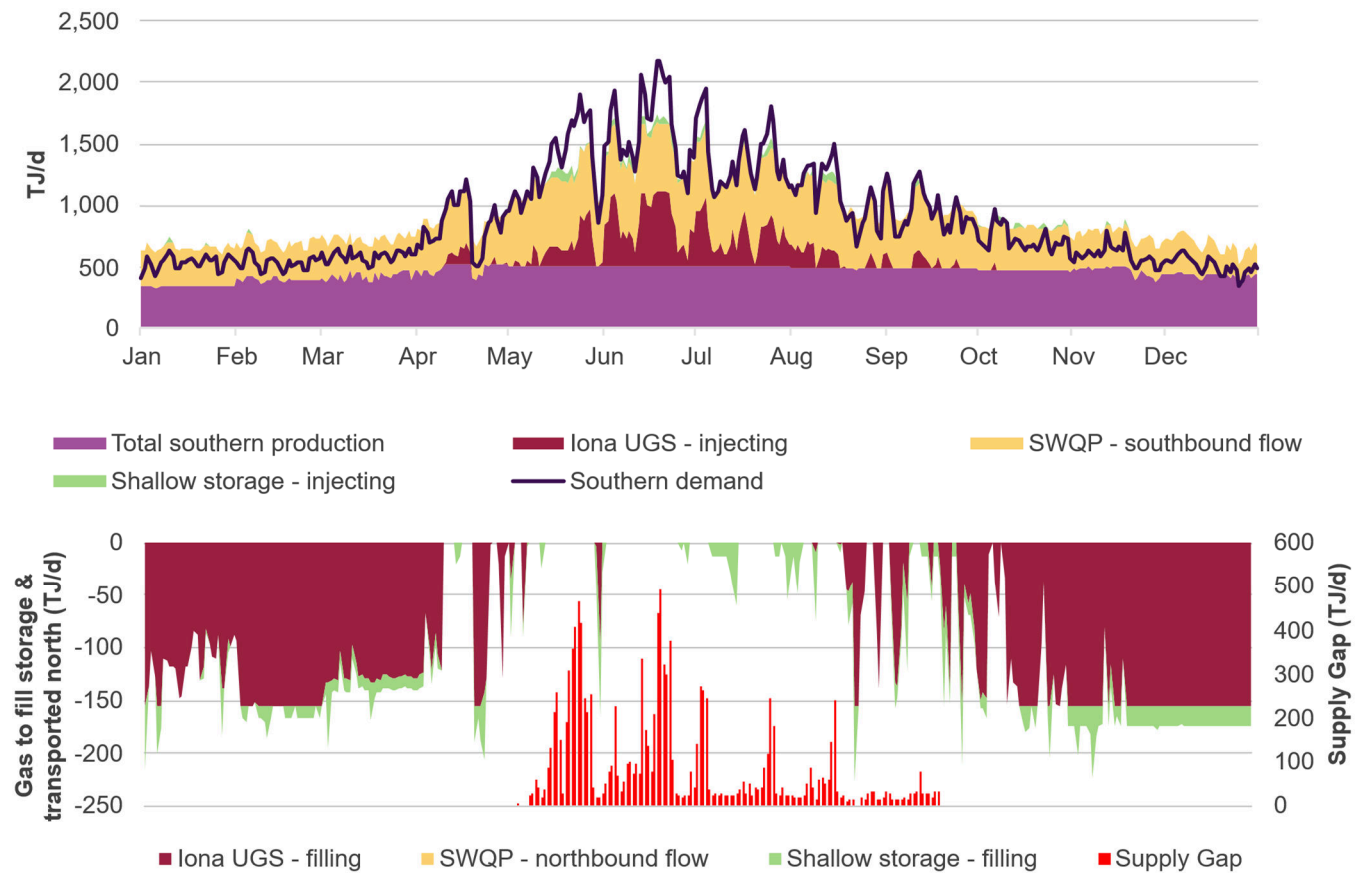


Figure 41 Forecast gas supply sources to meet southern daily demand, Step Change scenario, 2030 (TJ/d), (2024 reference year)



Near-term solutions to resolve forecast adequacy risks are progressing, but more investment will be needed

The 2026 GSOO highlights that committed supply and anticipated supply, storage, and infrastructure projects remain essential to maintaining short-term supply adequacy. Since the 2025 GSOO, new investment commitments by APA to increase transport capacity from the north have progressed, alleviating some supply adequacy challenges alongside new developments in the NEM that are reducing GPG needs in the short term (Eraring Power Station delayed retirement and the significant rise of CER and other large renewable energy projects).

However, the volume of new developments currently progressing is forecast to be insufficient to offset the scale of emerging shortfalls across the medium to longer term. The forecast shows southern supply remaining increasingly constrained, and the market facing a widening gap between forecast demand and available gas from the early 2030s. The supply-demand outlook shows:

- On-schedule development of committed and anticipated supply, storage, and pipeline projects 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 domestic demand and established Queensland LNG export contracts¹⁰⁰ from the end of 2026.

¹⁰⁰ The 2026 GSOO did not consider the impact of the Federal Government’s announced domestic gas reservation scheme or any other consequences relating to this policy.

- Increased investment in pipeline infrastructure will improve the ability for northern supply to reach southern customers, so long as northern supplies are available. The scale of additional committed transportation and northern supply investment, however, is not yet sufficient to replace declining southern production or meet winter peak day demands of similar magnitude to historical peaks.
- Ensuring storages are at full capacity prior to winter remains critical to reducing peak day gas shortfall risks but cannot substitute for new supply. Winter gas supply from the north is also important in managing southern states' gas supply adequacy and mitigating the risk of southern storage depletion.
- The timely development of transmission¹⁰¹, renewable energy, and storage projects in the NEM will reduce gas supply adequacy risks by reducing reliance on GPG operations. Prior to projected closure, 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 help mitigate gas adequacy risks.
 - The Draft 2026 ISP's optimal development path includes around 27 GW (101 GWh excluding Snowy 2.0) of grid-scale battery and pumped hydro storage by 2030. In total, 32 GW of battery storage projects are currently progressing through various stages in the connections process¹⁰². This substantial increase in NEM storage capacity, projected in the Draft 2026 ISP, must be delivered in full and on schedule, to minimise risk that GPG demand exceeds the levels assumed in this 2026 GSOO.
 - In extreme gas shortfall conditions, prudent use of secondary fuels to operate GPG for short periods and reduce gas use may reduce peak day gas shortfall risks without increasing risks to electricity reliability.

Overall, the on-time delivery of investments in committed and anticipated gas projects, investments in the NEM including for electrical storages, and consumer actions including electrification are expected to improve gas supply adequacy. However, without additional investment decisions beyond the current development pipeline, southern regions are forecast to face growing risks of both peak day shortfalls and supply gaps from 2030 onward.

Adequacy under alternative futures

The supply adequacy impact of two sensitivities built on the *Step Change* scenario are discussed below, both relating to one of the key drivers of uncertainty in the demand forecast – gas used for electricity generation, including market events that can increase GPG demand and developments in the NEM that can increase or decrease reliance on GPG. Further information on the demand forecasts used in the sensitivities is in Section 2.4.2.

Two demand sensitivities are shown in **Figure 42**:

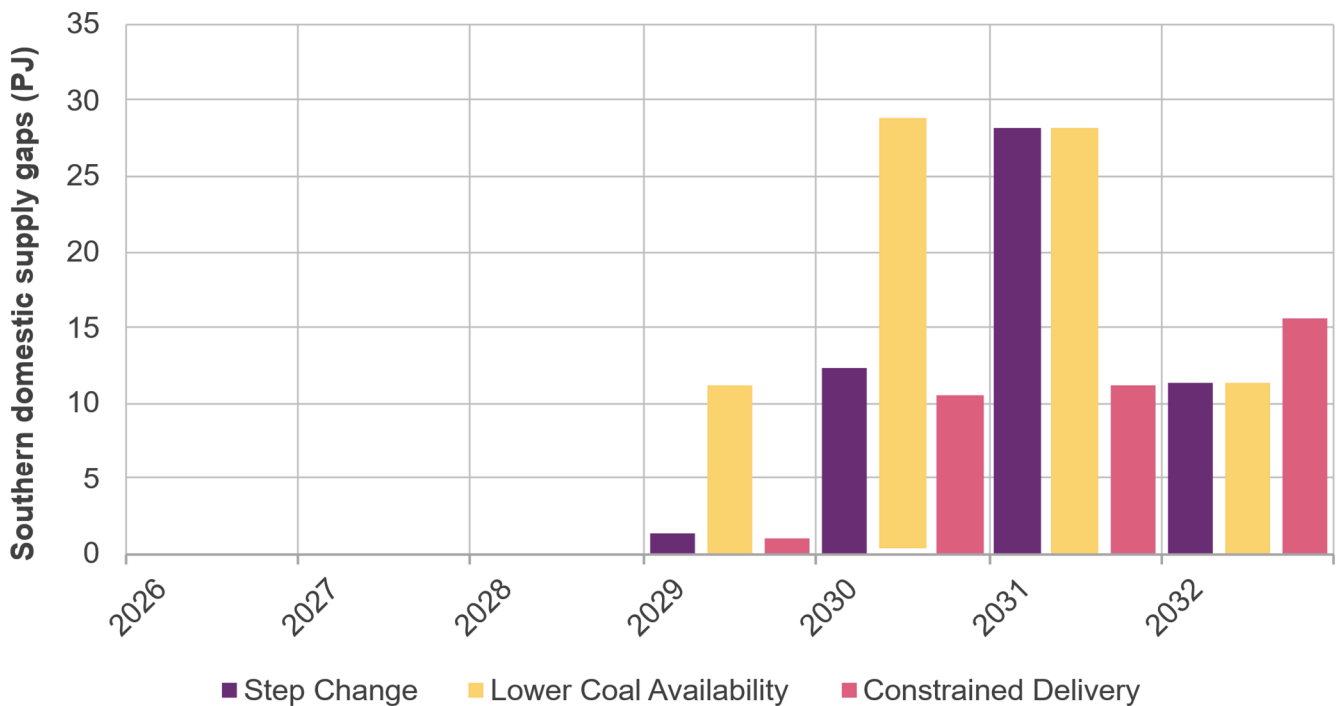
- **Step Change – Lower coal availability** assessed the impact on GPG demands and therefore gas adequacy associated with outages to coal power plants similar to those observed in 2022. In these conditions, GPG demand could be up to 55% more than the forecast average GPG consumption in *Step Change*. This sensitivity materially increases the forecast annual supply gap in 2029 and 2030 as GPG is relied on more heavily. The impact of this sensitivity reduces later in the outlook period as coal generation is projected to retire and be replaced with alternative forms of generation and, as such, the availability of the remaining coal fleet has a lessening impact on forecast GPG requirements over time.

¹⁰¹ Electricity transmission developments in the Draft 2026 ISP include Project EnergyConnect, HumeLink, Hunter Central-Coast Renewable Energy Zone (REZ) Network Infrastructure Project, Central-West Orana REZ Network Infrastructure Project and Western Renewables Link.

¹⁰² As reported in AEMO's December 2025 Connections Scorecard. See <https://www.aemo.com.au/newsroom/media-release/strong-delivery-growing-energy-investment-pipeline-in-december-quarter>.

- Step Change – Draft 2026 ISP Constrained Delivery** is a sensitivity from the Draft 2026 ISP that explored the impact of delayed delivery to electrical transmission, generation and storage projects compared to the optimal development path. In this sensitivity, delayed delivery of these assets requires greater operation of coal-fired generation. The upper end of the forecast supply gap in this sensitivity is therefore lower than in the *Step Change* scenario, due to slower coal retirements up to 2031 reducing the need for GPG in some weather reference years. Other weather reference years in this sensitivity are more impacted by the lower renewable generation developments, as discussed in Section 2.4.2. The supply gaps increase in 2032 as coal-fired generators retire rapidly to realign with the optimal development path trajectory.

Figure 42 Forecast southern annual supply gaps for Step Change and other sensitivities, 2026-32 (PJ)



Note: Columns in this chart represent a range of annual supply gaps across different weather patterns.

4.2 Northern supply adequacy

Northern gas producers provide critical support to keep domestic users adequately supplied¹⁰³. Queensland LNG producers control around 70% of total 2P reserves in the ECGM, and volumes of gas exported internationally via Curtis Island in Queensland represent around 75% of annual consumption in the ECGM.

¹⁰³ AEMO’s physical gas adequacy assessments assumed that gas from Queensland LNG producers is made available to the domestic market if required to avert domestic shortfalls.

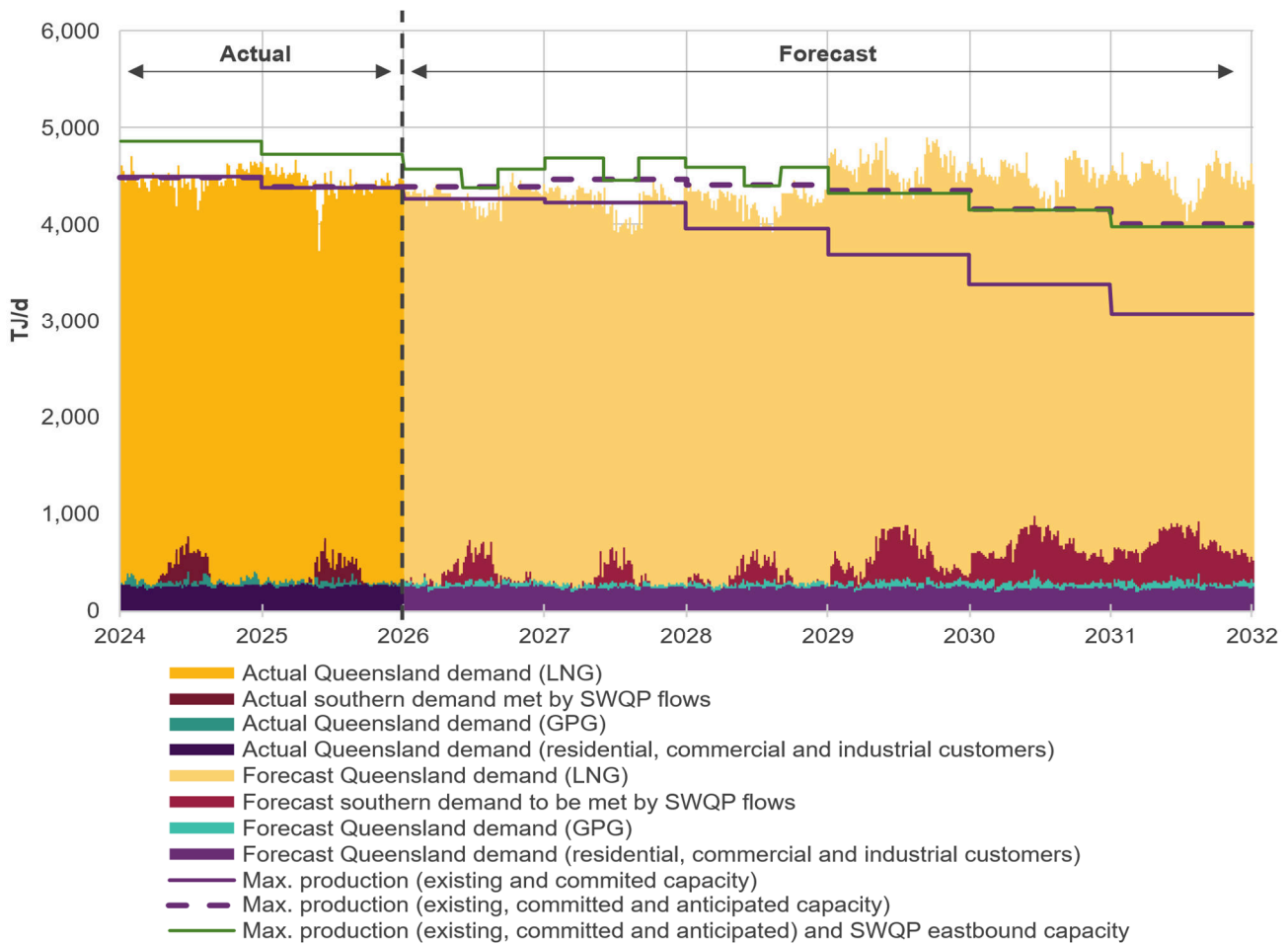
Timely delivery of northern producers' anticipated supplies is critical to support northern demand, and, from 2030, more uncertain supply is required to meet domestic demand (including southern consumers) and Queensland export agreements

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:

- From 2029, declining southern production is expected to limit gas flows from the south to northern regions along the SWQP, necessitating greater reliance on anticipated and uncertain northern supply developments to meet northern demand, while during summer the refilling of southern storages will increasingly depend on gas transported from northern fields through the SWQP.
- From 2030, uncertain supply developments will be required to satisfy northern demand and contracted volumes of LNG exports. Sufficient development of currently uncertain opportunities will also support southern demand.
- In winter, support from LNG producers in supplying gas not contracted for export to the domestic market remains essential throughout the entire outlook period. This will support flows to southern regions and help mitigate the risk of southern supply shortfalls.
- An increasing dependence on northern producers to make supply available to southern regions during winter is projected in all years of the outlook period, to mitigate the risk of southern peak day supply shortfalls and supply gaps. 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. Although recent commitments to increase north to south pipeline capacity will improve the outcomes for southern consumers, gas flow from the north to the south will continue to face transportation limits.

Figure 43 shows the actual and projected supply and demand of Queensland gas from 2024 to 2031 under the *Step Change* scenario. According to current projections, to satisfy northern and LNG export demand, anticipated northern supplies will need to be developed from 2026, as planned.

Figure 43 Actual and forecast Queensland gas demand and supply, including existing, committed and anticipated projects, and flows along the SWQP, 2024-31, Step Change (TJ/d)



Note: SWQP eastbound capability remains after 2029, but there is not sufficient forecast gas available from southern states to flow to Queensland. In this chart, the '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 2029.

Figure 44 shows the aggregate supply-demand balance for the LNG producers including production, third-party gas supply, expected exports and firm domestic supply commitments. This chart does not consider the impact of the Federal Government’s domestic gas reservation scheme or any other consequences relating to this policy. It shows that:

- LNG producers’ existing and committed developments, and domestically sourced third-party supply, is sufficient to meet 2026 contractual obligations.
- After 2026, anticipated developments will be required to meet domestic contractual requirements and forecast export demand.
- Assuming all anticipated supply comes online at the proponents’ advised time, there is projected to be enough gas to meet expected LNG exports and LNG producers’ domestic supply contracts until 2031, when very small shortfalls begin to emerge. If additional supply classified as ‘uncertain’ was delivered, gas adequacy risks would be mitigated for a few years, re-emerging from 2035.

