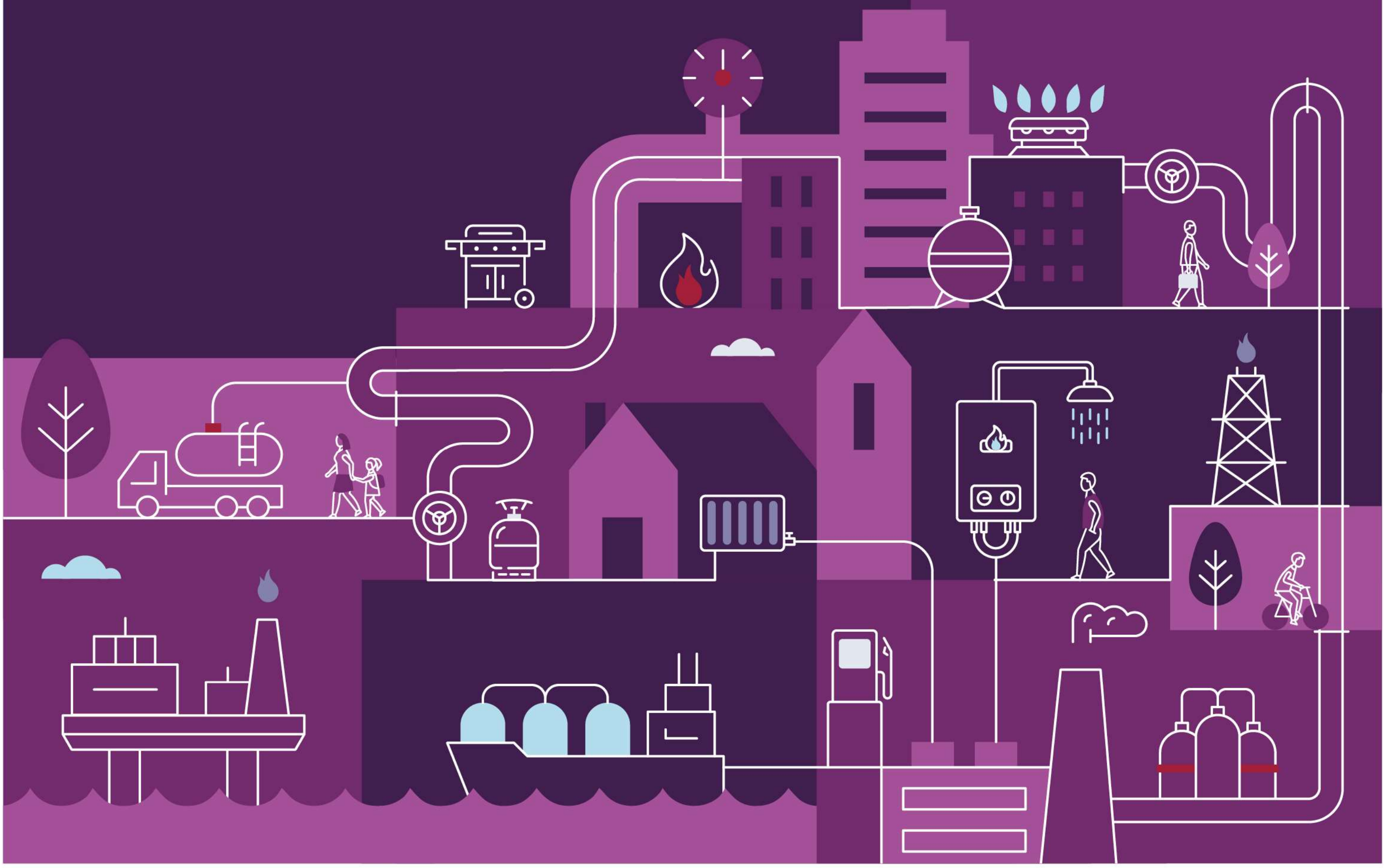
Gas Statement of Opportunities

March 2023

For central and eastern Australia



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 the natural gas industry.

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

This publication is generally based on information available to AEMO as at 31 December 2022, unless otherwise indicated.

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Version control

Version	Release date	Changes
1	16/3/2023	Initial publication.
1.1	27/3/2023	Corrected SWQP flow available to southern markets in Figures 4 and 36.
1.2	28/4/2023	Corrected LNG forecast for Diverse Step Change (1.8°C) in Figure 8.

AEMO acknowledges the Traditional Owners of country throughout Australia and recognises their continuing connection to land, waters and culture. We pay respect to Elders past and present.

Contents

Executive summary

The 2023 *Gas Statement of Opportunities* (GSOO) forecasts the adequacy of gas supplies, based on information from gas industry participants, to meet consumers' changing gas needs from now until 2042 in Australian jurisdictions other than Western Australia[1].

Despite increased production commitments from the gas industry since the 2022 GSOO, gas supply in southern Australia is declining faster than projected demand. As Australia transforms to meet a net zero emissions future, gas will continue to complement zero emissions and renewable forms of energy, and to provide a reliable and dispatchable form of electricity generation, and may provide potential pathways to incorporate hydrogen and other 'green' gases within Australia's energy landscape.

As identified in previous GSOOs, this 2023 GSOO highlights continued risks of short-term gas supply shortfalls and long-term gas supply gaps arising from reducing production from southern Australia. In particular, the risk of peak day shortfalls continues to be forecast under very high demand conditions in the southern states from winter 2023. Short-term critical gas adequacy conditions include:

- Extreme weather conditions across southern regions that drive high coincident peak demand for gas consumption may lead to gas shortfalls, particularly if combined with high gas generation (if alternative electricity generation resources are unavailable).
- Deep and shallow gas storages will be vital to meet peak day demand. The magnitude and frequency of forecast peak day shortfall risks increase if storages are unavailable or not adequately filled prior to winter.
- Peak day gas shortfall risks may be lower if reliance on gas use for electricity generation during periods of peak gas demand is reduced, including by the use of liquid fuel or management of electricity demand.
- Peak day shortfall risks would increase if committed infrastructure developments to reduce transmission constraints were not delivered to schedule.
- It will be important for production from liquefied natural gas (LNG) exporters, in excess of existing export contractual commitments, to be available to southern consumers. The risk of supply gaps increases if excess northern production is exported as spot cargoes rather than used to meet domestic demand.

Noting the risks above, annual physical gas supply from existing, committed and anticipated production is forecast to be adequate before 2027. Investments are needed in the near term to ensure operational solutions from 2027, despite falling gas consumption, noting that:

- From 2026, without additional commitments to expand domestic supply, or alternative developments such as hydrogen or biomethane that may offset natural gas demand, gas contracted for export by Queensland LNG producers may instead need to be used to maintain domestic gas adequacy.
- Investment uncertainty exists regarding the development of LNG import terminals, including the Port Kembla Energy Terminal (PKET) project. If an import terminal was developed in the south, including appropriate location and operation of floating storage and regasification units (FSRUs), imports may delay supply gaps.
- The scale of forecast gas consumption varies across AEMO's scenarios. As policy and consumer preferences to switch to alternate energy sources are unclear, so the preferred timing, type and size of gas supply and any supporting infrastructure required is uncertain. All future scenarios, however, forecast the long-term need for additional supply.

[1] See WA GSOO at https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/wa-gas-statement-of-opportunities-wa-gsoo.

GSOO purpose

The GSOO examines the demand for, and supply of, natural gas, and considers possible alternative fuels such as hydrogen, biomethane and other natural gas equivalent or constituent gases as alternatives to natural gas. However, as the gas sector identifies pathways to decarbonise, there may be a greater role for these alternative fuels within the gas system that future GSOOs will examine as the regulatory frameworks adapt to rule changes[2].

AEMO surveyed gas producers and operators of gas processing facilities, pipelines and storage facilities from September 2022 for this GSOO, prior to the Federal Government's policy to cap the price of natural gas being announced or legislated, and has included any available updated information from participants where appropriate and relevant. Given the price cap policy was only recently introduced, the effect it will have on consumer gas demand or supply investments is not yet clear.

AEMO's 2023 *Victorian Gas Planning Report* (VGPR)[3] complements this GSOO, focusing on the gas supply demand balance in Victoria for the next five years.

The GSOO focuses on the evaluation of available production capacity and transportation capabilities to physically meet forecast gas demand. While commercial and contractual positions may incentivise production behaviours that deviate from the physical capabilities, AEMO does not identify gas supply gaps in the short term if the gas is made physically available when required to meet consumption levels including during extreme weather conditions and for electricity from gas generation. As such, no consideration of contract positions beyond advised export contract positions influences the gas adequacy assessment, meaning that if surplus production capacity exists, and transportation capacity is available, the GSOO will forecast supply as adequate.

Key changes since the 2022 GSOO

Since publication of the 2022 GSOO, AEMO's consumption forecasts now feature:

- Adjusted scenario definitions to accommodate policy developments regarding Australia's commitments to net zero emissions, particularly the influence the *Climate Change Act (2022)*[4] may have on Australia's economy, and the share of emissions reduction AEMO forecasts from the energy sector, consistent with AEMO's *Draft 2023 Inputs, Assumptions and Scenarios Report* (IASR)[5].
- Slower forecast electrification (switching from gas to electricity) by consumers, particularly in the residential sector, based on a slower pace of fuel-switching observed, and
- The inclusion of biomethane as an alternate fuel available to consumers offsetting natural gas usage in some scenarios.

There has been progress towards delivering key infrastructure projects (although timeframes for completion remain tight), and some improvements to supply:

- Victoria's **Western Outer Ring Main** (WORM) pipeline and a second compressor at Winchelsea are expected to be commissioned before winter 2023. The WORM was considered committed in the 2022 GSOO, while the second compressor at Winchelsea is a new addition. These projects help increase peak supply capacity to Melbourne gas consumers by 83 terajoules a day (TJ/d).

[2] AEMC, *Review into Extending the Regulatory Frameworks to Hydrogen and Renewable Gases – Final Rules Report*, November 2022, p. 58, at https://www.aemc.gov.au/market-reviews-advice/review-extending-regulatory-frameworks-hydrogen-and-renewable-gases.

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

[4] At https://www.legislation.gov.au/Details/C2022A00037.

[5] At https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.

- The **East Coast Grid Stage 2 project** is now considered committed, increasing pipeline capacity to transport gas south from Queensland by 90 TJ/d prior to winter 2024. This was considered a proposed project last year.
- Forecast Gippsland (including Orbost) production capacity has increased to 915 TJ/d for 2023, 191 TJ/d higher than forecast in the 2022 GSOO, although this is still a 211 TJ/d reduction on the actual maximum supply of 1,126 TJ/d in winter 2022. Gippsland supply capacity is forecast to reduce further for winter 2024, to a similar level as forecast in the 2022 GSOO. Port Campbell production capacity is forecast to increase to 227 TJ/d in 2023, up from 188 TJ/d in 2022.

Forecast supply has also been impacted by delays to other key projects in the near term, and reclassification of commitment levels of production projects:

- The **Golden Beach Energy Storage Project** was reported as an anticipated project in the 2022 GSOO with production commencing in 2024. The project has been further delayed until 2025 and a final investment decision is not expected until mid-2023. Due to several years of delay, investment uncertainty, and rig availability, this project has not been included in the 2023 GSOO supply adequacy assessment as an anticipated project. The project is reported as an uncertain project in the 2023 GSOO and as a potential project in the 2023 VGPR.
- The connection of new offshore **Thylacine** wells to the Otway Gas Plant in Port Campbell has been delayed from January 2023 to July 2023, resulting in a production decrease via the Otway Gas Plant of 37 petajoules (PJ) in 2023, compared to the 2022 GSOO. This change also delays the Otway Gas Plant's expanded maximum daily production of 205 TJ/d once the connection is completed. Expected Otway production reduces to 84 TJ/d during winter 2023 if this work is not completed.
- Uncertainty around LNG import terminals in Australia remains. Based on information provided by the project proponent, this GSOO no longer considers **Port Kembla Energy Terminal (PKET)** as an anticipated project, due to there being insufficient contracted capacity to commit to locating the FSRU at the import terminal. This is despite infrastructure developments on a lateral pipeline that connects the terminal to the east coast network. Other terminal developments across southern regions are insufficiently progressed to be categorised as anticipated or committed.
- The availability of the **Newcastle Gas Storage Facility (NGSF)** is less certain than in previous years. The NGSF was empty for all of winter 2022 due to commercial factors, and no long-term commitment exists that ensures the availability of this facility[6]. AEMO considered NGSF available in the base scenarios for this GSOO, and explored the impact of unavailability through a sensitivity. Unavailability of shallow storages in southern regions, including NGSF, would increase the magnitude and frequency of peak day shortfalls.

As part of the Gas Transparency Measures package of reforms[7], extra information has been collected under the National Gas Rules (NGR) for the purposes of producing this GSOO. Although these rules did not come into effect until February 2023, AEMO requested the additional data voluntarily from gas producers, facility operators, pipeline operators, and storage operators under these new rules. This resulted in a majority of participants

[6] The NGSF began refilling in late 2022, and was reported available on the Gas Bulletin Board (see https://aemo.com.au/en/energy-systems/gas/gas-bulletin-board-gbb) from early 2023.

[7] See the Department of Climate Change, Energy, the Environment and Water's page on increasing transparency in the gas market (https://www.energy.gov.au/government-priorities/energy-ministers/energy-ministers-publications/regulatory-amendments-increase-transparency-gas-market), the AEMC's page on gas rules made by the South Australian Minister (https://www.aemc.gov.au/regulation/energy-rules/national-gas-rules/gas-rules-made-south-australian-minister) and AEMO's Procedures consultations (https://aemo.com.au/consultations/current-and-closed-consultations/gas-transparency-measures).

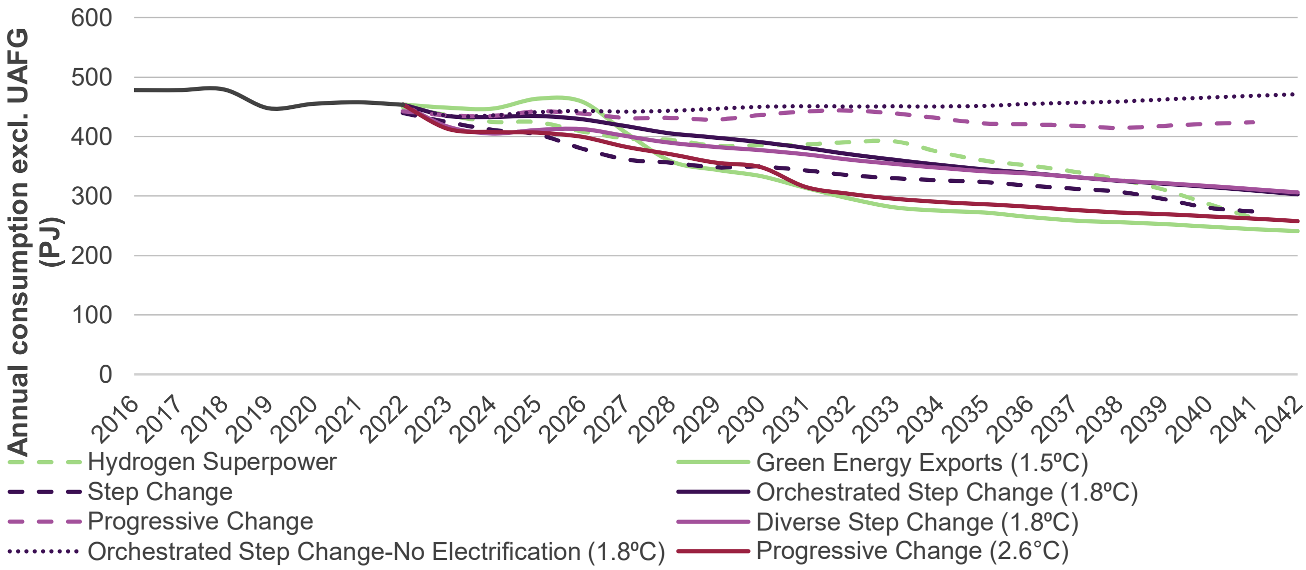
providing more granular and detailed data, supporting more detailed analysis. AEMO thanks these participants for their willingness to provide increased transparency and granularity prior to the requirements becoming effective.

Changes under the Gas Transparency Measures package of reforms will be in full effect for the 2024 GSOO, and AEMO encourages all reporting entities to review their obligations.

Demand forecasts vary across scenarios, leading to uncertainty about future gas needs

AEMO applies a scenario planning approach to planning and forecasting the energy transition, by examining a number of plausible futures as reported in the Draft 2023 IASR. These scenarios vary increasingly over time as more uncertainty affecting policy, technology and social change impacts gas consumption. **Figure 1** shows gas consumption forecasts under these scenarios and provides a comparison to the 2022 GSOO projections.

Figure 1 Forecast domestic natural gas consumption, excluding gas generation, all scenarios and compared to 2022 GSOO forecasts (PJ), 2016-42



Notes:
- The 2022 GSOO scenarios are dashed lines, the 2023 GSOO scenarios are solid lines, and the 2023 sensitivities are dotted lines.
- The 2022 GSOO did not include the Northern Territory as a participating GSOO jurisdiction. The Northern Territory is included in actual gas consumption from 2020 onwards and in the 2023 forecasts.

This GSOO focuses on the ***Orchestrated Step Change (1.8°C)*** scenario, the scenario most similar to the *Step Change* scenario identified in AEMO's 2022 *Integrated System Plan* (ISP)[8] as the most likely scenario. In this scenario, consumers are forecast to embrace opportunities to reduce emissions through electrification where technically and commercially practical, as well as investing in energy efficiency applications.

Electrification forecasts[9] have been updated for the 2023 GSOO considering the observable consumer change since the 2021 IASR, and consider a slower rate of fuel-switching than the 2022 GSOO forecast, particularly in the residential and commercial sectors. As a result, the 2023 GSOO gas consumption forecasts are comparatively higher than last year's forecasts in the short term.

[8] At https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp.

[9] See CSIRO and ClimateWorks Centre 2022 Multi-sector modelling report, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-climateworks-centre-2022-multisector-modelling-report.pdf.

Strong policy incentives and industry investment will be required to realise the level of electrification assumed under this scenario. While electrification investments are certain to impact gas consumption in future years, uncertainty remains over how quickly consumers shift their energy preferences away from natural gas. To identify the potential influence of slower electrification on gas adequacy risks, this GSOO also examines a conceptual halt on electrification (noted as the ***Orchestrated Step Change (1.8°C), No Electrification*** sensitivity).

Figure 1 incorporates forecasts from the residential, commercial and industrial demand sectors:

- Residential and small commercial consumption is forecast to gradually decline in the short term, with more significant fuel-switching in the medium to longer term as the economy transitions to meet net zero emissions goals. Overall, electrification is forecast to reduce natural gas consumption from residential and small commercial consumers by 158 PJ, down to 75 PJ by 2042. With slower electrification, gas consumption growth is possible given underlying trends in traditional growth drivers such as population and economic indicators. Some electrification is likely across the forecast horizon, however, so consumption is likely to be lower than forecast in the *Orchestrated Step Change (1.8°C), No Electrification* sensitivity (232 PJ by 2042).
- The industrial and large commercial sectors feature a sharp decline in forecast natural gas consumption in the near term, driven by the closure of Incitec Pivot's Gibson Island facility in Brisbane in January 2023[10]. A steady decline is forecast over the 20-year outlook, from 259 PJ in 2022 to 229 PJ by 2042 (down 12%), predominantly driven by fuel-switching away from natural gas to hydrogen from the late 2020s.

Gas for electricity generation

As AEMO's 2022 ISP[11] reported, electricity from gas generation is expected to play an important, continued role in the National Electricity Market (NEM). Gas generation is also critical to electricity supply in the Northern Territory, and other regions outside of the NEM within the GSOO central and eastern regions (including Mount Isa in Queensland).

Especially as coal generation retires in the NEM, gas generation can support the power system by responding to sudden changes in the supply demand balance, helping manage extended periods of low renewable generation, helping meet the NEM's energy needs if coal generation and other dispatchable sources are unavailable, and providing critical power system services to maintain grid security and stability.

Figure 2 shows recent and forecast volumes of gas consumption for electricity generation in the NEM, including the growing need for gas generation in the winter season. It shows that:

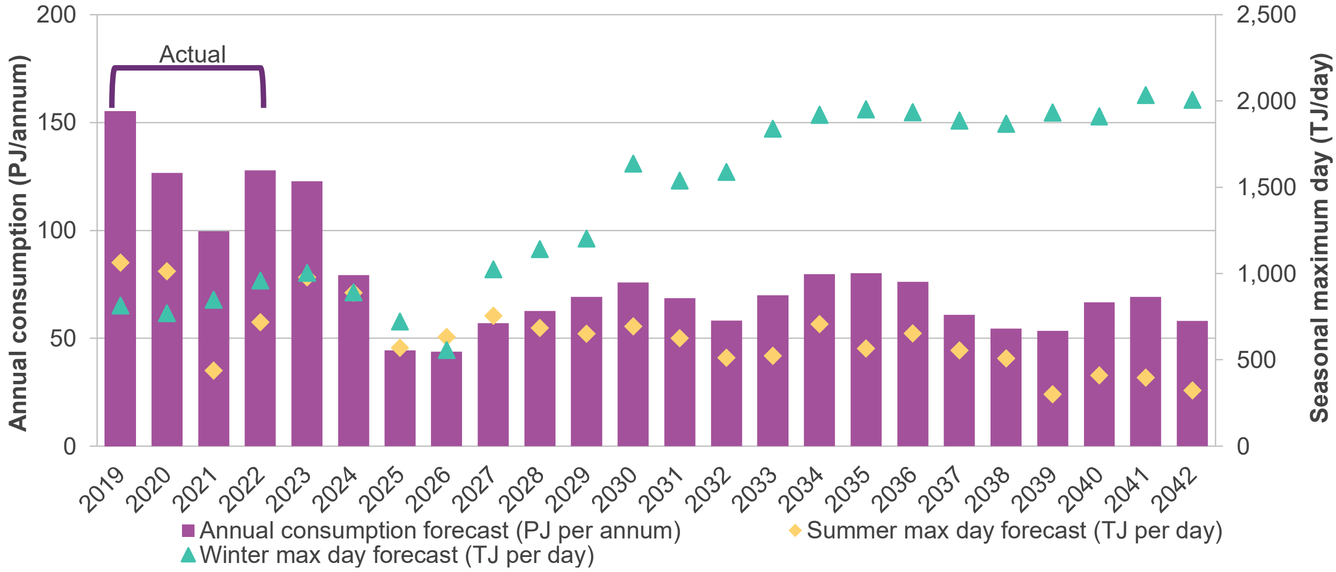
- The rise in gas consumption for electricity generation in 2022 is forecast to persist into 2023, before resuming its downward trend to 2026. Continued growth in wind and solar generation, including consumer energy resources such as distributed photovoltaic (PV) systems, is forecast to reduce the need for bulk energy from gas generators.
- In the medium and longer term, as much of the coal-fired generation fleet retires, gas consumption for electricity generation is forecast to rise. In the long term, gas generation is forecast to continue to provide firming of electricity supply in a system with a high reliance on variable renewable energy (VRE) such as wind and solar, complementing electricity storage systems such as battery storages and pumped hydro.

[10] See https://www.incitecpivot.com.au/about-us/about-incitec-pivot-limited/media/gibson-island-manufacturing-operations-to-cease-at-end-of-2022.

[11] At https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp.

- Winter peaks are forecast to grow due to increased electrification of heating load and periods of low VRE production, while summer maximum demand trends are flat with a slight long-term decline. Considering gas consumption is also naturally high during winter to provide space heating, this rising coincidence of gas and electricity peak demands may increase the challenge associated with operating both systems reliably without appropriate new, flexible and firm capacity.

Figure 2 Actual and forecast NEM gas generation annual consumption (PJ/y) and seasonal maximum daily demand (TJ/d), *Orchestrated Step Change (1.8°C)* scenario, 2019-42



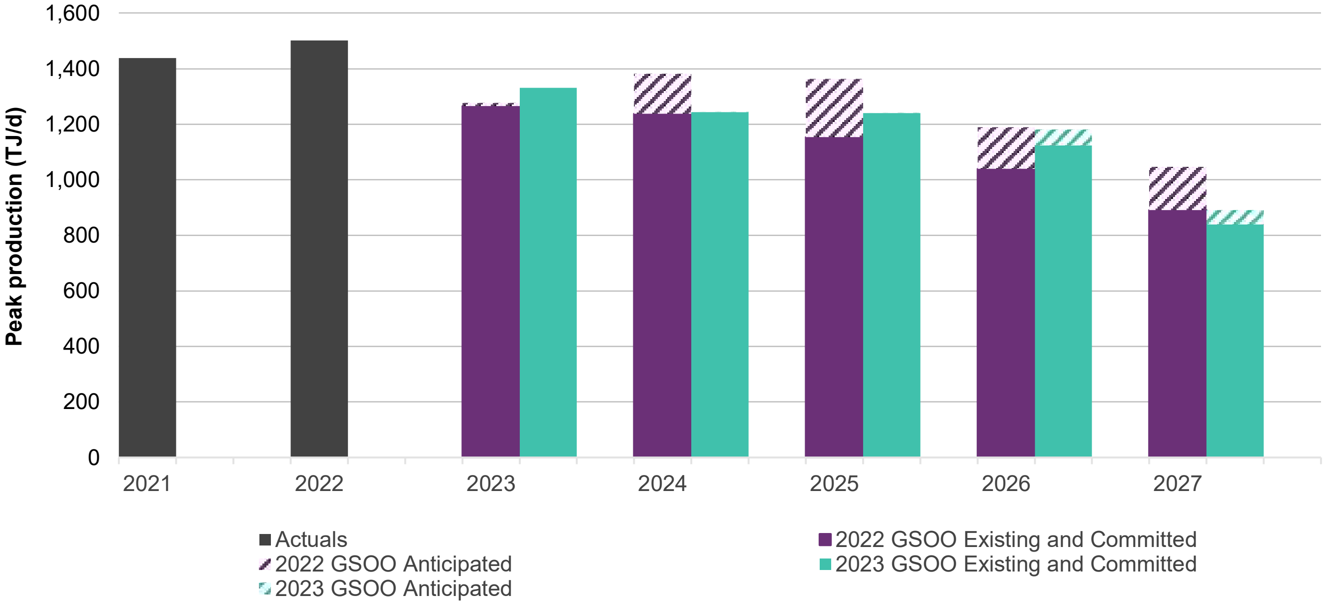
The forecast also shows the seasonality of gas-fired electricity generation becoming stronger, and more concentrated over periods of a few days, increasingly in winter, with prolonged periods of very little gas generation punctuated by short periods of intensive utilisation. With the withdrawal of coal-fired generation, gas is forecast to take over some of coal's role as a seasonal energy reserve for the electricity system, particularly during times when weather-dependent VRE is less available.

Existing and committed gas generation is increasingly important as a source of firm and flexible supply in the electricity sector, while coal plant performance degrades, as coal generators retire and before deep storage assets, such as Snowy 2.0 and other announced pumped hydro projects, are developed. While shallow battery storage solutions can contribute some increase in dispatchable capacity, these will not provide resilience to all reliability risks in the NEM. As such, while current investment interest is largely focused on shallow storages, AEMO forecasts currently indicate less regular but more important operation of gas generation as dispatchable capacity as electricity supply transitions to higher shares of renewable energy.

Key infrastructure projects have progressed, and production capacity has increased compared to the 2022 GSOO, but the risk of peak day shortfalls from 2023 remains

As shown in **Figure 3**, producers in southern regions have reported higher existing and committed production from 2023 to 2027 compared to the 2022 GSOO. While peak production capacity is higher than estimated for the 2022 GSOO, compared with historical production capacity there remains a noticeable and sustained forecast decline in production capacity.

Figure 3 Actual and forecast maximum daily production capacity from southern gas fields, 2021-27 (TJ/d)



The gas supply adequacy challenge from 2023 that AEMO reported in the 2022 GSOO remains, driven by:

- The continued decline of traditional supply from the Gippsland region, despite the increase in expected production for the 2023 GSOO in comparison to the 2022 GSOO.
- Limitations on the Moomba to Sydney Pipeline (MSP) and Southwest Queensland Pipeline (SWQP) capacity to transport gas from Queensland (where physical surplus production capacity remains) to the southern states (where shortfalls are forecast). Capacity limits may still inhibit even greater southbound support on peak demand days, even after the new Stage 2 of the East Coast Grid expansion completes from winter 2024 (expanding capacity by 90 TJ/d).
- Changing production and flow dynamics which mean that all southern regions (New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania) share shortfall risks, with South Australia now forecast to be within the constrained supply region.

Figure 4 depicts[12] the projected ability of southern production, pipeline capacity, and stored gas to meet actual southern gas demand in 2021 and 2022, and its projected ability to meet one-in-20[13] demand forecasts to 2027 in the *Orchestrated Step Change (1.8°C)* scenario, in both favourable weather conditions and unremarkable coincident demand (reference year 2017) and adverse weather conditions leading to extremely high coincident peak demand, particularly from gas generation (reference year 2019).

The horizontal lines in **Figure 4** show, for each year, how much supply has been and is forecast to be available to meet projected daily demands, based on:

- Maximum gas production in the southern regions only (solid purple line), plus

[12] Figure 4 provides an illustration of available supply, demonstrating the maximum supply capacity as a fixed value for each supply category (each horizontal line). AEMO's gas adequacy methodology calculates the adequacy of supply on a daily basis, allowing for dynamic infrastructure limits and the energy available in storage, and supply capacity may differ from this illustration.

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

- Expected gas imported from Queensland through the SWQP, taking into account the capacity of the pipeline and expected flows along the Carpentaria Gas Pipeline (CGP) to Mount Isa (dashed purple line), plus
- Deep storage from Iona (dotted purple line, assuming sufficient gas is stored to utilise at full capacity), plus
- Shallow LNG storages at Dandenong and Newcastle (solid red line, assuming sufficient gas is stored to utilise at full capacity).

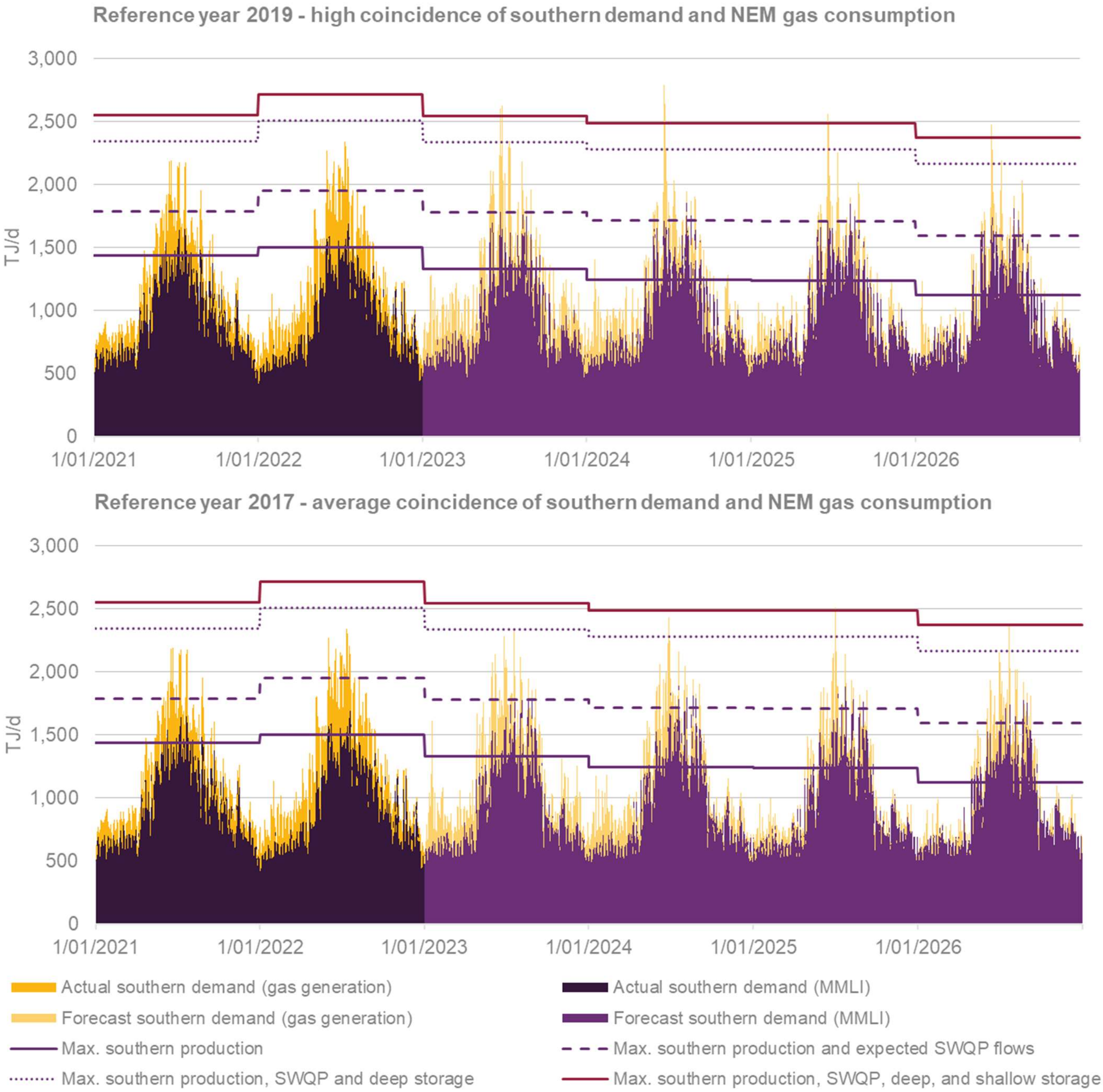
The key points highlighted in **Figure 4** are:

- Peak day shortfalls are forecast under extreme peak days in every year from 2023 to 2026 where large demand for gas generation coincides with significant residential, commercial and industrial consumption (such as in reference year 2019). Cold weather drives up demand for both electricity and gas for heating, and further stresses in the electricity system (such as coal unit outages or low wind) can drive up gas demand for electricity generation.
- Deep and shallow storages remain critical to meeting peak day demand, as southern production and flows along the SWQP alone are not enough to satisfy peak demand in winter.
- Without high coincidence of gas generation and residential, industrial and commercial demand, then peak day shortfalls may be narrowly avoided, but the supply demand balance remains very tight (such as for 2023 and 2024 in reference year 2017).

AEMO's physical gas adequacy assessments assume that gas from Queensland's LNG exporters is made available to the domestic market when required to avert domestic shortfalls. This may include gas that could otherwise be exported to international markets. Supply gaps affecting domestic consumers may result if this is not the case, and "LNG supply shortages" (where LNG exporter production is diverted to domestic consumers ahead of the exporters' contractual commitments) will occur if domestic supply does not develop in response to the supply gaps (see box later in this section for more information).

AEMO also forecasts limited gas supply to meet gas generation consumption across the entire horizon along the North Queensland Gas Pipeline, which runs from Moranbah to Townsville and is disconnected from the rest of the east coast grid. Anticipated and uncertain supply must be developed prior to late 2024 to maintain supply to gas consumers in that area.

Figure 4 Actual and forecast daily southern gas demand showing seasonality, peakiness, southern production, and total system capacity available to meet southern demand using existing and committed projects for the *Orchestrated Step Change (1.8°C)* scenario, under favourable and extreme weather (TJ)



Note: reference year 2019 (top chart) reflects adverse weather conditions leading to extremely high coincident peak demand, and reference year 2017 (bottom chart) reflects more favourable weather across southern regions with less coincident peak demand.

LNG volumes contracted for export may need to be supplied to domestic customers from 2026 to maintain domestic supply adequacy without expanded domestic supply

The volumes of gas exported internationally via Curtis Island in Queensland represent most of the gas demand on the east coast. As such, operation of these facilities can have significant impact on domestic supply adequacy.

Figure 5 presents a supply and demand balance of the LNG exporters (APLNG, GLNG and QCLNG) considering supply and expected export contracts only.

Figure 5 LNG exporters committed, anticipated and uncertain production, and third-party gas contracts in comparison to forecast exports, *Orchestrated Step Change (1.8°C)* scenario, 2023-42 (PJ/y)

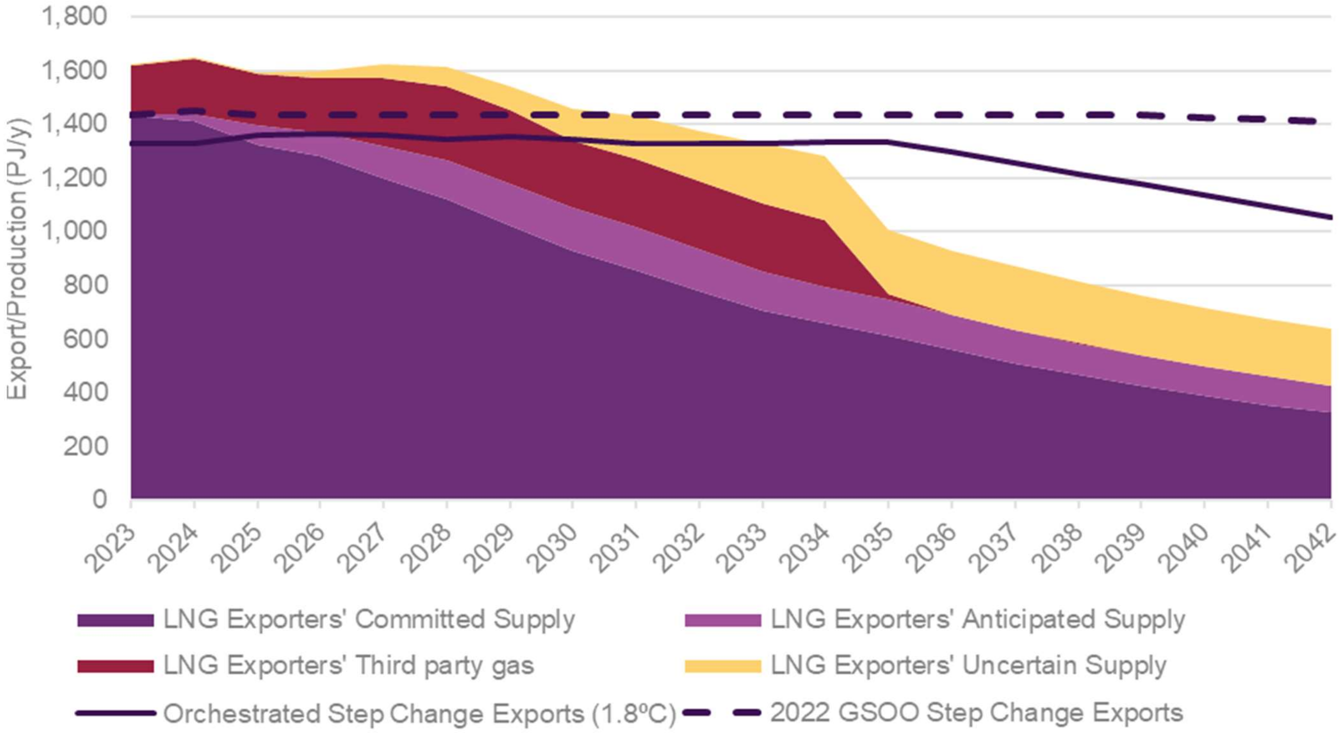


Figure 5 shows that the LNG exporters have:

- In 2023, excess supply[14] relative to advised contracted exports of 291 PJ, which includes a production excess[15] of 105 PJ from proprietary coal seam gas (CSG) production facilities (that is, excluding third party gas arrangements with other domestic producers).
- Sufficient production from existing and committed facilities to meet forecast exports until 2025.
- Sufficient production, if anticipated investments proceed, to meet forecast exports until 2027.

Forecast LNG exports from 2023 to 2035 are 80-90 petajoules a year (PJ/y) lower than forecast in the 2022 GSOO and represent expected LNG export contracts as submitted to AEMO by the LNG producers.

In the context of the east coast interconnected gas network, AEMO forecasts that, to support domestic supply adequacy:

- It remains critical that LNG exporters make supply available during winter to support flows along the SWQP and MSP to southern regions, to maintain domestic supply adequacy.
- In the absence of development of anticipated or uncertain supply (from all producers, not just LNG exporters), LNG supply shortages of up to 107 PJ may exist in 2026, increasing to 342 PJ in 2028. This indicates that the

[14] Excess supply is calculated as the difference between committed and third-party gas supply and expected exports.

[15] Production excess is calculated as the difference between committed supply, and expected exports.

domestic market requires more gas from the LNG exporters than their surplus in production. Development of anticipated supply sources reduces this to 53 PJ in 2027 and 72 PJ in 2028, and development of uncertain supply sources would delay domestic supply gaps, enabling contracted LNG exports to be filled beyond 2028.

If there is reduced supply from the Northern Territory to the east coast via the Northern Gas Pipeline (NGP), extra supply from the LNG exporters to the domestic market will be required, and this may impact their ability to meet contracted export quantites while supporting domestic consumers.

What if surplus production from LNG exporters is exported as spot cargoes?

The LNG exporters have the ability to provide significant volumes of currently uncontracted gas to the domestic market, however there may be economic incentive to instead export this gas if international markets prove more profitable than domestic sales.

The Australian Competition and Consumer Commission's (ACCC's) January 2023 *Gas Inquiry 2017-2030 Interim Report* indicates that LNG exporters anticipate 88 PJ of additional LNG spot cargoes will be sold in 2023[16]. This would increase total LNG exports to 1,384 PJ[17], above the advice provided to AEMO for this 2023 GSOO of the expected export contracts.

AEMO forecasts that if this quantity was exported, rather than supplied to domestic consumers, there may be a domestic supply gap of up to 33 PJ[18] in 2023. This differs from the *Gas Inquiry 2017-2030 Interim Report* as it applies gas generation at the upper end of the forecast range, with only committed and existing supplies.

Expanded southern supply or increased transportation capacity to access northern supply is needed to avoid domestic supply gaps

Although AEMO is forecasting declining gas consumption, supply is declining faster than forecast demand, and annual domestic supply gaps are forecast from 2027 (see **Figure 6**).

Compared to the 2022 GSOO *Step Change* scenario, these annual supply gaps are forecast six years earlier (largely due to PKET no longer being considered anticipated), and the range of supply gaps across scenarios is narrower (owing to a narrower spread of forecast demand outcomes), as shown in **Figure 1**.

However, there is still a significant spread of forecast supply gaps across scenarios, and therefore the preferred timing, type and size of investments in new gas supply and any supporting infrastructure required is uncertain.

This GSOO forecasts significant fuel-switching from gas to electricity. If the rate of electrification is slower than forecast, the risk of supply gaps increases, further highlighting the uncertainty in the investment needed in gas supply.

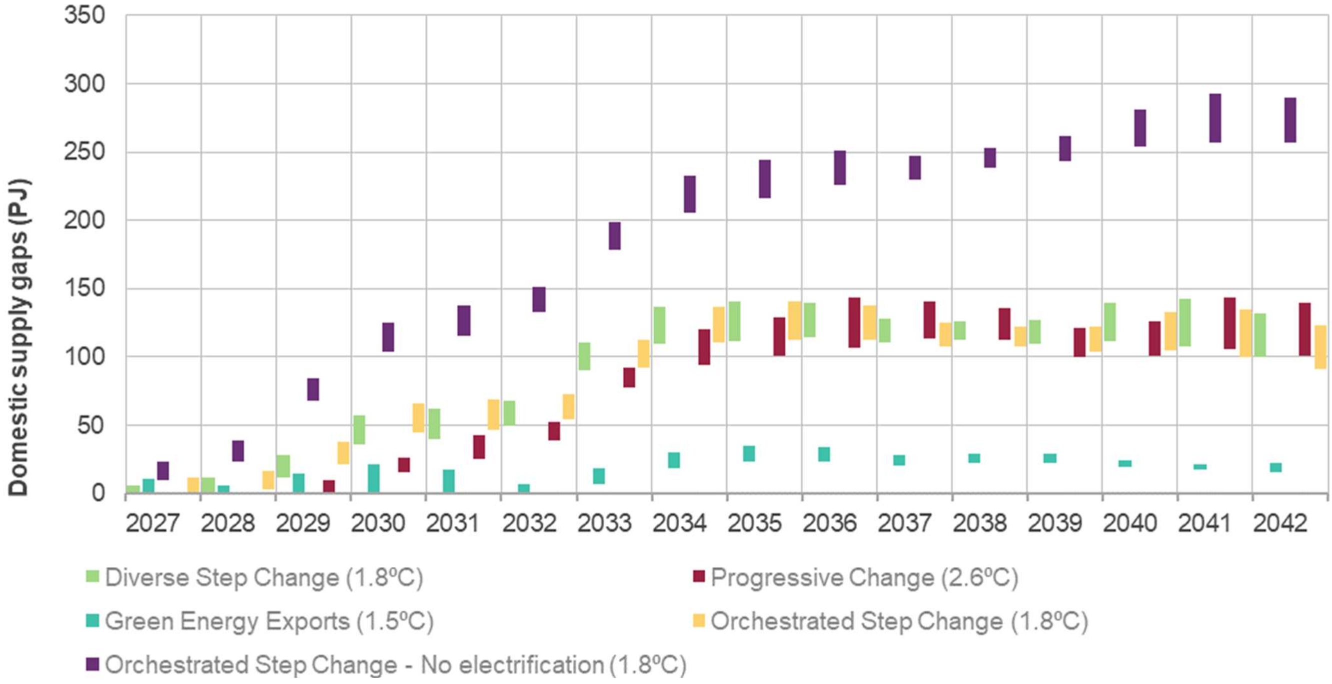
To mitigate annual supply scarcity risks, supplies beyond those currently existing, committed and anticipated must be developed from 2027. Development of an LNG import terminal, such as PKET, is forecast to delay annual supply gaps until 2033 in the *Orchestrated Step Change (1.8°C)* scenario.

[16] See page 30, at https://www.accc.gov.au/system/files/Gas%20Inquiry%20-%20January%202023%20interim%20report_1.pdf.

[17] The ACCC report presents LNG sale and purchase agreements (SPAs) at 1,296 PJ and 88 PJ of additional spot cargoes.

[18] The size of a supply gap will depend on many volatile factors (eg. weather); this 33 PJ estimate applies an upper range of gas generation.

Figure 6 Range of domestic annual supply gaps forecast in southern regions based on existing, committed, and anticipated developments, all scenarios, 2027-42 (PJ)



Project uncertainties

AEMO recognises that the current investment environment for projects is challenging and highly uncertain. Key uncertainties impacting project timelines and likelihood of completion include:

- **Russia-Ukraine conflict** – the Russian invasion of Ukraine in February 2022 has caused shocks in the global energy markets causing high international energy prices. The conflict is also driving up demand for electrolysers and FSRUs as Europe is driven to seek gas from sources other than Russia.
- **Inflation** – higher inflation in Australia and overseas, combined with rising rates to combat inflation, has increased high borrowing costs, threatening project economics. Some project costs are not keeping pace with long-term gas price projections.
- **Financing** – natural gas is becoming unpalatable for some investors who are screening investments on the basis of environment, social and governance (ESG) issues and want to limit exposure to fossil fuels.
- **COVID-19** – ongoing impacts of the COVID-19 pandemic have caused prolonged project timelines and delays procuring, or the complete unavailability of, specialist equipment and skilled resources.
- **Regulatory approvals** – environmental approvals for gas projects are becoming increasingly stringent. Industry has advised that the December 2022 Federal Court decision to set aside NOPSEMA's approval of Santos's Barossa Gas Project Environmental Plan[19] has increased industry uncertainty.
- **Market uncertainty** – from 23 December 2022, the Australian Federal Government imposed a $12/gigajoule (GJ) price cap to new domestic wholesale gas contracts for 12 months[20]. The Australian Federal Government

[19] Santos, "Full federal court decision for the Barossa Gas Project", 2 December 2022, at https://www.santos.com/news/full-federal-court-decision-for-the-barossa-gas-project/.

[20] Hon Katy Gallagher (Acting Treasurer), Treasury Portfolio, "Gas price cap to take effect", 22 December 2022, at https://ministers.treasury.gov.au/ministers/jim-chalmers-2022/media-releases/gas-price-cap-take-effect.

is also implementing a mandatory code of conduct that will apply to contracts between gas producers and their consumers on the east coast[21].

- **Competing investment interests for renewable gases** – policy and investment into renewable gases in other jurisdictions has been significant. Examples include the US Department of Energy's US$7 billion hydrogen hubs program[22], US$750 million clean hydrogen technology package[23] and clean hydrogen production tax credits[24], and the European Union's REPowerEU Plan[25].

Solutions will need to provide flexibility and account for uncertainty

Like the 2022 GSOO, this 2023 GSOO reports on a changing gas sector, a wide range of plausible futures for gas demand, and the impacts of uncertainty on market responses.

In the short term, **as shown above in Figure 3, there is limited anticipated supply that can be developed to mitigate forecast peak day shortfall risks.** Committed infrastructure and supply projects must be completed on time to minimise shortfall risks, and demand side solutions may need to be relied on to avoid shortfall risks in 2023 and 2024:

- It is important that the committed WORM and Winchelsea compressor upgrade in Victoria, and the Stage 1 and 2 upgrades of the SWQP and MSP (all currently considered as committed projects), are delivered on schedule. Increasing the amount of gas able to flow from Queensland to south-east consumers and removing constraints on injecting from or refilling Iona gas storage, these upgrades will increase the operability of the gas network and provide more flexibility to meet a variable and infrequent need under extreme circumstances.
- Maintaining availability of shallow storages at Dandenong and Newcastle, including ensuring that they are at, or near, full capacity prior to winter, is critical to reduce shortfall risks. Through winter, operating these appropriately to avoid unnecessary depletion during periods not requiring these reserves is also important.
  - The Declared Wholesale Gas Market (DWGM) interim LNG storage measures rule change[26] requires that AEMO contracts any uncontracted capacity in the Dandenong LNG tank from 2023 to 2025. This will ensure that the Dandenong LNG tank is full prior to winter during this period.
- Given the lead time needed to plan, obtain approval for, and build new greenfield infrastructure, demand flexibility is likely the best solution to address forecast short-term supply shortfall risks.
  - If gas generation drew less gas at times of peak gas demand, with greater potential use of secondary fuels (if available) at periods of gas scarcity, then gas shortfalls during extreme conditions may be avoidable under some operating conditions without compromising electricity reliability (subject to sufficient alternative electricity generating reserves being available to deliver the needs of the NEM).

[21] Hon Dr Jim Chalmers (Treasurer), Treasury Portfolio, 'Responsible and meaningful action on gas prices", 9 December 2022, at https://ministers.treasury.gov.au/ministers/jim-chalmers-2022/media-releases/responsible-and-meaningful-action-gas-prices.

[22] Department of Energy, "Biden-Harris Administration Announces Historic $7 Billion Funding Opportunity to Jump-Start America's Clean Hydrogen Economy", 23 September 2022, at https://www.energy.gov/articles/biden-harris-administration-announces-historic-7-billion-funding-opportunity-jump-start.

[23] Department of Energy, "Biden-Harris Administration Announces $750 Million to Accelerate Clean Hydrogen Technologies", 16 December 2022, at https://www.energy.gov/articles/biden-harris-administration-announces-750-million-accelerate-clean-hydrogen-technologies.

[24] Department of Energy - Hydrogen and Fuel Cell Technologies Office, "Financial Incentives for Hydrogen and Fuel Cell Projects", at https://www.energy.gov/eere/fuelcells/financial-incentives-hydrogen-and-fuel-cell-projects.

[25] European Commission, "REPowerEU Plan", 18 May 2022, at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2022%3A230%3AFIN&qid=1653033742483.

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

  - Demand side participation in the electricity market may reduce electricity demand, lowering demand for gas generation and reducing the risk of gas supply shortfalls.
  - Gas consumers may also voluntarily reduce their use of gas during forecast extreme peak day events if appropriately informed, however incentives and processes to deliver these are less mature than in the NEM.
- Beyond 2024, supply shortfall risks can be mitigated by the development of anticipated and uncertain supply, which may include the development and operation of an LNG import terminal. There may be technical, economic and regulatory challenges with bringing on uncertain supply.
- Proposed regulatory amendments are currently under consultation to extend AEMO's functions and powers to manage east coast gas supply adequacy in the near term. The new powers include the ability for AEMO to signal to the market where there is a potential shortfall and to call for an industry response, and to direct gas flows where required. These powers may assist with managing operational issues during times of peak demand, and will assist in ensuring there is maximum supply available for domestic demand. However, these powers will not mitigate shortfall risks where there is insufficient supply or transmission capacity available.

In the longer term, new sources of supply will be needed even though annual domestic gas consumption is forecast to decline:

- Annual supply gaps are forecast as early as 2027, however the timing, profile and magnitude of the gaps vary. Solutions should consider the changes and uncertainty described in this GSOO.
- The potential use of alternative zero-emissions fuels in the gas system to complement and/or substitute gas use (including in electricity generation) will impact the type and magnitude of additional gas supply required.

While consumption uncertainty is highlighted by differences across scenarios, increasing "peakiness" of gas demand is a common trend:

- In this context, opportunities for supply response are likely to come from more flexible, agile solutions that can support gas demand that is uncertain and increasingly peaky. Challenges can arise on days when gas generation needs to operate at high volumes to deliver electricity to consumers (potentially days where both electricity and gas demand are at, or near, peak levels).
- As well as flexible utilisation of infrastructure, demand response could potentially play a growing role in managing peak gas demand, as it does in the NEM. Greater use of the contingency gas mechanism in the Short Term Trading Markets (STTMs) or the NEM's Reliability and Emergency Reserve Trader (RERT) may help enable greater operational control of loads to reduce gas demand during extreme demand events. Enhancements to these mechanisms or additional mechanisms may need to be developed over time. Some large gas users may enter into interruptible gas supply contracts in exchange for lower supply costs. Further stages of the Energy Ministers' reform measures[27] will have consideration of demand management.

This GSOO reinforces the importance of sector coupling (interaction between electricity, gas and potentially hydrogen in future) in navigating the transition towards net zero emissions. Existing instruments such as the Gas Supply Guarantee, and new instruments such as the extension of AEMO's powers to monitor east coast supply adequacy, will be important for the gas and electricity sectors to optimally use available energy resources and reduce security and reliability risks in both systems while protecting domestic gas consumers.

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

1 Introduction

In this *Gas Statement of Opportunities* (GSOO), AEMO assesses the adequacy of reserves, resources, and infrastructure to meet domestic and export needs for gas over a 20-year outlook period across all Australian jurisdictions other than Western Australia, collectively referred to as central and eastern Australia.

The GSOO provides a physical assessment of gas adequacy, assessing the capability for currently committed and/or anticipated production capacities to meet the evolution of consumer demands for gas, including the important role for gas generation to support electricity consumers of the National Electricity Market (NEM).

Contractual and commercial dynamics may impact gas operations, including gas storages, and whether excess gas production capacity in northern regions are offered and transported to southern demand centres across the winter. Importantly, the GSOO does not assume that spare capacity is withheld for export, but identifies the level of physical capacity that is in excess of advised export positions, that could be available to domestic consumers as needed. This physical assessment provides an appropriate analysis of the required additional investments to meet the minimum requirements of the domestic market; if gas operators fail to utilise the infrastructure available, or fail to support appropriate availability to domestic consumers (including gas generators) by retaining gas for export, these minimum requirements may be insufficient.

The GSOO analyses a range of potential futures, focusing on the adequacy of the system to meet changing gas needs from now until 2042.

In this GSOO, "gas" means natural gas unless otherwise specified. This GSOO does not include blended gas from hydrogen, biomethane or any other natural gas equivalent or constituent gas in its modelling of gas supply adequacy, except where explicitly stated. Where appropriate, scenarios may consider offsets to demand from hydrogen or biomethane, as outlined in **Section 2**. There may be a greater role for these alternative fuels within the gas system that future GSOOs may examine as the regulatory frameworks adapt to rule changes[28].

1.1 Scenarios and sensitivities

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

For the 2023 GSOO, AEMO modelled the next 20 years using scenarios from the Draft 2023 *Inputs, Assumptions, Scenarios Report* (IASR)[29] to assess the impacts of changes to specific scenario assumptions.

These scenarios and sensitivities are described in detail in the Draft 2023 IASR, and remain highly comparable to scenarios used in the 2022 GSOO, with some differences. In summary:

- ***Orchestrated Step Change (1.8°C)*** is most similar to the 2022 ISP's *Step Change* scenario studied in the 2022 GSOO and continues to be used as the most likely scenario based on the 2022 ISP[30]. It applies the net zero emission commitments of the *Climate Change Act (2022)*, contributing towards energy-sector

[28] AEMC, *Review into Extending the Regulatory Frameworks to Hydrogen and Renewable Gases – Final Rules Report*, November 2022, p. 58, at https://www.aemc.gov.au/sites/default/files/2022-11/Hydrogen%20and%20Renewable%20Gas%20Review%20-%20Final%20Rules%20Report.pdf.

[29] At https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.

[30] The most likely scenario will be reassessed as part of the preparations for the 2024 ISP.

transformation and assumes global momentum towards decarbonisation. In this scenario, consumers embrace opportunities to reduce emissions through electrification across all sectors where technically practical, as well as investing in energy efficiency at a greater scale than in other scenarios.

  – Policy incentives and industry investment will need to expand beyond current commitments to realise the level of energy efficiency investments, fuel-switching and electrification forecast under this scenario across the horizon. While in many sectors the electrification of existing loads has already commenced, some uncertainty remains over how quickly consumers are able to invest to shift their energy use away from gas.
  – To identify the potential influence of slower electrification on gas adequacy risks, AEMO has also studied the impact if the current and future forecast electrification trends were halted, in the *Orchestrated Step Change (1.8°C), No Electrification* sensitivity.

- ***Diverse Step Change (1.8°C)*** scenario, like the *Orchestrated Step Change (1.8°C)* scenario, includes a global response to climate change with commensurate action domestically to meet Australia's climate change commitments. This scenario puts the greatest action to decarbonise on the industrial gas sector and features a lower contribution from end-use consumers to the energy transformation, with early development of biomethane resources. This scenario is a variation on the 2022 ISP's *Step Change* scenario, with increased biomethane blending in the near term as a means for gas supply to have greater contribution to emissions reduction, thereby slowing fuel-switching to electricity.
- ***Green Energy Exports (1.5°C)*** scenario reflects very strong decarbonisation activities domestically and globally to limit temperature increases to 1.5°C, resulting in rapid transformation of Australia's energy sectors, including greater development of alternative energy sources domestically, particularly green hydrogen.
- ***Progressive Change (2.6°C)*** scenario includes lower assumed forecast economic growth than historical trends. It follows a slower global recovery from the COVID-19 pandemic and ongoing disruptions affecting the international energy markets and associated supply chains, which affect energy consumers' actions to decarbonise the economy. This scenario is most similar to the 2022 ISP's *Slow Change* scenario that did not feature in the 2022 GSOO. This scenario anticipates slow economic growth and a challenging economic environment affecting energy consumers' actions to decarbonise the economy, including the greatest industrial closure risks. As such, this scenario is materially different to the 2022 GSOO *Progressive Change* scenario.

Key drivers of the 2023 GSOO scenarios

The scenarios apply alternative assumptions regarding the various dimensions and drivers affecting gas demand, particularly regarding traditional drivers of gas consumption (such as economic and population growth), the degree of electrification of existing gas demand, uptake of energy efficiency measures, biomethane demand, hydrogen demand, and the technology used to produce hydrogen.

Table 1 below summarises the key drivers affecting energy consumption considered most relevant to the gas market across the scenarios and sensitivities modelled.

Table 1 Scenario drivers of most relevance to the gas market

Driver	*Orchestrated Step Change (1.8°C)*	*Diverse Step Change (1.8°C)*	*Green Energy Exports (1.5°C)*	*Progressive Change (2.6°C)*
Economic growth, population, and gas connections outlook	Moderate	Moderate	Higher (partly driven by green energy)	Lower
Energy efficiency savings	Higher	Moderate	Higher	Lower
Electrification	Moderate, with a gradual pace in the short term, and increasing from the late 2020s onwards	Lower, with generally a gradual pace over the outlook period	Higher, with the greatest pace of electrification from the mid to late 2020s	Lower, with a gradual pace over the outlook period
Hydrogen use	Allowed	Allowed	Faster cost reduction. High production for domestic and export use.	Allowed
Hydrogen blending in gas distribution network[B]	10% vol (3% energy) by 2030, no further increase	10% vol (3% energy) by 2030, no further increase	10% vol (3% energy) by 2030, 80% vol (58% energy) by 2042	10% vol (3% energy) by 2030, no further increase
Biomethane blending in gas distribution network	No production within the forecast period	7.5% vol (7.5% energy) by 2030 and 13% vol (13% energy) by 2042	14% vol (14% energy) by 2030, no further increase	No production within the forecast period
Renewable energy generation	High	High	Very high	Moderate
Most similar 2022 GSOO scenario	Step Change	Step Change	Hydrogen Superpower	N/A[A]

A. The 2023 GSOO's *Progressive Change (2.6°C)* scenario is most like the 2022 ISP's *Slow Change* scenario, which did not feature in the 2022 GSOO.
B. Includes hydrogen volumes for residential and commercial uses only. It is assumed that additional hydrogen can be supplied to industrial customers via new dedicated hydrogen pipelines, where required.

1.2 Improvements in the 2023 GSOO

In this GSOO, AEMO has:

- Included the Northern Territory in the GSOO model and a corresponding supply adequacy assessment in this document. This also increased the accuracy with which flows from the Northern Territory to the east coast along the Northern Gas Pipeline (NGP) were modelled. Detailed analysis on the drivers affecting sub-sectoral consumption for the Northern Territory is not included.
- Included maintenance of pipelines and processing facilities in the GSOO model. Although the GSOO model may assume maintenance shifting is available to maintain supply adequacy, this inclusion results in improved modelling outcomes.
- Improved modelling of liquefied natural gas (LNG) import terminals to consider basic constraints due to shipping, unloading and regasification. LNG import terminals are modelled as sensitivities in the 2023 GSOO.
- Optimised the modelling consideration of gas storage to better reflect historical flows and operation.

1.3 Gas market reform

On 12 August 2022, Energy Ministers agreed[31] a set of actions to address the significant challenges experienced across east coast gas markets in 2022 and support a more secure, resilient and flexible east coast gas market. As a matter of urgency, Energy Ministers agreed to extend AEMO's powers and functions to provide it with tools to monitor, signal and manage gas supply shortfalls in the east coast gas system[32] from winter 2023 (first stage measures), including the implementation of a reliability and supply adequacy framework that can be used to identify and respond to reliability or supply adequacy threats and better manage periods of volatility.

The east coast gas system reforms present a material change to AEMO's roles and responsibilities across the east coast gas market, further supporting the national gas objective of reliability and security of supply of natural gas. First stage measures aim to provide the regulatory framework for AEMO to:

- Collect data and monitor the east coast gas system to assess the likelihood of a threat to the reliability or adequacy of gas supply,
- Signal to the industry where a threat has been identified, including the ability for AEMO to hold conferences (enshrining and broadening the Gas Supply Guarantee process),
- Direct gas industry participants to resolve a potential or actual threat (includes a compensation framework); and
- Trade in natural gas or purchase pipeline and other services to the extent required to prevent, reduce or mitigate an actual or potential threat.

Subject to the passage of legislation, AEMO aims to implement the first stage measures prior to winter 2023.

Further development (second stage measures) will focus on refining the framework implemented through the first stage measures as well as having consideration of demand management, storage obligations, obligations on retailers and generators and the development of reliability standards. Energy Ministers intend to consult on the development of these second stage measures subsequent to the implementation of the initial framework.

1.4 Supplementary information

Supporting material – including supply input data files, methodology reports, and figures and data – is available on AEMO's website[33], along with previous GSOO reports.

The supply input data files provide information (including capacity) about pipelines, production facilities, storage facilities, field developments, and any new projects or known upgrades considered in this GSOO analysis. These files also provide an update of reserves and resources and cost estimates used for the GSOO modelling[34].

AEMO's 2023 *Victorian Gas Planning Report* (VGPR)[35] complements the GSOO by providing a focused assessment of the supply demand balance to 2027 in Victoria's Declared Transmission System (DTS).

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

[32] "East coast gas system" includes all Australian states and territories apart from Western Australia.

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

[34] The published file showing reserves and resources is based on AEMO's survey of gas producers and information from Rystad Energy, supplemented by 2022 GSOO data if required.

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

Other relevant reference materials are listed in **Table 2**.

Table 2 Other relevant reference materials

Information source	Website address and link
Demand forecasting data portal	http://forecasting.aemo.com.au
Gas Bulletin Board – Map and Reports	https://www.aemo.com.au/energy-systems/gas/gas-bulletin-board-gbb
Draft 2023 Inputs, Assumptions, Scenarios Report (IASR), and Excel Workbook	https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation
BIS Oxford Economics, 2022 Macroeconomic projections report	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/bis-oxford-economics-2022-macroeconomic-outlook-report.pdf?la=en
CSIRO and ClimateWorks, 2022 Multi-sector energy modelling	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-climateworks-centre-2022-multisector-modelling-report.pdf?la=en
Strategy.Policy.Research, Energy Efficiency Forecasts 2021 – Final Report	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2021/strategy-policy-research---energy-efficiency-forecasts-2021.pdf
Lewis Grey Advisory, Gas Price Projections for Eastern Australia, 2023 Update – Report	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/lewis-grey-advisory-2023-gas-price-projections-for-eastern-australia.pdf?la=en
Lewis Grey Advisory, Gas Price Projections for Eastern Australia, 2023 Update – Workbook	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/lewis-grey-advisory-2023-gas-price-projection-workbook.xlsx?la=en

2 Gas consumption and demand forecasts

This section outlines forecasts of annual gas consumption and maximum daily gas demand across the various customer sectors of gas.

Consumption and demand forecasts are available on the AEMO Forecasting data portal[36].

Key forecast trends

- The annual, seasonal and peak daily needs of gas consumers are evolving, as Australia commits to, and develops new infrastructure to meet, a net zero emissions future. The degree of long-term uncertainty to 2050 is less than was forecast in the 2022 GSOO, however the pace at which the transition will occur and its impact on domestic, commercial and gas-powered generation gas requirements remains a key near-term uncertainty over the GSOO outlook.
- **Future annual gas consumption** will be influenced by the energy transformation, including the trend to electrify, the availability of alternative gas fuels such as biomethane and hydrogen, and the technical and social willingness to shift away from gas. The 2023 scenarios apply these drivers, and with all futures targeting a net zero economy, declining overall gas consumption is a feature of them all.
- **Maximum daily gas demand** is presently highly seasonal, with significant heating loads across southern regions in winter. The pace of electrification will impact daily peak requirements, particularly as gas heating loads reduce, however AEMO continues to forecast a strong degree of seasonality in the short, medium and long term.
- **Gas for generation of electricity** is forecast to provide a key firming role as the NEM electricity supply adapts to reduced availability and installation of coal generation. It is likely, as demonstrated in AEMO's scenario collection, that annual gas generation volumes will decline as renewable energy penetration grows, but maximum daily demands will continue to be high. This demand volatility is increasingly anticipated during winter as gas generation plays an increasingly important role in firming renewable energy as coal retires, and as newly electrified loads increase the energy consumed in the NEM. As identified in the *2022 ISP*, while gas volumes may decline, the key role for gas generation will be to provide flexible and firm electricity supply, albeit less frequently than operations occurred historically, but with greater importance to maintain NEM reliability.

Forecasts presented in this section are for all Australian states except Western Australia[37]. AEMO has produced approximate consumption and maximum daily demand forecasts for the Northern Territory[38]. Consumption and demand forecasts for the Northern Territory will be produced according to AEMO's demand forecasting

[36] At https://forecasting.aemo.com.au/ – first select either **Gas >> Annual consumption** or **Gas >> Maximum Demand**, then select 'GSOO 2023' from the Publication drop-down.

[37] Western Australia's gas forecasts are published in the Western Australia GSOO, at https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/wa-gas-statement-of-opportunities-wa-gsoo.