Information on LNG exporters’ contracting and uncontracted volumes is in the ACCC’s Gas inquiry reports¹⁰⁴.

¹⁰⁴ Refer to the ACCC Gas inquiry 2017-30 reports, at <https://www.accc.gov.au/inquiries-and-consultations/gas-inquiry-2017-30>.

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, 2026-45 (PJ)

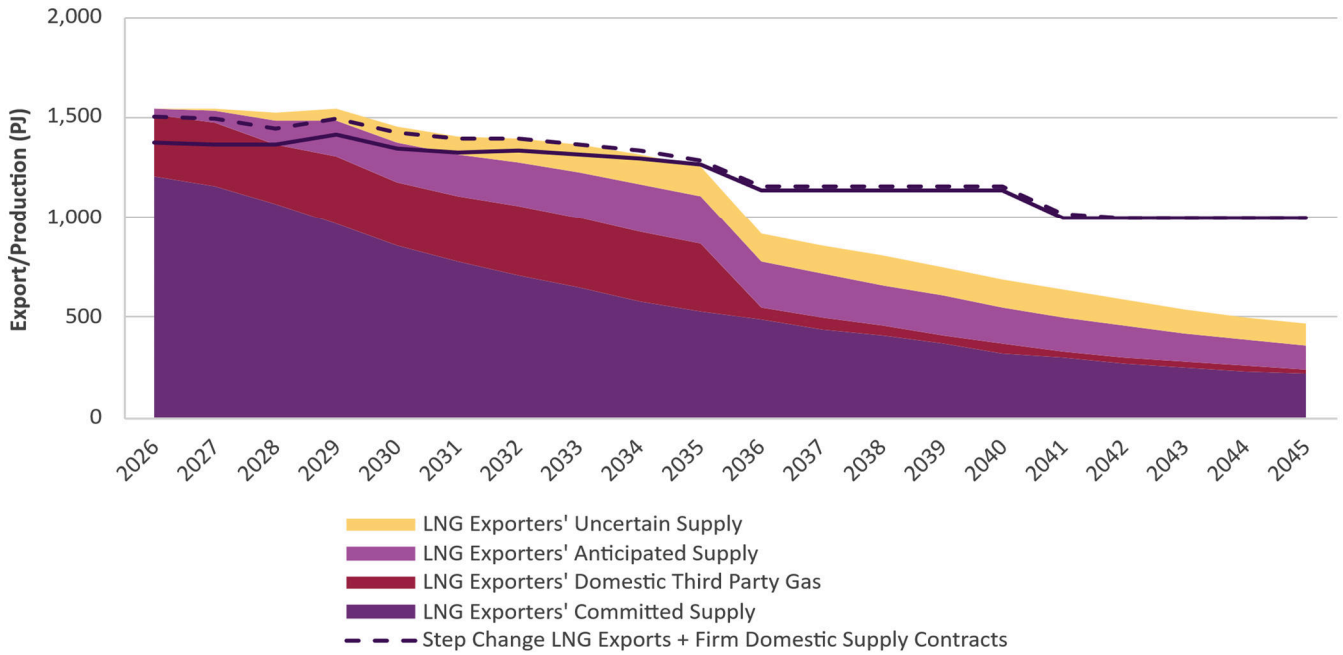
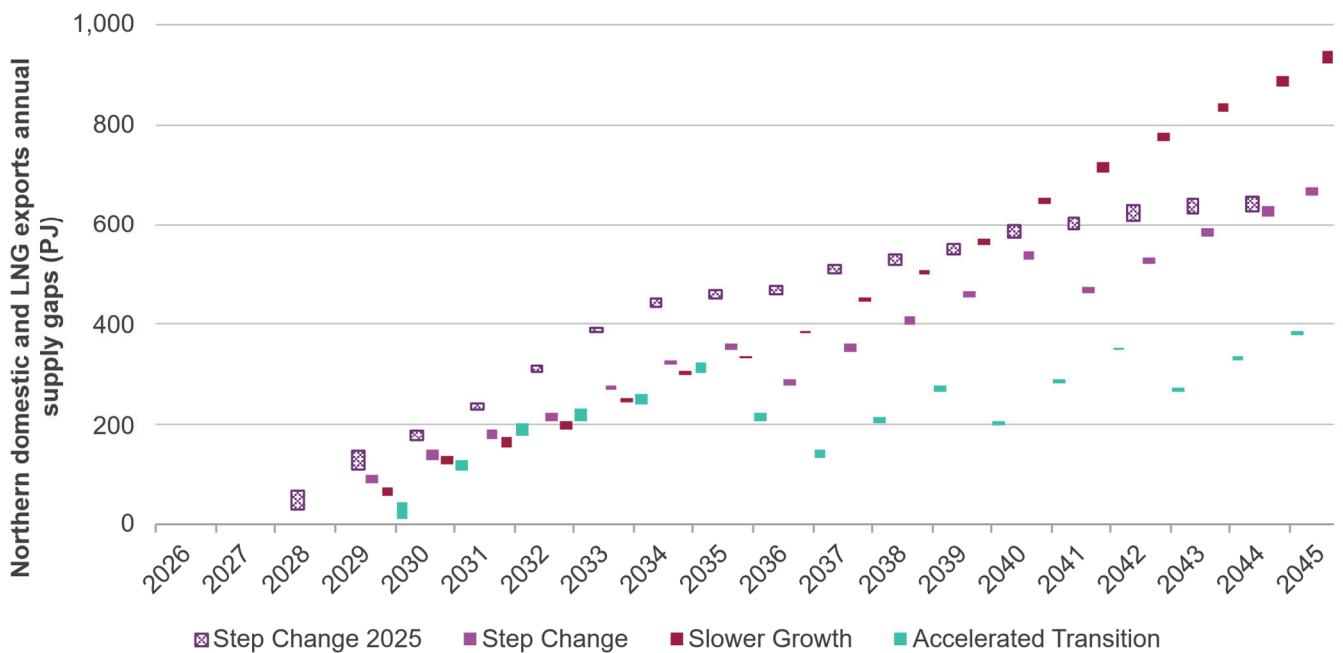


Figure 45 shows that substantial annual supply gaps continue to be forecast in Queensland as forecast production declines. Differences between the three scenarios, and between 2025 and 2026 GSOO outcomes, are driven by the scale of forecast LNG export demand assumed in each scenario, which is highly uncertain in the long term.

Figure 45 Forecast domestic and LNG export annual supply gaps in Queensland, assuming gas is made available to southern customers from the north as required, 2026-45 (PJ)



Note: analysis did not consider Northern Queensland adequacy as it is an isolated system. It is discussed separately later in this section.

Forecast increases in Northern Territory gas production are expected to meet local gas consumption needs, enabling more northern supply to be transported south

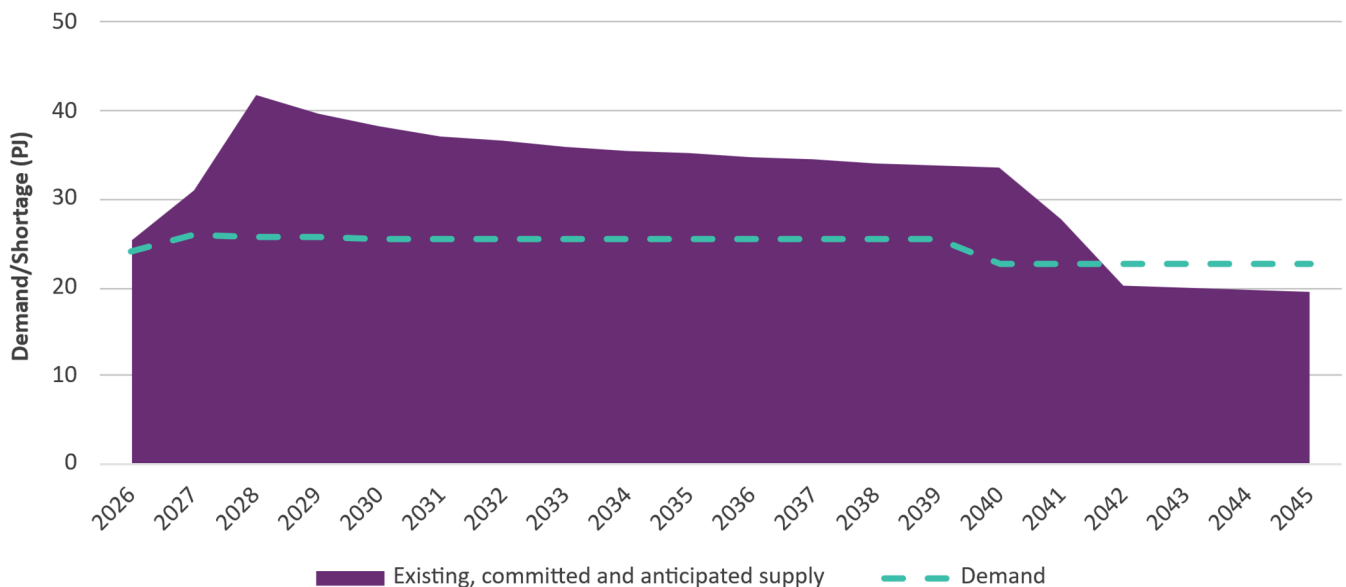
Compared to the 2025 GSOO, the 2026 GSOO has higher forecast production from existing fields and more supply from committed and anticipated projects in the Northern Territory. Committed projects in the Northern Territory include Tamboran’s pilot development of Shenandoah South development, which will be connected to the AGP by APA’s new Stuart Plateau Pipeline, and Beetaloo Energy’s Carpentaria Pilot Project.

This higher production forecast is expected to meet local Northern Territory demand and provide excess supply to support gas demand in Mount Isa in Queensland via the NGP. With sufficient gas supply to support Mt Isa, more Queensland gas could flow to Moomba via the SWQP and then onto the southern states rather than needing to flow north along the Carpentaria Gas Pipeline to service the Mount Isa demand.

Although gas producers in the Northern Territory have increased their forecast gas production compared to the 2025 GSOO, the region may need to continue to rely on alternative and interim gas supply arrangements, when existing gas supply is unable to meet the demand, until this production is available. The Northern Territory supplements its supply when required through emergency arrangements with Darwin LNG exporters¹⁰⁵ and other interim sources. The GSOO considered supply adequacy for Northern Territory domestic customers only; gas exported through Darwin LNG is not part of the ECGM.

Figure 46 shows from the early 2040s a potential supply gap is still forecast in the Northern Territory that may need to be filled by uncertain supply, lower GPG demand and/or increased demand flexibility. Gas use for electricity generation is about two-thirds of the forecast ECGM consumption for the Northern Territory, with the forecast for Northern Territory GPG consumption shown in Section 2.4.1.

Figure 46 Forecast annual demand and shortage in the Northern Territory, Step Change, 2026-45 (PJ)



¹⁰⁵ Detail on the arrangement is at <https://www.aemo.gov.au/sites/default/files/2019-08/Information%20sheet.pdf>.

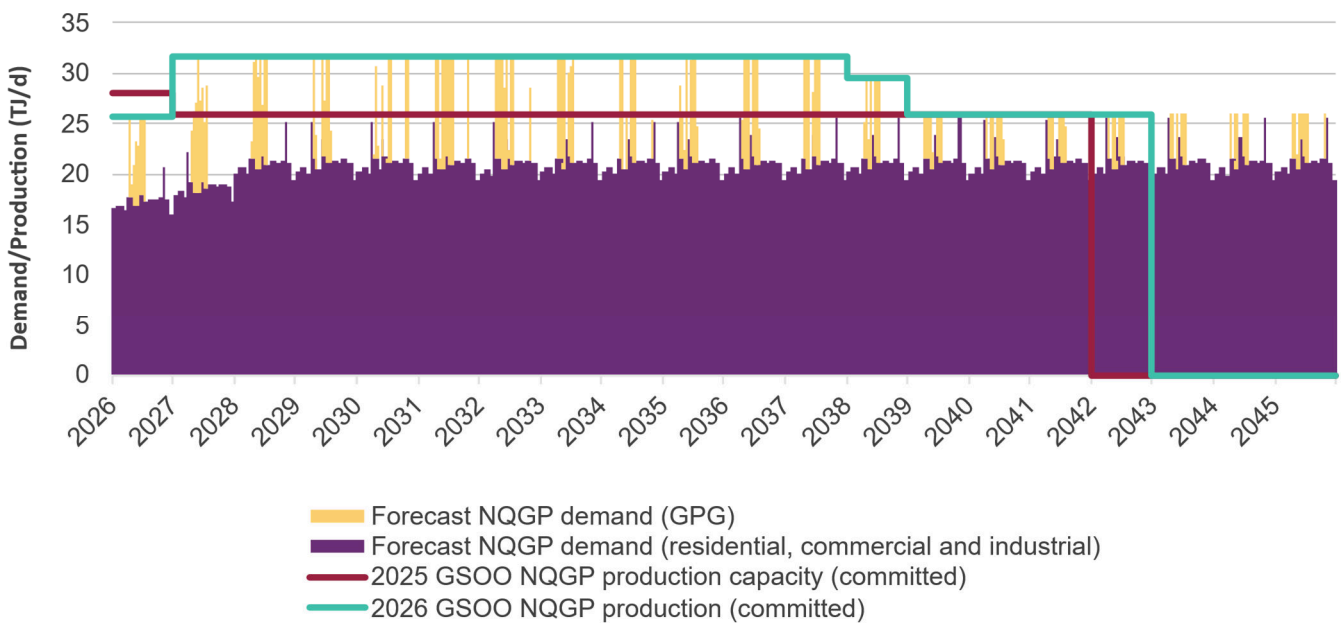
Supply forecasts for the Northern Queensland region have improved

Since the 2025 GSOO, AEMO has received updated development information regarding the Moranbah gas field in Queensland, and gas producers have provided updated production forecasts. The producers forecast higher gas production profiles this year based on improved insights from recent field performance reviews.

AEMO’s 2026 GSOO GPG forecast limits the Townsville GPG forecast to what is realistically achievable, taking into account inflexible gas supply production operations that feed into the Northern Queensland Gas Pipeline (NQGP).

Figure 47 shows projected daily supply and demand on the NQGP for *Step Change*, compared to the production forecast in the 2025 GSOO, highlighting that there is now sufficient committed and anticipated supply to meet forecast demand until 2043. Beyond 2043, uncertain gas supply developments will be required to meet forecast demand, or alternative electricity generation developments may lower GPG requirements in the region.

Figure 47 Forecast supply (2026 GSOO compared to the 2025 GSOO) and demand on the NQGP for the Step Change scenario, 2026-45 (TJ/d), reference year 2023



5 Options to address forecast supply challenges

As outlined in Section 4, increased commitments to invest in mid-stream infrastructure and updated production forecasts have improved the ECGM's gas adequacy, but additional investments in supply, transportation, storage or additional demand flexibility are needed to address forecast supply gaps and peak day shortfall risks over the medium term.

The gas industry is considering a range of projects including transportation developments, LNG regasification terminals, new domestic gas supply sources (including renewable gases), and additional gas storages, in addition to the projected levels of electrification and fuel-switching that are reducing forecast gas consumption.

Consistent with AEMO's physical assessment of gas adequacy and the forecast supply gaps, the 2026 GSOO includes a collection of *what if* analyses exploring potential supply, transportation, and storage projects proposed for development in the next five years, in addition to projects already classified as committed and anticipated.

Key insights

- **The assessed proposed project sets can provide sufficient supply to delay the forecast supply gaps one to five years**, depending on the project combination, and help to mitigate the risk of peak day shortfalls. Additional projects will be required in the long-term to sufficiently provide gas adequacy.
- Future gas investments will need to increasingly consider the need to support short periods of high gas demand. Flexible sources of gas supply, such as additional storages, or opportunities to increase the flexibility of gas demands (including the opportunity to lower GPG needs in the NEM at times of gas adequacy challenges in the ECGM), would be effective in addressing seasonal and peak shortfalls.
- Long-term forecasts of gas consumption, particularly for GPG, remain highly uncertain, and the investments most appropriate to support gas adequacy will depend on the pace of demand-side investments, and the need for firming provided by GPG in the NEM.

The Draft 2026 ISP includes an expanded consideration of gas market developments in determining optimal investments in electricity infrastructure, by applying limits to gas fuel availability based on potential development pathways for gas infrastructure (referred to in the ISP as 'gas development projections'). The project sets remain aligned with the gas development projections in the Draft 2026 ISP, with updated project information and improved representations of the *Southern supply* and *Pipeline expansions with new northern supply* project sets. The updated project sets will serve as the foundation for gas development projections in the final 2026 ISP.

This analysis did not consider all factors that may affect project feasibility – including costs, market dynamics, regulatory approvals, land use, social licence, safety, or operational challenges – and does not constitute a recommendation or endorsement of any project or investment. It also did not assess whether adjustments to the timing or type of investment in the power system would reduce GPG demand and ameliorate some of the gas supply gaps at lower cost than investment in gas infrastructure. The assessment also did not examine potential gas price impacts for consumers. As the projects assessed were not committed or confirmed, the technical assumptions applied reflect AEMO's current understanding based on information provided through participant surveys where available, and may change as projects progress.

5.1 Potential future supply, transportation, and storage projects

The supply, transportation, and storage projects considered in this section have been proposed by market participants for development within the next five years but have not progressed sufficiently to be classified as either committed or anticipated. As a result, none of these projects were included in the gas adequacy assessments presented in Section 4. The analysis in Section 5 provides an indicative assessment of how the development of selected combinations of uncertain projects could contribute to addressing the forecast physical gas adequacy risks identified across the GSOO outlook period.

Table 14 summarises the key supply challenges highlighted in Section 4 and the types of solutions that may be effective in addressing those challenges.