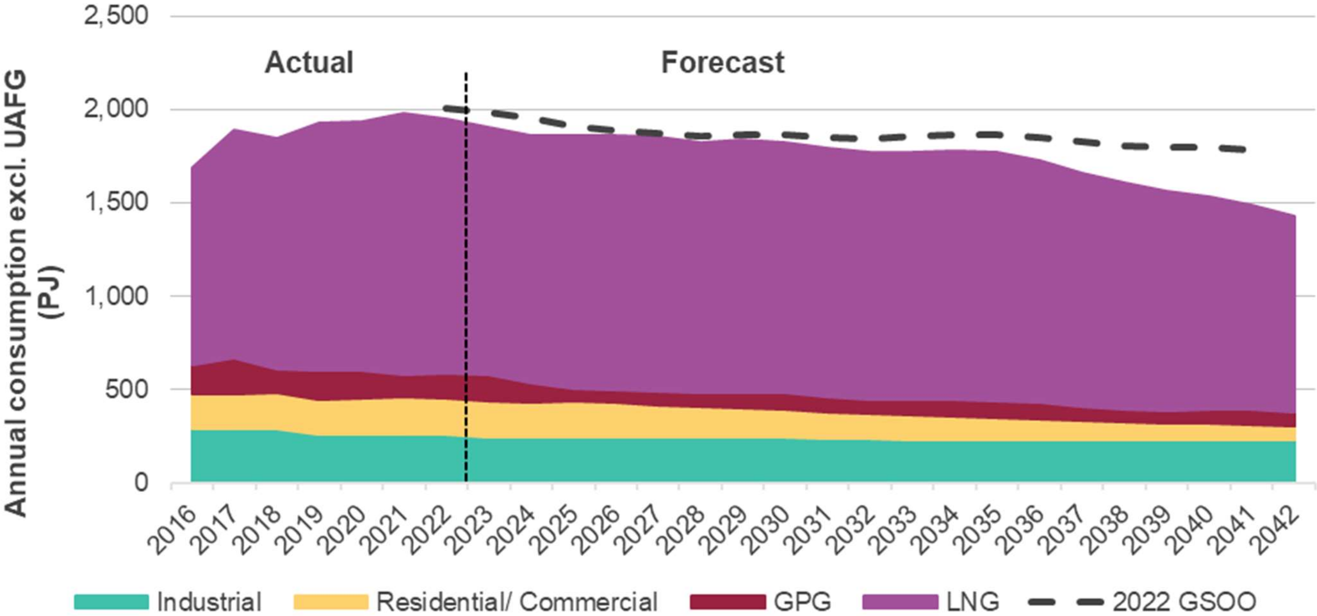
[38] Almost all gas consumed in the Northern Territory is for electricity generation. AEMO has based forecasts for gas consumption on three years of historical offtake, with adjustments for gas power station retirements and new entries in line with the most recent *Northern Territory Electricity Outlook Report*, at https://utilicom.nt.gov.au/publications/reports-and-reviews/2021-northern-territory-electricity-outlook-report.pdf.

methodology[39] from the 2024 GSOO onwards. For the purposes of this GSOO, AEMO has not varied the Northern Territory gas consumption and demand forecast across scenarios.

2.1 Total gas consumption forecasts

Figure 7 shows the 20-year total consumption forecast under the *Orchestrated Step Change (1.8°C)* scenario, broken down by consumer type for all Australian states except Western Australia. The drivers and trends for each sector are discussed in **Sections 2.2.1 to 2.2.4**.

Figure 7 Actual and forecast total annual gas consumption, all sectors, *Orchestrated Step Change (1.8°C)* scenario, 2016-42 (petajoules [PJ])



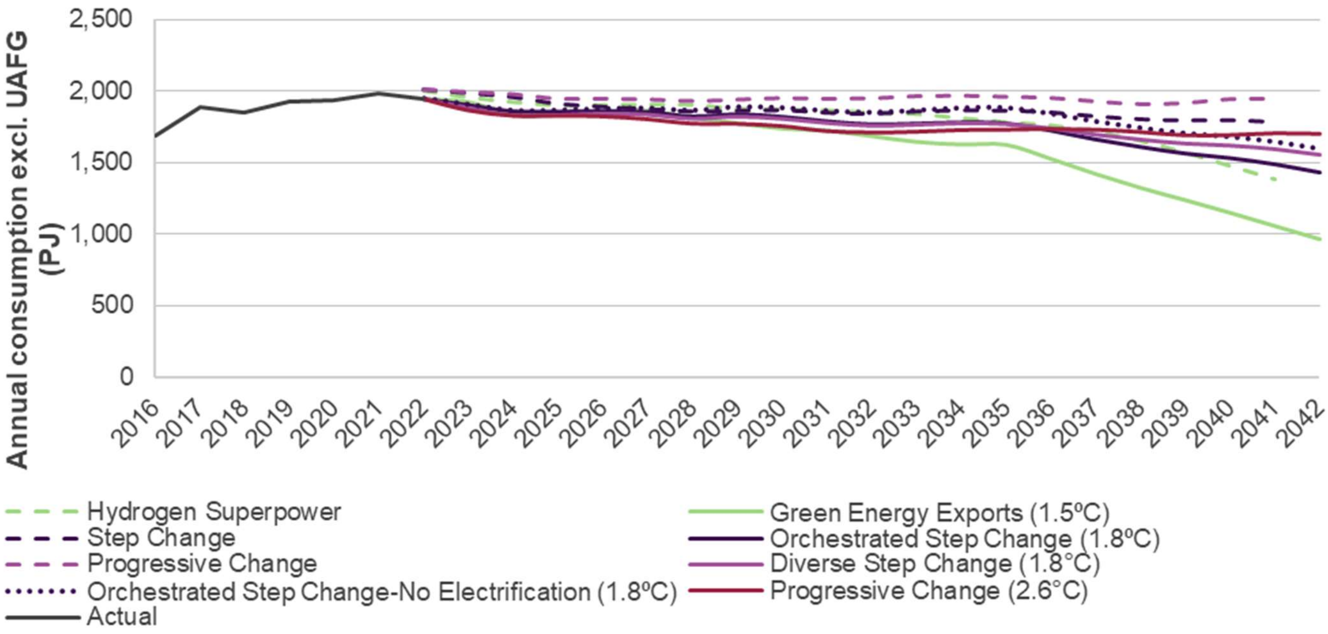
Note: The 2022 GSOO did not include the Northern Territory as a participating GSOO jurisdiction. The Northern Territory is included in actual gas consumption from 2020 onwards and in the 2023 forecasts.

The relative reduction in the 2023 GSOO forecasts is driven predominantly by lower forecasts for LNG exports and slightly decreased consumption for gas generation. These reductions are partially offset by an upwards revision for residential and commercial consumption across the outlook period. Residential and commercial consumption forecasts have increased relative to the 2022 GSOO largely due to a slower pace of electrification being evident than was previously forecast.

Figure 8 compares forecasts for the 2023 GSOO scenarios with those forecast in the 2022 GSOO. As required by the current NGR, these forecasts examine the demand for natural gas, however gas-equivalent alternatives may exist in future, and feature in some scenarios. Hydrogen and biomethane may present an alternative to natural gas. In some scenarios hydrogen production may result in increased natural gas demand for steam methane reforming (SMR) to meet domestic hydrogen demand (see **Section 2.2.2** below).

[39] The latest demand forecasting methodology is at https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo.

Figure 8 **Actual and forecast total gas consumption, all sectors, all scenarios, and compared to 2022 GSOO, 2016-42 (PJ)**



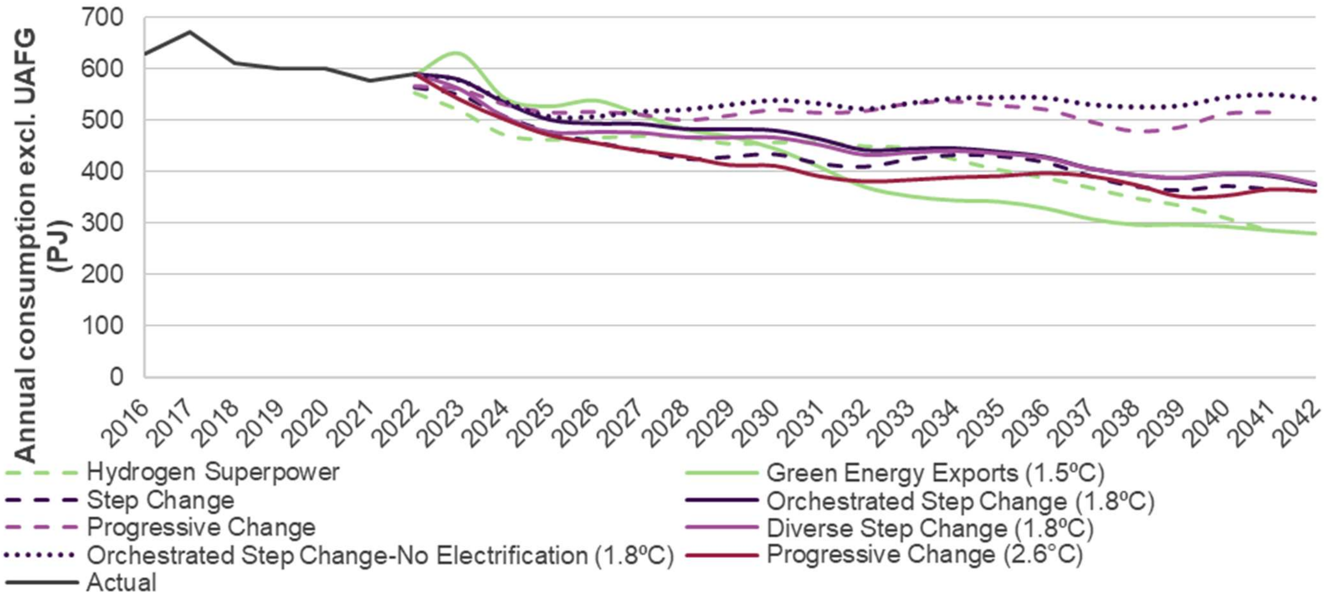
Notes:

- The 2022 GSOO scenarios are dashed lines, the 2023 GSOO scenarios are solid lines, and the 2023 sensitivities are dotted lines.
- The 2022 GSOO did not include the Northern Territory as a participating GSOO jurisdiction. The Northern Territory is included in actual gas consumption from 2020 onwards and in the 2023 forecasts.

Figure 9 shows annual consumption forecasts, excluding LNG exports, to isolate forecast trends in domestic consumption. The key drivers for the consumption trends in these forecasts include:

- Consumption is forecast to fall in all scenarios as consumers switch from natural gas to lower or zero emissions alternatives, including electricity, biomethane and hydrogen. Investments in energy efficiency, such as building quality improvements, are also key drivers for reduced gas consumption forecasts.
- There is reduced dispersion in the 2023 GSOO forecasts, reflecting the stronger net zero emissions commitments that all Australian jurisdictions have committed to, which result in greater inclusion of gas substitution and fuel-switching to electrification across all scenarios than featured in the 2022 scenarios.
- Gas consumption for electricity generation is a key influence on domestic consumption forecasts. Generator developments and retirements in the NEM are anticipated to have a key influence on how much gas is required to maintain reliability of electricity supply.

Figure 9 Actual and forecast domestic gas consumption, all scenarios, and compared to 2022 GSOO scenarios, 2016-42 (PJ)



Notes:

- The 2022 GSOO scenarios are dashed lines, the 2023 GSOO scenarios are solid lines, and the 2023 sensitivities are dotted lines.
- The 2022 GSOO did not include the Northern Territory as a participating GSOO jurisdiction. The Northern Territory is included in actual gas consumption from 2020 onwards and in the 2023 forecasts.

2.1.1 Trends in consumption drivers

Insights on trends in consumption drivers are not available for the Northern Territory for the 2023 GSOO, and the Northern Territory is not included in analysis or charts presented in this section.

Trends towards natural gas alternatives – electrification, hydrogen, and biomethane uptake

As Australia has committed to a net zero emissions future by 2050, investments to reduce the emissions intensity of the energy sector will influence the balance of energy sources used across Australia's economy. To inform the 2023 GSOO forecasts, multi-sector modelling examined decarbonisation pathways assuming the national (and international) decarbonisation objectives within AEMO's 2023 scenarios. The modelling establishes least-cost pathways for Australia's economy to achieve emissions targets within the parameters of scenario-based demand drivers[40]. The 2023 Draft IASR outlines the key assumptions and outcomes of the modelling.

Electrification is expected to impact all sectors – residential, commercial and industrial – although some industrial processes are more difficult or costly to electrify (for example, steel and aluminium manufacturing may have technical barriers to electrification). **Figure 10** shows the range of electrification forecasts across all scenarios; the scale of electrification is driven by the long-term commitments to meet Australia's collective emissions reduction policy targets, and significant additional stimulus may be required to achieve the scale of electrification indicated.

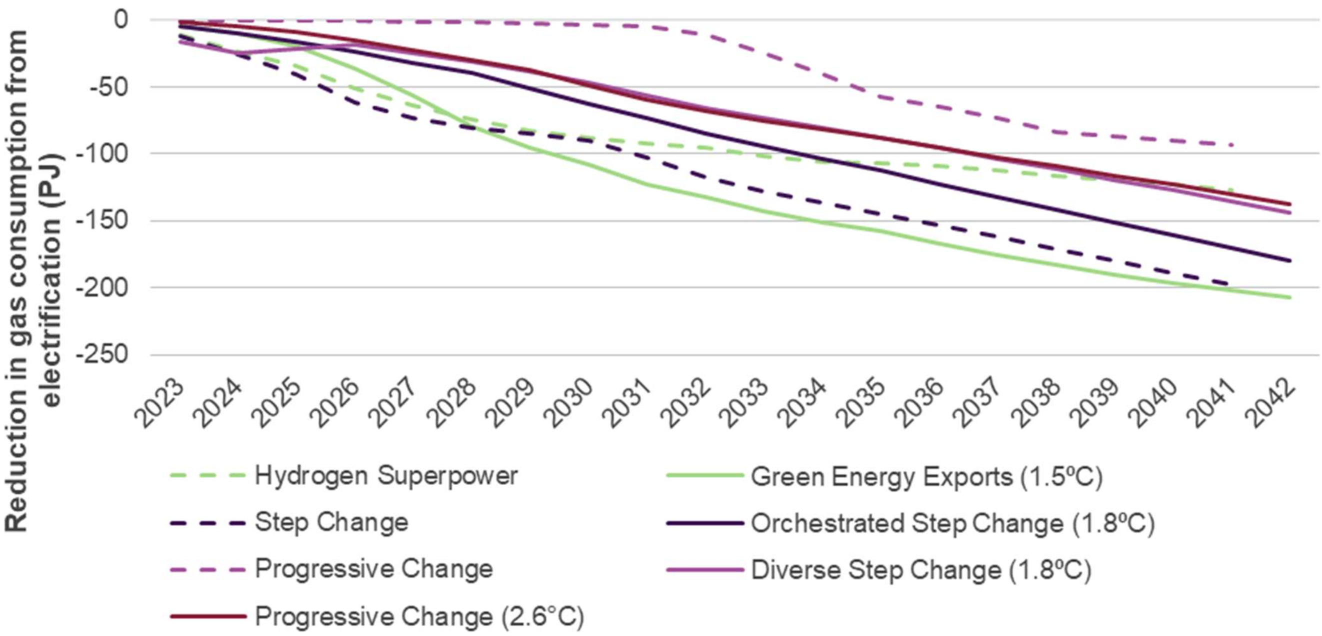
In contrast, the 2022 GSOO *Progressive Change* scenario delayed the investments in electrification, which would slow down the energy transformation towards net zero carbon emissions.

The pace of investments to electrify is a key uncertainty, and AEMO's scenarios feature a wide dispersion of this component to reflect this. For example, the *Green Energy Exports (1.5°C)* scenario applies more rapid industrial

[40] Multi-sector modelling was conducted for AEMO by CSIRO and ClimateWorks Australia. Full details are at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-climateworks-centre-2022-multisector-modelling-report.pdf.

sector electrification in response to more ambitious decarbonisation objectives (domestically and internationally), higher energy requirement from stronger economic growth, and faster assumed technological advances to fulfill these objectives. However, this sector's electrification will require significant capital outlay to transform existing industrial processes, and other scenarios reflect a much slower and more limited scale of electrification. In contrast, the 2022 GSOO *Progressive Change* scenario delayed the investments in electrification, which would slow down the energy transformation towards net zero carbon emissions. While it also targeted net zero emissions by 2050, it did not feature the pace of investments that are now considered important for the economy to meet Australia's 2030 targets under the *Climate Change Act (2022)*.

Figure 10 Forecast reduction in gas consumption from electrification by scenario, 2023-42 (PJ)



Notes:

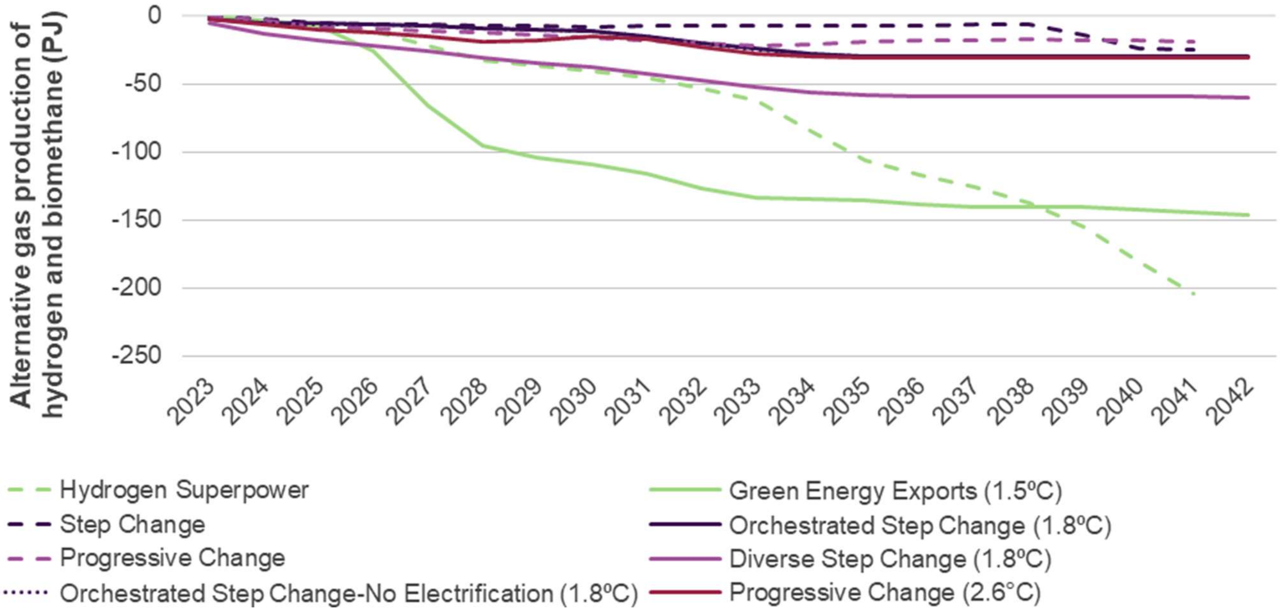
- The 2022 GSOO scenarios are dashed lines, the 2023 GSOO scenarios are solid lines, and the 2023 sensitivities are dotted lines.
- The 'no electrification' sensitivity to the *Orchestrated Step Change (1.8°C)* scenario features no reduction (0PJ) across this horizon.

Alternatives to electrification such as biomethane and hydrogen also vary across the scenarios. **Figure 11** shows the forecast reduction in gas consumption by scenario due to biomethane and hydrogen uptake.

Hydrogen could play a key role in industrial decarbonisation, as well as affecting commercial and residential sectors. Hydrogen uptake in the 2023 forecasts is comparatively stronger for most scenarios reflecting the increased activity and policy development supporting this technology's development. While hydrogen production will most likely reduce natural gas consumption, potential exists for some production of hydrogen from SMR (with CCS – Carbon Capture and Storage) as 'blue' hydrogen.

Compared to hydrogen, biomethane developments face fewer technical barriers and would provide a direct substitute to natural gas. AEMO's 2023 forecasts recognise the potential for biomethane development, with much of the near-term development variation between the *Green Energy Exports (1.5°C)* and the 2022 GSOO's *Hydrogen Superpower* scenario being due to assumed development of this alternative gas.

Figure 11 Forecast reduction in gas consumption due to biomethane and hydrogen uptake by scenario, 2023-42 (PJ)



Notes:

- This chart only considers hydrogen consumption due to fuel-switching from natural gas. Total hydrogen consumption is higher when considering fuel-switching from other sources, such as coal and oil.
- The 2022 GSOO scenarios are dashed lines, the 2023 GSOO scenarios are solid lines, and the 2023 sensitivities are dotted lines.

Economic and population outlook

In 2022, AEMO engaged BIS Oxford Economics to develop long-term economic and population forecasts for Australia[41]. The forecasts reflect Australia's emergence following the COVID-19 pandemic, with the removal of restrictions on activity and border closures that affected population and economic activity in the 2022 GSOO.

In 2022-23, strong household growth and labour market demand are expected to support the domestic economy even as the Reserve Bank of Australia's interest rate rises seek to quell strong inflationary pressures. The utilities sector is expected to grow strongly this financial year as energy prices, which increased globally largely as a result of the Russia-Ukraine war, begin to ease and industrial activity continues to normalise after the pandemic. Through the mid-2020s, the full impact of government fiscal policy during the pandemic is expected to pass through to the construction and manufacturing sectors, increasing their shares of economic activity.

Overall population growth forecasts remain relatively unchanged compared to the 2022 GSOO[42], however the state composition has been updated. A rebound in Victoria in 2023 is forecast following both low net overseas migration due to border closures and the large negative shock to net interstate migration (NIM) driven by the extended lockdowns. Queensland is expected to experience the strongest population growth and has seen growth revised upwards from the 2022 GSOO forecasts, reflecting a strengthening labour market and post-pandemic shift towards more affordable lifestyle locations, and consequently capturing a large share of NIM from New South Wales. Overall, these economic and population forecasts have a direct impact on the forecast number of connections to the gas system.

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[41] BIS Oxford Economics Macroeconomic Projections Report, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/bis-oxford-economics-2022-macroeconomic-outlook-report.pdf?la=en.

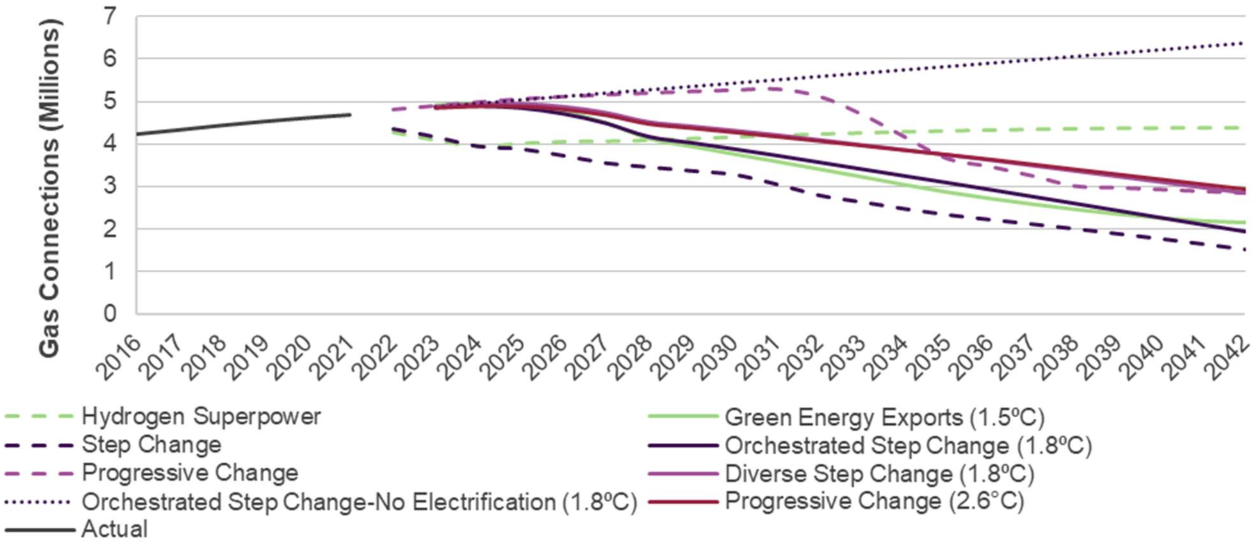
[42] There have been revisions to historical data back to 2017, following the release of the 2021 Census.

As **Figure 12** shows, the number of effective households and commercial businesses connected to gas is forecast to fall under all scenarios and sensitivities in the long term. However, compared to the 2022 GSOO *Step Change* scenario, forecast connections have been revised up in the *Orchestrated Step Change (1.8°C)* scenario due to weaker electrification assumptions.

The projected decline in effective household and commercial business connections reflects the forecast rise of electrification. The forecasts represent an 'effective' number of connections, representative of the number of connections if those connections maintained historical levels of consumption. The strict number of connections may be greater than this 'effective' forecast, however those connections may consume materially less volumes of gas than historical norms through the use of alternative electric appliances, for example removing gas cooking and gas hot-water loads but retaining gas heating. The physical number of connections may not reduce as rapidly as this forecast; however, the forecast allows for an equivalent assessment on the impact on gas consumption.

In summary, the forecast number of effective connections falls from 4.9 million in 2023 to 1.9 million in 2042 under the *Orchestrated Step Change (1.8°C)* scenario (0.4 million higher than the GSOO 2022 *Step Change* scenario).

Figure 12 Actual and effective forecast household and commercial business connections, all scenarios and compared to the 2022 GSOO, 2016-42



Note: the 2022 GSOO scenarios are dashed lines, the 2023 GSOO scenarios are solid lines, and the 2023 sensitivities are dotted lines.

Energy efficiency

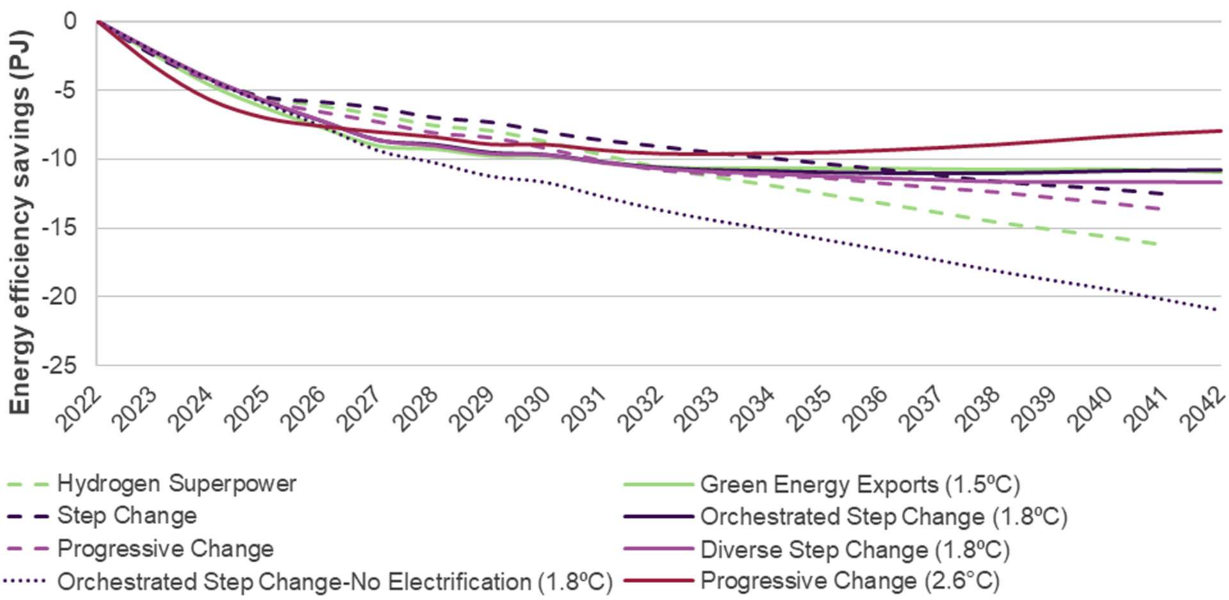
In 2021, AEMO engaged Strategy.Policy.Research to develop forecasts of gas savings from current and planned energy efficiency measures, including:

- The National Construction Code.
- State-based measures, such as the New South Wales Energy Savings Scheme, the Victorian Energy Upgrades Program, Victoria's Household Energy Savings Package, and South Australia's Retailer Energy Productivity Scheme.
- Disclosure measures including Commercial Building Disclosure and the National Australian Built Environment Rating System.
- Industrial assessments, including Victoria's Business Recovery Energy Efficiency Fund.

Additional (hypothetical) state-based measures and industrial assessments were also adopted for scenarios with high energy efficiency settings. AEMO further adjusted the forecasts to account for savings that will not be realised from connections fuel-switching away from gas.

Figure 13 shows the forecast reduction in gas consumption from energy efficiency savings, by scenario and compared to the 2022 GSOO. The forecasts represent the savings from energy efficiency investments from 2022, to enable appropriate comparison to the 2022 GSOO forecasts, and to ensure historical savings are not identified as additional savings.

Figure 13 Forecast reduction in gas consumption from energy efficiency savings, by scenario and compared to the 2022 GSOO, 2022 – 42 (PJ)



Note: the 2022 GSOO scenarios are dashed lines, the 2023 GSOO scenarios are solid lines, and the 2023 sensitivities are dotted lines.

The forecast energy efficiency savings are similar to the 2022 GSOO, given the same underlying consultant forecasts. These forecasts support the achievement of decarbonisation targets, by applying targets to existing measures[43] across all scenarios, and hypothetical measures in scenarios with stronger incentives to invest in energy efficiency.

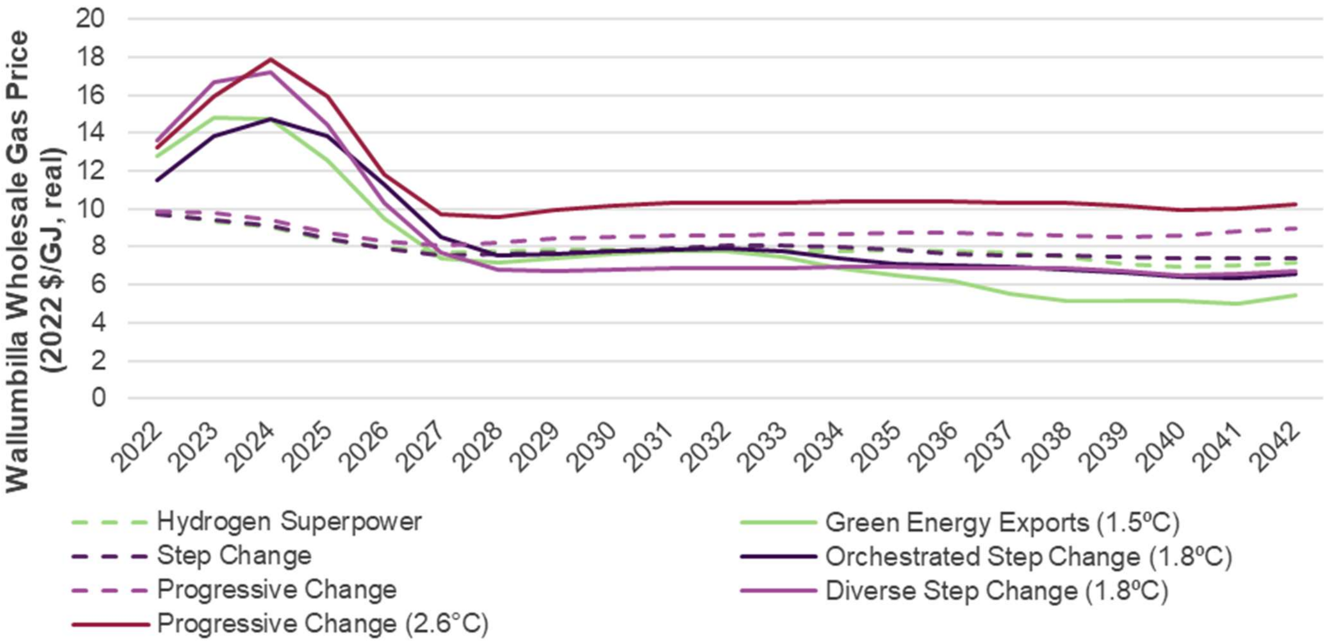
Updated electrification assumptions generally increase the energy efficiency forecast under some scenarios, including the *Orchestrated Step Change (1.8°C)*, compared to the 2022 GSOO, as weaker fuel-switching (from gas to electricity) means energy efficiency savings accrue from continued use of gas appliances and equipment. To further test the impact of electrification, a sensitivity analysis was undertaken with no electrification occurring. The *Orchestrated Step Change (1.8°C), No Electrification* sensitivity highlights that in the absence of electrification then gas savings would continue to grow with long-term retention of gas appliances.

[43] Depending on the scheme, the targets aim to save energy or reduce carbon emissions.

Wholesale and retail gas prices

AEMO engaged Lewis Grey Advisory (LGA) to prepare the wholesale contract gas price forecasts for the 2023 GSOO[44]. LGA forecasts for wholesale gas prices at the Wallumbilla Hub are shown in **Figure 14**.

Figure 14 Forecast wholesale prices at the Wallumbilla Hub, all scenarios compared to the 2022 GSOO, 2023-42 ($/gigajoule [GJ])



Note: the 2022 GSOO scenarios are dashed lines, the 2023 GSOO scenarios are solid lines, and the 2023 sensitivities are dotted lines.

LGA's modelling considered the global LNG price surge in 2022 due to Russia's invasion of Ukraine and the resulting sanctions on Russia as European gas consumers seek alternative supply due to the reduction in Russian gas supply. Australian LNG exporters responded to high global prices by increasing spot export sales, and offering short-term domestic (east coast) sales at high, export equivalent, prices[45]. LGA's modelling assumes that these conditions persist in the short term, although at lessening impact from 2026.

From December 2022, the Australian Federal Government imposed a gas (and coal) price cap[46] to new domestic wholesale contracts for a period of 12 months. The Federal Government is also implementing a mandatory code of conduct that will apply to contracts between gas producers and their consumers on the east coast[47]. These gas price forecasts were developed prior to these developments, and the influence these new arrangements will have on wholesale or retail gas prices for domestic consumers, including industrial and gas generation users is unclear and has not been considered in this gas price forecast.

The cost of any good or service influences the amount of consumption, with higher prices generally causing consumers to use or want less. Some discretionary goods are highly elastic, and a price rise will significantly

[44] Lewis Grey Advisory, *Gas Price Projections for Eastern Australia Gas Market 2023*, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/lewis-grey-advisory-2023-gas-price-projections-for-eastern-australia.pdf.

[45] See ACCC *Gas Inquiry 2017-2030 Interim Report*, January 2023, at https://www.accc.gov.au/system/files/Gas%20Inquiry%20-%20January%202023%20interim%20report%20-%20FINAL_0.pdf.