Table 14 2026 GSOO supply challenges and options assessed

Supply challenge	Types of solutions for resolving
Annual and seasonal supply gaps	<p>Addressing seasonal and annual supply gaps requires the development of additional gas supply to provide sufficient volumes for domestic use and export markets, or investment in demand-side options that lower gas consumption (including for electricity generation). Potential options to improve supply include:</p> <ul style="list-style-type: none"> • southern supply options, such as LNG regasification terminals, increased southern gas production, infrastructure to transport gas from northern regions, and renewable gas developments, and • northern supply options, including expansions or new production from existing basins such as the Surat and Bowen basins, as well as potential developments in emerging basins including the Beetaloo sub-basin, South Galilee, or North Bowen basins, or renewable gas projects. <p>Seasonal supply gaps, particularly those associated with higher winter demand in southern regions for heating and GPG, require additional flexible capacity, or investment in demand-side options that increase demand flexibility. Options to increase supply flexibility may be provided through a combination of:</p> <ul style="list-style-type: none"> • new gas storage facilities in southern regions, • upgrades to existing southern storage facilities, and • increased north to south pipeline transportation capacity.
Daily or multi-day peak day shortfalls	<p>Extreme daily demand conditions require sufficient injection capacity to meet short duration or multiday peak demand events, or demand-side investments that reduce the magnitude or frequency of extreme demand. Due to the seasonality of southern demand, these risks primarily materialise in southern regions. For southern customers, these challenges may be mitigated through new southern supply, increased north to south transportation capacity and/or demand-side management. Depending on the scale of peak demand and the injection capability of new supply sources, additional southern storage may still be required to adequately manage peak day shortfall risks. Potential options include:</p> <ul style="list-style-type: none"> • new storage facilities or expansions of existing storage, including both shallow and deep storage, • on-site storage at gas generators or dual fuel capability, to reduce peak withdrawal rates from the gas system during extreme conditions, • pipeline augmentations, including reversals of existing infrastructure, to increase transportation flexibility, • LNG regasification terminals providing both incremental supply and injection capability, and • demand side management measures aimed at reducing peak day gas demand.

This analysis considered combinations of uncertain projects, called “project sets”, which provide insight into the ability of these solutions to improve gas adequacy. The project sets considered are not exhaustive and are intended to provide indicative insights into the relative effectiveness of different types of solutions in addressing forecast supply challenges. No cost benefit assessment of these project sets has been undertaken. While some uncertain northern projects were considered, the focus of this analysis is the impact of each project set on southern supply adequacy.

The project sets considered were:

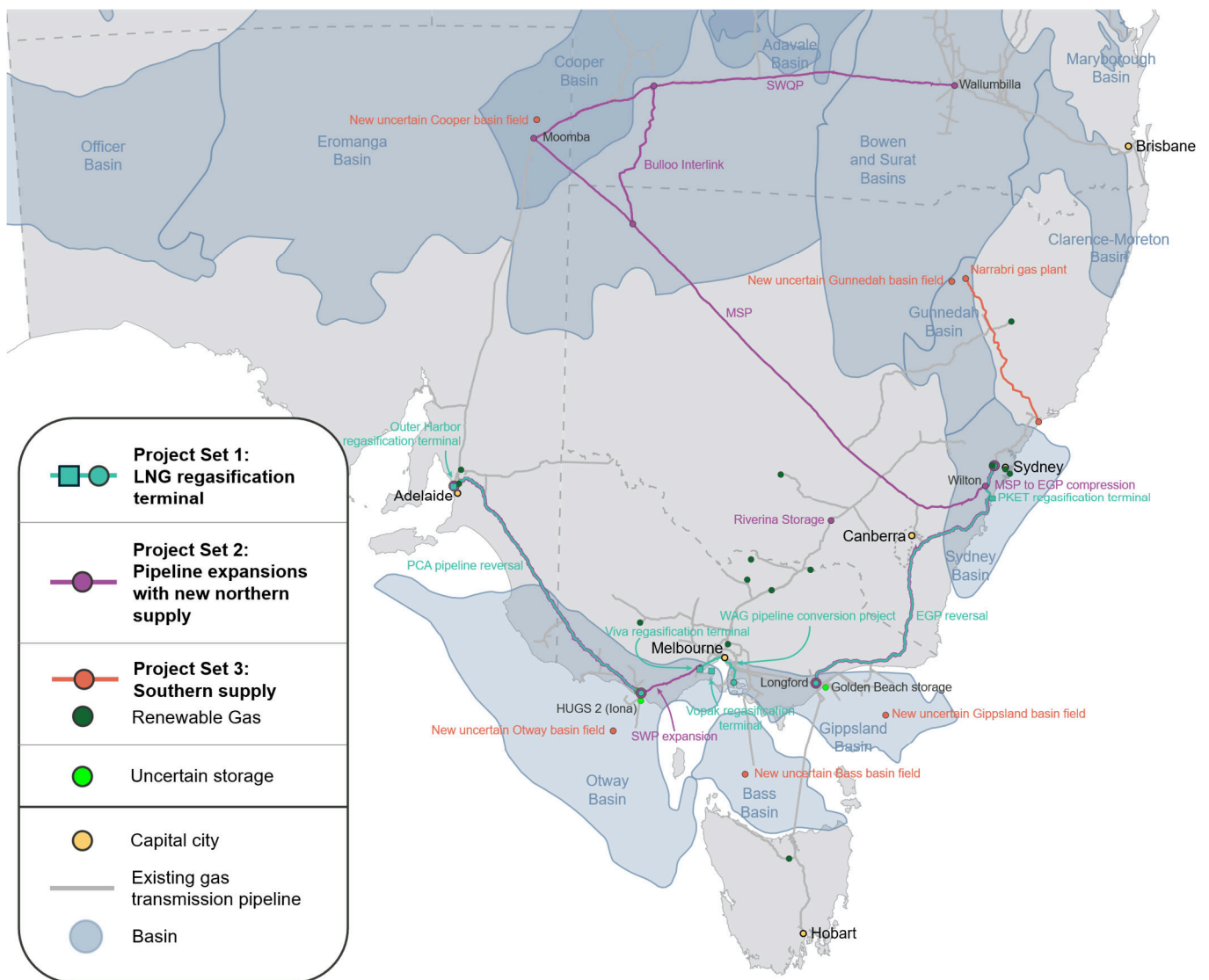
- Project Set #1: *LNG regasification terminal*,

- Project Set #2: Pipeline expansions with new northern supply, and
- Project Set #3: Southern supply.

AEMO also conducted sensitivity analysis on each project set, with additional gas storage projects currently classified as uncertain.

The project sets are described below, and the outcomes of the analysis are presented in Section 5.2. The locations of the projects considered in the projects sets and in the sensitivity analysis are shown in **Figure 48**.

Figure 48 Map of future supply, transportation and storage project sets assessed



Note: Project Set 2 includes additional northern supply developments such as expansions within existing basins, and developments in new basins which are not highlighted in this figure.

Project Set #1: LNG regasification terminal

The addition of an LNG regasification terminal in the ECGM would provide significant peak day injection capability and the potential for large quantities of annual supply. There are four LNG regasification terminal projects proposed in the south, with each project at a different stage of development (at Port Kembla in New South Wales, at Adelaide in South Australia,

and two at Geelong in Victoria; see Section 3.3.4). Regasification terminals will rely on augmentation of existing pipelines or new pipeline infrastructure to enable delivery of their injection capacity to domestic consumers. This project set includes three variants to capture the locational differences between the proposed terminals, but the set represents a single project and its relevant, complementary infrastructure only:

- **New South Wales (Squadron Energy's PKET)** – this includes Jemena's proposed modifications to the EGP, which would enable north to south flow capability, and a second stage which would further expand this capacity south.
- **South Australia (Atlantic, Gulf & Pacific [AG&P]'s Outer Harbor terminal)** – this includes modifications to SEA Gas's PCA pipeline which would enable flows from South Australia towards Victoria.
- **Victoria (Geelong)** – two LNG regasification terminals are proposed to connect near Geelong, one by Viva Energy and the other by Vopak. The 2026 GSOO has applied Viva Energy's terminal as representative of an LNG regasification terminal at Geelong. This project set also includes the conversion of the WAG crude oil pipeline to a natural gas service which is only for the Viva Energy project and would increase the SWP transportation capacity.

All of the LNG regasification terminals proposed in the ECGM depend on an FSRU being moored next to the onshore terminal, which would process incoming shipments of LNG. An FSRU can be relocated so available supply into the ECGM is influenced by the duration that the FSRU is at the terminal, as well as the shipping schedule to supply LNG to the FSRU. In this analysis, AEMO applied assumptions informed by project proponents' survey responses regarding the technically feasible volume of gas that may be provided to each project, which reflect an assumption of year-round availability of the FSRU. It may be the case that, during summer months when there is less gas demand in Australia, a project operator may relocate the FSRU to service alternative locations internationally during the northern hemisphere's winter.

Project Set #2: Pipeline expansions with new northern supply

As discussed in Section 4.1.1, the ability of the north to support the south is currently limited by the transportation capacity of the pipelines from north to south, most notably by the capacity of the SWQP. Since the 2025 GSOO, commitments made by APA to develop the ECGG Expansion Plan Stage 3A will increase the existing north to south capacity. This project set explores further expansion of north to south transport capacity through APA's ECGG Expansion Plan Stage 3B, which includes the Bulloo Interlink as well as additional expansions on the SWQP and MSP. While APA has announced the Bulloo Interlink project is continuing to progress through early works, it was not classified in the 2026 GSOO as anticipated or committed.

Other proposed pipeline projects that support improved flow capabilities within the southern regions, particularly from the north into Victoria demand centres, have also been included in this project set. This includes the MSP to EGP compression project, Jemena's EGP reversal, SEA Gas' PCA reversal and APA's SWP expansion. Riverina Storage, a future stage of APA's ECGG Expansion Plan, was also included in this project set and would provide a new shallow storage on the VNI lateral of the MSP.

To support southern consumers, this project set assumed the development of new, uncertain northern supply alongside the aforementioned additional transportation capacity. As identified in Section 4.2, development of uncertain supply is needed to support forecast LNG export commitments, northern domestic demand and continued north to south flows. The project set included northern supply developments such as expansions within existing basins (including development of new CSG wells), and developments in new basins such as the Beetaloo sub-basin, South Galilee, or North and South Bowen basins.

Supply from the Northern Territory into Queensland and on to the south is currently limited by the capacity of the NGP and CGP. If large new supply developments proceed in the Northern Territory, such as in the Beetaloo sub-basin, additional pipeline infrastructure in the north would be required to enable the south access to this supply. This could include:

- upgrades to Jemena's NGP, which would enable higher flows to Mt Isa and then into the CGP. Transportation capacity to the south would remain limited by the CGP and the SWQP, and
- larger-scale access via APA's North to East Australia Pipeline Project, which is proposed to provide an alternative flow path to the south by connecting to the south via the proposed Bulloo Interlink.

This project set did not consider infrastructure developments in the north that would enable additional access to Northern Territory production as they are not proposed for development within the next five years.

As this policy is currently under consultation, this project set did not consider the potential impact of the Federal Government's proposed domestic gas reservation scheme or any other consequences relating to this policy.

Project Set #3: Southern supply

AEMO uses the PRMS to categorise future natural gas supply developments that are submitted by gas producers and explorers through the GSOO survey process. For this section, uncertain developments can be further divided into projects by their PRMS status:

- **Contingent resources** (referred to as *uncertain 2C* in the GSOO) reflect the best estimate of a quantity of gas that is less certain, and potentially less commercially viable, than 2P. Each of these uncertain 2C projects face a unique set of challenges to reach their full delivery potential.
- **Prospective resources** are estimated gas volumes from undiscovered accumulations that remain highly speculative, as they have not been confirmed through drilling or exploration activities. Prospective resources often face the same challenges as uncertain 2C developments, but have an additional layer of uncertainty due to the speculative nature of the quantities of gas available. It may be the case that some prospective developments will be drilled only to discover that no material quantities of gas are available.

Some uncertain natural gas production developments are associated with existing gas processing plants alongside uncertain gas reserves, and these can be used to 'backfill' the production capacity of the existing processing plant. Such developments would help maintain production rates or mitigate production declines as existing, committed and anticipated gas is extracted over time. Other uncertain supply developments would require new processing plants and infrastructure to connect to the ECGM, which would have planning, approval and construction requirements in addition to the upstream development.

Uncertain renewable gas developments were also considered as potential new sources of southern supply. Many of the proposed renewable gas supply projects identified by proponents in the 2026 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.

This project set assessed two alternative southern production variants:

- **Southern backfill production** – included southern production projects with reported quantities of contingent gas that can backfill existing plants. This project set included production from resources in the Otway, Gippsland, Bass and Cooper basins with production profiles as reported to AEMO via the GSOO surveys.

- **New southern production and additional backfill** – included southern production projects with reported quantities of contingent gas or renewable gas developments that require a new gas plant, prospective supply that can backfill existing plants, and the projects included in the southern backfill production project set. This project set included production from resources in the Otway, Gippsland, Bass, Cooper and Gunnedah basins as well as renewable gas developments with production profiles as reported to AEMO via the GSOO surveys.

Project set sensitivity analysis: Storage

Gas storages enhance operational flexibility by enabling gas produced during lower-demand periods, such as summer, to be stored and withdrawn during winter when demand is higher. The ECGM currently relies on both deep and shallow storages to provide strategic gas reserves for southern regions.

As an extension to the base projects sets, AEMO completed modelling with uncertain storages to demonstrate the impact additional storages could have on supply adequacy in each project set. Excluding Riverina Storage, which was considered a pipeline project in this analysis, there are two uncertain storage projects currently under consideration for development in the ECGM: the Golden Beach Storage Project, which is a new storage facility proposed in Gippsland, and the HUGS Phase 2 project, which upgrades the existing Iona UGS facility (see Section 3.3.2). These uncertain storage projects were added to each project set in sensitivity analysis to evaluate their complementary impacts.

5.2 Proposed project sets can delay peak day shortfall risks and supply gaps

Table 15 below summarises the assumed capacities, development timings, and projected adequacy impacts of each project set considered.

The assessment indicates that:

- All proposed project sets are forecast to improve gas adequacy in the ECGM, although the magnitude of benefit varies across each set, as each project set has a different capability to provide southern consumers with increased peak day production, and annual gas supply.
- No single project set is expected to fully address all supply gaps or eliminate the risk of peak day shortfalls across the GSOO outlook period. Rather, progressive investments will be appropriate across the next two decades, enabling improved investment decisions as forecast gas needs are clearer over time.

This assessment does not represent a ‘best’ or ‘most economic’ assessment of the options. Each project set is presented individually. These project sets included developments classified as uncertain, and included developments from multiple developers. The analysis did not examine customer pricing impacts of any particular solution.

Table 15 Future supply, transportation and storage project sets assessed

Project set name	New supply		Augmentations to transportation capacity (if relevant)		Peak day shortfalls delayed to	Southern annual supply gaps delayed to
	Detail	Capacity	Detail	Capacity		
<i>LNG regasification terminal</i>	New South Wales (Port Kembla) from 2027	500 TJ/d, 130 PJ/y	<ul style="list-style-type: none"> Eastern Gas Pipeline (EGP) reversal Stages 1 and 2 	Stage 1: 200 TJ/d (anticipated) from 2026 Stage 2: 325 TJ/d from 2027	2031	2034
	South Australia (Outer Harbor) from 2028	405 TJ/d, 110 PJ/y	<ul style="list-style-type: none"> Port Campbell to Adelaide (PCA) pipeline reversal, from 2028 	250 TJ/d	2030	2034
	Victoria (Geelong ^A) from 2028	750 – 778 TJ/d, 140 – 270 PJ/y	<ul style="list-style-type: none"> WAG pipeline conversion project, from 2028^B 	120 TJ/d	2031	2034
<i>Pipeline expansions with new northern supply</i>	Northern production developments	200 – 500 PJ/y ^C	<ul style="list-style-type: none"> Bulloo Interlink (ECGG Plan Stage 3B^D), from 2028 MSP to EGP compression, from 2028 SWP expansion^E, from 2029 EGP reversal Stages 1 and 2, from 2027 PCA pipeline reversal, from 2028 Riverina storage pipeline, from 2029 	700 TJ/d Bulloo Interlink ^F 608 TJ/d SWQP 700 TJ/d MSP 200-500 TJ Riverina	2030	2031
<i>Southern supply</i>	Southern backfill production	<ul style="list-style-type: none"> Ramping to 110 PJ/y by 2030 Up to 45 PJ/y in the long term 			2031	2034
	New southern production and additional backfill production	<ul style="list-style-type: none"> Ramping up to 225 PJ/y by 2035 Declines gradually to 165 PJ/year by 2045 	<ul style="list-style-type: none"> Hunter Gas Pipeline (Narrabri to Newcastle), from 2028 	200 TJ/d	2034	2035

A. This could be either Viva Energy's or Vopak's proposed LNG regasification terminal project.

B. Only for Viva Energy's proposed LNG regasification terminal project. Timing is assumed similar to the operational date of the LNG regasification terminal

C. Projects included in this additional northern supply include 2C and prospective resources from the Bowen, Surat basins and Beetaloo sub-basin. This project set only includes production profiles from northern 2C resources reported to AEMO via the GSOO surveys.

D. Stage 3A includes the capacity increase of MSP Young to Culcairn by 39 TJ/d, MSP mainline to Wilton by 10 TJ/d and SWQP capacity by 58 TJ/d which are considered committed in 2026 GSOO and therefore included in all analyses in this section.

E. According to APA Group's press release on 19 February 2026, the maximum southbound capacity of the Bulloo Interlink can be up to 800 TJ/day. The capacity modelled in this project set was based on information AEMO received in 2026 GSOO surveys and engagement which is reflective of the first pipeline stage. See https://admin.apa.com.au/media/xc3hv0ud/260219_asx_release_ap_a_to_deliver_pipeline_capacity_needed_to_solve_projected_east_coast_gas_shortfalls.pdf.

F. Expansion capacity based on APA's Rule 80 application to expand the SWP. See <https://www.aer.gov.au/industry/registers/access-arrangements/apa-victorian-transmission-system-rule-80-application-expansion-south-west-pipeline/initiation#submissions>.