[46] See Competition and Consumer (Gas Market Emergency Price) Order 2022 https://www.legislation.gov.au/Details/F2022L01743

[47] Hon Dr Jim Chalmers (Treasurer), Treasury Portfolio, 'Responsible and meaningful action on gas prices", 9 December 2022, at https://ministers.treasury.gov.au/ministers/jim-chalmers-2022/media-releases/responsible-and-meaningful-action-gas-prices.

reduce consumer demand for that good, whereas others are relatively inelastic, and price rises tend to be absorbed and consumption maintained. Energy is typically a relatively inelastic good, being an essential service, and while price rises may lead to increased or faster investments in electrification or energy efficiency (to reduce exposure to price rises), AEMO applies only a mild response to retail gas price rises, given its relatively low substitutability, and the year-on-year price changes assumed only result in at most a 2 PJ year-on-year change for combined residential and commercial consumption (that is, a 1% impact or less on consumption).

2.2 Consumption forecasts by sector

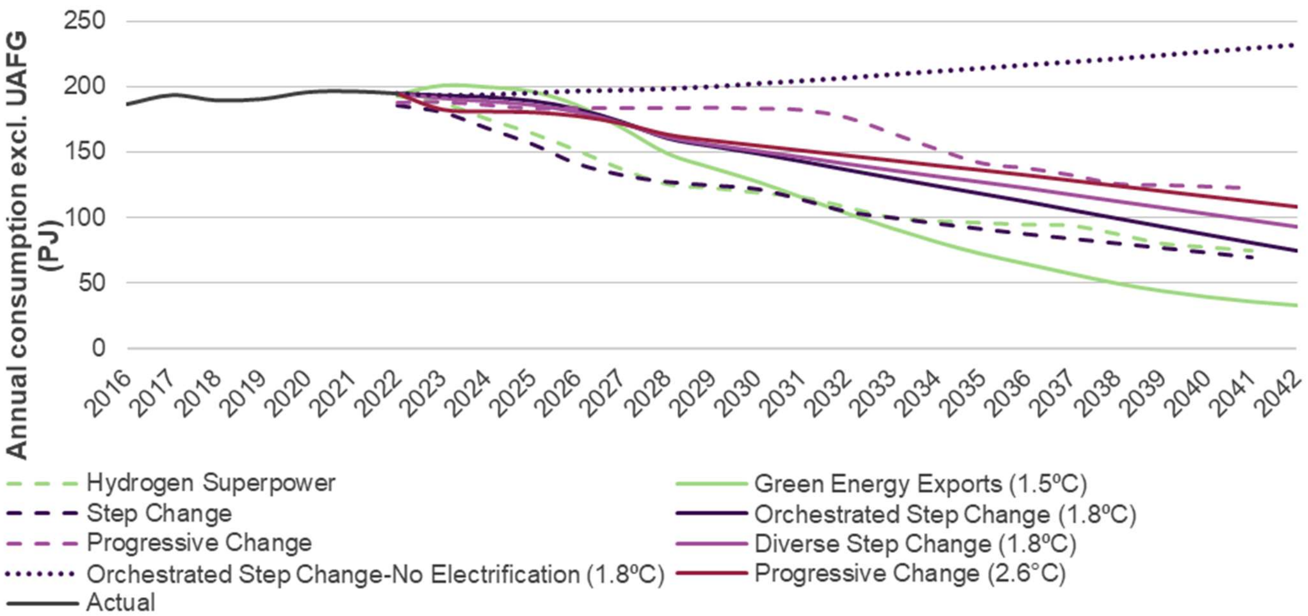
Insights on sectoral consumption forecasts are not available for the Northern Territory for the 2023 GSOO, and the Northern Territory is not included in analysis or charts presented in this section.

2.2.1 Residential and commercial consumption

Residential and commercial consumers are defined as those users that consume relatively small gas volumes, of less than 10 terajoules (TJ) of gas per annum, and have a basic gas meter. AEMO forecasts residential and commercial gas consumption on a per connection basis. The growth trajectory is driven by the gas connections forecast, with adjustments made for fuel-switching to electricity, alternative gases such as hydrogen and biomethane, energy efficiency savings, climate change impact, and behavioural response to retail prices.

Figure 15 shows forecasts for this sector across scenarios and compared to 2022 GSOO forecasts. The 2023 forecasts are calibrated on historical data to better align with recent consumption. The 2022 GSOO forecasts anticipated a faster reduction in consumption resulting in a lower starting point for that forecast. This consideration of previous forecast accuracy improves the 2023 forecast collection; more information on assessed forecast accuracy is available in **Appendix A1**.

Figure 15 Actual and forecast residential and commercial annual consumption, all scenarios and compared to 2022 GSOO, 2016-42 (PJ)



Notes:

- UAFG means "unaccounted for gas". It is gas lost in the network and not delivered to consumers.
- The 2022 GSOO scenarios are dashed lines, the 2023 GSOO scenarios are solid lines, and the 2023 sensitivities are dotted lines.

In the *Orchestrated Step Change (1.8°C)* scenario:

- Residential and commercial consumption is forecast to decline strongly, from 194 PJ to 75 PJ over the outlook period. The primary drivers of the forecast decline are new buildings transitioning to electric-only connections, and electrification of existing customers moving away from gas to electricity for heating, hot water, and to a lesser extent, cooking.
- Energy efficiency savings and hydrogen blending[48] are forecast to have a more modest impact on reducing consumption, by 9 PJ and 2 PJ respectively, by the end of the outlook period. In the case of energy efficiency, the potential for measures to lower consumption will reduce as customers fuel-switch to electricity. Biomethane blending is not considered in this scenario.
- If electrification were halted, growth in natural gas consumption would continue, in line with the forecast growth in connections under the no electrification sensitivity. While this future is highly implausible, the pace and scale of investments to electrify remain uncertain and may well fall between the *Orchestrated Step Change (1.8°C)* scenario and the no electrification sensitivity.

In other scenarios:

- The *Progressive Change (2.6°C)* scenario forecasts a steady decline in consumption, to 108 PJ (approximately half current consumption) by the end of the outlook period, as consumers shift towards electric alternatives more slowly than in the *Orchestrated Step Change (1.8°C)* scenario combined with comparatively slower growth in new gas connections.
- The *Diverse Step Change (1.8°C)* scenario forecasts a slower reduction in gas consumption than the *Orchestrated Step Change (1.8°C)* scenario, reaching 93 PJ by the end of the outlook period. This is a result of comparatively less fuel-switching to electricity as more alternative gas such as biomethane is assumed to be available. The net effect of these two drivers is a marginally higher long term forecast of gas consumption.
- The *Green Energy Exports (1.5°C)* scenario presents the highest consumption forecast in the short term, driven by an increasing number of gas connections from higher population growth settings. From the late 2020s onwards, there is a more rapid decline in consumption, to 33 PJ by the end of the outlook period, as a greater pace of decarbonisation leads to increased fuel-switching to electricity, increased energy efficiency investments for hard-to-electrify loads, and increased gas substitution from hydrogen production.

2.2.2 Industrial consumption

AEMO forecasts industrial sector consumption for the following customer categories:

- Large industrial loads (LILs) – this includes customers with consumption greater than or equal to 500 TJ per annum. LILs are forecast individually, informed by consumption estimates provided via survey and interview from the operators of each facility. LILs represent over 70% of total industrial sector consumption; this category comprises fertiliser producers, mineral processing, primary metal, paper and chemical producers, oil refineries, large food processors, and mining. Any on-site electricity generation that consumes gas is also included within this category[49].

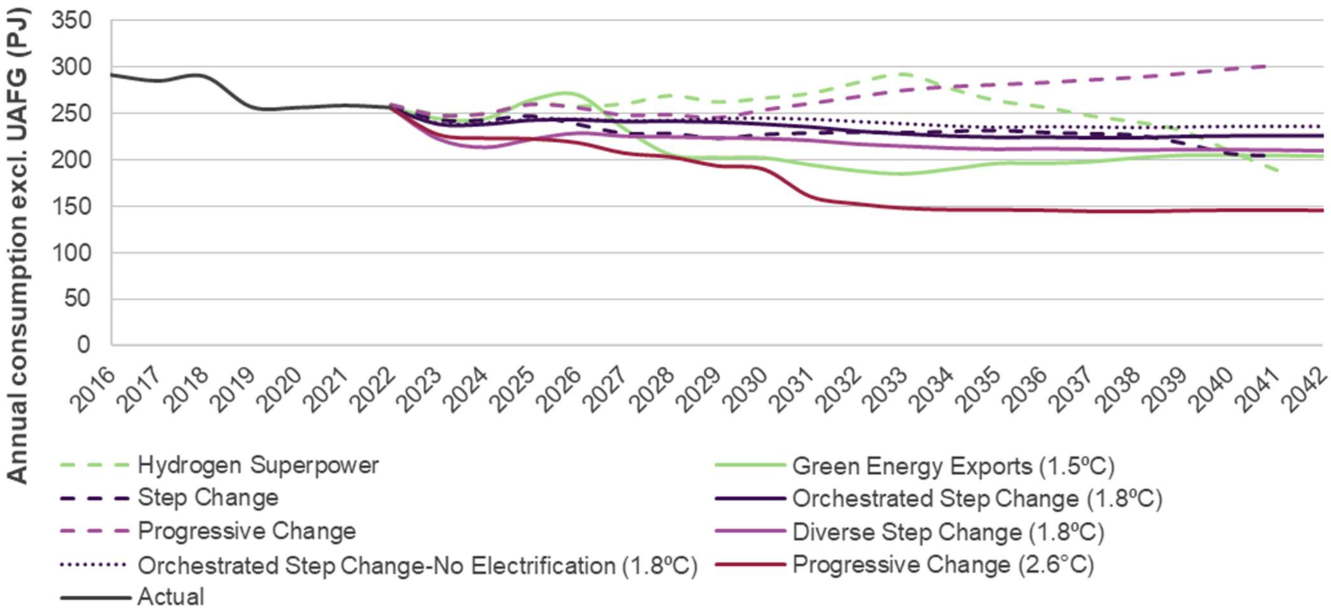
[48] Blending hydrogen gas into the gas network, substituting for natural gas, within the technical limits of the pipelines and what is safe for gas appliances to use.

[49] On-site gas generation reflects embedded generation that is "behind the meter", servicing the customer's own load rather than the NEM at large. These facilities are included in the LIL forecast category, rather than the gas generation category.

- Small to medium industrial loads (SMILs) – this category includes customers with consumption between 10 TJ and 499 TJ per annum at individual sites, and is forecast in aggregate.
- SMR load - 'blue hydrogen' production via SMR, with processes to capture emitted CO_2 via carbon-capture and storage technologies.

Figure 16 shows the combined industrial sector consumption forecast for all scenarios and compared to the 2022 GSOO. All scenarios feature a reduction in industrial consumption due to the closure of Incitec Pivot's Gibson Island facility in Brisbane in January 2023[50]. Note that the industrial forecast does not account for Opal Australian Paper's 15 February 2023 announcement that production of white paper at the Australian Paper Maryvale Mill is to cease from 21 January 2023 (production of brown paper and cardboard is expected to continue)[51].

Figure 16 Actual and forecast industrial annual consumption, all scenarios and compared to 2022 GSOO, 2016-42 (PJ)



Note: the 2022 GSOO scenarios are dashed lines, the 2023 GSOO scenarios are solid lines, and the 2023 sensitivities are dotted lines.

In the *Orchestrated Step Change (1.8°C)* scenario:

- Consumption is forecast to decline in the short term, before slightly increasing to around 240 PJ until the early 2030s. Compared to the 2022 GSOO, the 2023 forecast reflects a slower rate of electrification.
- In the longer term, stronger forecast hydrogen consumption (compared to the 2022 GSOO *Step Change* scenario) offsets the need for gas, reducing industrial gas consumption by 28 PJ in the final years of the forecast.
- SMR load reaches approximately 14 PJ by 2042, about half the rate assumed in last years' forecast, as more production is met by electrolysis.
- If all electrification trends were halted, as reflected in the no electrification sensitivity, the sector would likely increase consumption, but would not be effectively contributing to the economy's net zero commitments. The

[50] See https://www.incitecpivot.com.au/about-us/about-incitec-pivot-limited/media/gibson-island-manufacturing-operations-to-cease-at-end-of-2022.

[51] See https://opalanz.com/news/opal-australian-paper-maryvale-mill-supply-update/

sensitivity represents an unlikely future but is provided to give consideration for the range of potential outcomes.

In other scenarios:

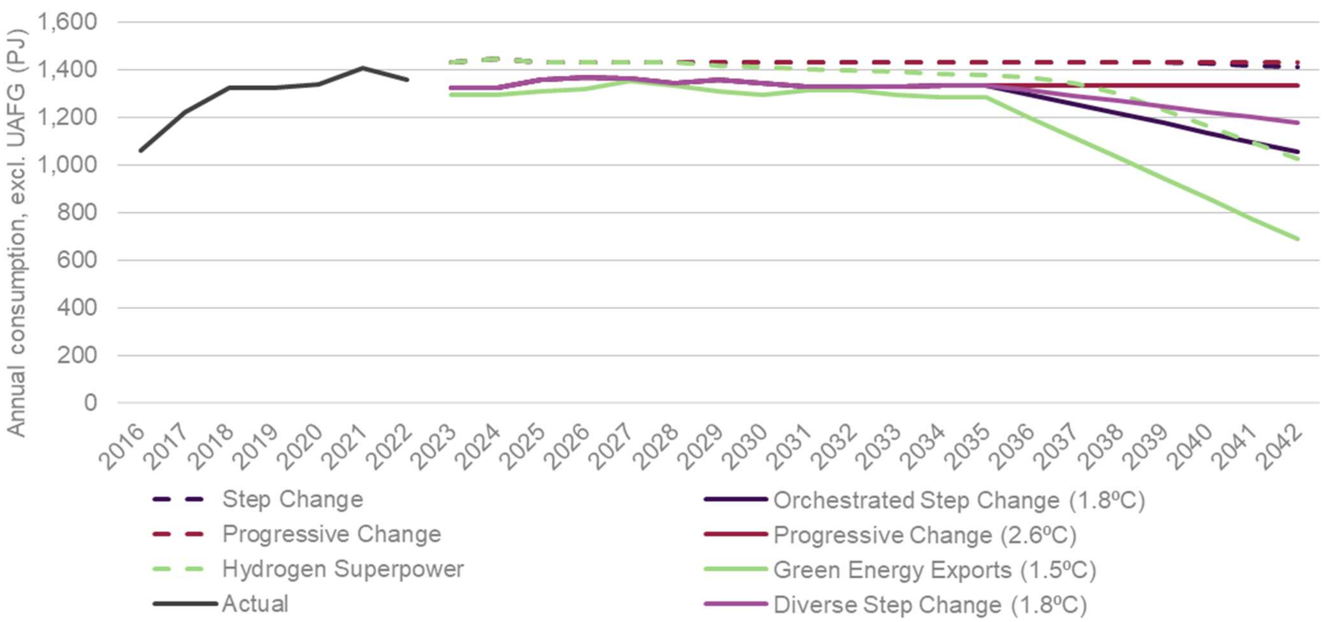
- The *Diverse Step Change (1.8°C)* scenario follows a similar trend, with biomethane production offsetting natural gas consumption by a greater volume than the *Orchestrated Step Change (1.8°C)* scenario.
- The *Green Energy Exports (1.5°C)* scenario forecasts a temporary increase in consumption in the short term due to higher economic outcomes inherent in the scenario and significant growth in SMR hydrogen production from 2025. From 2027 onwards, increasing availability of biomethane and hydrogen (direct fuel-switching, or hydrogen blending within distribution networks), reduces the need for gas.
- The *Progressive Change (2.6°C)* scenario projects the most significant decline in consumption, driven by risks of industrial closures under this scenario after current gas or electricity contracts end in the short to medium term.

2.2.3 LNG export

To produce LNG export forecasts, AEMO surveys the Queensland LNG producers for their expected, minimum, and maximum forecast volumes of gas to be exported over the forecast horizon. These surveys also include information about their expected gas production from their coal seam gas (CSG) fields, and accessible gas via third-party arrangements. CSG supply and export quantities tend to be linked; increased LNG exports will most often be available if there is increased CSG production, while insufficient CSG production to meet contract positions will require access to third party gas (or the use of other suppliers in each producer's global gas portfolio to deliver to the relevant international customer).

LNG exported from Curtis Island in 2022 was 1,358 PJ, a 49 PJ decrease from 2021, and lower than the 2022 GSOO forecasts which largely expected a similar level of export to 2021 levels in 2022. **Figure 17** shows recent and forecast LNG exports for different scenarios and compared to the 2022 GSOO.

Figure 17 Actual and forecast liquefied natural gas consumption, by scenario and compared to 2022 GSOO, 2016-42 (PJ)



The LNG producers have advised of a forecast level of LNG export of between 1,295 PJ and 1,326 PJ in 2023, approximately 100 PJ lower than was advised for the 2022 GSOO.

The LNG producers advised a forecast outlook to 2035, beyond which AEMO has assumed a scenario dispersion in line with trends observed in International Energy Agency (IEA) forecasts[52], applied to the scenarios as follows:

- In the *Progressive Change (2.6°C)* scenario, low economic growth and reduced steps towards global decarbonisation mean that LNG exports has been forecast flat across the horizon.
- The *Diverse Step Change (1.8°C), Orchestrated Step Change (1.8°C),* and *Green Energy Exports (1.5°C)* scenarios apply increasing levels of decarbonisation action to lower energy-sector emissions, and therefore reducing levels of LNG export are forecast. The significant spread in forecast LNG export by 2042 reflects the strong uncertainty regarding the scale of export demand across these scenarios.

2.2.4 Gas consumption for electricity generation

AEMO's 2022 ISP reiterated the importance of flexible and firm energy supplies as the transition of Australia's energy sector accelerates. As coal generation retires, flexible gas generation will be crucial both to respond to sudden changes in the supply demand balance as well as to provide critical power system services to maintain grid security and stability (complementing other forms of dispatchable capacity, including storage). In a high-renewable-penetration grid, a range of technologies will be needed to effectively manage resource variability and provide backup capacity over extended periods of low variable renewable energy (VRE) output, including gas generation and storage technologies.

All NEM gas generation forecasts in the 2023 GSOO incorporate the optimal development path (ODP) of the 2022 ISP, including the ISP development opportunities (in new generation capacity and retirements) as well as all committed, actionable and future transmission projects, as well as all generation developments and retirements. The gas generation forecasts incorporate announced committed and anticipated generation projects, and announced retirements, from the Generation Information November 2022 release[53].

Gas generation dispatch volumes will depend on participants' bidding strategies, and how they change over time as the portfolio of generation changes to incorporate more VRE. AEMO uses a bidding model (trained on past portfolio behaviour) to model likely future market outcomes in the NEM. This model takes account of the availability of VRE that operates at relatively low cost but is subject to weather variability, while respecting the technical capabilities of all generator technologies to respond to demand and supply variations.

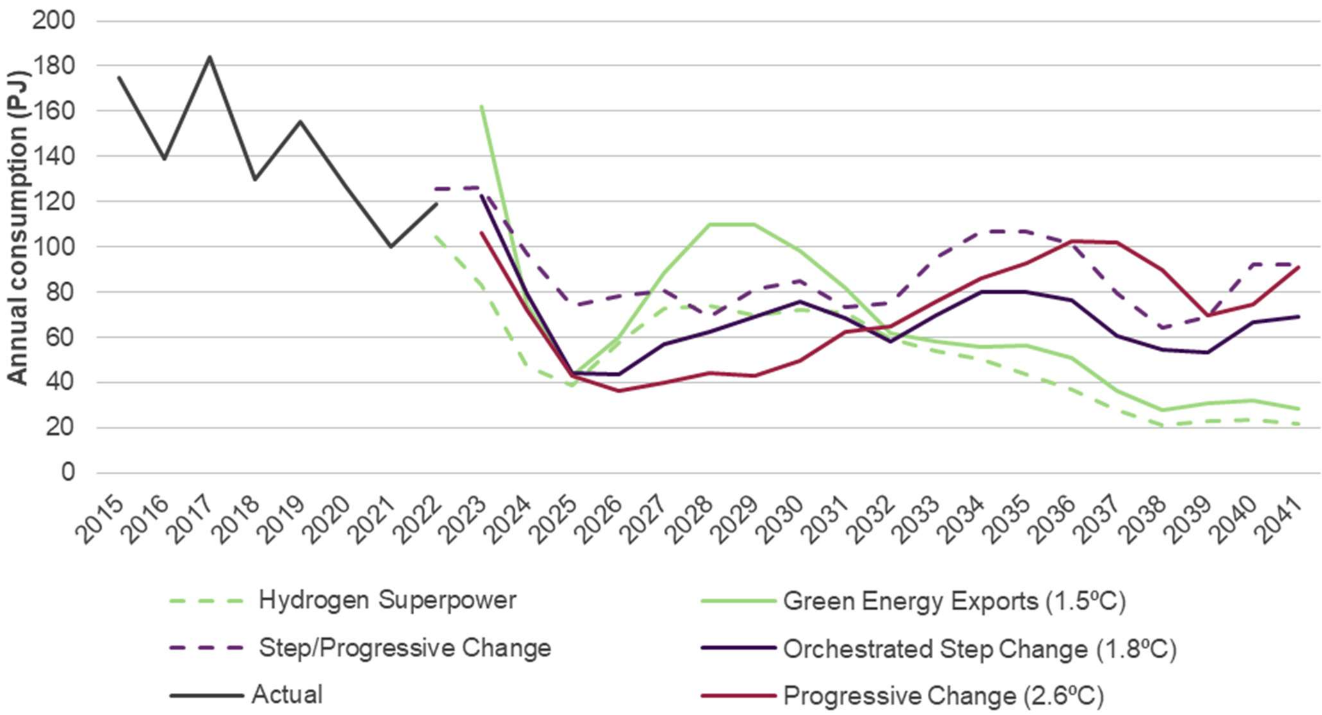
Forecast trend in gas generation consumption

Figure 18 shows actual NEM gas use for gas generators between 2015 and 2022, and the average forecast gas use from gas generators across different scenarios in both the 2023 and 2022 GSOOs. It illustrates that since 2014, the consumption of gas for gas generation in the NEM has generally declined. In 2021, the NEM recorded its lowest gas generation consumption in over a decade, and despite significant market volatility in 2022, including energy limitations on coal and hydro generators during winter 2022, the rebound in gas generation was relatively minor compared with prior years.

[52] The Draft 2023 IASR aligns AEMO scenarios with IEA scenarios. AEMO has therefore aligned IEA forecasts of LNG export from Australia from the 2022 World Energy Outlook (see https://www.iea.org/reports/world-energy-outlook-2022) with AEMO forecasts where possible.

[53] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

Figure 18 Actual and forecast NEM gas generation consumption, all scenarios and compared to 2022 GSOO, 2015-41 (PJ)



Note: 2022 GSOO forecasts are plotted with dashed lines, 2023 GSOO with solid lines.
Note: *Diverse Step Change (1.8°C)* applies the same forecast gas generation as *Orchestrated Step Change (1.8°C)*.
Note: In February 2023, AEMO was informed of an extension to the operation of Osborne Power Station in South Australia, deferring closure from 2023 to 2026. Upon receiving this advice, AEMO undertook sensitivity analysis and concluded that the effect on overall gas generation consumption of this change is forecast to be minor (although the availability of the power station may importantly increase the reliability of the power system). For more information on forecast NEM reliability, see the February 2023 *Update to the 2022 ESOO*, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/february-2023-update-to-the-2022-esoo.pdf?la=en.

A key driver of the declining gas generation trend is increasing penetration of renewable generation, both large-scale (grid-connected) and distributed (installed behind the meter by business and household consumers), which is continuing at pace. However, gas generation is still forecast to be a critical contributor to power system reliability and security in the NEM, to:

- Provide critical dispatchable capacity, providing a firming role to support VRE generation, and also to meet the NEM's needs if coal generation and other dispatchable sources are unavailable. For example, in 2021, major outages at Callide and Yallourn power stations drove higher reliance on gas generation in the NEM to cover for the sudden reduction in coal availability.
- Provide essential power system services to maintain grid security and stability, particularly following unexpected outages or earlier than expected generation withdrawal.

AEMO has used gas generation forecasts based on the 2022 *ISP Step Change* scenario to forecast gas generation in both the *Orchestrated Step Change (1.8°C)* and *Diverse Step Change (1.8°C)* scenarios. These forecasts project consumption for gas generation in 2023 to be similar to 2022. Unless there are major unexpected NEM events (discussed further in the next section), gas generation is forecast to decline as VRE developments are forecast to increase to meet various renewable energy policies to 2030, although the latter years of the decade also anticipate announced coal closures which will lead to greater frequency of gas dispatch in the NEM. As coal capacity declines, gas generators are projected to start more frequently and run for longer periods of time, with an increasingly important role in firming intermittent renewable energy generation.

While investment in longer duration storage may reduce the frequency of gas generators being needed to operate for extended periods, gas generators are forecast to continue to play a pivotal role during challenging weather conditions and when other infrastructure is unavailable. In these circumstances, high gas generation may be needed to maintain NEM reliability, and the east coast gas network will need to accommodate such flexible operation of gas generation within its production, storage and transportation capabilities (or greater use of secondary fuels may be needed).

Key items to note in the other scenarios are:

- Stronger electricity consumption in the *Green Energy Exports (1.5°C)* scenario is offset by greater renewable and storage developments, resulting in a relatively consistent outlook to the *Orchestrated Step Change (1.8°C)* scenario. Like all scenarios, gas generators will continue to be needed to cover peak events, although with greater (electrical) load flexibility assumed in this scenario, then the NEM may be more able to operate through low renewable generation periods while operating gas generation at lower relative levels.
- Lower electricity consumption growth and slower renewable developments (in the *Progressive Change (2.6°C)* scenario) are offset by slower coal closures, reducing the need for gas generation, until coal closures require alternative energy sources to provide for the needs of electricity consumers, at which time similar insights apply from other scenarios.

Future gas generation consumption is highly uncertain

Gas generation forecasts are highly uncertain and depend on many factors in the NEM, particularly power station failures, coal supply chain disruptions, and environmental interruptions that affect alternative energy sources (including to the electricity transmission that can deliver to consumers, and natural weather variations in wind and hydro productivity).

Impact of unforeseen events

The historical data in **Figure 18** above show a general decline from 2015, but also several spikes in consumption, especially from 2017 onwards, when the NEM faced multiple unforeseen events:

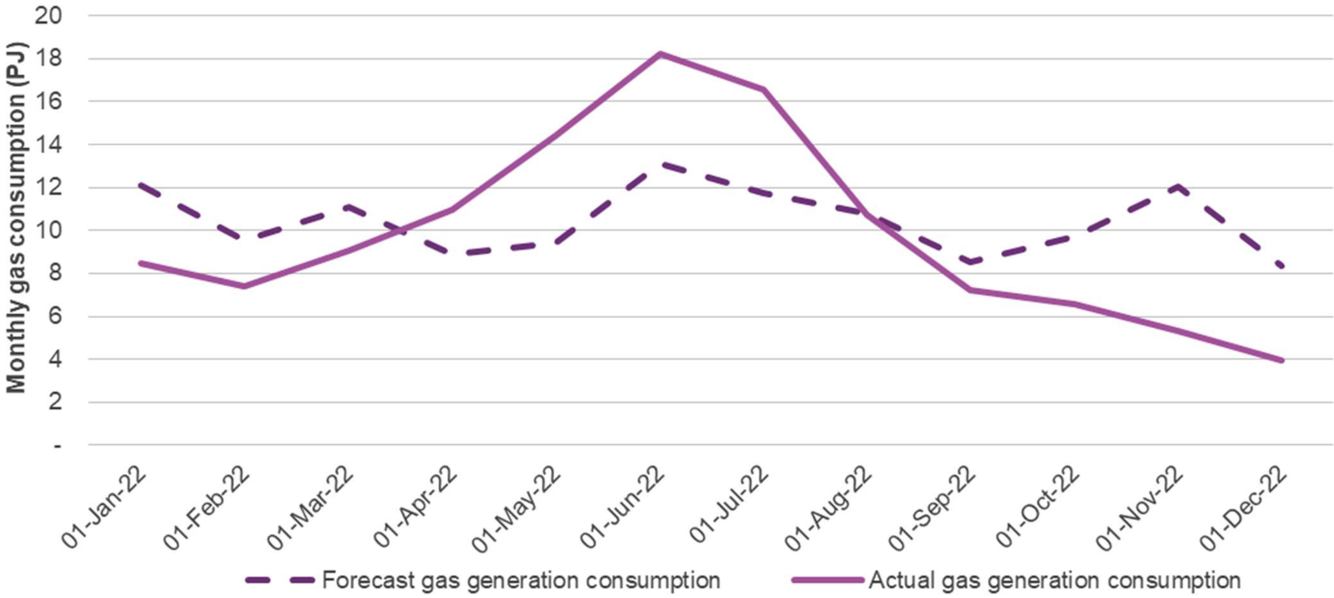
- 2017 – the closure of the coal-fired Hazelwood Power Station with short notice and extended outage at the coal-fired Yallourn Power Station.
- 2019 – outages at Victorian coal generators, coal shortages affecting New South Wales coal generators, extended hot weather particularly in Victoria, and bushfires affecting New South Wales and Victoria.
- 2020 – long coal-fired generation outages affecting Queensland power stations, transmission outages affecting the Heywood interconnector (connecting South Australia and Victoria).
- 2021 – coal plant failures at Callide in Queensland (one unit still offline), coal mine flooding at Yallourn in Victoria affecting generation.
- 2022 – floods across Australia impacting coal production, as well as supply chain issues, and geopolitical turmoil resulting in abnormally high fuel costs for both gas and coal, resulting in market suspension of the NEM.

Figure 19 shows the difference in the 2022 calendar year between the 2022 GSOO's gas generation forecasts (which did not assume any abnormal outages or events), and the monthly gas consumption that actually occurred for the NEM. While the month-to-month accuracy of the forecast will always be imperfect, overall gas consumption across the NEM was close to that forecast for 2022, and the individual differences are due to the event-driven nature of gas generation. The figure shows an under-forecast of gas generation in winter, and an over-forecast over the summer and shoulder months:

- The winter under-forecast was due to significant market events, from rising fuel prices to coal unavailability, culminating in the market suspension of June 2022. The difference from forecast to actual in winter was 17 PJ.
- The shoulder and summer periods saw mild conditions putting downward pressure on electricity demand, while continuous commissioning of new renewable developments reduced the market share of gas generators. The difference in shoulder and summer was -24 PJ.

Given that major unexpected events have been occurring in the NEM in five of the last six years, AEMO has allowed for the potential for unexpected events in the 2023 GSOO forecast by applying reductions in coal availability in the forecast (first included for the 2022 GSOO forecasts) as a surrogate for a major event affecting alternative energy sources than gas generation. As these events are by their nature uncertain, the forecasts represent a reasonable approximation of the impact of an event or events of this nature.

Figure 19 Monthly gas generation consumption, actual versus system normal forecast in calendar year 2022 (PJ)

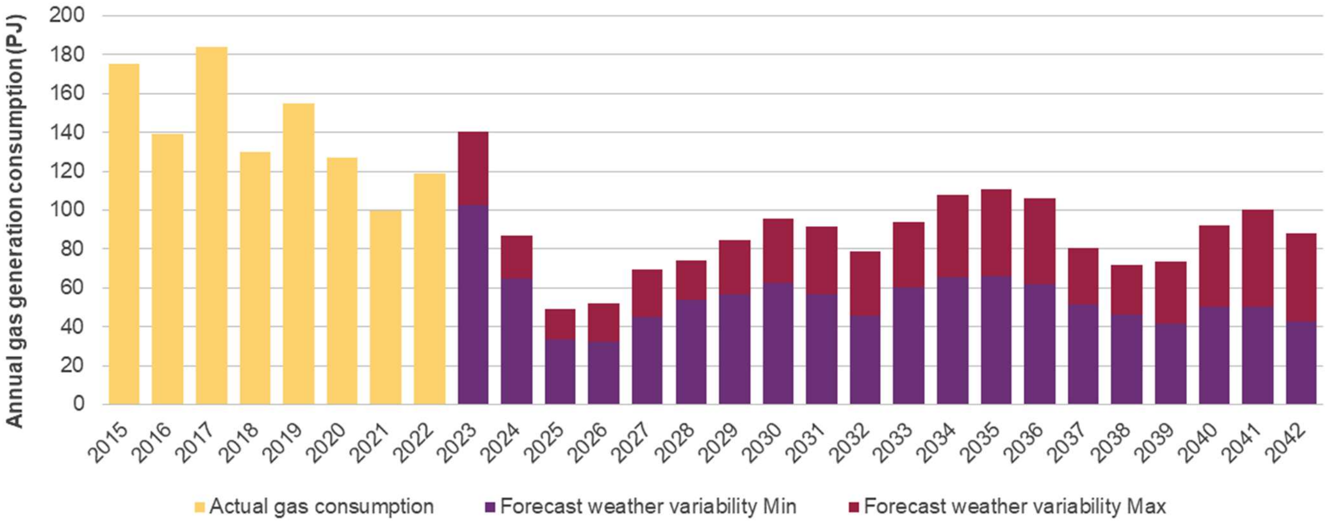


Weather variability

AEMO's gas generation forecasting considers a range of weather events, applying a spread of historical weather conditions. Based on these conditions, **Figure 20** shows the range of simulated gas generation consumption outcomes, influenced by the availability of wind, solar and hydro generation technologies (as well as the shape of electricity consumption, which itself is influenced by temperature and other weather-driven variables).

Whether gas generation volatility increases in future years will be influenced by the development of other flexible and dispatchable forms of generation, such as storage developments, or hydrogen gas turbines.