Figure 49 presents the forecast southern gas adequacy impact of each project set on addressing peak day shortfall risks and closing annual supply gaps that are forecast with only existing, committed and anticipated projects, showing that in this analysis:

- An *LNG regasification terminal* is forecast to delay the forecast supply gaps to 2034¹⁰⁶, if the associated pipeline infrastructure to ensure effective delivery from the terminal is also developed and if shipping schedules and FSRU availability provide sufficient gas volumes to southern consumers. While all terminals investigated delay peak day shortfalls, the supply capacity of the different terminals and their supporting pipeline infrastructure varied, resulting in a delay of peak day shortfall risks to either 2030 or 2031.
- *Pipeline expansions with new northern supply* improves north to south flow capacity and are forecast to delay the forecast peak day shortfalls to 2030 and supply gaps to 2031. This project set is also dependent on additional northern gas becoming available to be transported south, beyond currently committed and anticipated production. Additional investments in the north may materially improve the effectiveness of this project set. The 2026 GSOO has not attempted to examine future stages of APA Group's ECGG Expansion Plan, or the North to East Australia Pipeline Project or upgrades to the NGP that would enable better access to proposed developments in the Northern Territory. Likewise, it has not incorporated additional, complementary southern storage developments that may provide additional supply flexibility, if also delivered. See Section 5.2.2 for analysis on the additional support that uncertain storage developments may provide to complement this, and other, project sets.
 - This project set is less effective at delaying the annual supply gaps than the *Pipelines expansions and upgrades* project set assessed in the 2025 GSOO. The 2026 project set included a more detailed representation of uncertain supply and infrastructure developments in the north, resulting in a more accurate representation of the north to south transportation constraints.
- The development of all *Southern supply* that could backfill the production capacity of existing plants is forecast to defer forecast peak day shortfalls to 2031 and supply gaps to 2034. If additional southern supply was developed, including production from all currently uncertain new gas plants and further backfill using prospective resources, this could further delay the peak day shortfalls to 2034 and supply gaps to 2035.
 - It is important to note that both of the *Southern supply* project sets require the successful development of many individual projects with different proponents. Some of these supplies, particularly production from prospective resources, may fall short of estimated volumes.

¹⁰⁶ Impact on supply gaps for this project set presented in **Figure 49** is the range of the different LNG regasification terminals described in **Table 15**.

Figure 49 Range of annual supply gaps for each project set assessed across various weather conditions, in comparison to the *Step Change* scenario, 2026-45 (PJ)

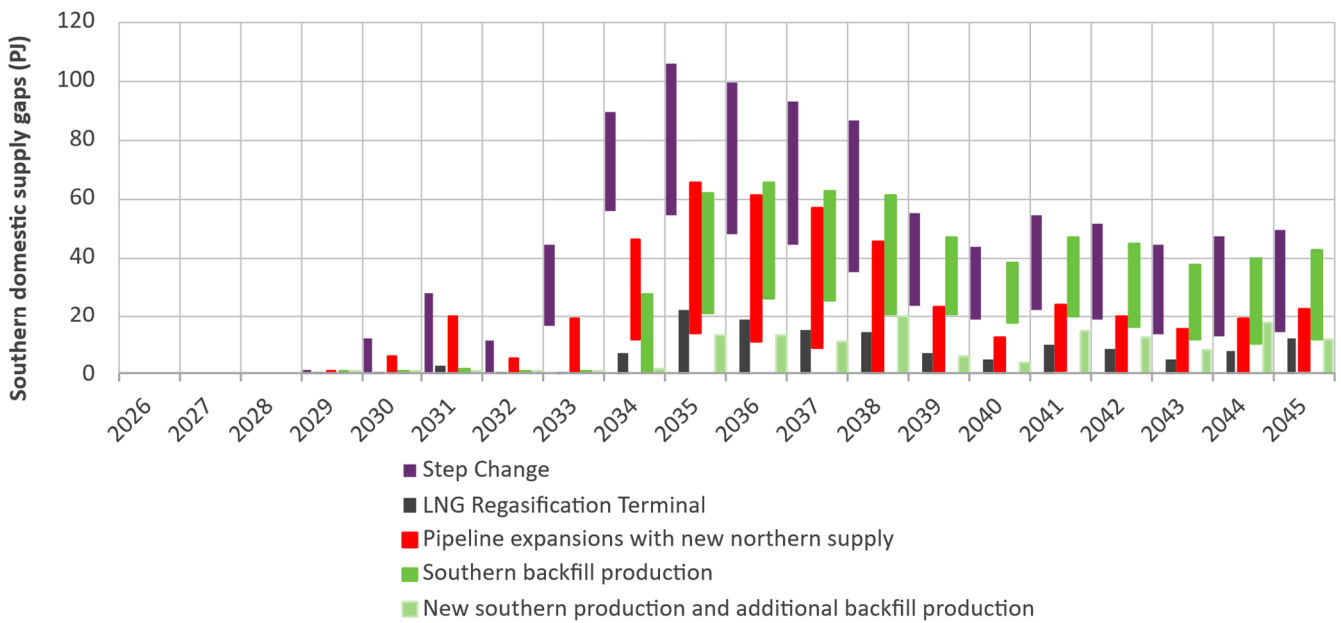


Figure 50 shows that while the risk of daily shortfalls under extreme peak demand conditions is reduced in all project sets relative to *Step Change*, additional investments above those assessed are still projected to be needed to fully address the risk of daily peak supply shortfalls, from 2030 in some project sets and later in others. This could be delivered by a combination of the projects assessed, new or expanded capacity from storage, or additional expansions to the north to south transportation capacity.

From a whole-of-system perspective, greater investment in gas demand-side opportunities, or in NEM capacity that reduces GPG usage while maintaining reliability and system security, could also help close the supply gap cost-effectively. This is particularly relevant for the 2034 to 2038 period, when the expected supply gap is largest and most sensitive to weather uncertainty.

Figure 51 shows how, for all project sets assessed, gas supply adequacy in the southern regions continues to rely on supply from the northern states. Lower amounts of gas transported from the north to the south are expected for the project sets that increase supply in the southern states, either through a regasification terminal or new southern supply, offsetting the amount of gas relied on from the north. More northern gas would be able to support the south with an expanded north to south pipeline capacity, shown by the higher gas transported south in the pipelines project set. Flows increase over time as southern production continues to decline and more northern gas is also required to refill storages outside peak periods, particularly from 2033. North to south flows decline from the late 2030s for project sets with long-term sources of new southern supply as forecast southern consumption decreases.

Figure 50 Forecast southern daily adequacy for each of the future project sets assessed, reference year 2024, 2026-35 (TJ/d)

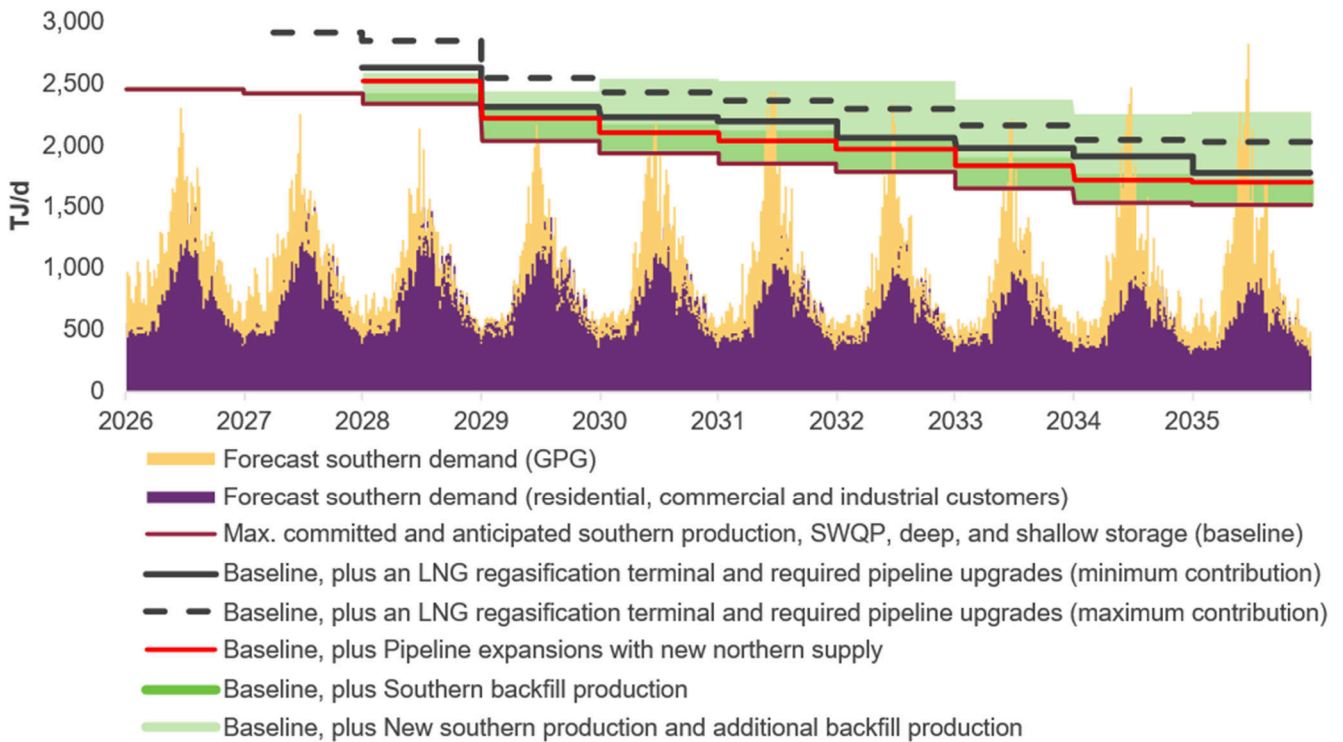
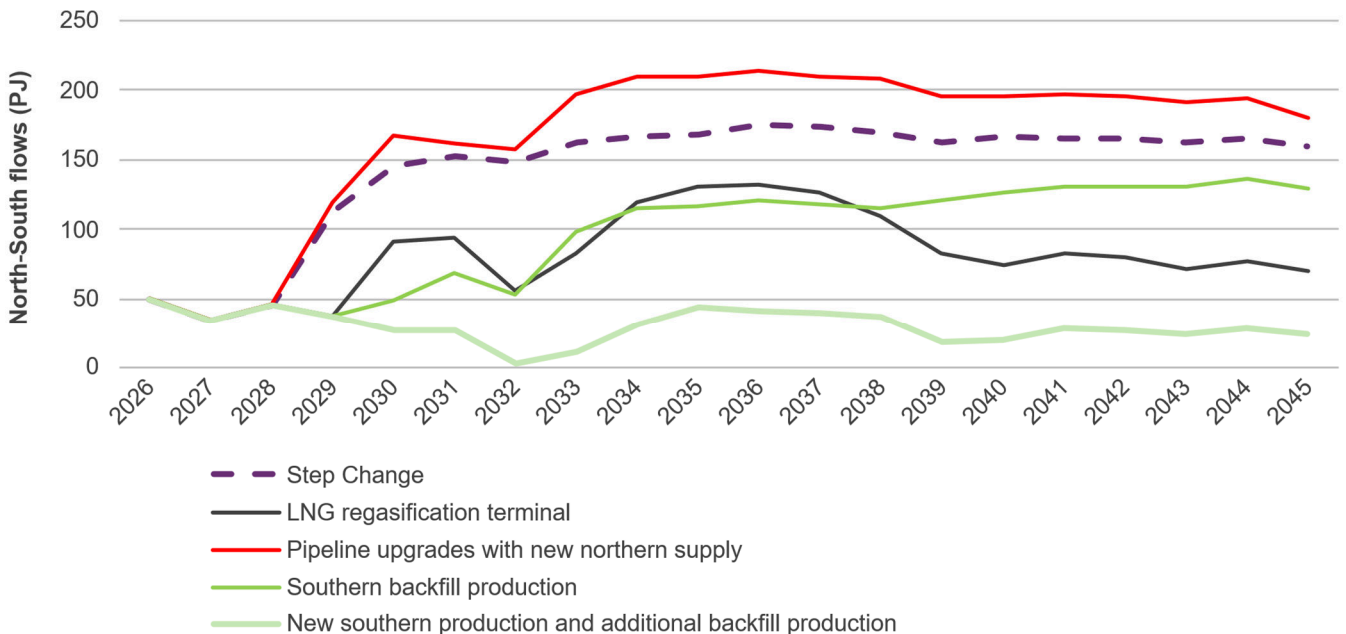


Figure 51 Gas transported from north to south for all project sets assessed, compared to flows with only existing, committed and anticipated developments, Step Change, reference year 2024, 2026-45 (PJ)



5.2.1 Examining the supply profile of proposed project sets

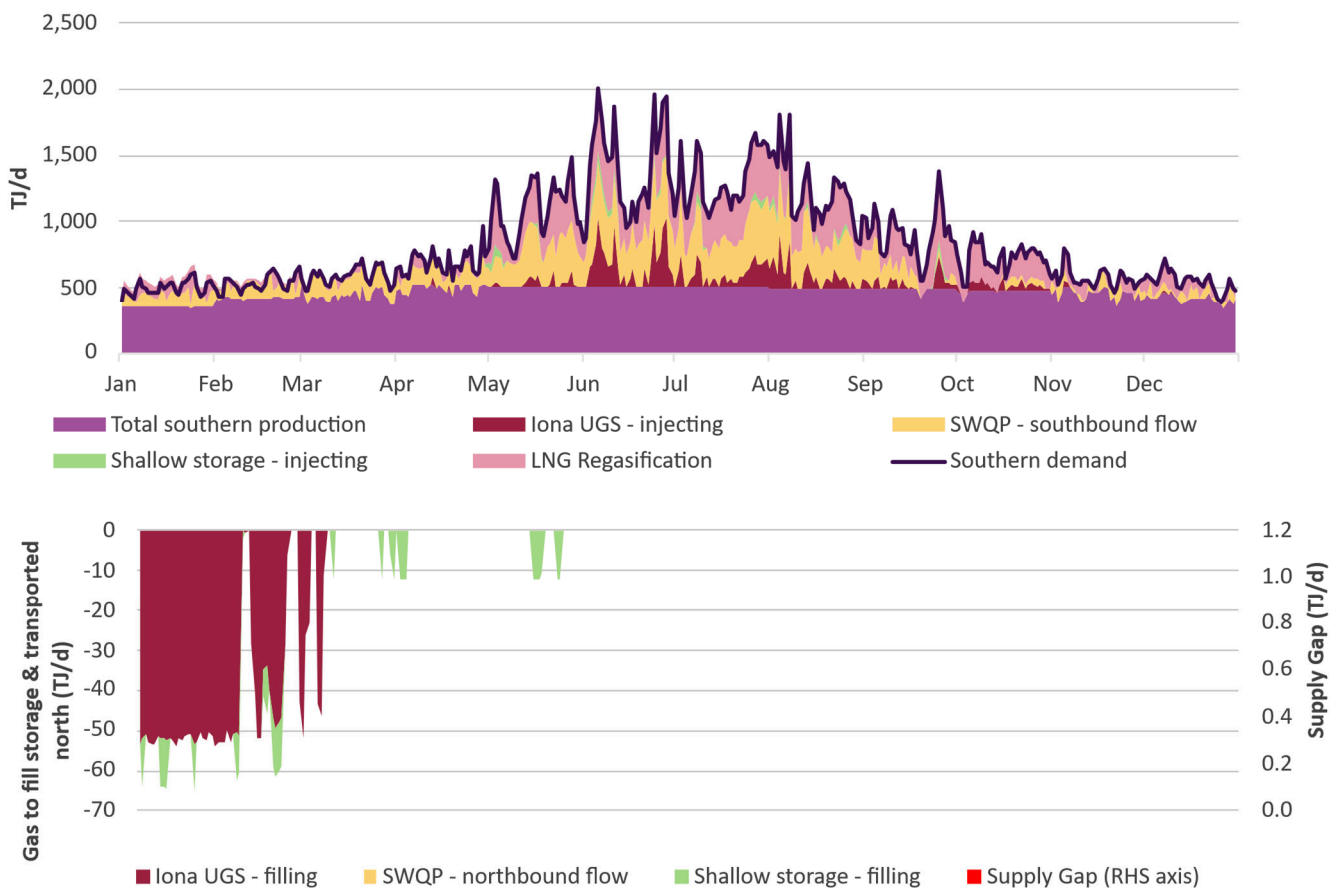
The effectiveness of each project set to support ongoing gas supply adequacy varies depending on the capability of the project set to meet peak day demand and seasonal storage refilling requirements. This section examines the daily supply

trends of each project set to meet consumer needs during 2030, as an example year, in the *Step Change* scenario, using the 2020 weather reference year.

Figure 52, Figure 53 and Figure 54 show that:

- Gas from the north will be a key source of supply to meet southern demand during winter, even if supplies are available from a new *LNG regasification terminal* (Figure 52) and especially in the *Pipeline upgrades with new northern supply* project set (Figure 53).
- With new, uncertain *Southern supply* (Figure 54), less reliance on northern gas would be enabled, but some supply would still be expected to support winter requirements.
- Storage operations are critical in all project sets. Re-filling is required throughout the summer months to provide critical operational flexibility to meet elevated gas demand between June and September.
- While no annual supply gaps are observed in 2030 in any of the displayed project sets¹⁰⁷, peak day shortfall risks and seasonal supply gaps may still exist in winter during more extreme weather conditions.

Figure 52 Forecast gas supply sources to meet southern daily demand for the *LNG regasification terminal* project set, *Step Change*, reference year 2020, 2030 (TJ/d)



¹⁰⁷ The peak day adequacy of the *LNG regasification terminal* project set depends on the specific terminal developed in the project set, as some terminal and infrastructure combinations provide higher peak day production capabilities than others, as described in Table 15.