Figure 20 Actual gas generation consumption and forecast variation in consumption due to weather conditions, Orchestrated *Step Change (1.8°C)* scenario, 2015-42 (PJ)



Sensitivities analysis to NEM market impacts

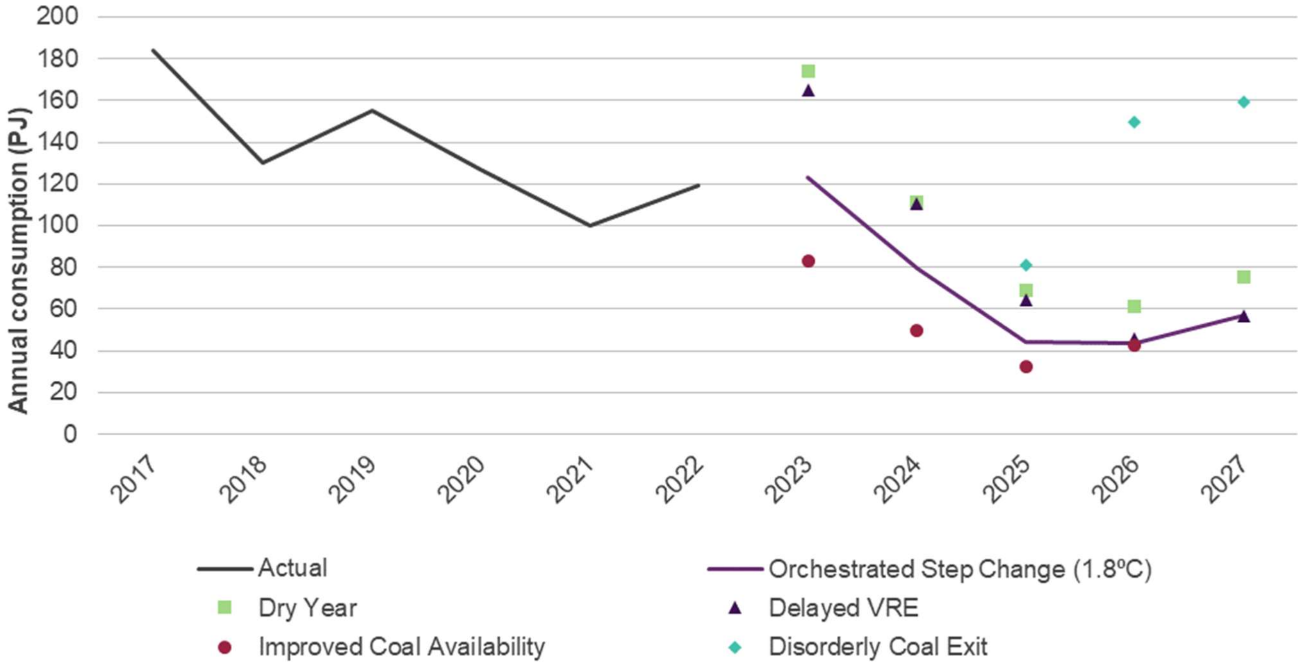
This 2023 GSOO includes four short-term gas generation sensitivities applied to the *Orchestrated Step Change (1.8°C)* scenario:

- ***Dry Year*** – assesses the impact of extended drought conditions affecting rainfall inflows to large hydro schemes in the NEM. In this sensitivity, with reduced rainfall to levels observed in the 'millennium drought' of 2006-07 (approximately 45% less inflow yield relative to average years), the forecast for gas generation increased by approximately 30-50%, depending on VRE penetration.
- ***Delayed VRE*** – committed and anticipated renewable developments delay their full commissioning by one year from the full commercial use date indicated in Generation Information. This sensitivity observed a 38% increase in gas generation to compensate.
- ***Disorderly Coal Exit*** – applying the generation developments that meet AEMO's 'committed' and 'committed*' commitment criteria, as well as announced generator closures[54]. Considering there is a significant pipeline of anticipated and policy-driven investments anticipated over the horizon, this sensitivity reflects a 'worst case' level of gas reliance to maintain reliability. This sensitivity observed triple the gas consumption in the year following the Eraring Power Station closure in 2025, reversing the decline observed in the base *Orchestrated Step Change (1.8°C)* scenario.
- ***Improved Coal Availability*** – the decline of coal availability reverses, and recovers to the level observed in 2019. This sensitivity observed up to 33% less consumption of gas for gas generation would be needed.

Figure 21 shows the range of outcomes forecast in these sensitivities across the next four years.

[54] Assumptions aligned as close as possible to the February 2023 *Update to the 2022 ESOO*, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/february-2023-update-to-the-2022-esoo.pdf.

Figure 21 Actual and forecast NEM gas generation consumption, sensitivities to *Orchestrated Step Change* (1.8°C) scenario, 2017-27 (PJ)



2.3 Maximum daily gas demand forecasts

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

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

The following section discusses the seasonality of peak demand, followed by the maximum daily demand forecast for the first two components listed above in **Section 2.3.2**, and with gas used for electricity generation covered in **Section 2.3.3**.

2.3.1 Seasonal variance and extreme peaks

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

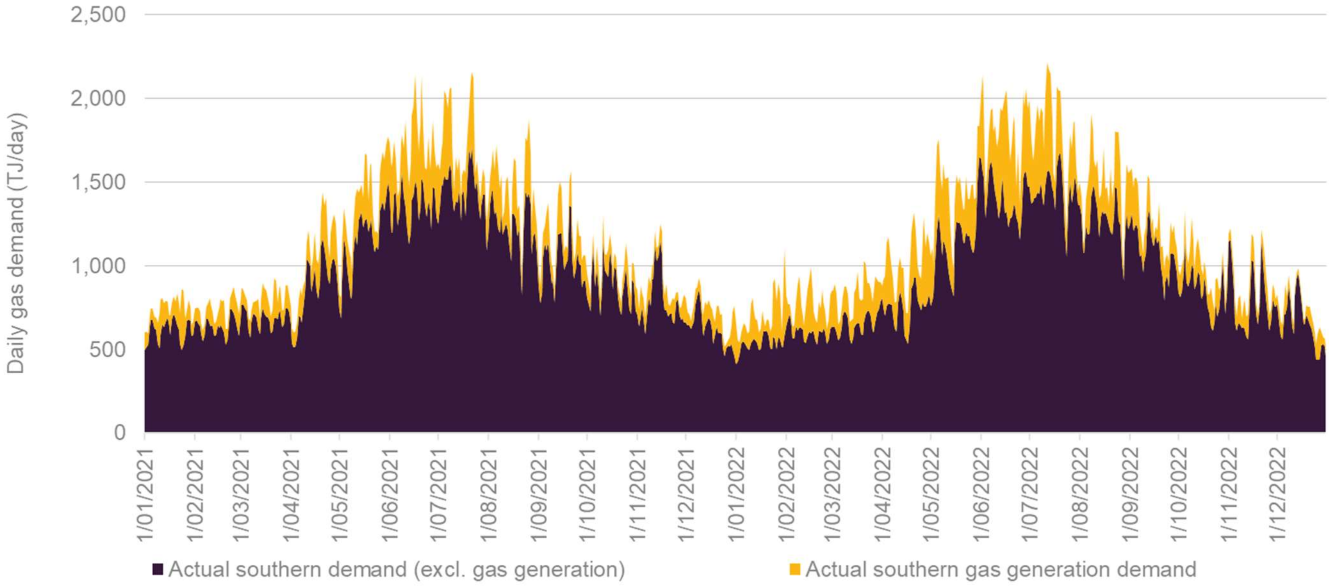
The most extreme southern daily gas demands observed each year typically only occur on a relatively small number of days, when conditions compound to lead to very high utilisation of residential and commercial heating appliances. It is possible for these events to occur in conjunction with conditions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

Figure 22 below demonstrates the historical volatility and the strong seasonality of daily peak demand in the southern regions of New South Wales (including the Australian Capital Territory), South Australia, Victoria and Tasmania in 2021 and 2022.

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

Gas volumes required for electricity generation (yellow in chart) depend on the requirements of electricity consumers and the availability of other electricity generating technologies. High gas generation may coincide with high gas demand by residential, commercial and industrial consumers, as cold weather in winter that drives higher gas demand typically also leads to higher electricity demand, and winter typically has lower utilisation of renewable resources (with shorter days reducing PV output, for example). As outlined in **Section 2.3.3**, while traditionally winter peak gas generation demands have been less significant than summer peaks, the relative magnitude of winter peaks for gas generation is forecast to grow and gas generation is likely to become winter peaking, with increased electrification.

Figure 22 Actual domestic daily gas demand in southern regions from January 2021 to Dec 2022, showing seasonality and peakiness (TJ)



Gas used for LNG exports may also be seasonal, but is not captured in the southern regions profile in the figure above because the export is from Queensland. LNG demand has its typical seasonal peak in summer, when key Asian markets experience their northern hemisphere winter.

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

Table 3 and **Table 4** show recent actual observed daily maximum demand for each region, as well as the seasonal forecasts of daily gas demand for all sectors excluding gas generation in the *Orchestrated Step Change (1.8°C)* scenario, across the summer and winter seasons.

The *Orchestrated Step Change (1.8°C), No Electrification* sensitivity is also provided to demonstrate the impact of electrification on seasonal peaks.

These forecasts include unaccounted for gas (UAFG) that is lost while being transported through the gas network.

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

Regional forecasts for all scenarios are available on AEMO's National Electricity and Gas Forecasting portal[55].

Table 3 Total 1-in-2 and 1-in-20 forecast maximum demand, summer, all sectors excluding gas generation, including UAFG (TJ a day [TJ/d])

	NSW		QLD (incl LNG)		QLD (excl LNG)		SA		TAS		VIC		NT[A]	
	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
2020	279		4,651		336		94		21		489		10	
2021	286		4,546		342		97		20		517		11	
2022	266		4,530		334		97		19		354		9	
Orchestrated Step Change (1.8°C)														
2023	315	338	4,283	4,298	322	337	102	109	23	25	440	554	10	10
2024	324	349	4,274	4,289	313	327	101	109	26	28	433	544	10	10
2025	329	353	4,372	4,386	318	332	99	107	31	33	431	547	10	10
2030	307	329	4,322	4,336	313	327	95	101	30	33	365	453	10	10
2040	260	277	3,701	3,716	310	324	85	90	22	23	262	313	10	10
Orchestrated Step Change (1.8°C), No Electrification														
2023	315	338	4,283	4,298	322	336	102	109	23	25	440	559	10	10
2024	325	349	4,274	4,288	313	327	101	109	27	29	436	557	10	10
2025	331	355	4,372	4,386	318	332	100	108	31	34	439	560	10	10
2030	342	367	4,330	4,345	322	336	102	110	31	33	445	567	10	10
2040	339	365	3,731	3,746	339	355	103	111	23	24	459	603	10	10

A. As approximate forecasts were prepared for the NT for the 2023 GSOO, the 1-in-2 and 1-in-20 forecasts are the same. The forecasts are also the same across scenarios.

Table 4 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[A]	
	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
2020	438		3,926		340		147		22		1213		9	
2021	469		4,155		345		149		23		1134		9	
2022	483		4,086		345		134		23		1093		9	
Orchestrated Step Change (1.8°C)														
2023	502	529	3,921	3,935	331	346	149	158	25	27	1131	1217	9	9
2024	512	540	3,912	3,926	323	337	148	157	28	30	1118	1201	9	9
2025	517	544	4,001	4,015	327	341	146	154	33	35	1104	1185	9	9
2030	463	488	3,955	3,968	322	336	132	139	32	34	890	956	9	9

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

	NSW		QLD (incl LNG)		QLD (excl LNG)		SA		TAS		VIC		NT[A]	
	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
2040	363	383	3,390	3,404	317	330	108	113	24	25	569	610	9	9
Orchestrated Step Change (1.8°C), No Electrification														
2023	502	529	3,921	3,935	331	345	149	158	25	27	1129	1219	9	9
2024	514	542	3,912	3,926	323	336	149	158	29	31	1125	1212	9	9
2025	524	552	4,001	4,015	328	341	148	156	33	35	1133	1218	9	9
2030	540	570	3,964	3,978	332	346	151	159	33	35	1167	1263	9	9
2040	549	580	3,422	3,437	349	364	155	164	24	26	1283	1380	9	9

A. As approximate forecasts were prepared for the NT for the 2023 GSOO, the 1-in-2 and 1-in-20 forecasts are the same. The forecasts are also the same across scenarios.

Outlook for *Orchestrated Step Change (1.8°C)*

As identified in the above tables, the *Orchestrated Step Change (1.8°C)* scenario observed variations in regional trends in winter maximum daily gas demands (excluding both gas for LNG export and gas generation) are:

- **New South Wales** is projected to increase its maximum demand to 2025, followed by a slow and steady decline to the end of the forecast horizon. Relative to the 2022 GSOO, this forecast starts slightly higher, gradually decreasing and becoming lower by the end of the forecast period.
- **Queensland** is projected to almost maintain a steady maximum daily demand throughout the forecast horizon, however, there is a slight step down in 2033. Relative to the 2022 GSOO, the forecast is generally higher after consideration of updated advice from industrial load facilities.
- **South Australia** is projected to decrease its maximum daily demand to the end of the forecast horizon. Relative to the 2022 GSOO, the decrease is slightly slower across the horizon.
- **Tasmania** is projected to initially increase its maximum daily demand until 2025, then remain stable until 2036. Then it declines until 2038 and continues to flatten until the end of the forecast horizon. The trend is similar to the 2022 GSOO forecast.
- **Victoria** is projected to decrease its maximum daily demand to the end of the forecast horizon. The trend is generally similar to the 2022 GSOO forecast.
- **Northern Territory** is projected to remain flat across the forecast horizon (and is a new addition to the 2023 GSOO).

The differences between regions are largely explained by different drivers in LILs (particularly in New South Wales, Queensland and Tasmania), potential SMR developments, and electrification for other industrial customers. For residential and commercial customers, the differences can be largely explained by different drivers in energy efficiency and electrification (particularly in Victoria).

Maximum daily gas demand used for LNG export is forecast to remain relatively flat until 2035, then to decline steadily, consistent with drivers reducing annual LNG export consumption (see **Section 2.2.3**).

2.3.3 Trends in peak demand for gas used in electricity generation

While annual gas generation is forecast to reduce in *Orchestrated Step Change (1.8°C)* (outlined in **Section 2.2.4**), peak gas demand for gas generation is projected to remain significant and to become peakier.

This is because gas generation provides a flexible form of dispatchable capacity and can quickly ramp production up (and down) to balance fluctuations in electricity supply from other sources. As the system transitions and this role becomes increasingly valuable, an increasing proportion of gas generators' annual consumption is expected to be driven by their firming role in the NEM, providing a greater degree of volatility, with some very high utilisation days coexisting with declining average capacity factors.

Gas generation becomes winter peaking

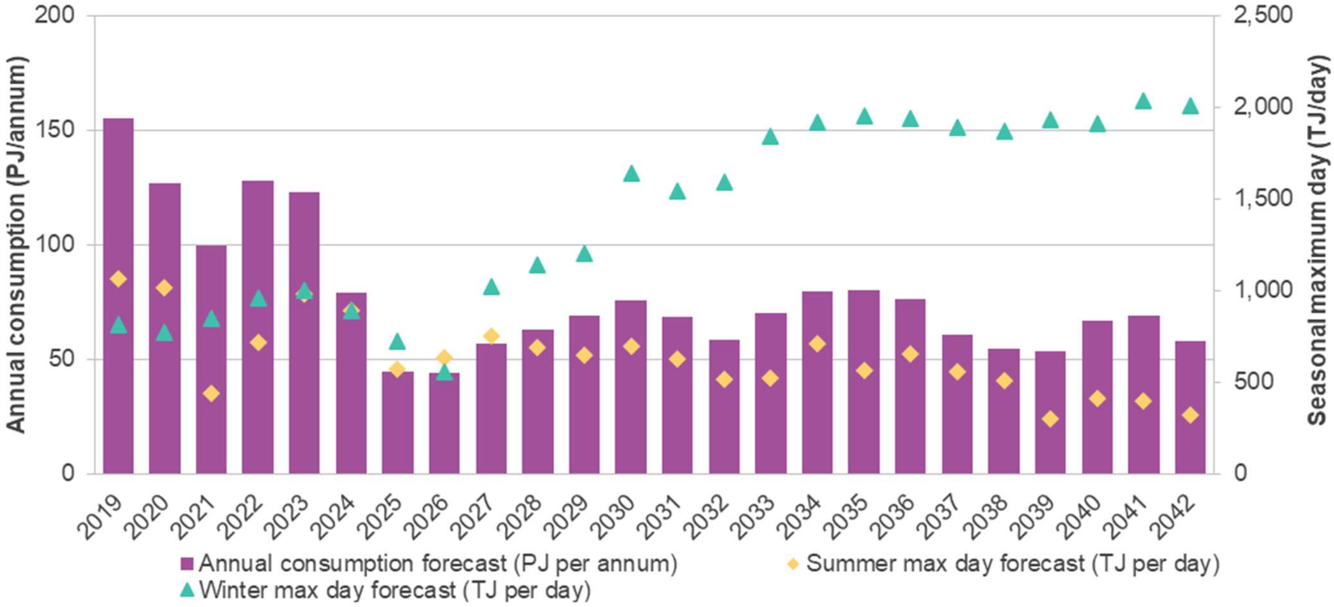
The seasonality of gas generation is also projected to change. **Figure 23** shows forecast annual gas generation consumption in *Orchestrated Step Change (1.8°C)* (previously shown in **Figure 18**) alongside the summer and winter maximum daily gas generation demand forecasts. All three forecasts have been averaged across a range of weather reference years.

This figure shows that the summer maximum daily demand forecast follows similar trends to the annual consumption forecast (although on a different scale), with an initial drop and long-term flattening, whereas the winter maximum daily demand for gas generation is forecast to nearly double between 2023 and 2042 as the NEM's winter load increases with electrification of winter heating loads.

Gas generation historically has been highest in summer, responding to the high summer peaks in the NEM associated with air-conditioning loads. As more renewable generation and storage operates in the NEM, gas generation retains its key role in summer, particularly at times of peak demand and unavailability from other generation technologies.

Winter is forecast to become an increasingly important season for gas generation to also provide firming support. During gloomy winter days with minimal sunshine and early sunsets, and during periods with low wind, reliance on gas generation is forecast to increase, particularly following the retirement of coal generation and depending upon the development of deeper storage solutions.

Figure 23 Actual and forecast gas generation annual consumption (PJ/y) and seasonal maximum daily demand (TJ/d), *Orchestrated Step Change (1.8°C)* scenario, 2019-42

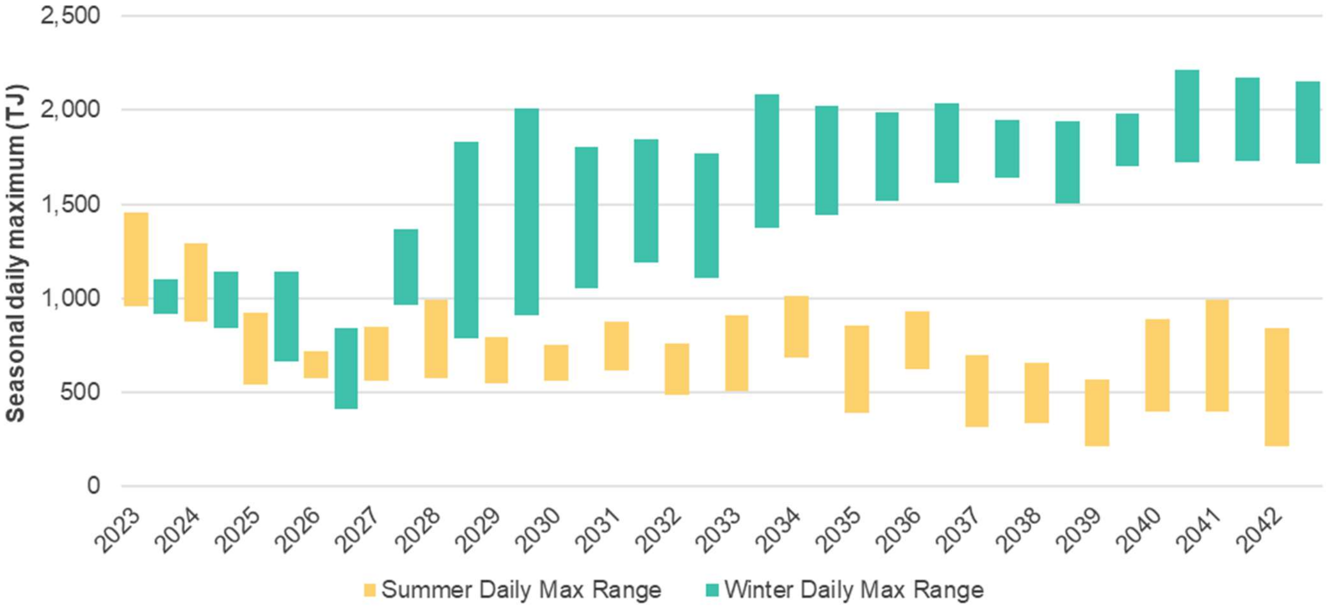


Note: The shown forecast maximum daily demand for summer and winter represents the median across different weather patterns.

Figure 24 shows the forecast seasonal (summer and winter) whole-NEM maximum daily demand for gas generation, across a range of weather conditions, in *Orchestrated Step Change (1.8°C)*.

As this figure shows, winter peaks are forecast to grow, while summer maximum demand trends generally flatten. The emerging winter as the season of greatest gas generation demand will increase the likelihood that peak demand for gas generation and from other gas consumers will coincide and put further stress on gas supplies and infrastructure to meet peak gas demands across the gas system.

Figure 24 Forecast range of whole-NEM seasonal peak day demand across various weather patterns, *Orchestrated Step Change (1.8°C)* scenario, 2023-42 (TJ)



The role of gas generation to firm the NEM is increasing as coal generation retires, leading to greater volatility of gas consumption

Figure 25 shows the monthly variability of gas generation within New South Wales and Victoria, based on weather conditions historically observed in 2019, referred to as the 2019 reference year[56]. Other reference years studied produced a similar outcome.

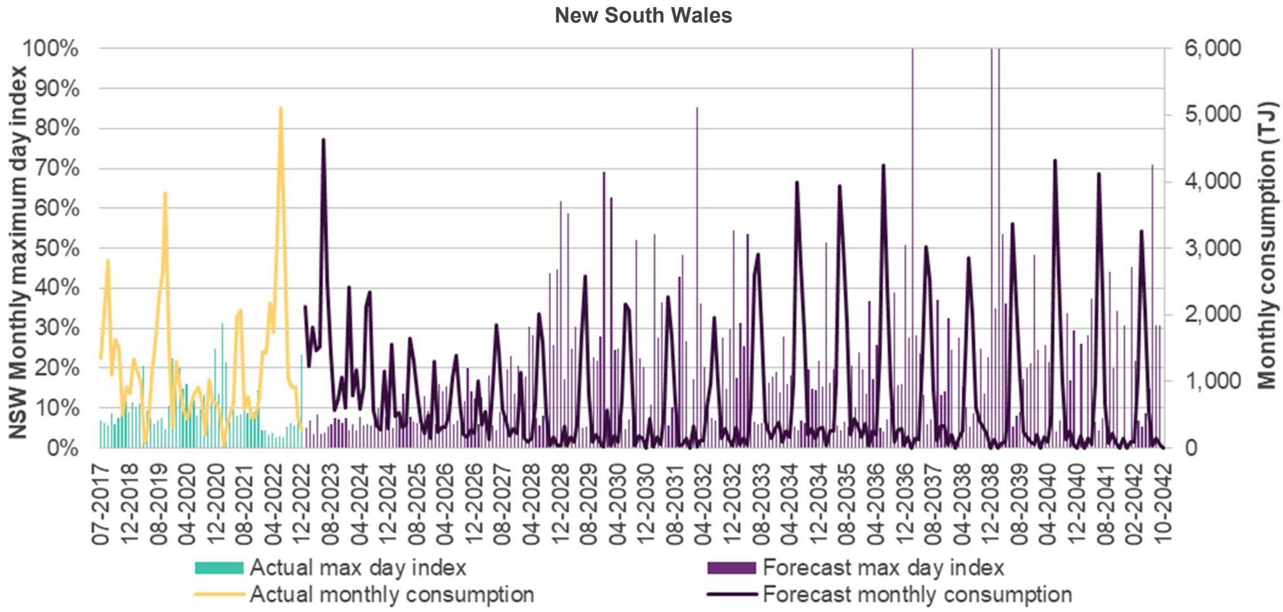
The variability is captured with the 'monthly maximum day index' shown on the figure – that is, the peak gas used in a single day within each month divided by the total gas consumed for gas generation in that same month. Where this index shows a low value (for example, 10% or less), it indicates that gas consumption for gas generation is spread fairly evenly throughout the month, with no single day peaking particularly high. Where this index increases, it means that a single day's gas demand increasingly accounts for larger proportions of the total gas consumption in that month.

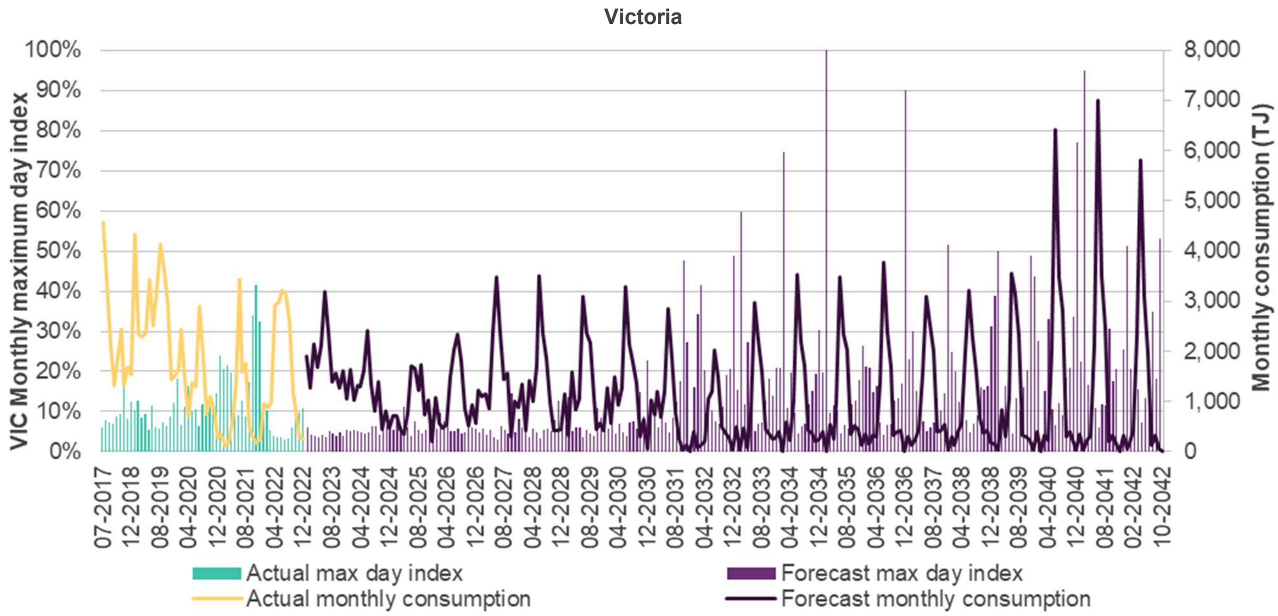
Figure 25 demonstrates that for increasingly large periods of the year, gas generation is forecast to be only required at very low levels, but increasingly gas generation be required at high volumes, for short periods. On these days, gas generation is important for electricity consumers. Should the gas system be unable to provide gas flexibly to meet these peaks, alternative resources (such as electricity demand response, alternative secondary

[56] AEMO optimises NEM market modelling across multiple historical weather years known as "reference years" to account for short- and medium-term weather diversity. The use of multiple reference years allows the modelling to capture a broad range of weather patterns affecting the coincidence of customer demand, wind, solar and hydro generation outputs.

generation fuels, stored energy in electrical storages) will be needed to maintain NEM reliability. Flexible gas infrastructure and supply solutions to deliver the gas required under these challenging conditions will become increasingly important, and could include utilisation of the linepack within high-pressure pipelines, local gas storages, and major industrial sites being on interruptible contracts.

Figure 25 Monthly maximum day index and monthly energy for New South Wales (top) and Victoria (bottom), *Orchestrated Step Change (1.8°C)* scenario, 2019 reference year (TJ)





3 Gas supply and infrastructure forecasts

This section provides an overview of the reserves, resources and production forecasts for supplies connected to the gas system, as well as an overview of the system's midstream infrastructure (that is, pipelines, storages, and LNG import terminals).

Key insights

- Overall, compared to the 2022 GSOO, the **sum of reserves and resources in existing, committed and anticipated categories has increased slightly**, but there has been a reduction from prospective and uncertain projects.
- **While annual production forecasts have decreased for southern facilities, maximum daily production forecasts have increased in the short term** in comparison to the 2022 GSOO, improving the relative capability to meet peak demand conditions. Existing and committed available annual production from southern fields is forecast to reduce from 392 PJ in 2023 to 255 PJ in 2027.
- Pipelines and other infrastructure continue to be an important means to deliver supply where it is needed, particularly as southern production declines.
  - Committed upgrades to the Moomba to Sydney Pipeline (MSP), South West Queensland Pipeline (SWQP) and the Western Outer Ring Main (WORM) will increase the system's capacity to deliver gas to consumers in the southern regions of New South Wales (including the Australian Capital Territory), Victoria and Tasmania, including improving the capability to use the Iona underground gas storage (UGS) facility to supply Melbourne.
  - Proposed LNG import terminals represent an alternative way to supply gas to consumers as gas production declines. A number of these are proposed, such as Port Kembla Energy Terminal (PKET), Geelong, Port Adelaide and Port Phillip Bay. The 2023 GSOO no longer considers PKET as an anticipated project, due to insufficient contracted capacity from prospective buyers, or the operator's own demand, to commit to locating the floating storage and regasification unit (FSRU) at the import terminal.

3.1 Changes since the 2022 GSOO

Since the 2022 GSOO, there has been progress towards delivering key infrastructure projects (although timeframes for completion remain tight):

- Victoria's WORM pipeline and a second compressor at Winchelsea are expected to be commissioned before winter 2023. The WORM was considered committed in the 2022 GSOO, while the second compressor at Winchelsea is a new addition. These projects assist to improve peak supply capacity to Melbourne gas consumers by 83 TJ/d.
- The East Coast Grid Stage 2 project is now considered committed, increasing pipeline capacity to transport gas south from Queensland by 90 TJ/d over East Coast Grid Stage 1 improvements, prior to winter 2024. The project was considered a proposed project in the 2022 GSOO.

There are many changes to forecast supply in the short term informed by gas producers as part of AEMO's GSOO surveying process, mostly delays to projects in the near term and reclassification of commitment levels, but also some supply increases. AEMO has been advised that:

- Forecast Gippsland (including Orbost) production capacity has increased to 915 TJ/d for 2023, 191 TJ/d higher than forecast in the 2022 GSOO, although this is still a 211 TJ/d reduction on the actual maximum supply of 1,126 TJ/d in winter 2022. Gippsland supply capacity is forecast to reduce further for winter 2024, to a similar level as forecast in the 2022 GSOO.
- The Golden Beach Energy Storage Project was classified as an anticipated project in the 2022 GSOO with production commencing in 2024. The project has been delayed until 2025 and final investment decision (FID) is not expected until mid-2023. Due to several years of delay, AEMO now classifies as an uncertain project in this 2023 GSOO and as a potential project in the 2023 VGPR.
- The connection of new offshore Thylacine wells to the Otway Gas Plant in Port Campbell has been delayed from January 2023 to July 2023 due to COVID-19 related delays, resulting in a production decrease via the Otway Gas Plant of 37 PJ in 2023, compared to the 2022 GSOO. The increase in the Otway Gas Plant's maximum daily production capacity, from 84 TJ/d to 205 TJ/d, is also delayed.
- Beach Energy's Enterprise project has progressed sufficiently to be classified as a committed project, and is expected to come online in early-2024[57]. Enterprise was considered an anticipated project in the 2022 GSOO.
- The Trefoil development was considered an anticipated project in the 2022 GSOO, however Beach Energy has delayed FID[58], which has resulted in the reclassification of the Trefoil reserves to contingent resources, and AEMO now considers this project as uncertain supply.
- Senex recently announced a $1 billion expansion to its Atlas and Roma North developments[59]. This is mostly treated as anticipated supply in the 2023 GSOO.
- Lochard Energy's committed Iona UGS upgrade was previously targeted for winter 2023. This upgrade is now occurring in a staggered fashion, and the facility will have 24 PJ of storage, with 558 TJ/d of injection capacity into the network available in 2023, and 24.5 PJ of storage with 570 TJ/d of injection capacity available in 2024. The upgrade project remains committed.
- Increased uncertainty exists regarding the establishment of LNG import terminals in southern regions. Based on information provided by the project proponent, the GSOO no longer considers PKET as an anticipated project, due to there being insufficient contracted capacity to commit to locating the FSRU at the import terminal. This is despite infrastructure developments on a lateral pipeline that connects the terminal to the east coast network. Other terminal developments across southern regions are insufficiently progressed to be categorised as anticipated or committed.
- The availability of the Newcastle Gas Storage Facility (NGSF) is less certain than in previous years. The NGSF was empty for all of winter 2022 due to commercial factors, and AEMO has been advised that no long-term

[57] Beach Energy, "FY23 Second Quarter Activities Report ", 31 January 2023, at https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/2A1427801/BPT_FY23_Second_Quarter_Activities_Report.pdf.

[58] Beach Energy, "Bass Basin update", 20 May 2022, at https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/6A1092400/BPT_Bass_Basin_update.pdf.

[59] Senex Energy, " Senex to invest more than A$1 billion to boost domestic natural gas supply", 11 August 2022, at https://www.senexenergy.com.au/senex-to-invest-more-than-a1-billion-to-boost-domestic-natural-gas-supply/.

commitment exists that ensures the availability of this facility[60]. This facility started filling again in December 2022 and is expected to be available for high demand days in winter 2023. AEMO considers NGSF will be available in this 2023 GSOO, although sensitivity analysis explores the impact to gas adequacy if it were not operating (see **Section 4.2**).

3.2 Reserves, resources, and production facilities

Ensuring gas supply is available for consumers relies on continued investment to identify, prove, and then exploit gas reserves and resources. AEMO's production forecasts rely primarily on survey responses from producers to project available quantities of gas, plans for extraction, and the capability and capacity of gas processing plants. Forecasts of gas production must consider uncertainties on both technical and commercial grounds. Production forecasts, including for 2P, 2C and prospective reserves and resources (as defined below) are becoming increasingly uncertain from both a volume and timing perspective. This is further discussed in **Section 4.2**.

The surveys were conducted for most gas producers in September 2022. These supply forecasts therefore reflect the best advice provided to AEMO at this time. Consideration of project development lead time is also per the advice of project proponents.

In this GSOO, the following definitions apply[61]:

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

Under this classification structure, each project represents a specific investment decision, with an associated quantity of recoverable gas reserves and resources, that may be more, or less, certain.

3.2.1 Reserves and resources

Gas developments are categorised according to the level of technical and commercial uncertainty associated with recoverability. These uncertainties could include securing finance, obtaining government approvals, negotiating contracts, overcoming geological challenges, or the quality/purity of the gas.

The following categories are applied across the industry:

- A gas reserve is a quantity of gas expected to be commercially recovered from known accumulations. When estimating the existing, committed, and anticipated gas reserves, the best estimate values are quoted as "proven and probable" (**2P**) reserves. The estimate reflects statistically that there should be at least a 50% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable reserves.

[60] The NGSF began refilling in late 2022, and was reported available on the Gas Bulletin Board (see https://aemo.com.au/en/energy-systems/gas/gas-bulletin-board-gbb) from early 2023.

[61] AEMO began using these classifications in the 2020 GSOO, after stakeholder consultation. The classifications are aligned with the Society of Petroleum Engineers Petroleum Resource Management System (PRMS) project maturity sub-classes.

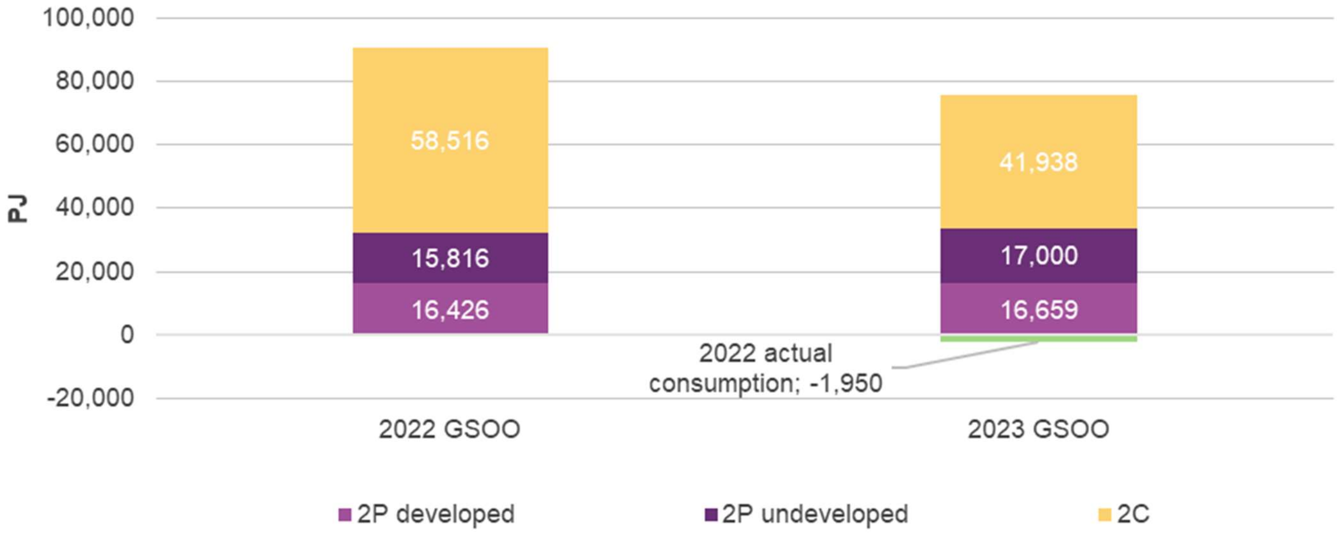
- Gas resources are defined as less certain, and potentially less commercially viable, sources of gas. When estimating these uncertain resources, the best estimate of contingent resources (**2C**) is used.
- More broadly, there are also prospective resources, which are estimated volumes associated with undiscovered accumulations of gas. These resources are highly speculative and have not yet been proven by drilling.

The gas reserves and resources for the 2023 GSOO[62] include all major fields in Australia excluding Western Australia, and the Northern Territory gas fields developed for LNG export. Fields in the Northern Territory that deliver gas for Australian domestic use are included. Over time, gas reserves and resources develop, deplete, or are reassessed (particularly against commercial benchmarks), so forecasts of gas reserves and resources change.

Figure 26 shows the best estimate of gas reserves and resources for this GSOO at 31 December 2022, compared to the estimate published in the 2022 GSOO. It shows:

- The sum of 2P developed and undeveloped reserves is very similar, however the 2C reserves have reduced by over 16,000 PJ.
- Considering the reserves and resources categories individually:
  - 2P developed reserves are 1.4% higher, largely due to improved survey responses in the 2023 GSOO. For similar reasons, 2P undeveloped reserves have increased 7.5%.
  - 2C reserves are 28% lower, due to updated data on prospective and uncertain projects.
- Reserve and resource estimates closely align with Australian Competition and Consumer Commission (ACCC) estimates[63].

Figure 26 Reserves and resources reported in the 2022 GSOO and 2023 GSOO



[62] The natural gas reserve and resource estimates in the 2023 GSOO used information from gas producers, supported by estimates from research from a wide variety of sources, particularly for the more uncertain gas resources.

[63] See Table A.2 at https://www.accc.gov.au/system/files/Gas%20Inquiry%20-%20January%202023%20interim%20report%20-%20FINAL_0.pdf.

3.2.2 Available annual production

Gas must be extracted and processed before it can be injected into pipelines for consumers. The rate of production is determined by a variety of factors, including but not limited to:

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

Table 5 shows the annual forecast of available production from 2023 to 2027[64], surveyed from gas producers. These estimates provide an upper bound on possible annual production, representing the production capability as advised by the producers. Actual production will rely on the quantity of gas demanded for domestic consumption or international export. It also shows that, compared to the 2022 GSOO:

- The total projected existing, committed, and anticipated supply is lower from 2023 to 2027, in both the northern and southern regions. This may be attributed to delays in production projects, and revisions to production expectations. This production figure is in close alignment with that published by the ACCC in its January 2023 Gas Inquiry 2017-2030 Interim Report.
- Very little anticipated production is forecast to come online in southern regions in the next five years. Some of the anticipated production reported in the 2022 GSOO has converted into committed production, but there is no new anticipated supply to take its place.
- Total annual production is forecast to rise from 2023 to 2024, particularly in the north, before gradually declining across the rest of the five-year outlook.

Table 5 Forecast of available annual production as provided by gas producers, 2023-27 (PJ)

	Commitment criteria	2023	2024	2025	2026	2027
Northern (QLD / NT)	**Existing and committed**	1,577	1,571	1,492	1,430	1,344
	Anticipated	13	53	125	204	295
	Total	1,589	1,624	1,617	1,633	1,639
	Difference from 2022 GSOO	-25	-53	-55	-49	N/A
Southern (VIC / NSW / SA^)	**Existing and committed**	392	390	386	339	255
	Anticipated	0	1	0	13	14
	Total	392	390	386	352	269
	Difference from 2022 GSOO	-70	-69	-42	-61	N/A
Total east coast gas production		1,981	2,015	2,003	1,986	1,908
Difference from 2022 GSOO		-94	-121	-97	-110	N/A

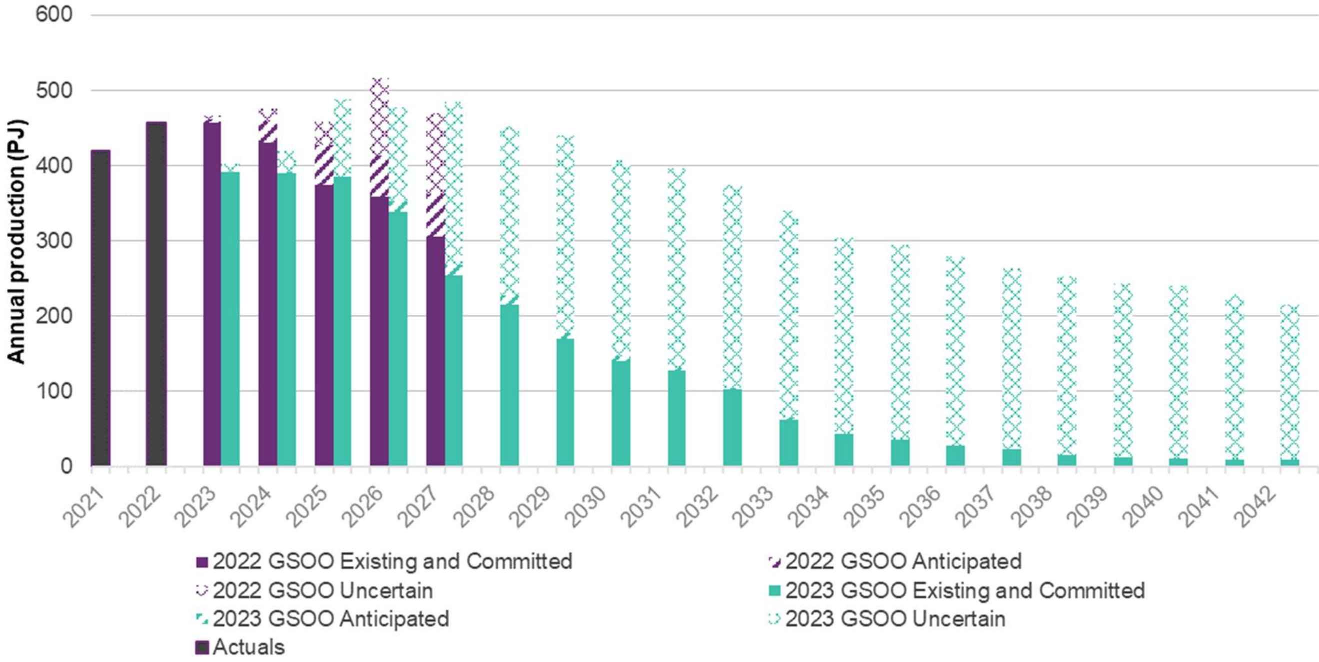
^ The Queensland component of the Cooper Eromanga basin appears in the Southern category.
Note: Increased consideration of Northern Territory supply is considered in this 2023 GSOO given the inclusion of the Northern Territory region.

[64] For the 2023 GSOO, extra information was gathered under voluntary requests for information, and reliable forecasts beyond the first five years have been collected. For the 2022 GSOO, producers only provided forecasts for the first five years of the horizon, limiting the scope of this comparison.

Figure 27 shows that existing and committed production is projected to decline significantly over the forecast horizon. Much of the short-term decline in southern production is occurring in the Gippsland Basin (see the 2023 VGPR for more information[65]). There is very little anticipated production, but development of uncertain supply may offset the decline in existing and committed supply. The lead time of new projects is often long, and during that period a development may experience greater setbacks than is allowed for. As the changes between the 2022 and 2023 GSOOs noted in **Section 3.1** show, it is not uncommon for schedule delays to be observed.

Uncertain supply must, by definition, still overcome many hurdles before it is brought online, so the likelihood and schedule for the development of these supplies is possible to be an optimistic estimate provided by producers.

Figure 27 Actual and forecast annual production from southern gas fields (excluding uncertain LNG imports), 2021-42 (PJ)



Note: for the 2022 GSOO, producers only provided production forecasts for five years.

3.2.3 Maximum daily production capacity

The **maximum daily production capacity** defines the quantity of total gas that can be injected into the system each day. This maximum daily production capacity is critical to the operation of the gas markets to ensure sufficient gas is available to meet peak winter demands.

Estimates of daily production capacity have been provided to AEMO by gas producers through the GSOO survey process, and provide an upper bound on possible daily production.

For many facilities, their annual production forecasts are strongly proportional to their peak production capacity, as the processing plant may normally operate near capacity, although this is not exclusively the case. The maximum daily production capacity is the lesser of the maximum daily production capacity from gas fields, and the maximum daily processing capacity at the connected gas plant.

[65] See Chapter 3 of the 2023 VGPR, at https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/victorian-gas-planning-report.

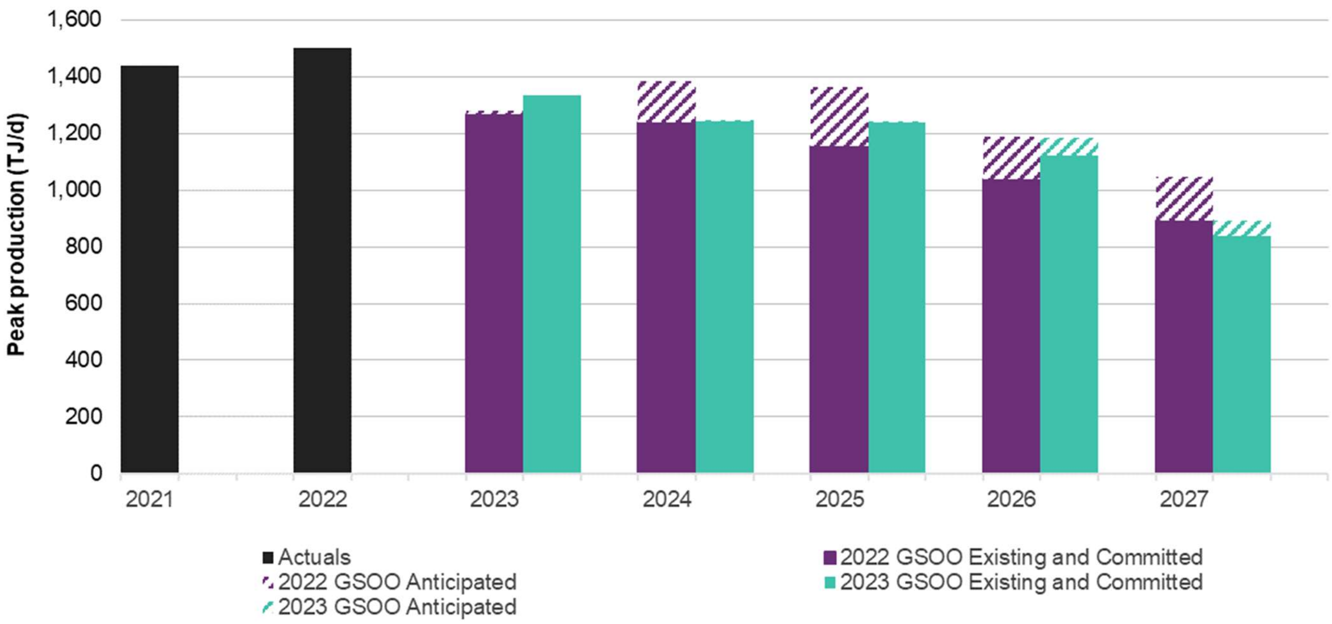
Southern daily production capacity

Figure 28 shows that the daily production forecasts from the southern fields are slightly higher than forecast in the 2022 GSOO, but continue to present an overall decline in existing and committed daily production capacity.

Figure 28 focuses on the first five years of the horizon to highlight key trends during this period. Longer term, the projected maximum daily production capacity declines in line with annual production forecasts (shown in **Figure 27**).

Forecast supply from Gippsland (which includes multiple supply sources including, Longford, Orbost and BassGas) has increased relative to the 2022 GSOO to 915 TJ/d for 2023, 191 TJ/d higher than advised for the 2022 GSOO, with smaller increases also projected in 2024 to 2027 relative to the 2022 GSOO advice. Despite these improvements, Gippsland supply is still forecast to decline. The gas system relies heavily on supply from Gippsland to meet peak demand during winter. As the size of this resource reduces, other means, such as pipelines connecting gas supply from the north or new southern gas production or production of other alternatives to natural gas (such as biomethane), are needed to replace declining Gippsland supply.

Figure 28 Actual and forecast maximum daily production capacity from southern gas fields, 2021-27 (TJ/d)



Northern daily production capacity

In the north, production operates at near full capacity all year around, due in part to less seasonal domestic demand, and the relationship that exists between field operations and export operations.

3.2.4 Contracted supply

AEMO presents new analysis on the level of annual contracted gas supply, supported by data provided voluntarily by GSOO reporting entities[66] for the 2023 GSOO. This data will become mandatory for producers to provide for

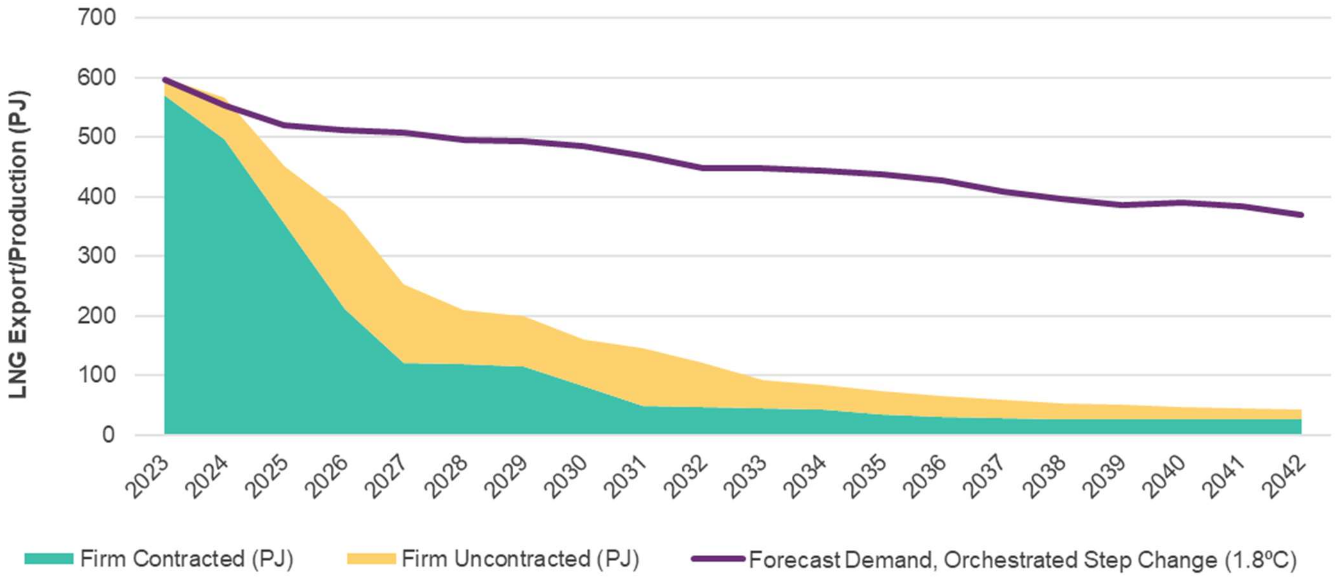
[66] "GSOO reporting entities" includes owners and operators of a range of gas facilities (pipelines, compression service facilities, gas processing plants, LNG facilities, storage facilities, gas generators) and fields, Bulletin Board reporting entities, retailers, and shippers. It is defined in the GSOO Procedures, at https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo.

the 2024 GSOO. Ahead of these new mandatory requirements, the submitted voluntary dataset provides majority, but not complete, coverage of total production.

When a user enters a contract for the firm supply of gas from a producer (firm contracted supply), that supply must be made available when requested under the terms of the contract. Firm uncontracted supply is firm supply that is not contracted, but available to be contracted by market participants. If supply is not contracted, it may be sold on spot markets. Gas available for firm supply contracts from a producer is not necessarily equal to their production forecast, and therefore analysis in this section alone does not provide insights on supply adequacy.

Figure 29 shows that while much of forecast domestic consumption is contracted, a growing gap between contracted and uncontracted demand is emerging. It is not uncommon for there to be a gap in future years, as consumers may prefer not to enter into long-lived contracts while their own operations are uncertain, or if the terms offered are not supportive of a long-lived agreement. Nonetheless, it represents a significant challenge for gas consumers, and gas producers alike, for such significant volume to need to be developed effectively 'at-risk', and consumed without agreed pricing positions.

Figure 29 Firm contracted and firm uncontracted contract quantities for non-LNG producers in comparison to forecast domestic demand, *Orchestrated Step Change (1.8°C)* scenario (PJ)



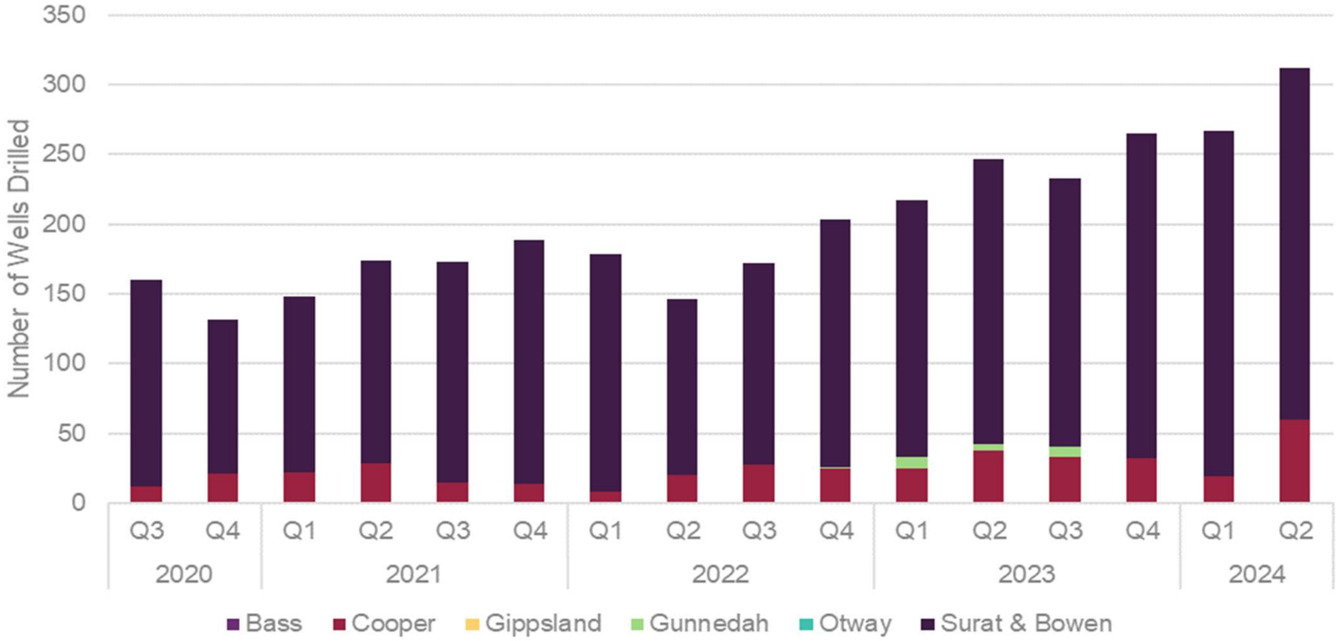
3.2.5 Wells drilled

This analysis on well drilling activity is supported by data supplied voluntarily for the 2023 GSOO. Not all producers provided information on the number of wells drilled, therefore data presented here is incomplete and the analysis is limited. It will become mandatory to submit this data from the 2024 GSOO.

Figure 30 shows that:

- Increased drilling activity is forecast in 2023 and 2024, in comparison to 2020, 2021 and 2022.
- The vast majority of the drilling activity is concentrated in the Surat and Bowen basins, to support LNG exports.

Figure 30 Actual and forecast number of wells either developed, explored or appraised each quarter, 2020-24



3.2.6 Alternative, renewable gases

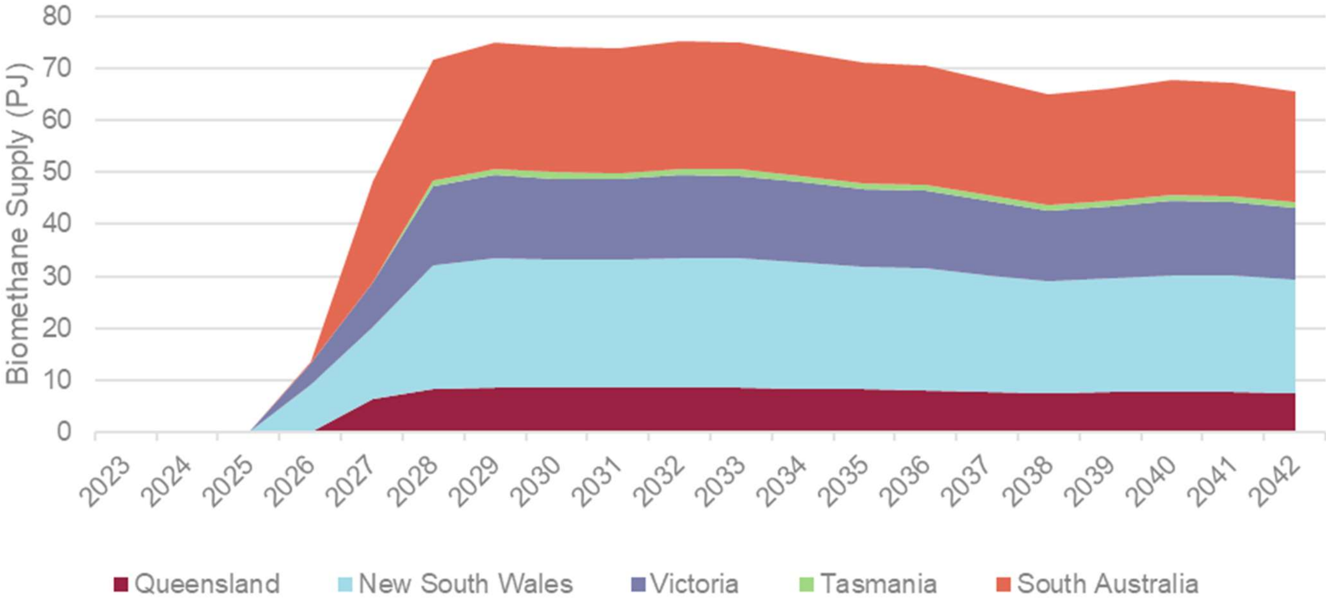
This GSOO considers the opportunity for gas consumption to decline due to the development and delivery of biomethane over the forecast horizon. The possible development of biomethane is explored in the *Diverse Step Change (1.8°C)* and *1.5°C Green Energy Export* scenarios, and gas consumption (**Section 2**) and gas adequacy (**Section 4**) net off the potential development to focus on natural gas consumption only.

Biomethane development is not assumed in the *Orchestrated Step Change (1.8°C)* scenario, ensuring that gas adequacy is examined comparing traditional sources of gas relative to forecast gas consumption, with some allowance for forecast hydrogen production that may offset gas consumption for some consumers.

In the scenarios that include greater gas source diversity, AEMO considered a mix of urban and rural supply sources, broadly informed by literature and subject to many assumptions. Biomethane supply locations were chosen based on feedstock availability, proximity to transmission and distribution infrastructure, and estimated cost of supply. **Figure 31** shows the assumed biomethane supply for each state in the *1.5°C Green Energy Export* scenario.

Where possible, biomethane developments would be best located in southern regions to support the high local seasonal demand, and preferably downstream of any potential pipeline constraints that may limit operational effectiveness at servicing peak demands.

Figure 31 Assumed biomethane supply by state in the *Green Energy Export (1.5°C)* scenario, 2023-42 (PJ)



3.3 Midstream gas infrastructure

Midstream infrastructure provides the linkage between producers in the various gas producing basins and consumers, and includes pipelines, storages, and potential LNG import terminals[67].

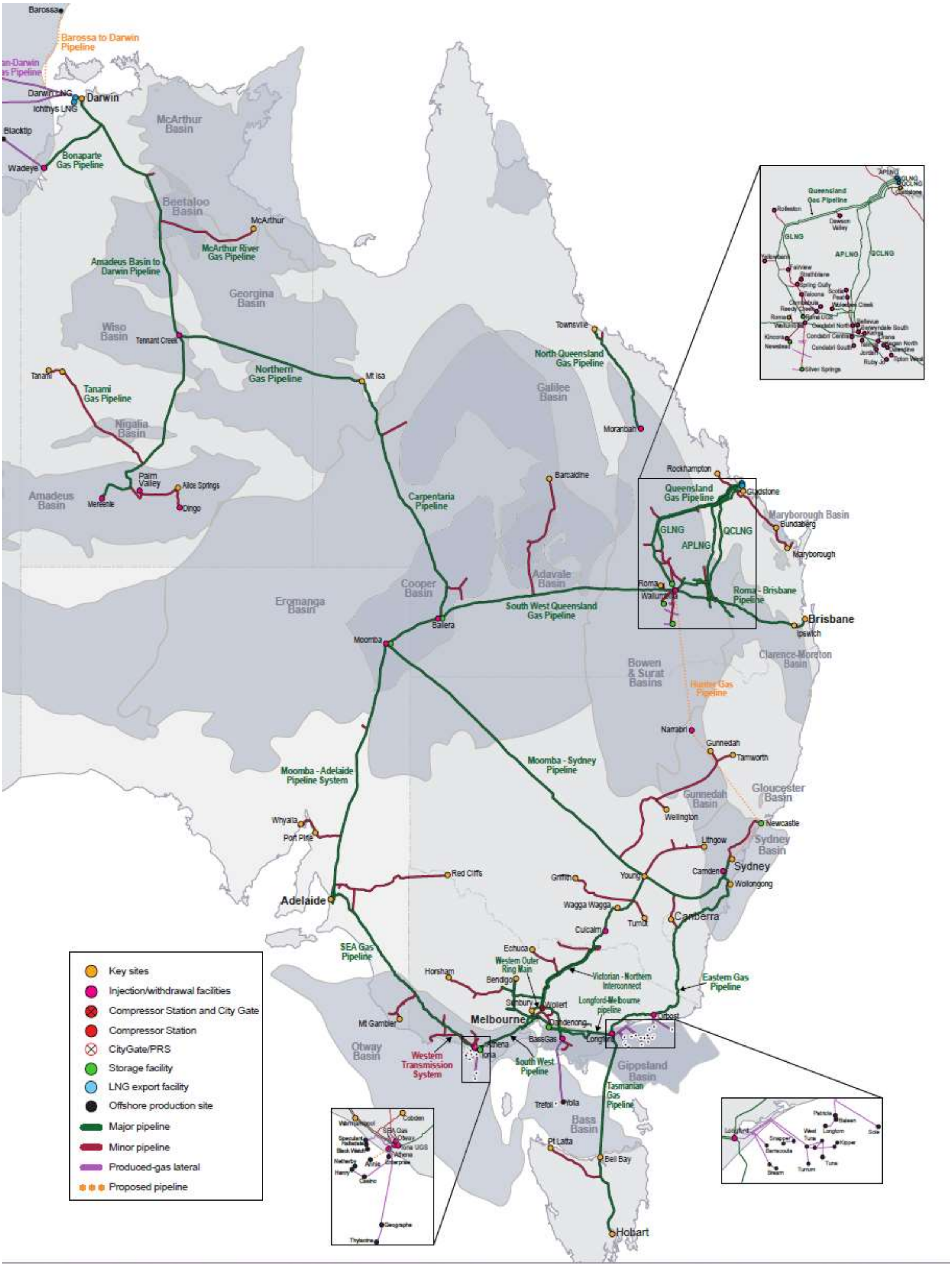
Figure 32 provides a map of the basins, pipelines, and load centres across central and eastern Australia assessed in this 2023 GSOO.

As gas production and consumption patterns change, the requirements on midstream infrastructure may also change. In assessing gas adequacy, AEMO bases its modelling of midstream infrastructure on technical capability and does not consider contracted positions. The ACCC's January 2023 *Gas Inquiry 2017-2030 Interim Report* provides valuable context on potential implications of pipeline contracts[68].

[67] LNG export terminals are considered consumers.

[68] At https://www.accc.gov.au/system/files/Gas%20Inquiry%20-%20January%202023%20interim%20report%20-%20FINAL_0.pdf.

Figure 32 Map of basins, major pipelines and load centres



Note: the LNG facilities and associated pipelines in the Northern Territory are not modelled in the GSOO. These are treated as a closed system that do not impact domestic supply adequacy. More information is in Section 4.2.

3.3.1 Major gas transmission pipelines

In the geographical area covered by this GSOO, there are a number of major pipelines that connect regions or geographically separated supply and demand centres. This section does not provide a comprehensive list of all major pipelines, but discusses some key pipelines which are part of the supply demand adequacy discussion in **Section 4**, particularly impacting north-south flowing gas.

South-West Queensland Pipeline (SWQP)

The SWQP runs from Wallumbilla to Moomba and connects with the Carpentaria Gas Pipeline (CGP), which can receive gas from the Northern Gas Pipeline (NGP). The SWQP acts as a gateway between the large northern gas fields (including those that service the three Gladstone LNG export plants) and southern regions, where much of the highly seasonal demand is located.

As explained under the MSP section below, availability of this pipeline to enable north-south gas flows is increasingly important. APA[69] has committed to both a Stage 1 and Stage 2 expansion of the SWQP and MSP:

- Stage 1 will increase capacity on the SWQP by 49 TJ/d from 404 TJ/d to 453 TJ/d, and on the MSP by 30 TJ/d from 446 TJ/d to 475 TJ/d, before winter 2023. This will allow 49 TJ/d of additional northern gas to be supplied to southern markets. This expansion will consist of an additional compressor between Moomba and Young and an additional compressor on the SWQP.
- Stage 2 will increase the capacity from Queensland to the southern states by 59 TJ/d, with an additional compressor station constructed on both the SWQP and MSP. This will increase the nominal capacity of the SWQP by 59 TJ/d from 453 TJ/d to 512 TJ/d and the MSP by 90 TJ/d from 475 TJ/d to 565 TJ/d. This stage is expected to be completed prior to winter 2024.

Stages 1 and 2 capacity expansions are included in this GSOO modelling as committed projects.

There are proposed projects that could expand the capacity of the SWQP further, by increasing compression, but these are not yet classified as anticipated or committed.

Moomba – Sydney Pipeline (MSP)

The MSP connects the Moomba Gas Hub in northern South Australia to Sydney. It also connects with the Victorian Northern Interconnect (VNI) at Young, and therefore also provides for additional gas sharing with Victorian consumers.

At present[70], any gas flowing from northern Australia, and from Moomba, into New South Wales, Victoria, or Tasmania must pass through the MSP. Similarly, at times, surplus Victorian gas supply has been transported north on the MSP to supplement northern supply. As such, the MSP – and the SWQP – are key to maintaining the capability to share gas between northern and southern regions.

APA performs maintenance on the MSP during summer, which can reduce the capacity of the pipeline by up to 50%. Also, the dynamic interaction between Young – Sydney and the VNI lateral may impact the total southern haul capacity of the MSP south of Moomba. The total MSP capacity is generally higher when the quantities delivered south via Sydney are higher.

[69] APA is the owner and operator of a number of pipelines in Australia including the MSP.