Figure 53 Forecast gas supply sources to meet southern daily demand for the Pipeline upgrades with new northern supply project set, Step Change, reference year 2020, 2030 (TJ/d)

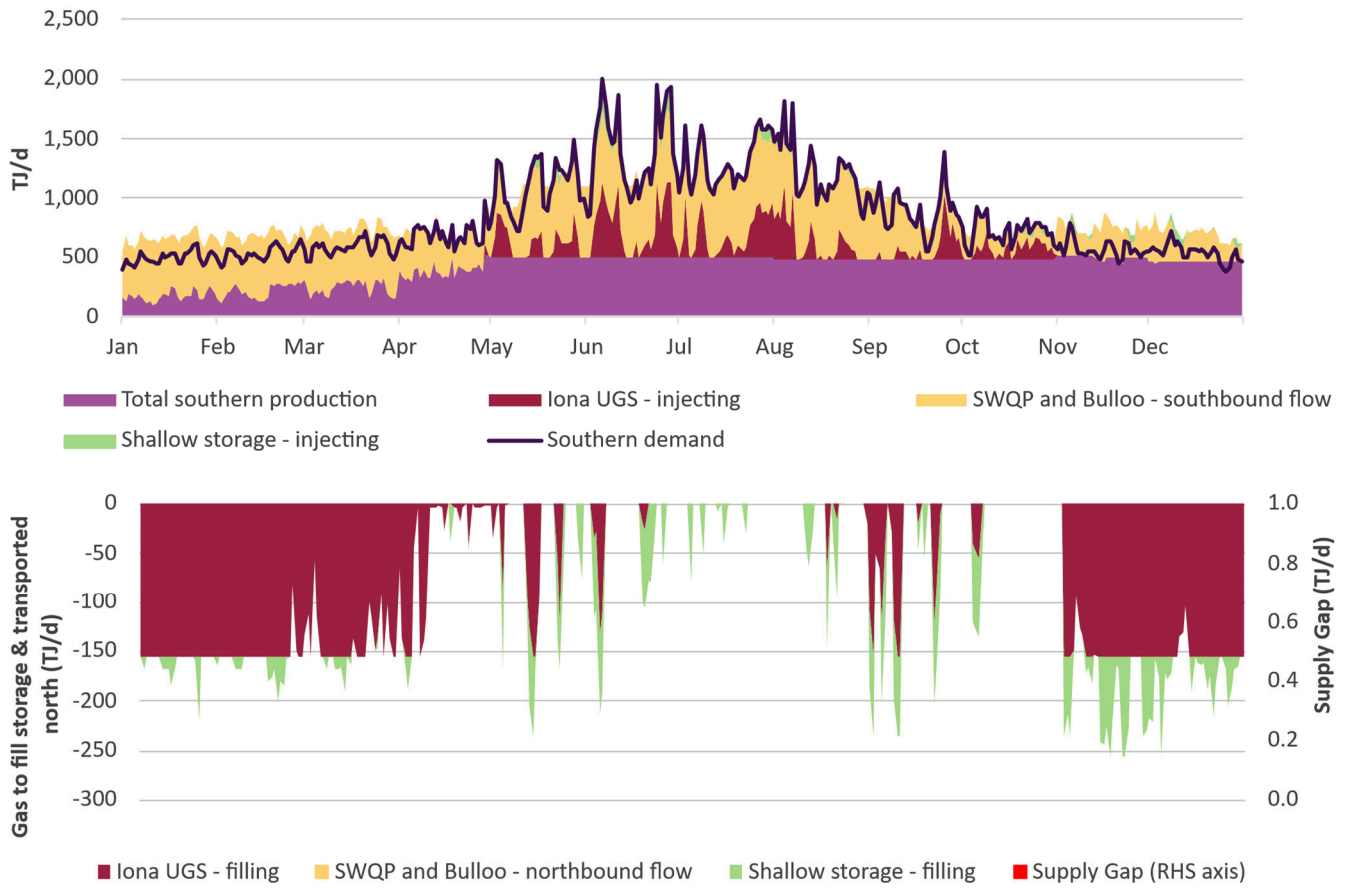
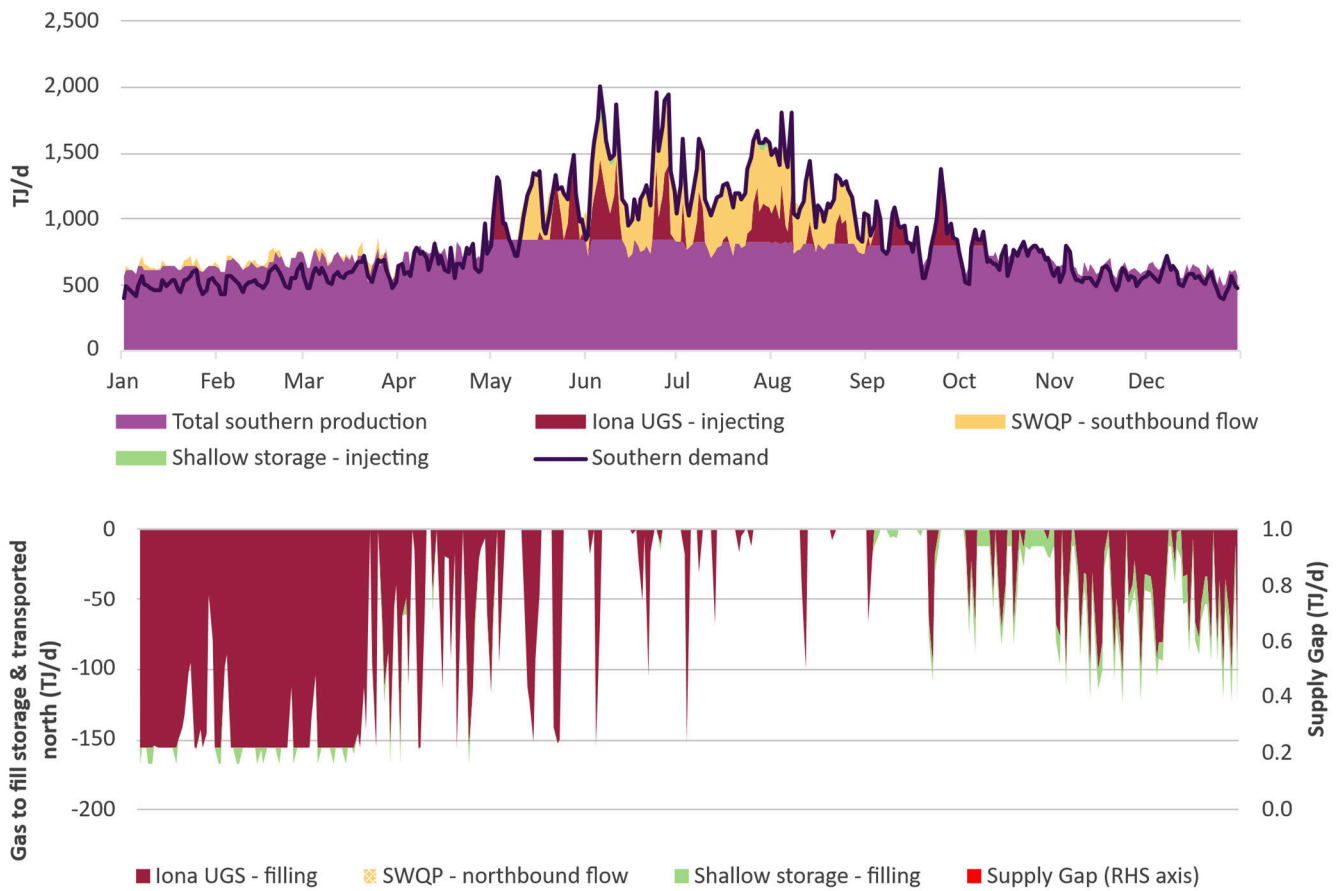


Figure 54 Forecast gas supply sources to meet southern daily demand for the *Southern supply (Southern backfill production) project set, Step Change, reference year 2020, 2030 (TJ/d)*



5.2.2 New storage developments are beneficial in addressing peak day shortfall risks

As reported in the Draft 2026 ISP, GPG is forecast to have an increasing role to firm renewable energy generation in the NEM, particularly after coal generators retire. Developments in alternative dispatchable generation, such as battery or pumped hydro schemes, may influence the magnitude of GPG requirements. The 2026 GSOO aligns with the GPG forecasts in the Draft 2026 ISP, with increasing operational volatility requiring gas supply to service concentrated periods of high gas demand, driven by volatile GPG requirements, particularly when electricity demands are high and renewable generation availability is low.

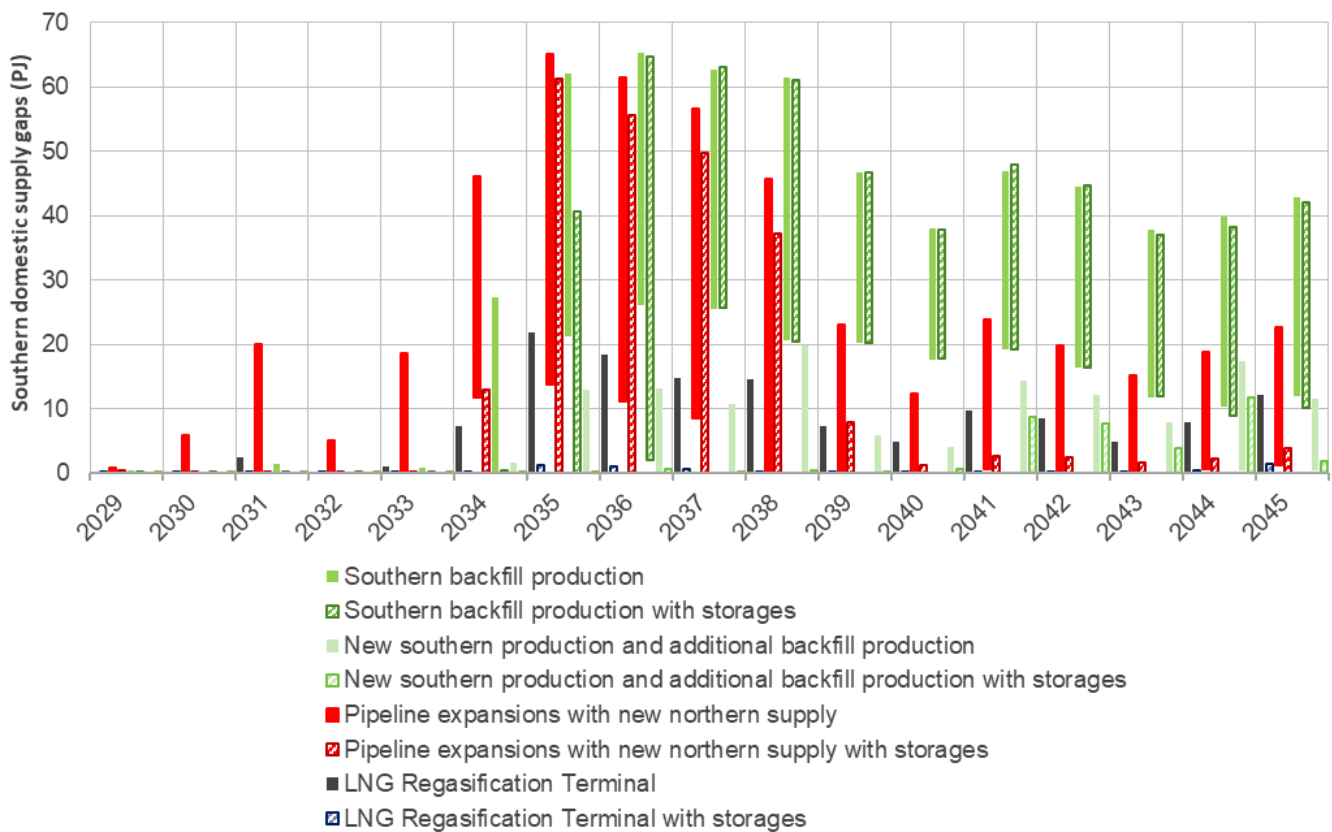
As a result of these demand-side dynamics, along with declining forecast residential, commercial and industrial gas consumption, the project sets reveal a need for supply flexibility to mitigate risks associated with peak day and seasonal shortfalls in extreme conditions.

Gas storage is an effective solution to manage peak seasonal demands, if in locations that provide sufficient access to consumers and gas supply. Storage provides flexible injection capability into the market during peak periods, the ability to respond quickly to changes in demand, and potential relief of existing transportation constraints within the gas network. All types of existing storage facilities are critical in addressing the seasonal adequacy challenges and winter peak demands, including GPG demand (as demonstrated in Section 2.4).

Figure 55 presents the range of southern annual supply gaps for each supply project set when uncertain storage projects are also included, showing that in this analysis:

- The development of uncertain storages is a good complement to the *LNG regasification terminal* project set, with annual supply gaps largely addressed with additional storage. If the FSRU is available year-round, as assumed in this analysis, large quantities of gas supplied by the regasification terminal can be stored during summer and into the shoulder periods for use in winter.
- The *Pipeline expansions with new northern supply* project set can provide year-round supplies to the south. Southern storages would be a key complement to increased transportation capacity, providing increased supply flexibility to meet variable southern demand. The development of additional uncertain storages would provide additional peak support, while benefiting greatly from the off-peak refilling opportunities from northern imports to support southern winter demand. Under this project set, new uncertain storage capacity can materially reduce both peak day shortfall risks and annual supply gaps through the early to mid-2030s, with benefits extending into the 2040s. Larger supply gaps remain between 2035 and 2038, when annual GPG consumption is at its highest.
- Within the *Southern supply* project sets, additional storage capacity can assist in mitigating peak day shortfall risks and reducing annual supply gaps until the mid-2030s. From this period, there is a limit to the amount of uncertain 2C gas available to backfill existing plants, which limits the effectiveness of uncertain storages, and there is little difference with and without storages from 2037. If new uncertain gas plants, including renewable gas, and prospective resources are developed to backfill existing plants, this results in a much longer-term improvement to supply adequacy.

Figure 55 Range of southern annual supply gaps for future supply project sets assessed, including additional storage, 2029-45 (PJ)





5.2.3 Longer-term adequacy requirements

Declining southern production and an increasing peak GPG demand, coinciding with high residential, commercial and industrial demand in winter, is projected to place additional pressure on gas supply adequacy. To address the needs of all gas users, a combination of investments that provide new gas supply is needed to provide sufficient daily production capability and to provide sufficient annual supply to meet forecast gas demand and consumption across the 20-year assessment. The project sets included complementary investments, yet each project set identified peak day shortfall and annual supply gap risks that would need additional investments to increase supply capacity, or additional demand-side investments to reduce gas needs, across the forecast horizon.

This represents a reduced long-term gas supply and infrastructure requirement compared to that identified in the 2025 GSOO, so long as:

- residential, commercial and industrial gas consumption continues to decline as forecast, and
- increasing penetration of NEM storages reduce the relative volume of supply required from GPG.

Long-term forecasts of gas consumption, particularly for GPG, are highly uncertain.

The final 2026 ISP will apply these updated gas forecasts on the plausible gas development projections that extend these project sets. The most efficient long-term investment outcomes will depend on the pace of demand-side electrification and the scale of NEM storage and other firming investments that reduce reliance on GPG. The interdependence between gas adequacy and power system needs is a key consideration for investment requirements to support gas adequacy for consumers.



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 2021, 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 (since 2022, the central scenario has often been labelled with a *Step Change* naming convention).

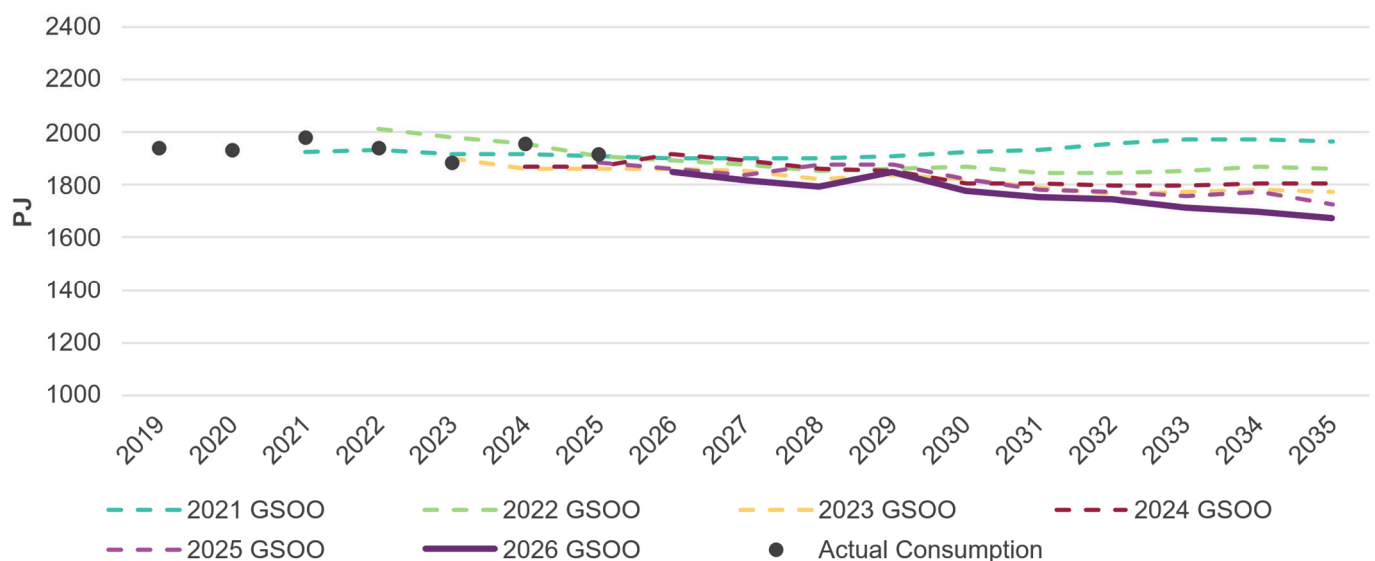
Actual annual gas consumption is partly driven by weather. For example, in a very cold year, gas consumption will be higher due to increased use of space heating. AEMO’s forecasts are developed on a weather-normalised basis (with typical weather conditions), so some difference between forecast and actual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

As outlined in AEMO’s 2026 *Gas Demand Forecasting Methodology Information Paper*, 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 2026 *Gas Demand Forecasting Methodology Information Paper*.

A1.1 Total gas consumption forecasts

Figure 56 shows total gas consumption forecasts, including consumption for LNG export, over successive GSOO publications.

Figure 56 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 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 2022 GSOO over-estimated gas consumption for the 2022 calendar year, mainly driven by lower than forecast LNG consumption.
- The 2023 GSOO over-estimated consumption in the 2023 calendar year. The variance mainly came from lower than forecast consumption from GPG generation and residential and commercial sectors.
- The 2024 GSOO and 2025 GSOO under-estimated consumption for the corresponding 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 large scale of gas consumption for LNG creation in the north.

Table 16 provides an overview of the forecast accuracy of the calendar year immediately following the forecast. It shows that year ahead forecasts have been within 5% of actuals for the past five years. Forecast accuracy in this case is measured as the percentage error, calculated as:

$$\text{Percentage error} = (\text{Forecast} - \text{Actual}) / \text{Actual}$$

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 total forecast error.

Table 16 Year ahead historical forecast accuracy, total consumption (PJ)

	2021	2022	2023	2024	2025
Year ahead forecast	1,928	2,009	1,904	1,869	1,889
Actual consumption	1,959	1,923	1,880	1,951	1,917
Forecast accuracy	-1.6%	4.5%	1.3%	-4.2%	-1.4%
Source	2021 GSOO	2022 GSOO	2023 GSOO	2024 GSOO	2025 GSOO

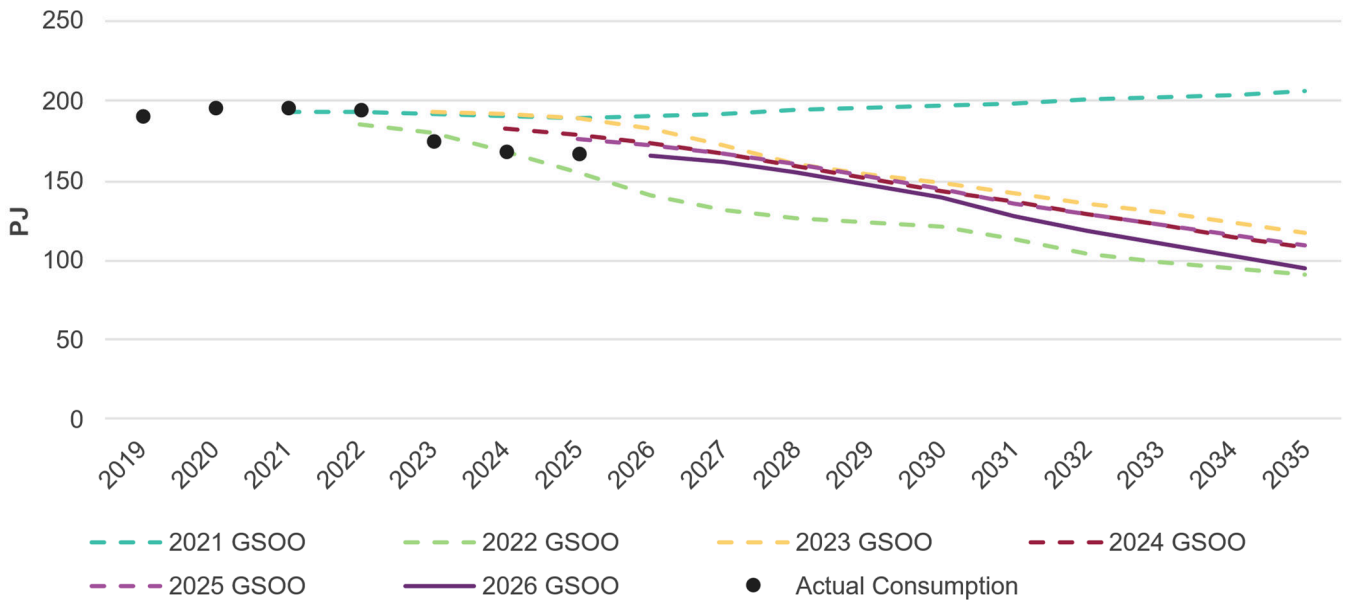
Note: Minor variations in historical consumption reported in previous GSOO reports may occur due to refinements to connection point mapping and updates of estimates with actual information.

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

A1.2 Residential and commercial gas consumption forecasts

Figure 57 shows AEMO’s residential and commercial gas consumption forecasts over successive GSOO reports for central scenarios compared to actual outcomes. AEMO’s forecasts are driven by various components including growth of connections and population, policy targets by various governments that encourage decarbonisation activities including growth and the impacts of investments in energy efficiency, gas fuel-switching such as electrification, as well as other factors including gas prices and economic activity. These factors are described in more detail in Section 2.2.1.

Figure 57 Gas consumption forecast comparison to actuals in the residential and commercial 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 17 provides an overview of the residential and commercial gas consumption forecast accuracy of the calendar year immediately following the forecast. The projection of residential and commercial consumption in AEMO’s 2025 GSOO was 5% higher than actual consumption levels in calendar year 2025. After accounting for differences between realised and assumed weather conditions, the 2025 GSOO residential and small commercial consumption forecast exceeded actuals by 3.5 PJ, or 2%. The largest share of weather-corrected forecast discrepancy in 2025 was in Victoria, where almost 6 PJ additional gas was projected to be consumed. This lower consumption, even after adjusting for weather impact, suggests a declining trend in residential and small commercial gas consumption which was not captured in the 2025 GSOO.

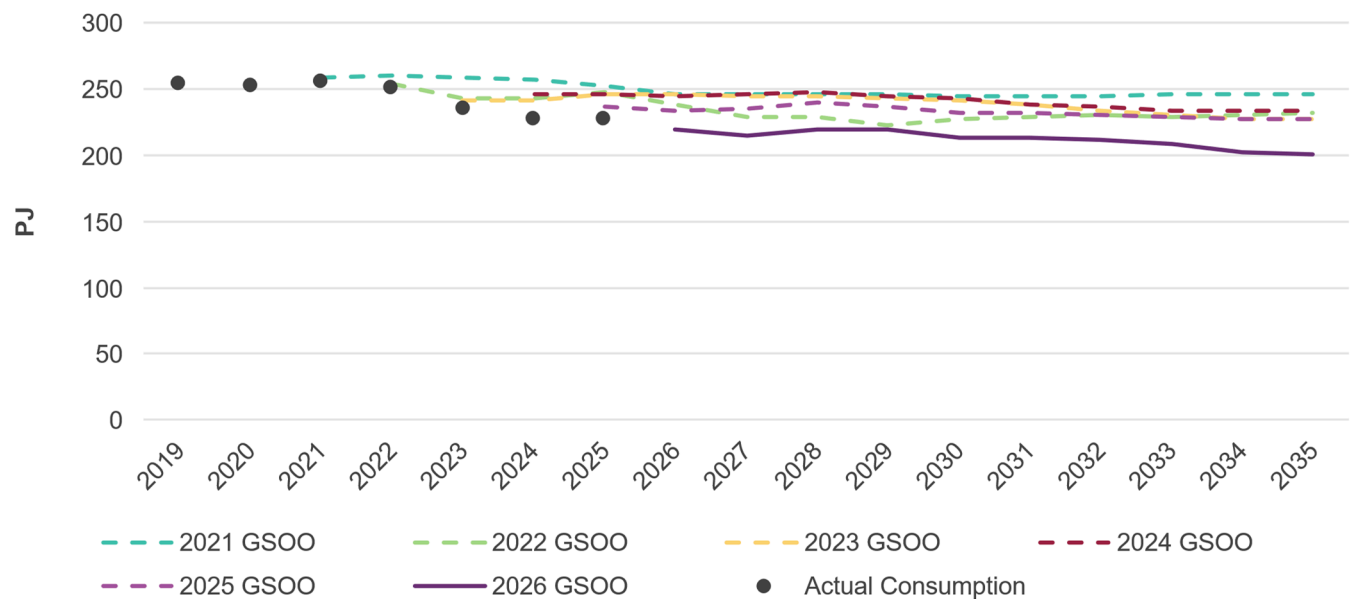
Table 17 Year ahead historical forecast accuracy, residential and commercial total consumption (PJ)

	2021	2022	2023	2024	2025
Year ahead forecast	194	185	193	182	176
Actual consumption	196	194	175	169	167
Forecast accuracy	-1.2%	-4.6%	10.1%	8.0%	5.2%
Source	GSOO 2021	GSOO 2022	GSOO 2023	GSOO 2024	GSOO 2025

A1.3 Industrial gas consumption forecasts

Figure 58 shows AEMO’s industrial gas consumption forecasts. AEMO’s industrial consumption projections are based on two categories – large industrial loads (LILs) and small to medium industrial loads (SMILs). Operators of LILs 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 58 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 18 provides an overview of the industrial gas consumption forecast accuracy of the calendar year immediately following the forecast.

Table 18 Year ahead historical forecast accuracy, industrial total consumption (PJ)

	2021	2022	2023	2024	2025
Year ahead forecast	260	254	242	247	237
Actual consumption	257	252	237	228	229
Forecast accuracy	1.2%	1.0%	2.1%	8.3%	3.5%
Source	2021 GSOO	2022 GSOO	2023 GSOO	2024 GSOO	2025 GSOO

Over 85% of large industrial gas-consuming customers (by volume) responded to AEMO through the 2026 GSOO and VGPR surveys. Consistent with the methodology, AEMO adopted an econometric modelling approach to forecast the remaining industrial customers in aggregate¹⁰⁸, which included an allowance for the potential fuel-switching of industrial consumers to electricity and other gases¹⁰⁹.

Forecast industrial gas consumption continues to follow a long-term declining trend. Variations from forecasts to actual industrial consumption arise from changes in operational plans that were not captured in the LIL surveys.

AEMO’s 2025 GSOO industrial projection was 3.5% higher than actual consumption in the 2025 calendar year. The lower LIL consumption can be attributed to operational changes at facilities in Victoria, New South Wales and Queensland.

¹⁰⁸ For details on AEMO’s econometric modelling, see the *Gas Demand Forecasting Methodology Information Paper*, at https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2026/2026-gsoo-methodology-demand-forecasting.pdf.

¹⁰⁹ Consumption impacts of potential fuel-switching to electricity and hydrogen from gas were based on multi-sectoral modelling conducted by consultants CSIRO and ClimateWorks.

A1.4 LNG export segment consumption forecasts

In 2025, gas consumption by LNG export facilities in Queensland represented 75% of total gas consumption across the ECGM. The GSOO does not include any LNG exports from the Northern Territory.

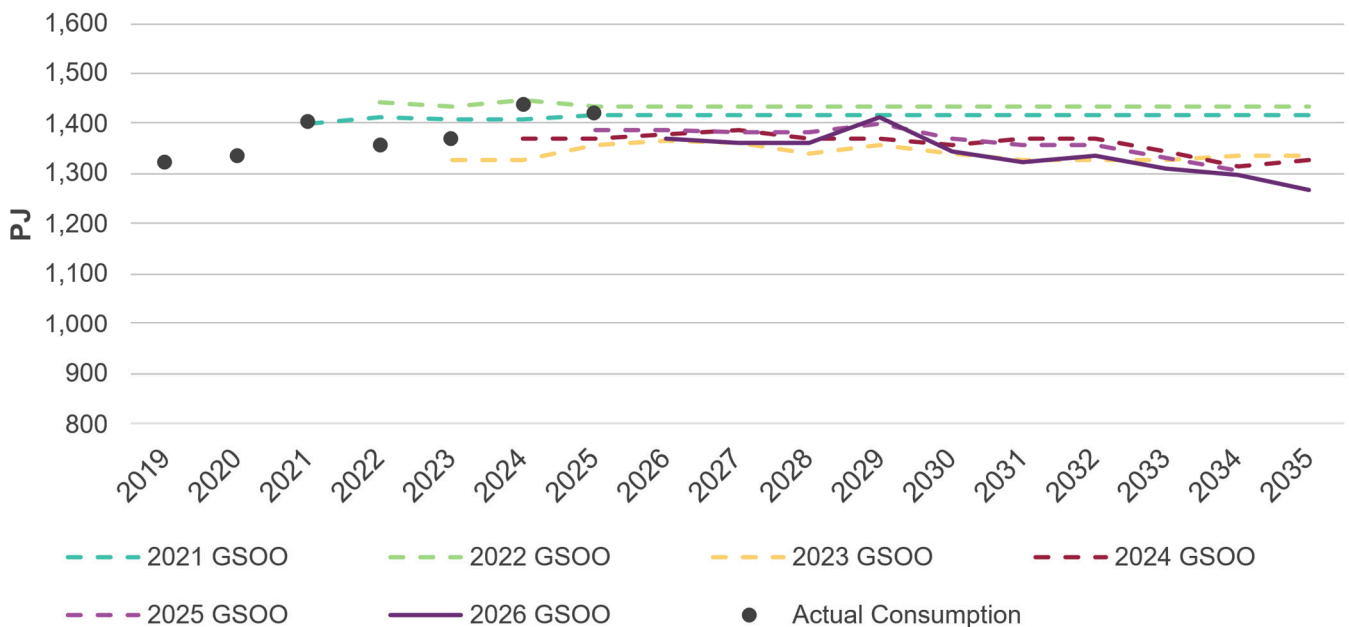
LNG export consumption is driven by factors including:

- 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, and
- contractual considerations affecting local production.

Forecasts of LNG export consumption until 2035 were advised by LNG producers via the GSOO survey process, like LIL consumption, in accordance with the *Gas Demand Forecasting Methodology Information Paper*¹¹⁰. 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 59 and Table 19 compare LNG export forecasts to actual LNG exports from Curtis Island in Queensland.

Figure 59 Annual gas consumption forecast comparison, Queensland LNG (PJ)



¹¹⁰ At https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2026/2026-gsoo-methodology-demand-forecasting.pdf

Table 19 Year ahead historical forecast accuracy, all Queensland LNG facilities total consumption (PJ)

	2021	2022	2023	2024	2025
Year ahead forecast	1,401	1,444	1,326	1,369	1,387
Actual consumption	1,407	1,358	1,371	1,439	1,423
Forecast accuracy	-0.5%	6.4%	-3.3%	-4.9%	-2.5%
Source	2021 GSOO	2022 GSOO	2023 GSOO	2024 GSOO	2025 GSOO

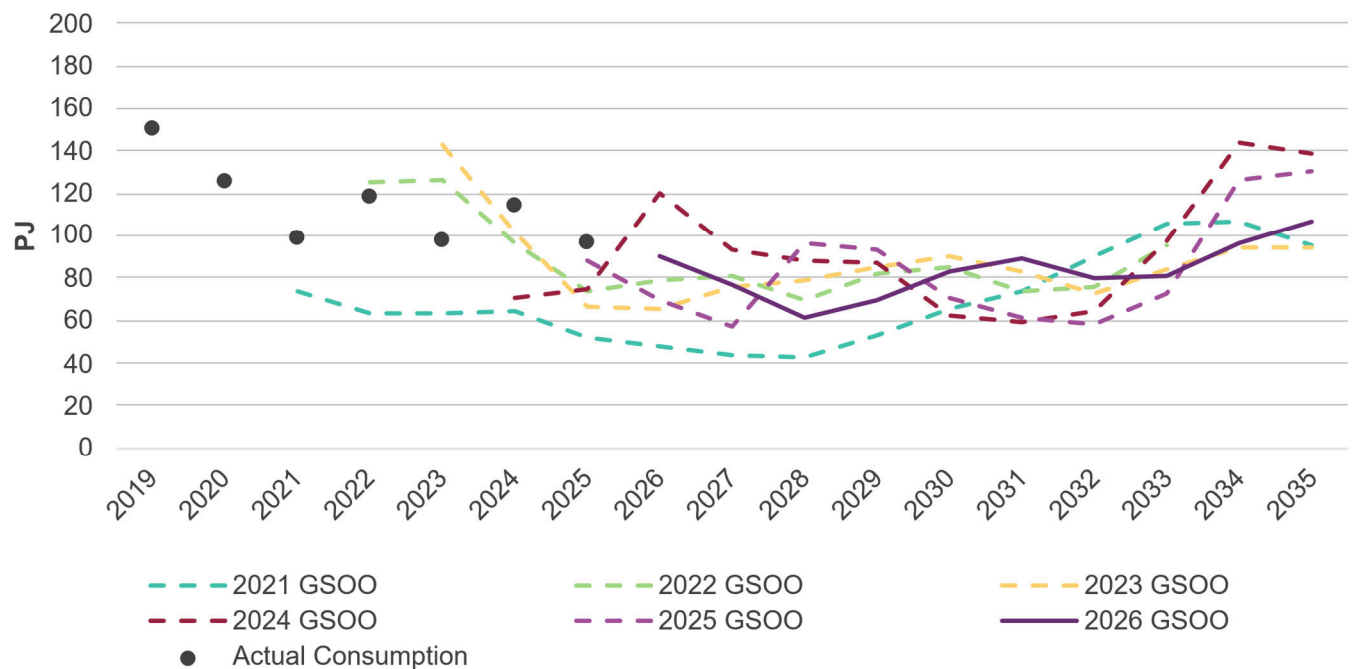
Table 19 shows that the year-ahead forecast produced in each GSOO represents a combination of under- and over-forecast errors. In 2025, Queensland LNG exports were higher than advised by the LNG producers in the 2025 GSOO survey process. Lower domestic gas consumption, enabled greater LNG exports than forecast, although lower than the record high quantities exported in 2024. For more information, refer to AEMO’s 2025 *Quarterly Energy Dynamics* reports¹¹¹.

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 60** and **Table 20**, which highlight discrepancies between projected and actual gas usage.

Figure 60 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.

¹¹¹ At <https://www.aemo.com.au/energy-systems/major-publications/quarterly-energy-dynamics-qed>.

Table 20 Year ahead historical forecast accuracy, gas generation in the NEM and Northern Territory, total consumption (PJ)

	2021	2022	2023	2024	2025
Year ahead forecast	74	125	143	71	89
Actual consumption	117	137	98	115	97
Forecast accuracy	-37%	-8%	47%	-38%	-9%
Source	2021 GSOO	2022 GSOO	2023 GSOO	2024 GSOO	2025 GSOO

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

- 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 there was an 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.
- In 2024, 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 2025 GSOO GPG average consumption forecast was 89 PJ, 9% lower than the actual 2025 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 61 shows the 2025 GSOO GPG forecast's monthly consumption range across the range of weather conditions that were forecast in the 2025 GSOO, demonstrating that each month of the year was within the monthly forecast range.