[70] Additional pipelines, such as the Queensland – Hunter Gas Pipeline, or an LNG import terminal in the south, may change this situation.

As noted above, APA has committed to a Stage 1 and Stage 2 expansion of the MSP and SWQP.

Eastern Gas Pipeline (EGP)

The EGP runs from the Longford and Orbost Gas Plants in Victoria's Gippsland Basin to Sydney, with Canberra supplied from the EGP at the Hoskinstown connection. The EGP presently only flows north towards Sydney, but the PKET project has associated EGP modifications to allow bi-directional flow, so gas can be transported both north (to Sydney) and south (to Victoria) simultaneously from PKET.

South West Pipeline (SWP)

The SWP is a bi-directional pipeline that runs between Port Campbell and Lara in Victoria. At Lara it connects to the Brooklyn – Lara Pipeline (BLP).

The SWP is typically used to:

- Transport gas from Port Campbell (including Otway Basin) and Iona UGS facilities towards Melbourne.
- Support Iona UGS reservoir refilling, and
- Provide supply to Victorian demand west of Port Campbell (including Mortlake Power Station) and to South Australia via the South East Australian Gas (SEAGas) Pipeline, during periods of lower Victorian gas demand in the summer and shoulder seasons.

The SWP capacity from Port Campbell to Melbourne is dependent on system demand and is maximised on peak demand days. Current maximum capacity is 430 TJ/d on a one-in-20 system demand day. This is expected to increase to 513 TJ/d following completion of the WORM project (see below) and installation of a second compressor at Winchelsea, both of which are committed projects expected to be completed prior to winter 2023.

APA announced FID on the construction of a second compressor at Winchelsea following the publication of the 2022 GSOO[71]. This project will assist in increasing the SWP capacity by approximately 50 TJ/d (from 464 TJ/d with the WORM alone to 513 TJ/d), and will provide redundancy in compression services. The completion timeline for this project is tight, and AEMO has considered the impact of a one-year delay through sensitivity analysis (see **Section 4.1**).

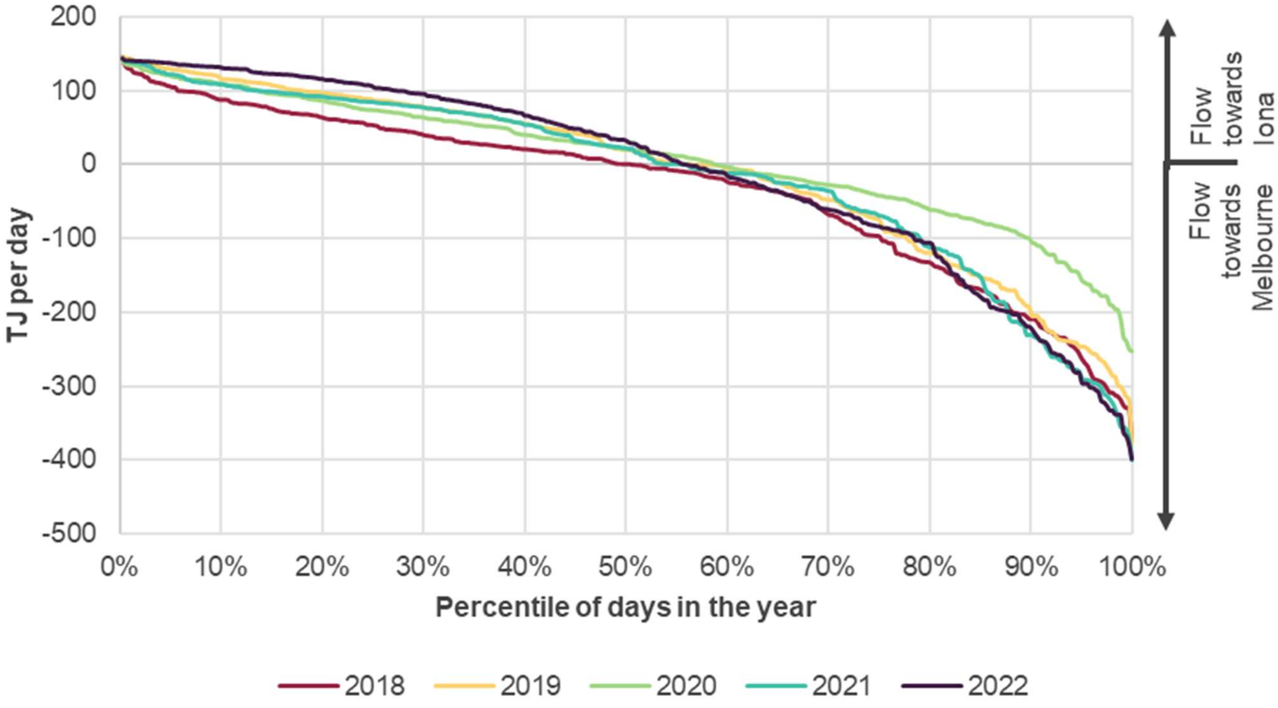
The SWP capacity from Melbourne to Port Campbell is also dependent on system demand and is maximised on low demand days. Current maximum capacity is 152 TJ/d on a low demand day. This will increase to 348 TJ/d following completion of the WORM.

Historical flows along the SWP over the last five years are shown in **Figure 33** below.

The SWP is forecast to be constrained on some peak days, although forecast SWP constraints are less prevalent than in the 2022 GSOO due to the addition of a second compressor at Winchelsea. If further supply in the Otway Basin is developed, or further capacity expansions occur at Iona beyond those already committed (see **Section 3.3.2**), it is expected that the SWP will become constrained more regularly.

[71] APA "APA announces additional capacity in Victoria ahead of forecast gas shortfalls", 21 April 2022, at https://www.apa.com.au/news/media-statements/2022/apa-announces-additional-capacity-in-victoria-ahead-of-forecast-gas-shortfalls/.

Figure 33 Cumulative distribution of flows along the SWP, 1 January 2018 to 31 December 2022 (TJ/d)



Western Outer Ring Main (WORM)

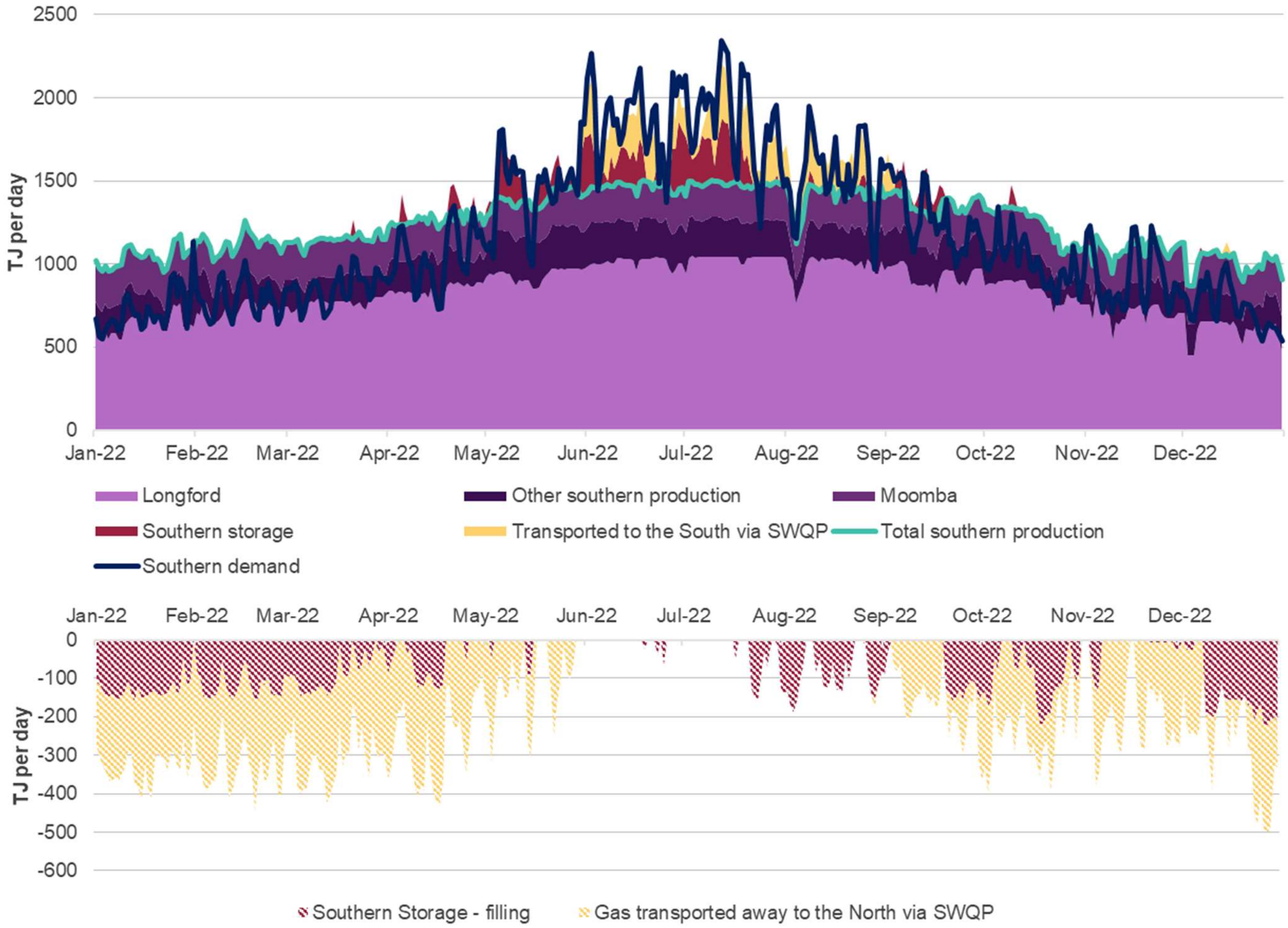
The WORM is a committed augmentation of the Victorian DTS that will connect the SWP/BLP at Plumpton and the Longford Melbourne Pipeline (LMP) at Wollert. The project will also include the installation of additional compression. The scheduled completion date is winter 2023.

Use of mid-stream infrastructure to meet southern demand

Figure 34 highlights the significant and important contribution of the SWQP to meet southern demand in 2022. The figure also shows the daily profile of supply sources used to meet southern demand across 2022, including:

- Gas production in Longford, Moomba and other southern fields.
- Withdrawal (and injection) from gas storages within the southern regions.
- Gas flow from northern regions to southern regions via the SWQP at times of high southern demand.
- Gas flow from southern regions to northern regions via the SWQP at times of low southern demand.

Figure 34 Observed gas supply used to meet peak southern demand in 2022 (TJ/d)



Note: total demand may not equal total supply due to changes in linepack levels, and metering error. Negative flows on SWQP mean gas being transported to the North.

Other pipelines

Table 6 lists other major midstream infrastructure servicing domestic consumers.

Table 6 Additional major midstream infrastructure (existing and proposed)

Name	Description and relevant information
Existing	
Moomba – Adelaide Pipeline System (MAPS)	Connects Adelaide to the Moomba gas production facility in northern South Australia. It also supplies regional South Australia, and connects to a lateral which supplies Mildura in Victoria.
South East Australian Gas Pipeline (SEAGas)	Connects Adelaide to supply from Otway Basin in Victoria, including Iona UGS. There is a limited capability for gas to flow from SEAGas into the MAPS, but gas cannot flow from the MAPS into SEAGas. It also supplies regional South Australia, the South East South Australia (SESA) pipeline, and the South East Pipeline System (SEPS).
Northern Gas Pipeline (NGP)	Connects the Northern Territory (at Tennant Creek) to Mt Isa and the CGP (described below).
Amadeus Gas Pipeline (AGP)	Connects the Amadeus Basin in the south of the Northern Territory to Darwin in the north. The pipeline is bi-directional.
Bonaparte Gas Pipeline (BGP)	Connects supply from the Blacktip field to the AGP at Ban Ban Springs.
Carpentaria Gas Pipeline (CGP)	Connects Mount Isa and the NGP to Queensland's pipeline system, at Ballera on the SWQP.

Name	Description and relevant information
Victoria Northern Interconnect (VNI)	Connects Wollert (on the Melbourne ring) to Young, intersecting with the MSP.
Brooklyn – Lara Pipeline (BLP)	Connects supply from the SWP at Lara to Brooklyn
Longford – Melbourne Pipeline (LMP)	Connects Melbourne to supply from Longford Gas Plant. Does not provide access to the Orbost Gas Plant.
Roma – Brisbane Pipeline (RBP)	Connects Brisbane to supply from Wallumbilla Gas Hub.
Tasmanian Gas Pipeline (TGP)	Connects Bell Bay to supply from Longford Gas Plant.
North Queensland Gas Pipeline (NQGP)	Connects Townsville to supply from Moranbah Gas Plant
Sydney – Newcastle Pipeline (SNP)	Connects Newcastle to Sydney (and draws supply from the MSP and EGP). Presently this is not considered to be a transmission pipeline, but is a large full regulation distribution pipeline. However, given Newcastle proposals for a new LNG import terminal, new gas generation, or the Queensland – Hunter Gas Pipeline (QHGP), the SNP may need expansion or even duplication.
Proposed developments	
Queensland – Hunter Gas Pipeline (QHGP)	A new Wallumbilla to Sydney connection, which would connect the proposed Narrabri Gas Plant to Newcastle in the south and Wallumbilla in the north, providing a new pathway for north/south gas transfer. If the QHGP progressed it is likely that expansion of the SNP would also be required to connect down to the EGP, which would also be developed to be bidirectional.

Note: the Western Slopes Pipeline, mentioned in the 2022 GSOO as a proposed development, is no longer being progressed. See https://www.apa.com.au/about-apa/our-projects/western-slopes-pipeline/.

3.3.2 Storage facilities

Storage facilities store surplus gas supplies produced in summer for use in winter when the demand is higher. They provide critical flexibility and peak capacity to help the gas system meet peak demand requirements. At times, pipeline capacity limitations can affect the ability of storages to:

- Be refilled to capacity, and/or
- Deliver gas to the system at maximum withdrawal rate.

Table 7 lists existing market-facing storage facilities and proposed upgrades or facilities.

Table 7 Key existing market-facing and proposed storage infrastructure

Name	Connecting location	Maximum storage capacity (PJ)	Maximum withdrawal rate (TJ/d)
Silver Springs	Wallumbilla, Queensland	46	25
Iona UGS	Otway Basin, Victoria		
• **Existing**		24	558
• **Committed upgrade (winter 2024)[A]**		24.5	570
• **Proposed upgrade**		26-28	570-615
Newcastle LNG Storage	Newcastle, New South Wales	1.5	120
Dandenong LNG Storage	Melbourne, Victoria	0.68	87[B]
Other proposed developments or upgrades			
Golden Beach Storage	Gippsland Basin, Victoria	12.5	250

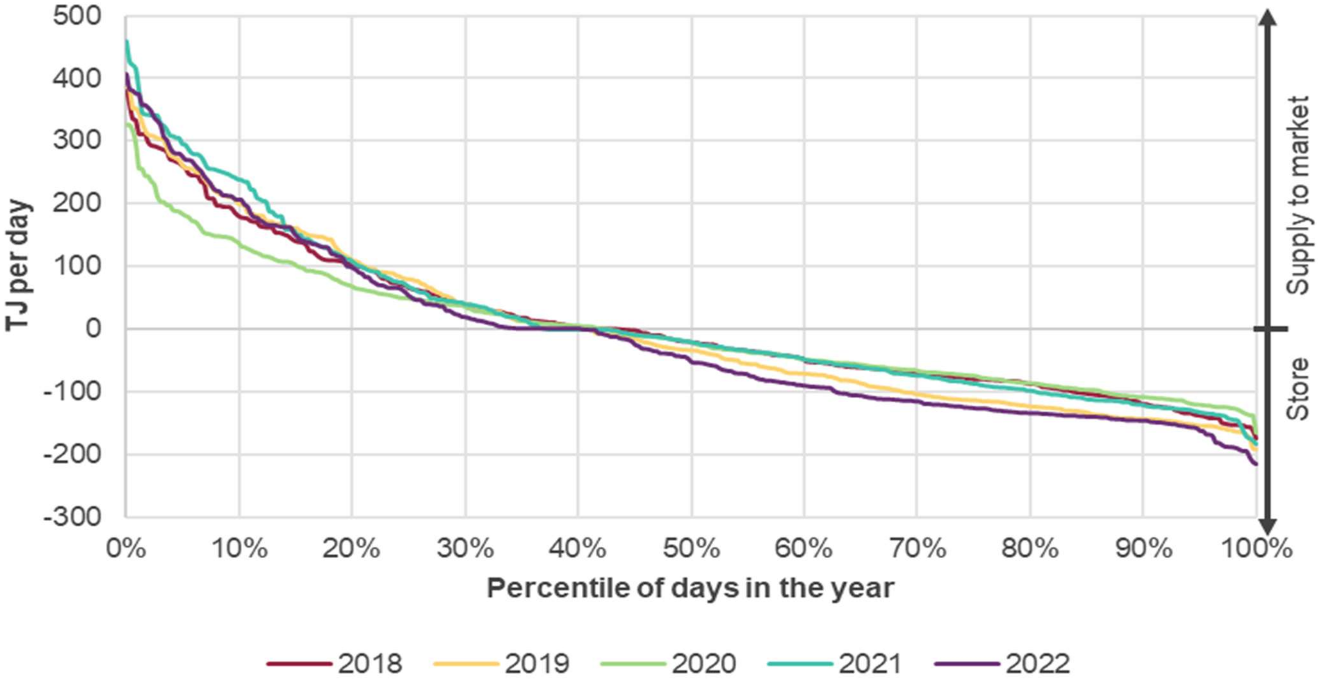
A. Proposed upgrade in Iona UGS (additional 0-45 TJ/d and 1.5-3.5 PJ storage) is not included in base GSOO gas adequacy assessments
B. This storage can supply at faster rates for short periods of time, but that is non-firm supply and not able to be supported across a 24-hour period.

Figure 35 demonstrates that Iona UGS is routinely relied upon to inject at high rates to support demand, with 2021 and 2022 observing the greatest daily withdrawal in the past five years, both above 400 TJ/d.

Shallow storages at Dandenong and Newcastle will need careful operational management so they hold enough gas when it is needed to provide necessary operational flexibility and help mitigate shortfall risks. While these storages have relatively high withdrawal rates, the volumes they hold are small, so withdrawals cannot be sustained for many days, and the refilling speed is slow.

The Declared Wholesale Gas Market (DWGM) interim LNG storage measures rule change[72] requires that AEMO contracts any uncontracted capacity in the Dandenong LNG tank from 2023 to 2025. This will ensure that the Dandenong LNG tank is full prior to winter during this period.

Figure 35 Cumulative distribution of net changes in storage level for Iona UGS, 1 January 2018 to 31 December 2022 (TJ/d)



3.3.3 LNG import terminals

LNG import terminals represent an alternative way to supply gas to consumers than transportation via traditional pipelines. They could effectively operate as virtual pipelines, sourcing gas from both international and domestic markets and delivering it to demand centres – for example, bringing gas from the northern to the southern regions. The total annual volume that could be supplied would depend on shipment schedules and approvals.

The timing for commissioning of proposed LNG import terminals has been delayed since the 2022 GSOO. Amidst the ongoing Ukraine-Russia conflict, demand for FSRUs[73] internationally has continued to be high[74]. Except for PKET, all other LNG import terminal proposals are yet to sign charter deals or other contractual arrangements for an FSRU, or commence construction of onshore infrastructure. Most proponents of LNG import terminals have

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

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

[74] Offshore Engineer, "Demand for FSRUs Soars as Europe Works to Cut Reliance on Russian Gas", 21 June 2022, at https://www.oedigital.com/news/497481-demand-for-fsrus-soars-as-europe-works-to-cut-reliance-on-russian-gas.

also informed AEMO that they have environmental and regulatory approvals outstanding, and have listed these along with securing an FSRU as key risks that may further delay their commencement dates.

Table 8 lists proposed LNG import terminals, with important considerations about each. These proposals are at various stages of development.

Table 8 Proposed LNG import terminals

Name	Region	Earliest assumed timing	Capacity	Additional considerations
Port Kembla Energy Terminal (PKET)[A]	New South Wales	2026	500 TJ/d 130 PJ/y	• Annual production limitation of approximately 130 PJ.[B] • Onshore infrastructure remains on track for completion in December 2024, but timing of FSRU location and commencement is uncertain. • Located near Sydney with a pipeline connecting into the EGP. • EGP to be upgraded to become bidirectional. Upgrade of the EGP to allow initially 200 TJ/d in reverse flows south to Victoria concurrently with the PKET development. A potential future expansion to 323 TJ/d can be achieved with additional compression.
Geelong[C]	Victoria	2025	600 – 750 TJ/d Up to 140 PJ/y	• Pending FID. • Located adjacent to the Geelong Oil Refinery. • Submitted Environmental Effects Statement (EES)[D] and the Minister has since requested a supplementary information statement to assist their decision[E] • Working to secure an FSRU for the project after losing previous allocation[F]. • Would be complimented by an upgrade to the SWP to allow coincident maximum injections from LNG imports, Iona storage, and Otway supply.
Port Adelaide[G]	South Australia	2026	Up to 405 TJ/d 60 PJ/y estimated	• Construction approval granted Dec 2021, expected to be online in 2026, subject to FID. • The floating terminal will operate as a take-or-pay tolling facility, with foundation gas customers to source their own LNG. • Would require upgrades to the SEAGas pipeline to allow for flow from Adelaide to Port Campbell.
Port Phillip Bay[H]	Victoria	2026	Up to 700 TJ/d ~260 PJ/y	• Pending FID • Proponents have submitted a referral to the Minister for Planning to determine if an EES is required for the project. • Would be complimented by an upgrade to the SWP to allow coincident maximum injections from LNG imports, Iona storage, and Otway supply.

A. For more, see https://www.squadronenergy.com/port-kembla-energy-terminal/?utm_medium=301&utm_source=aie_home.
B. AEMO understands that the PKET has environmental restrictions that will limit water discharge and reduce the volume of imports to 130 PJ/y.
C. For more, see https://www.vivaenergy.com.au/energy-hub/gas-terminal-project/about-our-project.
D. Victorian Government – Department of Environment, Land, Water and Planning, "Viva Energy Gas Terminal Project", 7 December 2022, at: https://www.planning.vic.gov.au/environment-assessment/browse-projects/projects/viva-energy-gas-terminal-project.
E. Viva Energy, "Viva Energy Gas Terminal Project update", 8 March 2023, at https://events.miragle.com/DownloadFile.axd?file=/Report/ComNews/20230308/02641357.pdf.
F. Sonali Paul and Florence Tan, MarketScreener, "Europe's dash for gas puts Australia's LNG import plans at risk", 30 May 2022, at https://www.marketscreener.com/quote/stock/VIVA-ENERGY-GROUP-LIMITED-44388561/news/Europe-s-dash-for-gas-puts-Australia-s-LNG-import-plans-at-risk-40589187/.
G. For more, see https://veniceenergy.com/south-australian-power-project/.
H. For more, see https://www.vopak.com/newsroom/news/news-vopak-lng-studies-feasibility-develop-lng-import-terminal-victoria and https://www.argusmedia.com/en/news/2197082-vopak-eyes-lng-import-terminal-in-australias-victoria.

The PKET was considered an anticipated project in the 2022 GSOO with supply from this project anticipated to become available from 2024. Since then, despite infrastructure remaining on track for completion in December 2024, Squadron Energy has advised AEMO that there are still insufficient contracted volumes at PKET to justify the location and commencement of the FSRU at Port Kembla. Early 2026 has been advised as a possible date for services to commence based on prospective buyers' and Squadron Energy's own demand. Given the forecast date from which gas will become available remains dependent on uncertain FRSU commencement, PKET (and other proposed LNG receiving terminals) are not considered as anticipated projects in the GSOO supply adequacy assessment. The 2023 GSOO considers PKET and other LNG import terminal projects as uncertain and includes these only in sensitivity analysis within the gas adequacy analysis (**Section 4.2**). EPIK recently ceased development of a proposed LNG import terminal in Newcastle due to it no longer being economically feasible[75].

3.3.4 Impact of renewable gases

Currently, it is assumed that hydrogen can be blended into the low-pressure distribution network at low percentages without any adverse effects to infrastructure or consumer appliances. The feasibility of hydrogen transportation at high pressures and percentages remains uncertain, and therefore the impact of hydrogen on mid-stream infrastructure is also uncertain.

Biomethane is chemically very similar to natural gas, and therefore there are no material technical challenges regarding transport or consumer appliance compatibility. The impact of biomethane transportation on mid-stream infrastructure is therefore expected to be minimal.

[75] Mandurah Mail, "Gas market volatility kills off $590m gas terminal", 3 February 2023, at https://www.mandurahmail.com.au/story/8071497/gas-market-volatility-kills-off-590m-gas-terminal/?src=rss.

4 Gas supply adequacy assessment

Based on the demand and supply forecasts in **Sections 2 and 3**, this section provides a gas supply adequacy assessment for all Australian jurisdictions other than Western Australia.

Key insights

- **There is a risk of peak day shortfalls in most scenarios across southern regions from 2023** if coincident, extreme conditions in southern regions coincide with a high need for electricity from gas generation**.**
  - Shortfall risks could be avoided if the demand for electricity from gas generation was reduced at times of peak gas demand. This could be achieved through moderation of electricity demand, including Reliability and Emergency Reserve Trader (RERT) or curtailment, or utilisation of alternate fuels (such as diesel) in dual-fuel capable generators.
  - During these conditions, pipeline capacity constraints on SWQP and MSP limit more supply from being provided by northern producers, even after committed upgrades are commissioned. On-schedule completion of committed infrastructure upgrades is important to mitigate shortfall risks from 2023.
  - This assumes that the LNG exporters make their uncontracted production volumes available to the domestic market, including on peak demand days during winter, subject to pipeline constraints.
  - Deep and shallow storages remain critical to meeting peak day demand in winter and are useful assets for risk mitigation against unplanned events, which may be frequent.
- **Domestic supply gaps are at risk of emerging:**
  - From 2023, if Queensland LNG exports are greater than advised contract levels[76], with a supply gap of up to 33 PJ[77]. This differs from the ACCC's *Gas Inquiry 2017-2030 Interim Report* as it applies gas generation at the upper end of the forecast range, with only committed and existing supplies. The Australian Domestic Gas Security Mechanism (ADGSM) and Heads of Agreement between the Federal Government and LNG producers are important to ensure domestic supply is maintained.
  - From 2026, without anticipated supplies being developed, Queensland LNG exporters must divert gas contracted for export to the domestic market to maintain domestic adequacy. Domestic supply gaps would result if the gas required by southern customers is instead exported to meet advised export contract commitments.
  - From 2027, even with the development of anticipated supplies, and with Queensland LNG exporters diverting the maximum amount of gas possible (limited by pipeline capacity) to southern customers, supply gaps affecting southern regions are forecast to emerge. The timing and size of emerging supply gaps is uncertain across scenarios, meaning scalable solutions with delivery flexibility may be preferred while the pace of gas sector transformation is uncertain.

[76] The ACCC's January 2023 *Gas Inquiry 2017-2030 Interim Report* indicates that LNG exporters anticipate 88 PJ of spot cargoes to be exported. AEMO's suveyed data from LNG producers did not provide an indication of spot cargo volumes. AEMO's gas adequacy assessment examines physical gas availability, assuming that these uncontracted volumes would be available to domestic consumers, as required under the Heads of Agreement and Mandatory Code of Conduct provisions.

[77] The size of a supply gap will depend on many volatile factors (eg. weather); this 33 PJ estimate applies an upper range of gas generation.

- Overall, to meet forecast supply gaps:
  - Greater resource development is needed to offset declining production, particularly in southern states, or natural gas alternatives (such as biomethane or hydrogen) will be needed,
  - Infrastructure solutions must be developed to get the gas to where and when it is needed (such as local shallow storage, increased compression – expanding both pipeline capacity and linepack – and larger deep storage), and/or
  - Demand side options (which would take time and consultation to develop) can supplement infrastructure to meet the infrequent peaks.

Defining a shortfall

For GSOO purposes, an inability to supply gas to meet domestic (industrial, commercial, residential or gas generation) demand is identified as either a shortfall or supply gap:

- A **peak day shortfall** is driven by insufficient capacity to meet demand on an extreme peak day.
- A **seasonal or annual supply gap** is driven by a broader lack of available gas production or transport capacity, rather than just capacity on a single day.

In this GSOO, AEMO has modelled total production, including from LNG exporters. This GSOO provides a physical assessment of gas adequacy, assessing the capability of forecast gas production to meet gas demand. LNG exporters are assumed to offer gas (including gas they are entitled to under third party arrangements) to the domestic market as required, and shortfalls that result are reported as 'LNG export supply gaps'. The supply adequacy assessment takes into account all pipeline transmission capacity and constraints, and energy limitations from production facilities, storage and LNG import terminals.

Use of scenarios for the adequacy assessment

While the 2022 GSOO noted that the 2022 ISP *Step Change* scenario was most likely, it included gas adequacy assessments of both the *Step Change* and *Progressive Change* scenarios to describe opportunities under faster and slower rates of energy transformation respectively.

In this 2023 GSOO, the adequacy assessment focuses on *Orchestrated Step Change (1.8°C)*. The *Orchestrated Step Change (1.8°C)* is most comparable with the 2022 GSOO *Step Change* scenario, as it adopts a central view of economic outlook, effective connections growth and applies similar decarbonisation targets affecting fuel-switching in the short, medium and longer term.

In contrast, the 2023 *Progressive Change (2.6°C)* scenario is no longer a scenario linked to central or moderate economic activity; it applies weaker commercial outcomes and therefore lower industrial consumption, relatively lesser effective connections growth, and other downside drivers affecting overall gas consumption. It is not appropriate to extend the 2022 *Progressive Change* scenario into the *Progressive Change (2.6°C)* scenario.

As detailed in **Section 2.2** and in the forecast accuracy appendix (**Appendix A1**), the *Orchestrated Step Change (1.8°C)* scenario reflects observed trends impacting residential, commercial and industrial consumption and the likely near-term continuation of these trends, but forecasts under all scenarios will have an inaccuracy variance (from weather impacts, policy change, consumer or infrastructure developments).

This section provides insights regarding seasonal consumption patterns, including the monthly variance that may be expected from predictable uncertainties (such as the weather) in any given scenario.

While the GSOO does not report the shortfall and supply gap analyses across all scenarios in detail, the range of scenario outcomes in the adequacy assessment is designed to provide a broad perspective of the uncertainties that may influence gas adequacy and investment needs.

4.1 Short-term supply adequacy

This 2023 GSOO analysis highlights the risk of peak day shortfalls under extreme conditions in the southern regions in the short term in most scenarios. The only scenario which avoids shortfall risks is the *Progressive Change (2.6°C)* scenario, due to its assumptions about the potential reduced operation or closure of industrial loads.

This gas adequacy analysis focuses mainly on Australia's southern region of New South Wales (including the Australian Capital Territory), Victoria, South Australia and Tasmania. The 2022 GSOO supply adequacy analysis focused on the south-eastern region, which did not include South Australia. The 2023 GSOO analysis has identified that due to updated production estimates across southern fields, South Australia now is within the potentially constrained supply region. Shortfalls described in this section may occur anywhere within the southern region.

Figure 36 shows[78] the projected ability of southern production, SWQP capacity, and stored gas to meet actual southern gas demand in 2021 and 2022, and its projected ability to meet one-in-20[79] demand forecasts to 2027 in the *Orchestrated Step Change (1.8°C)* scenario, based on:

- Typical weather diversity between southern regions that results in most load centres having independent peak day events, with 'normal' reliance on gas generation at these times (reference year 2017), and
- Adverse weather conditions across multiple regions simultaneously, resulting in extremely high coincident peak demand, and high simultaneous demand from gas generation (reference year 2019).

The horizontal lines in **Figure 36** show, for each year, how much supply has been and is forecast to be available to meet projected daily demands, based on:

- Maximum gas production in the southern regions only (solid purple line), plus
- Expected gas imported from Queensland through the SWQP, taking into account the capacity of the pipeline and expected flows along the CGP to Mt Isa (dashed purple line), plus
- Deep storage from Iona (dotted purple line, assuming sufficient gas is stored to utilise at full capacity), plus
- Shallow LNG storages at Dandenong and Newcastle (solid red line, assuming sufficient gas is stored to utilise at full capacity).