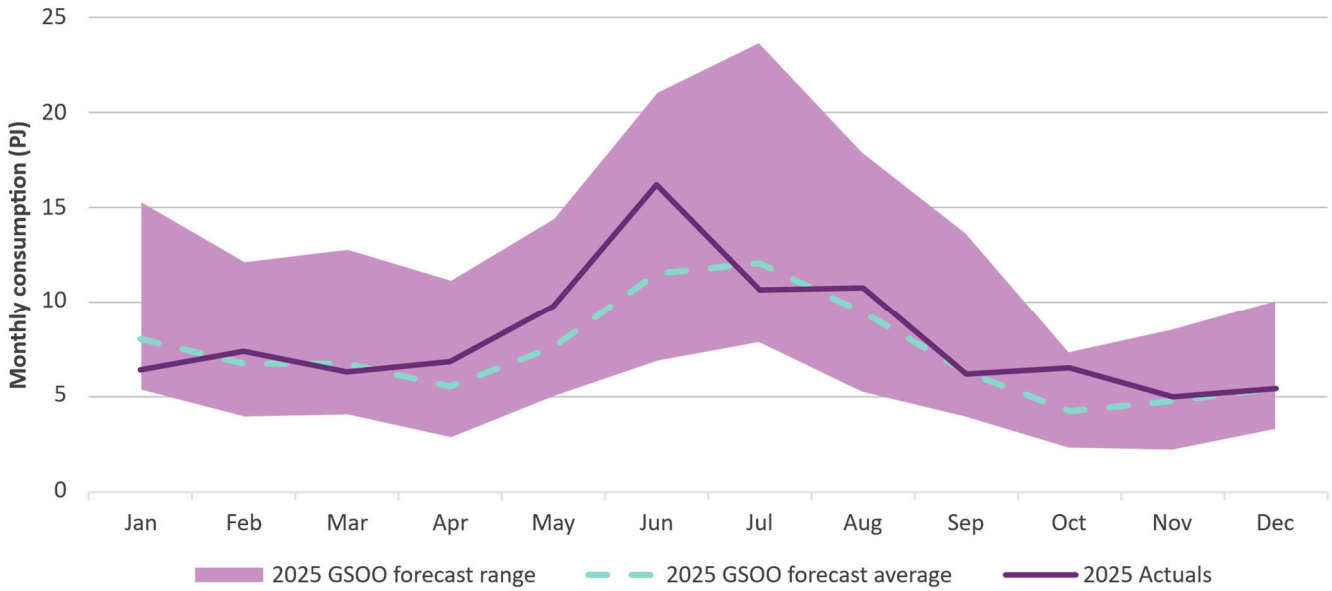
In 2025, there were two key drivers of higher and lower monthly consumption, depending on the month:

- Months with lower actual levels of GPG than the average forecast were primarily attributable to a rapid increase of grid-scale batteries competing directly with GPG in price-setting.
- In June 2025, actual GPG consumption was considerably higher than the forecast average, with gas demand for GPG reaching new daily highs on June days when cold winter conditions combined with very low wind availability. NEM GPG demand totalled 1,049 TJ on 26 June 2025, a new winter record and the fourth-highest daily total on record for any time of year¹¹².

¹¹² AEMO, Q2 2025 *Quarterly Energy Dynamics*, at https://www.aemo.com.au/-/media/files/major-publications/qed/2025/qed-q2-2025.pdf?rev=8732b44ba628445da5883f92e84cd87d&sc_lang=en.

The 2025 weather reference year was not included in the forecast modelling for the 2026 GSOO due to the timing of data availability. It will be included in the 2027 GSOO.

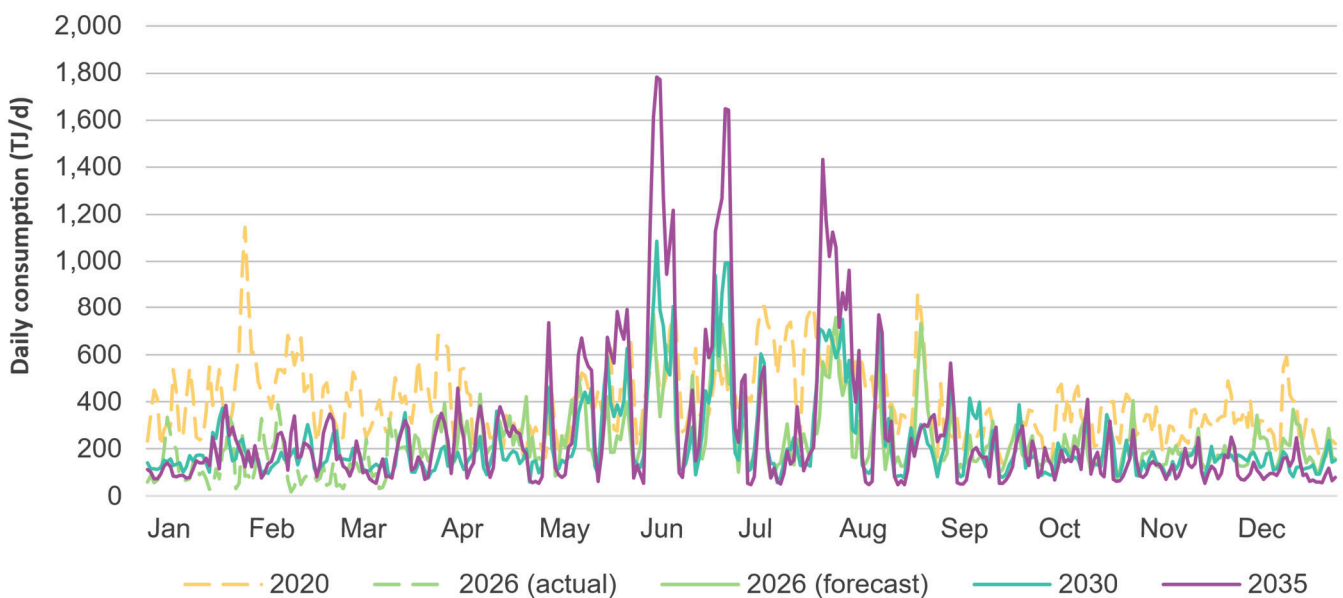
Figure 61 Actual and 2025 GSOO forecast monthly consumption from gas generators in the NEM and Northern Territory in 2025 (PJ)



A2. Forecasting the role of gas-powered generation in the National Electricity Market

Figure 62 presents the actual daily consumption profile in 2020 and forecast profiles for 2026, 2030 and 2035 under 1-in-10-year peak electricity demand conditions¹¹³, based on the 2020 observed weather year. It demonstrates the shifting role of GPG in the NEM, transitioning from consistent provision of electricity year-round to a more seasonal firming role, primarily in winter.

Figure 62 Actual and forecast NEM and Northern Territory daily gas consumption (TJ/d) for electricity generation in 2020, 2026, 2030, and 2035, Step Change scenario, reference year 2020



This figure shows that for the same underlying weather year, but for an evolving power system as outlined in the Draft 2026 ISP:

- **In 2020**, gas consumption was relatively steady throughout the year, with peaks exceeding 1,000 TJ/d to support peak day demand conditions in summer.
- **In 2026**, winter daily peaks are expected to remain lower than 2020 levels, largely due to a rapid increase in grid-scale battery storages.
- **By 2030**, renewable generation and electrical storages are forecast to provide increasing electricity production and firming capacity, reducing the potential need for GPG while these resources are available, and conditions allow for

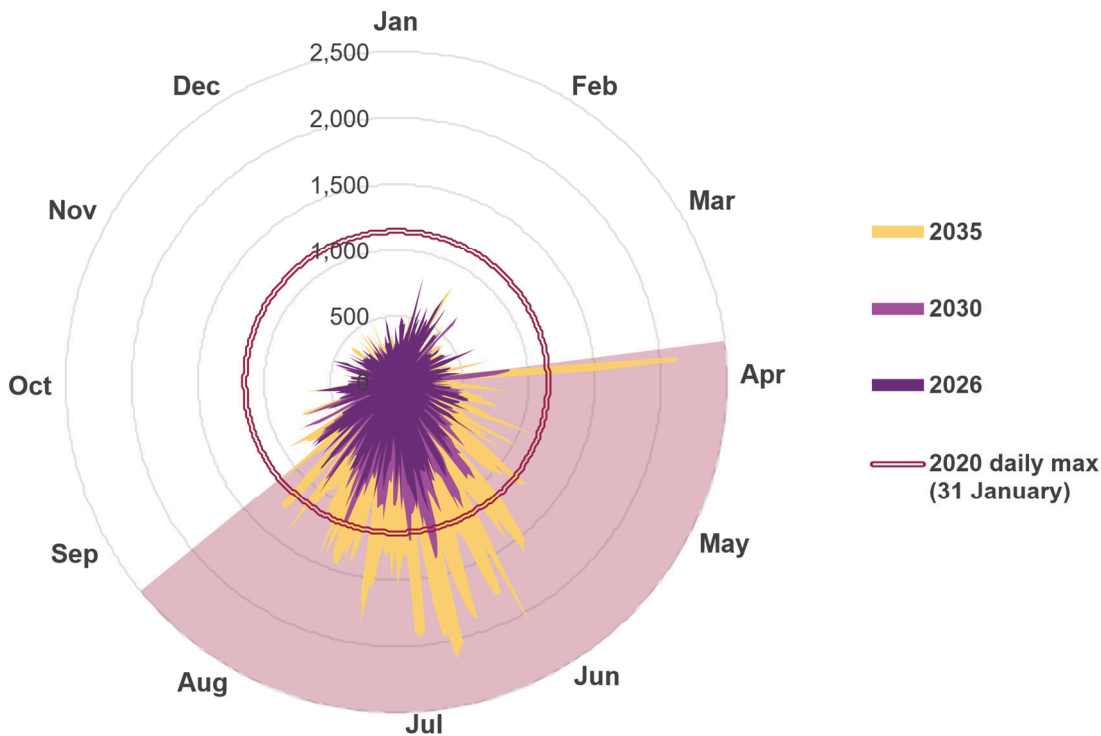
¹¹³ Electricity demand traces are constructed from forecasts for each NEM region, weather reference year, forecast year, scenario, and probability of exceedance. The 1-in-10-year peak electricity demand trace represents a non-coincident peak demand. For more detail, refer to the *Electricity Demand Forecasting Methodology* at https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2024-electricity-demand-forecasting-methodology-consultation/final-determination/electricity-demand-forecasting-methodology_.pdf?la=en.

effective management of electrical storages. However, when VRE generation is low, coupled with reduced availability from coal generators as they age and eventually retire and higher electricity demand due to electrification, peak gas demand may exceed 1,000 TJ/d in winter.

- **By 2035**, gas demand is forecast to become even more dependent on available renewable generation across the seasons. Under extreme conditions, forecast GPG demand exceeds 1,000 TJ/d for more than 35 days and, if electricity demands peak at times of low coincident renewable availability, may surpass 1,750 TJ/d, nearly double historical levels during the winter.

Figure 63 shows forecast potential maximum daily volumes of gas consumption for electricity generation for 2026, 2030, and 2035, and also for comparison the historical maximum daily demand in 2020 (which occurred on 31 January 2020). This figure represents the forecast maximum GPG demand in the specified year, simulated across the full range of weather sequences studied.

Figure 63 Forecast NEM potential maximum GPG daily consumption for 2026, 2030 and 2035, Step Change scenario, maximum of reference years 2014-24 (TJ/d)



Note: This figure represents the maximum daily GPG observed across all simulated weather conditions, and therefore the resulting daily GPG demand across this time series exceeds the forecast volume of GPG demand across each forecast year. Rather, this figure demonstrates that the risk of GPG volatility extends across a wider period than traditional season definitions.

The figure highlights a forecast shift in seasonal usage patterns, particularly that GPG demand will not only be volatile during summer and winter, but that VRE lulls can occur at other times and drive high GPG needs:

- During **summer**, high spikes in generation that historically have been observed are forecast to be more subdued relative to other times of the year, with fewer and smaller spikes owing to greater solar availability in summer and increased electrical storage penetration.
- During **winter**, the peak daily gas demand for GPG has been greater than in summer months since 2021, and volatility in daily demand is greater than in summer. Winter and autumn shoulder peak daily demand is forecast to increasingly

exceed the historical maximum daily demand observed in 2020. The historical peak is exceeded for a few days in 2030 and for many days in 2035.

- The figure includes an exceptional shoulder peak daily demand simulated over four days in April 2035. This reflects a low probability but potentially high impact event that leads to much greater GPG demand to firm a seasonally early VRE lull, as observed in the modelled weather pattern of 2014.

GPG is forecast to be highly variable due to factors including:

- weather patterns and their impact on peak day demand but particularly also wind and solar availability and hydro inflows,
- coal generator availability, including from planned and unplanned outages, seasonal mothballing, and due to retirements,
- electricity transmission outages (planned and unplanned),
- fuel supply constraints, such as the availability of coal, and
- the pace of investment in electrical storage solutions and the resulting storage depth of electricity storages.

The impact of electrical storages on GPG

As the NEM transitions to a system that is increasingly reliant on weather, electrical storages will play an important role in firming the electricity system. Batteries can store surplus energy from daytime solar to use in the evening and morning peaks, and to support grid security and reliability as coal plants withdraw. On a daily cycle, this shaping can be achieved by households and businesses energy systems, by community-scale batteries embedded within distribution networks, and by grid-scale batteries and new hybrid grid-scale systems that combine solar and/or wind generation with battery assets.

In the Draft 2026 ISP, *Step Change* projects 33 GW of dispatchable, grid-scale battery and pumped-hydro storage would be needed by 2050, with 27 GW by 2030, complemented by CER.

The connections pipeline¹¹⁴ for battery storages has increased, from approximately 3 GW in September 2022, to 15 GW in 2024 and to 32 GW (including the battery component capacity of VRE battery hybrids) in 2025.

In the long term, GPG may be used to pre-charge electrical storages to their maximum capacity in advance of periods of very low VRE availability, similar to how gas storages are managed ahead of winter. This contributes to the stable annual consumption forecast for the long term, as GPG increasingly becomes a source of energy to pre-charge electrical storages in advance of periods of very low VRE availability.

This pre-charging of batteries, including from GPG, can help reduce winter peak daily GPG gas demand through reduced need of instantaneous GPG during peak electricity demand periods, helping to smooth that GPG operation across days prior to low VRE availability periods. The extent to which this occurs would depend on sufficient forewarning of weather events to trigger adequate market signals to pre-charge available storages through early commitment of GPG and corresponding battery load.

¹¹⁴ See AEMO's *Connections Scorecard*, September 2025, at <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/connections-scorecard>.

A3. Monthly demand forecast for 2026 and 2027

Table 21 and **Table 22** detail the monthly demand forecast by region and sector for 2026 and 2027. Forecasts are provided for the *Step Change* scenario, 2024 reference year, with potential variation due to weather shown in brackets.

Table 21 Forecast monthly demand by region and sector (GPG and combined residential, commercial and industrial [RC&I]) for each month in 2026 (PJ)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Northern Territory	GPG	1.6 [+0,-0]	1.5 [+0,-0]	1.7 [+0,-0]	1.5 [+0,-0]	1.4 [+0,-0]	1.3 [+0,-0]	1.3 [+0,-0]	1.3 [+0,-0]	1.6 [+0,-0]	1.6 [+0,-0]	1.7 [+0,-0]	1.7 [+0,-0]
	RC&I	0.5 [+0,-0]	0.4 [+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]	0.5 [+0,-0]	0.5 [+0,-0]	0.5 [+0,-0]	0.5 [+0,-0]
Queensland	GPG	1.9 [+1,-0]	2.3 [+0,-2]	1.8 [+1,-0]	1.7 [+0,-1]	1.7 [+1,-0]	2.0 [+0,-1]	2.2 [+0,-0]	2.0 [+0,-0]	1.5 [+0,-0]	1.6 [+0,-0]	1.5 [+0,-0]	1.6 [+0,-0]
	RC&I	8.3 [+0,-0]	7.2 [+0,-1]	7.2 [+1,-0]	7.4 [+1,-0]	7.8 [+1,-0]	7.9 [+0,-1]	8.1 [+1,-1]	7.9 [+1,-0]	8.1 [+0,-1]	7.9 [+0,-0]	8.0 [+0,-1]	8.4 [+0,-1]
Total northern		12.3 [+1,-0]	11.5 [+0,-1]	11.1 [+1,-0]	11.0 [+1,-0]	11.4 [+1,-0]	11.7 [+1,-1]	12.0 [+1,-1]	11.8 [+1,-1]	11.7 [+0,-1]	11.7 [+1,-1]	11.7 [+0,-1]	12.3 [+0,-1]
New South Wales	GPG	0.9 [+1,-0]	1.0 [+0,-1]	0.9 [+0,-0]	0.7 [+0,-0]	1.1 [+0,-0]	2.3 [+0,-1]	1.5 [+0,-1]	1.3 [+0,-1]	0.7 [+0,-0]	0.5 [+0,-0]	0.4 [+0,-0]	0.4 [+0,-0]
	RC&I	6.7 [+0,-1]	5.4 [+1,-0]	6.8 [+1,-0]	8.0 [+0,-1]	9.7 [+1,-1]	11.4 [+0,-1]	11.2 [+1,-1]	10.3 [+1,-0]	9.0 [+1,-0]	8.6 [+0,-2]	7.5 [+0,-1]	6.6 [+1,-0]
Victoria	GPG	1.5 [+0,-1]	1.2 [+0,-1]	2.2 [+0,-2]	1.8 [+0,-2]	2.9 [+0,-2]	4.5 [+0,-3]	1.5 [+3,-1]	2.6 [+0,-2]	1.2 [+0,-1]	0.8 [+0,-1]	0.5 [+0,-1]	0.2 [+1,-0]
	RC&I	7.6 [+0,-1]	7.0 [+0,-1]	8.5 [+0,-1]	12.0 [+0,-3]	17.0 [+2,-3]	21.6 [+0,-2]	23.4 [+0,-2]	17.9 [+4,-0]	15.2 [+2,-2]	11.3 [+3,-2]	8.8 [+2,-1]	7.3 [+1,-0]
South Australia	GPG	2.3 [+0,-1]	1.9 [+0,-1]	3.2 [+0,-2]	2.8 [+0,-1]	3.7 [+0,-2]	5.8 [+0,-3]	3.7 [+2,-1]	4.0 [+0,-2]	2.3 [+0,-1]	1.8 [+0,-1]	1.8 [+0,-1]	1.6 [+0,-0]
	RC&I	2.0 [+0,-0]	1.8 [+0,-0]	2.0 [+0,-0]	3.2 [+0,-1]	3.7 [+0,-1]	2.9 [+0,-0]	3.3 [+0,-0]	3.0 [+0,-0]	3.3 [+0,-1]	2.9 [+0,-1]	1.8 [+1,-0]	1.6 [+1,-0]
Tasmania	GPG	0.1 [+0,-0]	0.2 [+0,-0]	0.0 [+0,-0]	0.1 [+0,-0]	0.1 [+0,-0]	0.2 [+0,-0]	0.1 [+0,-0]	0.1 [+0,-0]	0.1 [+0,-0]	0.3 [+0,-0]	0.4 [+0,-0]	0.1 [+0,-0]
	RC&I	0.4 [+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]	0.5 [+0,-0]	0.5 [+0,-0]	0.5 [+0,-0]	0.5 [+0,-0]	0.5 [+0,-0]
Total southern		21.4 [+0,-3]	19.0 [+0,-2]	24.2 [+0,-5]	29.2 [+0,-6]	38.6 [+1,-8]	49.1 [+0,-10]	45.1 [+5,-5]	39.8 [+4,-3]	32.2 [+2,-4]	26.8 [+2,-4]	21.8 [+1,-3]	18.3 [+2,-0]
Total domestic		33.7 [+0,-4]	30.5 [+0,-3]	35.3 [+0,-5]	40.2 [+0,-6]	50.0 [+1,-8]	60.8 [+0,-11]	57.1 [+5,-5]	51.6 [+3,-3]	43.9 [+2,-4]	38.4 [+2,-4]	33.5 [+1,-3]	30.6 [+2,-1]
Queensland	LNG	121.3 [+1,-9]	109.0 [+3,-2]	122.9 [+0,-16]	116.3 [+9,-0]	111.6 [+16,-0]	102.4 [+1,-8]	102.7 [+3,-5]	107.1 [+3,-8]	114.6 [+9,-0]	124.4 [+5,-0]	117.7 [+3,-3]	121.5 [+4,-8]
Total		155.0 [+0,-11]	139.5 [+2,-3]	158.2 [+0,-20]	156.5 [+4,-3]	161.6 [+10,-6]	163.2 [+0,-18]	159.9 [+3,-7]	158.7 [+6,-8]	158.5 [+10,-0]	162.9 [+4,-4]	151.2 [+5,-5]	152.1 [+6,-7]

Note: Data is shown for the 2024 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.

Table 22 Forecast monthly demand by region and sector (GPG and residential, commercial and industrial [RC&I]) for each month in 2027 (PJ)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Northern Territory	GPG	1.6 [+0,-0]	1.5 [+0,-0]	1.6 [+0,-0]	1.5 [+0,-0]	1.4 [+0,-0]	1.3 [+0,-0]	1.3 [+0,-0]	1.4 [+0,-0]	1.6 [+0,-0]	1.6 [+0,-0]	1.7 [+0,-0]	1.7 [+0,-0]
	RC&I	0.7 [+0,-0]	0.5 [+0,-0]	0.6 [+0,-0]	0.6 [+0,-0]	0.6 [+0,-0]	0.6 [+0,-0]	0.6 [+0,-0]	0.6 [+0,-0]	0.7 [+0,-0]	0.7 [+0,-0]	0.7 [+0,-0]	0.7 [+0,-0]
Queensland	GPG	2.0 [+0,-1]	1.8 [+0,-0]	1.6 [+1,-0]	1.7 [+0,-0]	1.7 [+1,-0]	2.2 [+0,-1]	1.5 [+1,-0]	1.5 [+0,-0]	1.1 [+0,-0]	1.1 [+0,-0]	1.0 [+1,-0]	1.5 [+0,-0]
	RC&I	7.8 [+0,-0]	6.8 [+0,-0]	7.1 [+1,-0]	7.0 [+1,-0]	7.5 [+1,-0]	7.4 [+0,-1]	7.8 [+0,-1]	7.5 [+1,-0]	7.8 [+0,-1]	7.5 [+0,-0]	7.5 [+0,-1]	7.9 [+0,-1]
Total northern		12.2 [+0,-1]	10.6 [+1,-1]	11.0 [+1,-0]	10.9 [+1,-0]	11.2 [+1,-0]	11.6 [+1,-1]	11.2 [+1,-0]	11.0 [+1,-0]	11.1 [+0,-1]	10.9 [+1,-1]	11.0 [+0,-1]	11.9 [+0,-1]
New South Wales	GPG	0.6 [+0,-0]	0.5 [+1,-0]	0.7 [+0,-0]	0.6 [+0,-0]	0.9 [+1,-0]	2.2 [+0,-1]	0.8 [+1,-0]	0.7 [+0,-0]	0.5 [+0,-0]	0.2 [+0,-0]	0.2 [+0,-0]	0.8 [+0,-0]
	RC&I	6.7 [+0,-1]	5.6 [+1,-0]	6.5 [+1,-0]	7.9 [+1,-1]	9.8 [+1,-1]	11.1 [+0,-1]	11.5 [+0,-1]	10.4 [+1,-0]	9.2 [+1,-0]	8.8 [+0,-2]	7.6 [+0,-1]	6.6 [+1,-0]
Victoria	GPG	1.0 [+0,-1]	0.8 [+0,-1]	1.6 [+0,-1]	2.7 [+0,-3]	2.9 [+0,-3]	4.2 [+0,-3]	0.6 [+1,-0]	0.9 [+0,-1]	0.3 [+0,-0]	0.1 [+0,-0]	0.2 [+0,-0]	0.2 [+0,-0]
	RC&I	7.4 [+0,-1]	7.1 [+0,-1]	8.0 [+1,-0]	11.5 [+1,-2]	16.6 [+2,-3]	20.7 [+0,-2]	23.4 [+0,-3]	17.7 [+4,-0]	15.1 [+2,-2]	11.3 [+3,-2]	8.8 [+1,-1]	7.3 [+1,-0]
South Australia	GPG	2.2 [+0,-1]	1.7 [+0,-1]	3.3 [+0,-2]	3.2 [+0,-1]	4.3 [+0,-3]	5.6 [+0,-3]	2.7 [+2,-1]	2.9 [+0,-2]	1.7 [+0,-1]	1.4 [+0,-1]	1.4 [+0,-1]	1.4 [+0,-0]
	RC&I	2.0 [+0,-0]	1.8 [+0,-0]	2.1 [+0,-0]	2.9 [+0,-0]	3.3 [+0,-0]	3.2 [+0,-0]	3.4 [+0,-0]	3.0 [+0,-0]	2.9 [+0,-0]	2.6 [+0,-0]	2.2 [+0,-0]	2.0 [+0,-0]
Tasmania	GPG	0.1 [+0,-0]	0.2 [+0,-0]	0.5 [+0,-0]	0.4 [+0,-0]	0.3 [+0,-0]	0.3 [+0,-0]	0.0 [+0,-0]	0.0 [+0,-0]	0.0 [+0,-0]	0.0 [+0,-0]	0.1 [+0,-0]	0.0 [+0,-0]
	RC&I	0.4 [+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]	0.5 [+0,-0]	0.5 [+0,-0]	0.5 [+0,-0]	0.5 [+0,-0]	0.5 [+0,-0]
Total southern		20.4 [+0,-2]	18.3 [+2,-2]	23.1 [+0,-4]	29.8 [+1,-7]	38.6 [+2,-9]	47.8 [+0,-9]	42.9 [+3,-4]	36.0 [+5,-0]	30.2 [+2,-3]	25.0 [+4,-4]	20.9 [+1,-2]	18.8 [+1,-1]
Total domestic		32.6 [+0,-3]	28.9 [+2,-2]	34.1 [+0,-4]	40.7 [+1,-7]	49.8 [+2,-9]	59.4 [+0,-9]	54.1 [+3,-4]	47.0 [+6,-1]	41.4 [+2,-3]	36.0 [+3,-4]	31.9 [+2,-2]	30.6 [+1,-2]
Queensland	LNG	121.1 [+1,-9]	109.0 [+2,-2]	121.0 [+0,-14]	113.6 [+13,-0]	111.2 [+15,-1]	101.9 [+2,-8]	101.7 [+5,-5]	106.2 [+2,-9]	113.8 [+9,-0]	123.8 [+5,-0]	116.6 [+3,-3]	121.0 [+4,-10]
Total		153.7 [+0,-11]	137.9 [+2,-4]	155.1 [+0,-18]	154.3 [+7,-6]	161.0 [+11,-8]	161.3 [+0,-17]	155.7 [+3,-7]	153.2 [+8,-8]	155.1 [+10,-0]	159.8 [+5,-3]	148.5 [+5,-5]	151.7 [+4,-10]

Note: Data is shown for the 2024 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 64 and Figure 65 show forecast monthly demand in petajoules a month (PJ/m) for 2026 and 2027, taken as an average across all reference years, by region and by sector respectively. Forecasts are provided for all months of 2026, including the months which are already in the past.

Figure 64 Forecast monthly domestic demand by region for 2026-2027, Step Change, average across all reference years (PJ)

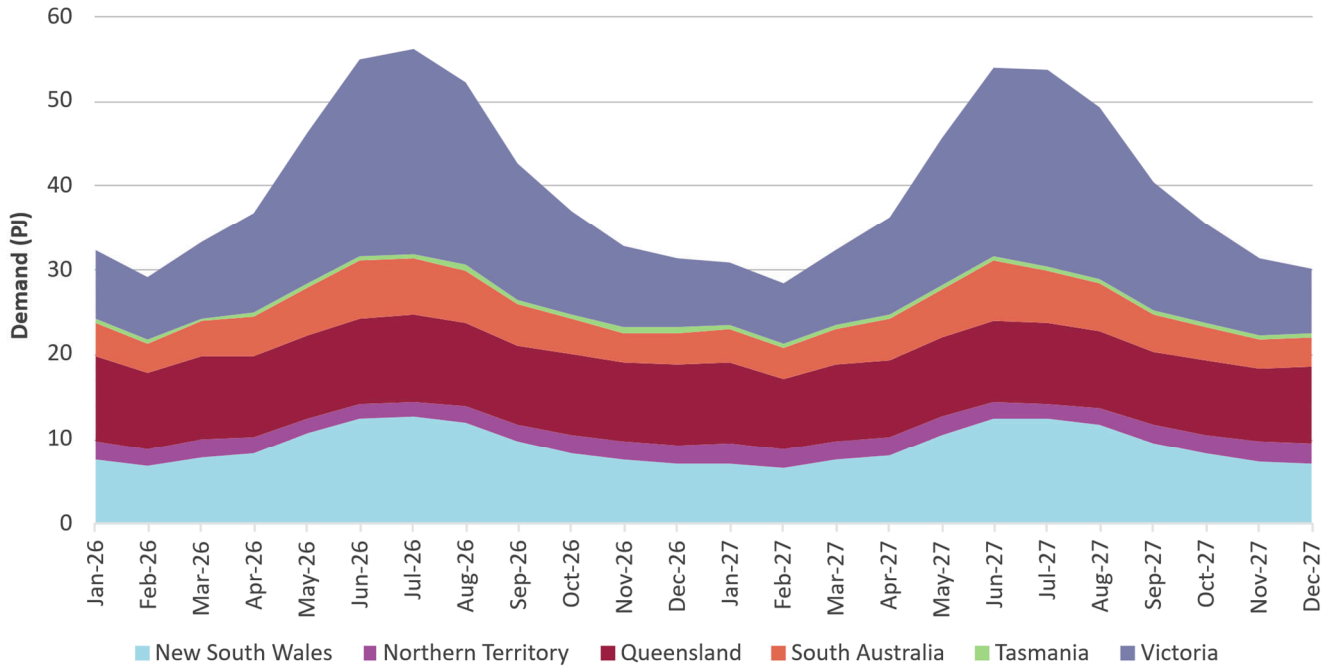
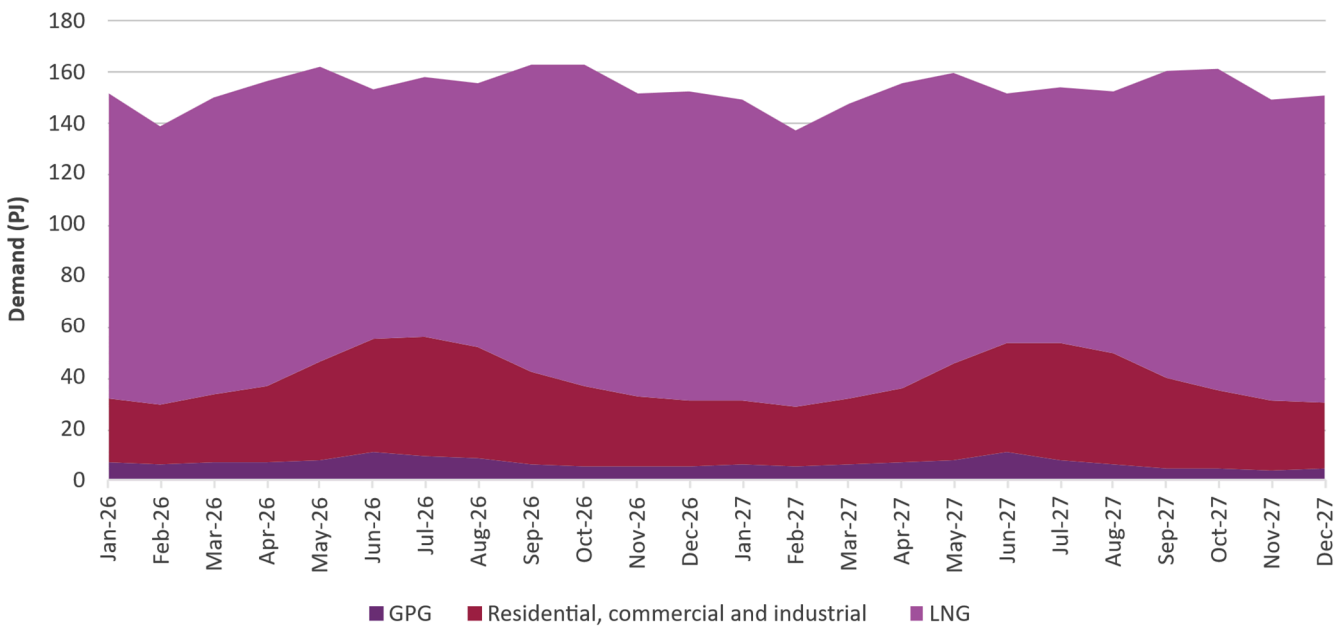


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Measures, abbreviations and glossary

Measures

Term	Definition
GW	gigawatt/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
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AGP	Amadeus Gas Pipeline
APLNG	Australia Pacific LNG
BLP	Brooklyn Lara Pipeline
BGP	Bonaparte Gas Pipeline
CER	consumer energy resources
CGP	Carpentaria Gas Pipeline
CSG	coal seam gas
DCCEEW	Department of Climate Change, Energy, the Environment and Water
DTS	Declared Transmission System
DWGM	Declared Wholesale Gas Market
ECGG	East Coast Gas Grid
ECGM	East Coast Gas Market
ECGS	East Coast Gas System
ECMC	Energy and Climate Change Ministerial Council
EES	Environmental Effects Statement
EGP	Eastern Gas Pipeline
FID	final investment decision
FSRU	floating storage regasification unit
GBJV	Gippsland Basin Joint Venture
GDP	Gross Domestic Product
GLNG	Gladstone LNG

Term	Definition
GPG	gas-powered generation
GSA	gas supply agreement
GSOO	<i>Gas Statement of Opportunities</i>
HUGS	Heytesbury Underground Gas Storage
IASR	<i>Inputs, Assumptions and Scenarios Report</i>
IEA	International Energy Agency
ISP	<i>Integrated System Plan</i>
KKLP	Kurri Kurri Lateral Pipeline
LIL	large industrial load
LMP	Longford Melbourne Pipeline
LNG	liquefied natural gas
MAPS	Moomba Adelaide Pipeline System
MSP	Moomba Sydney Pipeline
MSEP	Moomba Sydney Ethane Pipeline
NEM	National Electricity Market
NGP	Northern Gas Pipeline
NGR	National Gas Rules
NGSF	Newcastle Gas Storage Facility
NQGP	North Queensland Gas Pipeline
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
RC&I	residential, commercial and industrial
RBP	Roma Brisbane Pipeline
SMIL	small to medium industrial load
SWP	South West Pipeline
SWQP	South West Queensland Pipeline
TGP	Tasmanian Gas Pipeline
UAFG	unaccounted for gas
UGS	underground gas storage
VGPR	<i>Victorian Gas Planning Report</i>
VNI	Victorian Northern Interconnect
VRE	variable renewable energy
WAG	Westernport Altona Geelong (pipeline)
WEO	World Economic Outlook

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	Projects that developers consider justified on the basis of a reasonable forecast of commercial conditions, and reasonable expectations that all approvals will be obtained and final investment decision (FID) made.
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.
committed projects	Projects that are ready to commence or already underway.
consumption	Gas consumed over a period of time, usually a year but sometimes a month.
covered gas	Natural gas, hydrogen, biomethane or a blend of these gases.
demand	The amount of gas used on a daily basis.
electrification	Fuel-switching to electricity, in the GSOO this most often refers to from gas to electricity.
extreme peak day demand	Very high coincident daily demand from residential, commercial and industrial customers and GPG.
gas-powered generation (GPG)	Electricity generated from gas turbines (combined cycle gas turbine [CCGT] or open cycle gas turbine [OCGT]).
green commodities	Products of selected industries, such as steelmaking, mineral processing, and chemicals, which primarily use green hydrogen as a feedstock.
industrial consumers	Consumers that use over 10 TJ per year (TJ/y).
large industrial load	Customers that consume an amount of gas greater than or equal to 500 TJ per annum.
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.
LNG netback price	The price at which an LNG exporter could sell gas domestically, rather than LNG, and make the same profit.
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.
northern Australia	Queensland and the Northern Territory
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.
project set	Collection of uncertain projects proposed for development by the gas industry.
renewable gases	Carbon-neutral natural gas substitutes that do not generate additional greenhouse gas emissions when burnt. Renewable gases include biomethane and hydrogen.
residential and small commercial consumers	Consumers that use less than 10 terajoules (TJ) of gas per year and are equipped with a basic gas meter
seasonal or annual supply gap	A seasonal or annual supply gap is driven by insufficient gas supply to meet total seasonal or yearly consumption.
small to medium industrial loads	Customers in this category consume between 10 TJ and 499 TJ per annum at each individual site.
southern Australia	New South Wales (including the Australian Capital Territory), South Australia, Tasmania and Victoria
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	Projects that are at earlier stages of development or face challenges in terms of viability or approvals.
underground gas storage (UGS)	A storage facility which reinjects gas into depleted gas reservoirs, which can be withdrawn out at a later date.
winter	June to August.