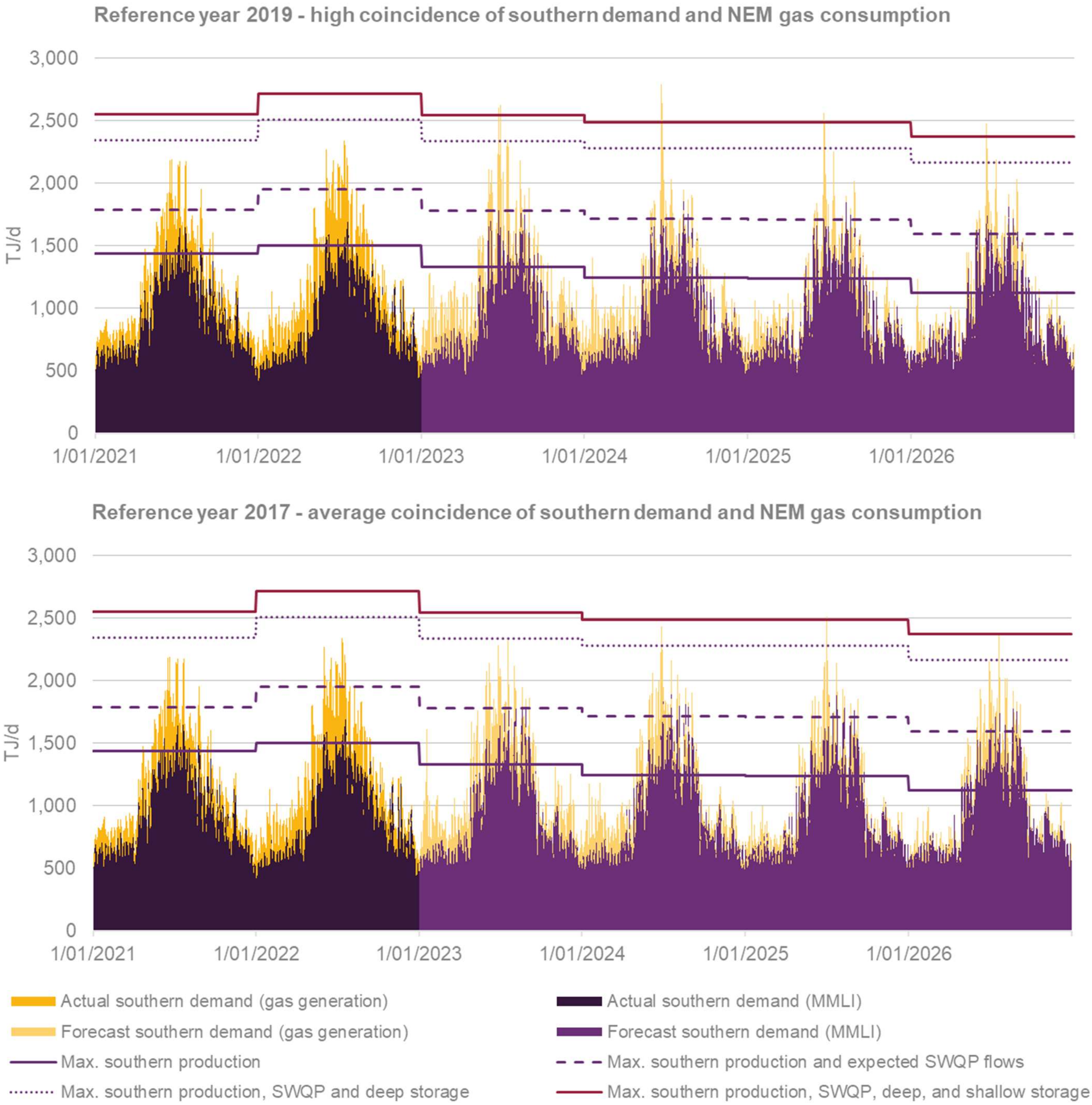
The key points highlighted in **Figure 36** are, for the *Orchestrated Step Change (1.8°C)* scenario:

[78] The figure provides an illustration of available supply, demonstrating the maximum supply capacity as a fixed value for each supply category (each horizontal line). AEMO's gas adequacy methodology calculates the adequacy of supply on a daily basis, allowing for dynamic infrastructure limits and the energy available in storage, and supply capacity may differ from this illustration. Due to this, the magnitude of shortfalls shown in this figure are approximate only, and may differ from shortfalls presented in Table 11.

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

- **Peak day shortfalls are forecast under extreme peak days in every year from 2023 to 2026 where large demand for gas generation coincides with significant residential, commercial and industrial consumption** (such as in reference year 2019). Cold weather drives up demand for both electricity and gas for heating, and further stresses in the electricity system (such as coal unit outages or low wind) can drive up gas demand for electricity generation.
- **Deep and shallow storages remain critical to meeting peak day demand**, as southern production and flows along the SWQP alone are not enough to satisfy peak demand in winter. Under extreme weather conditions, these are also insufficient, and shortfalls are possible.
- **Without high coincidence of gas generation and residential, industrial and commercial demand then peak day shortfalls may be narrowly avoided**, but the supply demand balance remains very tight (such as for 2023 and 2024 in reference year 2017).
- **Peak day adequacy is contingent on supply from Queensland, and in particular uncontracted supply from the LNG exporters, being made available on peak demand days** to support SWQP flow. Peak day shortfalls may occur on a greater number of days during each winter from 2023 if insufficient gas is available from northern regions to ensure the SWQP is flowing at full capacity on peak demand days.

Figure 36 Actual and forecast daily southern gas demand showing seasonality, peakiness, southern production, and total system capacity available to meet southern demand using existing and committed projects, for the *Orchestrated Step Change (1.8°C)* scenario, under favourable and extreme weather (TJ)



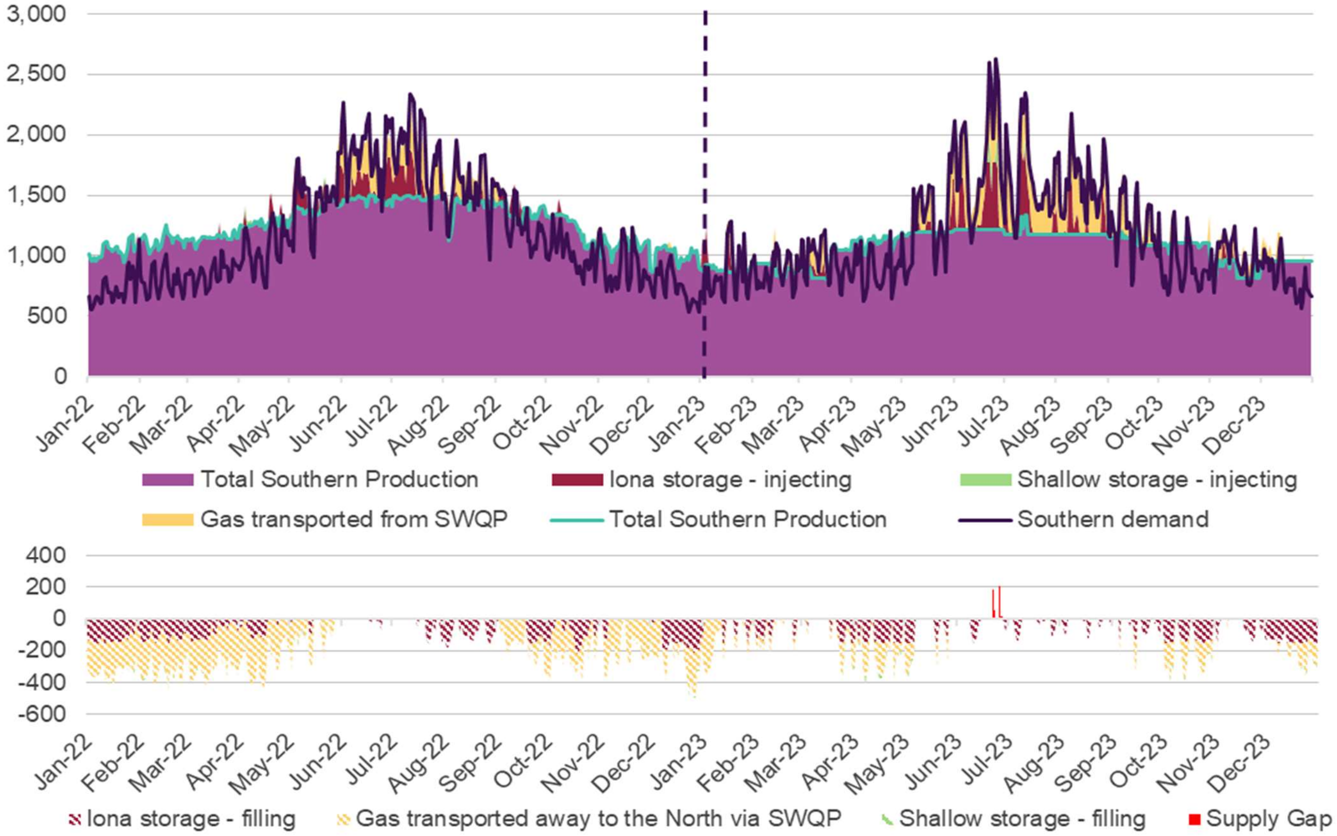
Note: reference year 2019 (top chart) reflects adverse weather conditions leading to extremely high coincident peak demand, and reference year 2017 (bottom chart) reflects more favourable weather across southern regions with less coincident peak demand.

Figure 37 demonstrates the production, flow and storage dynamics that are required in 2023 under the most extreme weather combination (2019 reference year) to meet southern demand, compared with historical data. It highlights that there is a significant reduction in production capacity (during both summer and winter) in 2023 in comparison to 2022, and shows that, should demand conditions coincide to extreme levels in winter, then:

- Both deep and shallow storage is required at a higher capacity than was seen in 2022 to meet large but infrequent peaks in demand. To accommodate this high winter reliance, significant filling of storages is required over the summer period to ensure there is sufficient storage for the following winter.
- Storage and SWQP flows towards the southern states are required for an increased amount of time, and ahead of the winter need, to enable storage management and to support demand during what is typically the maintenance period for key southern production facilities.

Historically, gas along the SWQP has often flowed to northern consumers outside the winter months. From 2023, declining southern production through the entire year leads to significantly less gas being available to be sent north.

Figure 37 Observed gas supply used to meet peak southern demand in 2022, and forecast committed supply to meet forecast demand in 2023, *Orchestrated Step Change (1.8°C)* scenario, reference year 2019 (TJ/d)



Expanding on this, **Figure 38** shows actual (in 2022) and forecast storage levels for 2023 in the southern regions in these extreme, high-coincident weather conditions (2019 reference year), and highlights:

- Utilisation of Iona storage in 2023 is forecast to be similar to the storage utilisation actually observed in 2022. To manage this demand, refilling of Iona storage in summer will continue to be critical to mitigate the risk of winter shortfalls.
- Forecast utilisation of shallow storages (Dandenong and Newcastle LNG facilities) in 2023 is forecast to be higher than was needed in 2022. These shallow storages provide critical peak capacity, and with reduced winter production capacity from southern producers, they will be increasingly important to mitigate peak day shortfall risks. In the extreme conditions forecast, they will be required on many days during winter (evidenced by a sharp decline in storage levels over winter).

- Note that filling the shallow storages to the maximum level would not remove the peak day shortfall risk described in this section, because shallow storages are injecting at maximum capacity on peak demand days, including on days when shortfalls are forecast.
- Shallow storages are important risk mitigation assets if effectively managed and filled ahead of winter. These assets provide greater operational flexibility to mitigate events such as unplanned facility outages, or greater gas generation, particularly if needed at short notice. While the figure below shows, with perfect foresight, that these storages may provide the necessary support when less than full, greater insurance coverage will exist if these were filled above this level, or near full, ahead of each winter period to mitigate the underlying risk potential.

Figure 38 Actual and forecast storage levels, 2022-24, reference year 2019, *Orchestrated Step Change (1.8°C)* scenario (PJ)

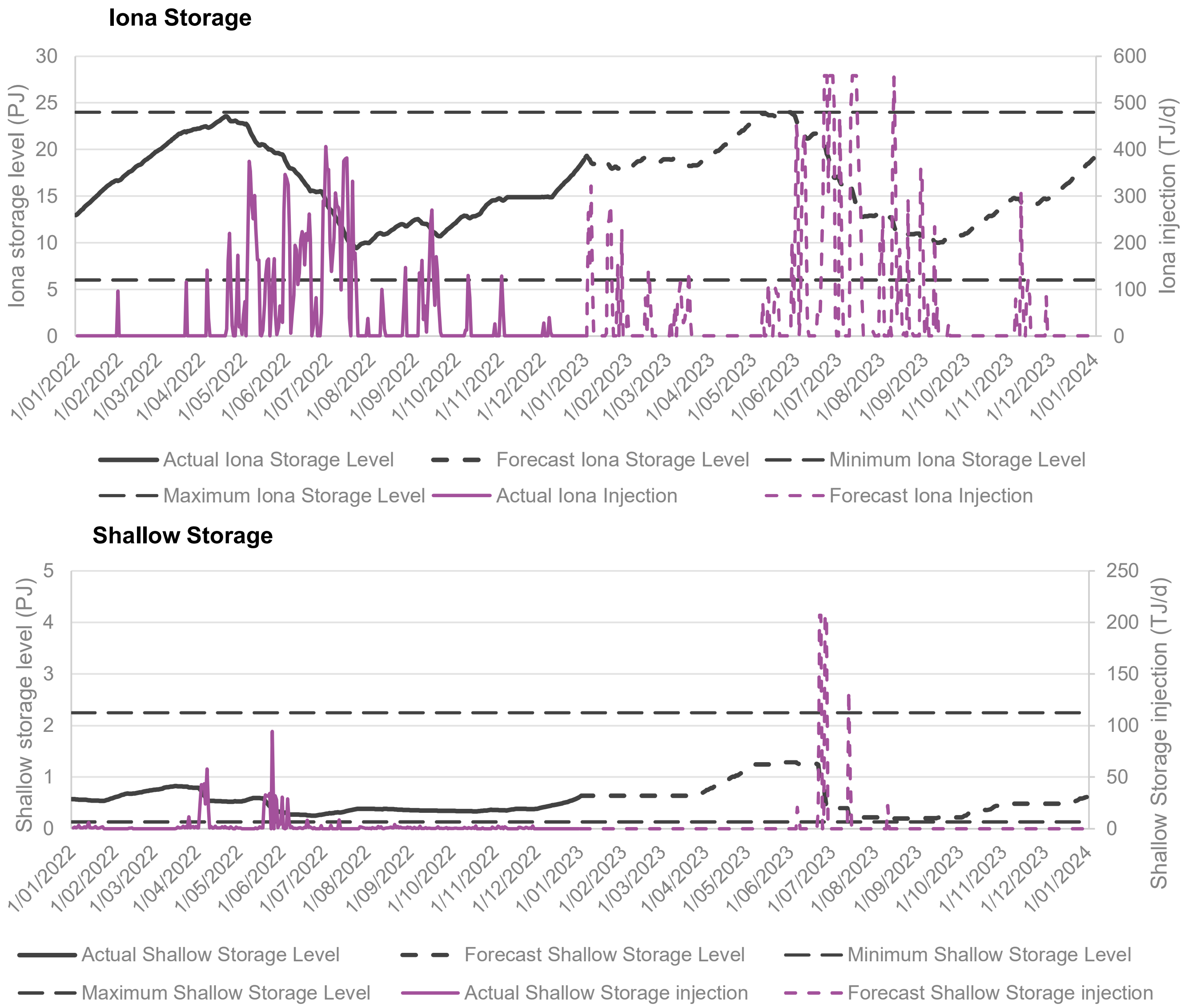


Table 9 presents key seasonal supply data from **Figure 37** and **Figure 38** on a quarterly basis for the next two years.

Table 9 Quarterly supply and demand data for the southern region for 2023 and 2024, reference year 2019, *Orchestrated Step Change (1.8°C)* scenario (PJ)

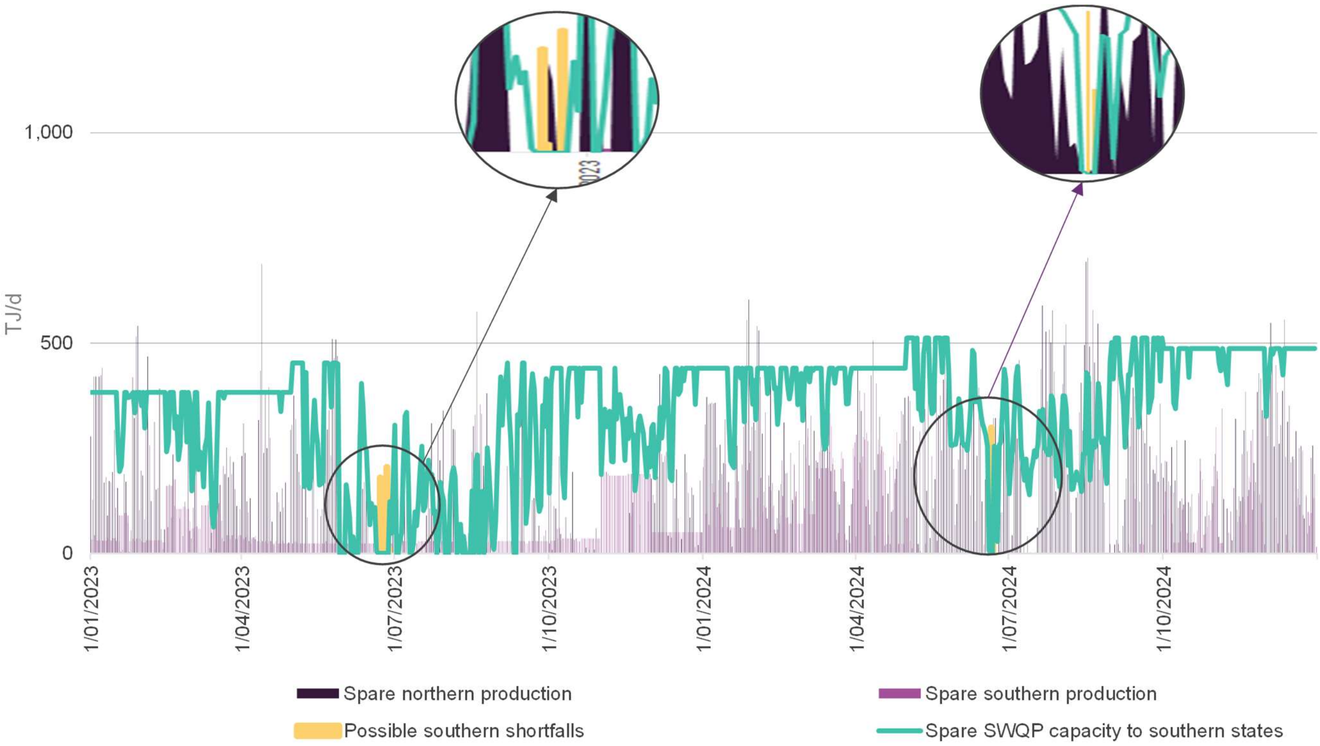
		Southern committed production (PJ)	Net storage withdrawal[A] (PJ)	SWQP flow[B] (PJ)	Demand (PJ)	Shortage (PJ)
2023	Q1	81.3	-0.3	-0.8	80.2	0.0
	Q2	107.0	2.6	10.1	120.2	0.5
	Q3	107.2	6.2	24.7	138.1	0.0
	Q4	89.8	-8.5	1.7	83.0	0.0
2024	Q1	77.6	1.1	-1.6	77.1	0.0
	Q2	100.9	5.4	6.8	113.6	0.5
	Q3	111.0	5.9	14.7	131.6	0.0
	Q4	94.2	-12.4	-5.1	76.6	0.0

A. Net storage withdrawal is calculated as all withdrawals from southern storages minus all injections into southern storage.
B. SWQP flow relies on physical gas being available in northern regions, from LNG exporters or other northern producers, including consideration of supply from the Northern Territory via NGP.

A summary of monthly demand by state and sector can be seen in **Appendix A2**.

Figure 39 demonstrates that on many days there is surplus production from both southern and northern fields, as well as spare capacity on the SWQP. But as the magnified areas in the figure show, during times of shortfall there is no spare southern production capacity, and SWQP is providing maximum southbound flow, so any spare production capacity from northern fields is unable to be utilised on those potential shortfall days in the south.

Figure 39 Daily spare production capacity in 2023 and 2024 with zoom-in to possible supply gap days, reference year 2019, *Orchestrated Step Change (1.8°C)* scenario (TJ/d)



Note: this examines the 2019 reference year for the *Orchestrated Step Change (1.8°C)* scenario and demonstrates the constrained SWQP pipeline capacity only, relying on physical gas being available in northern regions to flow along SWQP, from LNG exporters or other northern producers.

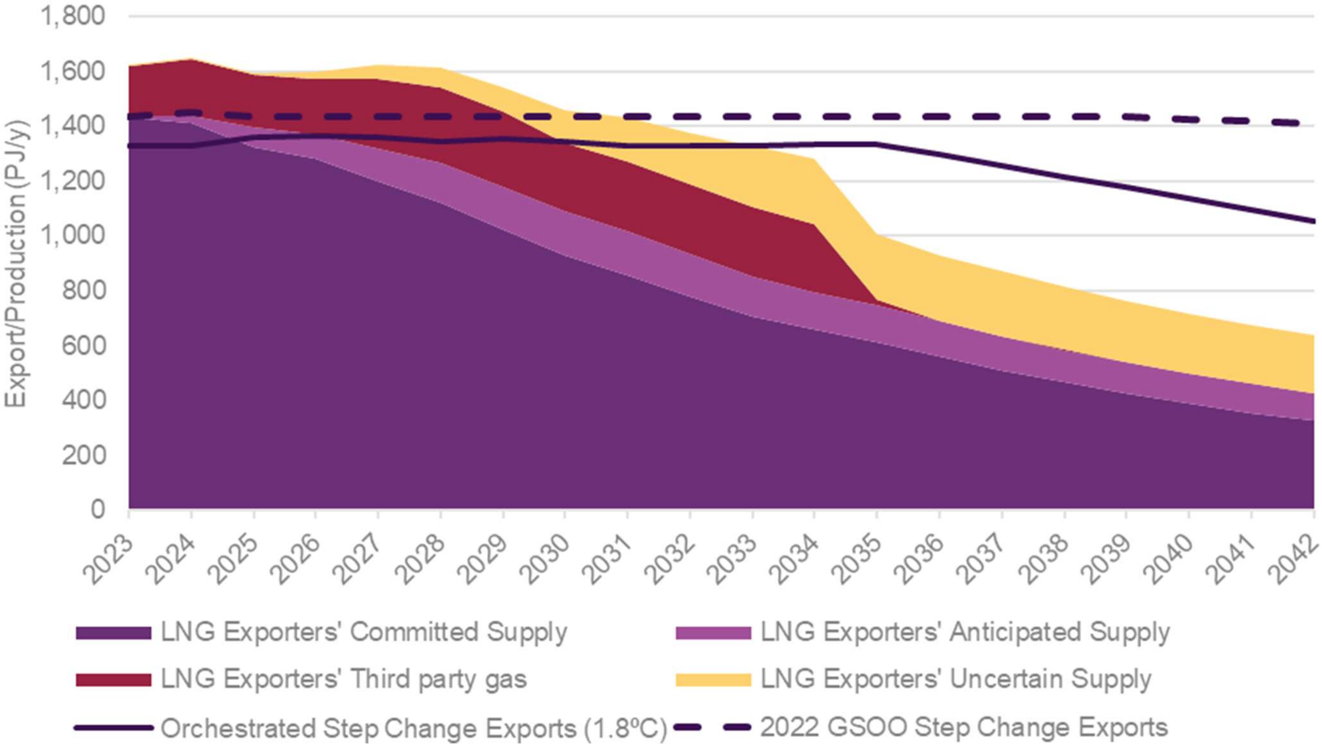
LNG volumes contracted for export may need to be supplied to domestic customers from 2026 to maintain domestic supply adequacy without expanded domestic supply

The volumes of gas exported internationally via Curtis Island in Queensland represent most of the gas demand on the east coast. Similarly, production from CSG fields by LNG exporters represent a significant proportion of gas production in eastern Australia. As such, operation of these facilities can have significant impact on domestic supply adequacy.

Forecast LNG exports from 2023 to 2035 are 80-90 petajoules a year (PJ/y) lower than forecast in the 2022 GSOO and represent expected LNG export contracts as advised to AEMO by the LNG exporters. **Figure 40** presents a supply and demand balance of the LNG exporters considering supply and expected export contracts. It shows that the LNG exporters have:

- In 2023, an excess supply[80] relative to advised contracted exports of 291 PJ, which includes a production excess[81] of 105 PJ from proprietary CSG production facilities (that is, excluding third party gas arrangements with other domestic producers).
- Sufficient production from existing and committed facilities to meet forecast exports until 2025.
- Sufficient production, if anticipated investments proceed, to meet forecast exports until 2027.

Figure 40 LNG exporter committed, anticipated and uncertain production, and supply from third-party gas contracts in comparison to forecast exports, *Orchestrated Step Change (1.8°C)* scenario, 2023-42 (PJ/y)



The above chart considers supply available to the LNG exporters and expected export volumes, and does not consider any supply contracts the LNG exporters may hold with domestic customers.

[80] Excess supply is calculated as the difference between committed and third-party gas supply and expected exports.

[81] Production excess is calculated as the difference between committed supply, and expected exports.

In the context of the east coast interconnected gas network, and assuming that LNG exporters' excess production is sold domestically, AEMO forecasts that to support domestic supply adequacy:

- It is possible for expected LNG exports to be met in 2023 to 2025, while preventing domestic annual supply gaps.
- In the absence of development of anticipated or uncertain supply (from all producers, not just LNG exporters), up to 107 PJ of LNG supply shortages may emerge in 2026, increasing to 342 PJ in 2028. This indicates that the domestic market is forecast to require more gas from the LNG exporters than their production excess. Development of anticipated supply sources is projected to provide sufficient production in 2026, and reduce supply gaps to 53 PJ in 2027 and 72 PJ in 2028. Development of uncertain supply sources is projected to delay domestic supply gaps, enabling contracted LNG exports to be filled to beyond 2028.

Table 10 summarises quartlerly committed production from LNG exporters, expected export, and production excess for 2023 and 2024. It shows that there is significant production excess from LNG exporters in these years, particularly during Q2 and Q3, which can be used to support domestic winter demand.

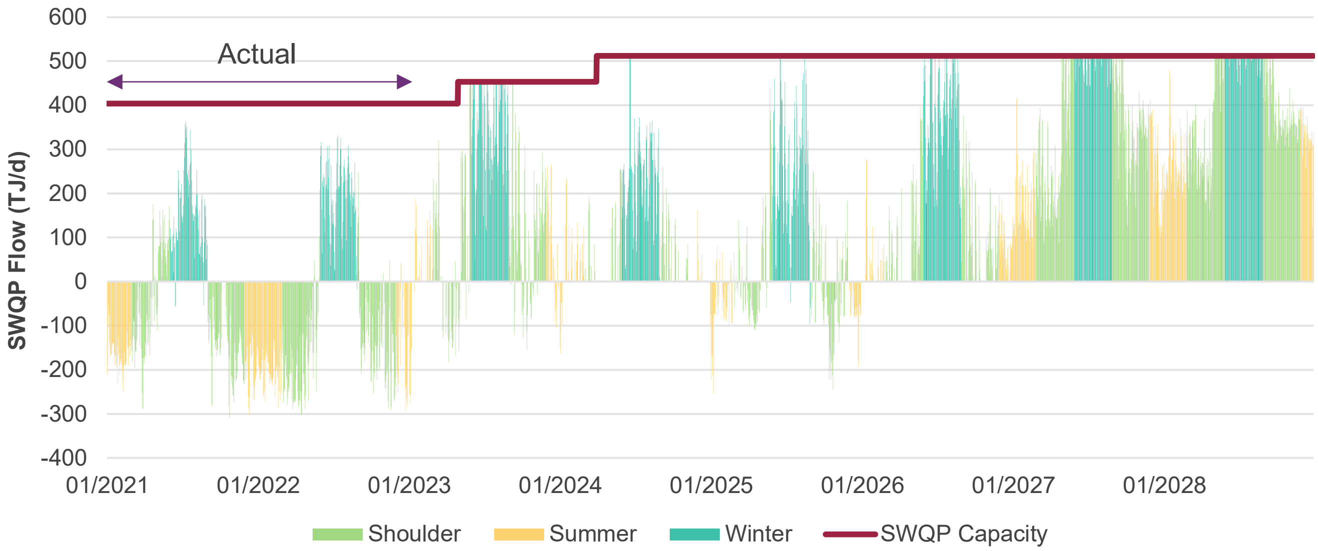
Table 10 Quarterly committed production from LNG exporters, expected LNG export demand, and LNG exporter committed production excess, *Orchestrated Step Change (1.8°C)* scenario, reference year 2019, 2023 and 2024 (PJ)

		Committed production from LNG exporters (PJ)	Expected LNG export demand (PJ)	LNG exporter committed production excess (PJ)
2023	**Q1**	350.0	329.4	20.6
	Q2	357.5	324.4	33.1
	Q3	243.9	213.3	30.6
	Q4	480.1	459.0	21.0
2024	**Q1**	348.8	332.4	16.4
	Q2	350.0	322.5	27.5
	Q3	238.3	213.3	25.1
	Q4	472.0	457.9	14.1

It remains critical that LNG exporters make supply available during winter to support flows along the SWQP and MSP to southern regions, to maintain domestic supply adequacy – to reduce supply shortfall risks, and to mitigate risks of seasonal supply gaps.

As shown in **Figure 41**, forecast daily southern flows in winter 2023 are higher than historical levels and are routinely constrained at pipeline capacity. Winter 2024 flows are forecast to be similar to historical levels, but flows up to pipeline capacity are forecast to be required on peak demand days. The forecast northerly flow along the SWQP in summer is also reduced relative to historical levels, as production from southern fields decreases; the consequences of this is northern domestic consumers have increased reliance on excess production from the LNG exporters.

Figure 41 Actual and forecast daily SWQP flows in the *Orchestrated Step Change (1.8°C)* scenario, reference year 2019, and SWQP capacity (TJ/d)



Note: positive SWQP flow indicates a southerly flow direction, from Queensland to the southern states.

What if surplus production from LNG exporters is exported as spot cargoes?

The LNG exporters have the ability to provide significant volumes of currently uncontracted gas to the domestic market, however there may be economic incentive to instead export this gas if international markets prove more profitable than domestic sales.

The ACCC's January 2023 *Gas Inquiry 2017-2030 Interim Report* indicates that LNG exporters anticipate 88 PJ of additional LNG spot cargoes to be sold in 2023[82]. This would increase total LNG exports to 1,384 PJ[83], above the advice provided to AEMO for this 2023 GSOO of the expected export contracts.

AEMO forecasts that if this quantity was exported, rather than supplied to domestic consumers, there would be a domestic supply gap in 2023 of up to 33 PJ[84] . Should this occur, mechanisms such as the Heads of Agreement[85], the ADGSM [86] and AEMO's powers of direction will be important to ensure sufficient gas is available to the domestic market for 2023 and beyond. Under the newly drafted version of the ADGSM guidelines[87], the minister may determine whether there are shortfalls and limit LNG exports on a quarterly basis.

[82] See page 30, at https://www.accc.gov.au/system/files/Gas%20Inquiry%20-%20January%202023%20interim%20report_1.pdf.

[83] The ACCC report presents LNG SPAs at 1296 PJ and 88 PJ of additional spot cargoes.

[84] The size of a supply gap will depend on many volatile factors (for example, weather); this 33 PJ estimate applies an upper range of forecast gas generation while considering existing and committed supply only. This differs from the ACCC's *Gas Inquiry 2017-2030 Interim Report*, which allows for supplies beyond what AEMO classifies as existing and committed, and average demand conditions.

[85] Agreement between the Federal Government and east coast LNG exporters for The Australian East Coast Domestic Gas Supply Commitment, 29 September 2022, at https://www.industry.gov.au/sites/default/files/2022-09/heads_of_agreement_the_australian_east_coast_domestic_gas_supply_commitment.pdf.

[86] Australian Government – Department of Industry, Science and Resources, "Securing Australian domestic gas supply", at https://www.industry.gov.au/mining-oil-and-gas/oil-and-gas/securing-australian-domestic-gas-supply for more information.

[87] Draft guidelines available at https://storage.googleapis.com/converlens-au-industry/industry/p/prj24970e8f4bf9962622726/public_assets/draft-adgsm-guidelines.pdf.

Northern Territory supply eases gas adequacy risks in Eastern Australia

During 2022, supply issues at the Yelcherr gas plant in the Northern Territory reduced NGP flow to 0 TJ/d from October[88]. If there is reduced supply from the Northern Territory to the east coast via the NGP, as observed in 2022, extra supply from the LNG exporters to the domestic market will be required, and this may impact their ability to meet contracted export quantites. This is because the NGP can supply a significant proportion of demand in Mount Isa, and without Northern Territory supply flowing towards Queensland along the NGP, Mount Isa demand must instead come from Queensland via the SWQP and CGP.

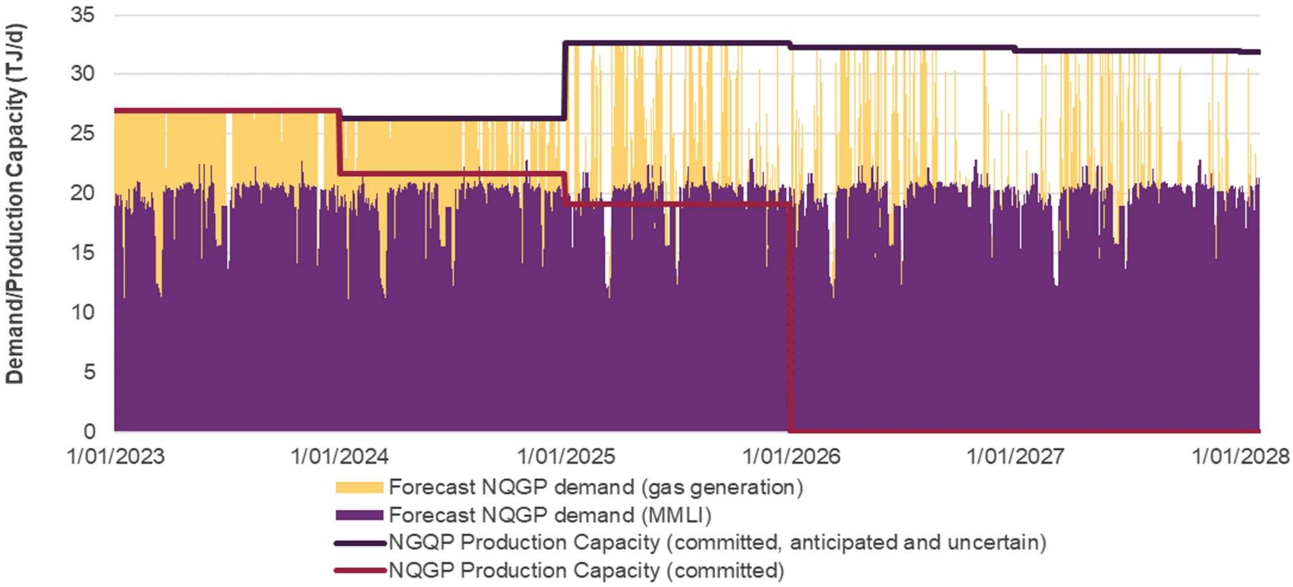
AEMO estimates that if NGP did not flow towards Queensland, LNG exporters would have to increase supply to the domestic market by up to 6 PJ in 2025, and up to 5 PJ in 2026.

North Queensland supply adequacy is at risk

The North Queensland Gas Pipeline (NQGP) runs from Moranbah to Townsville (see **Figure 32** in **Section 3.3**) and is disconnected from the rest of the east coast grid. As **Figure 42** shows, AEMO forecasts that:

- There is limited gas supply to meet forecast consumption from gas generation across the entire horizon. Alternative North Queensland generation sources exist, and the *Queensland Energy and Jobs Plan*[89] identifies further regional development opportunities.
- Committed supply only will be insufficient to meet demand from residential, industrial, and commercial customers on some days in 2024, and more frequently from 2025.
- Anticipated and uncertain supply must be developed prior to late 2024 to maintain supply to residential, industrial, and commercial customers on the NQGP.

Figure 42 Forecast supply and demand on the NQGP for the *Orchestrated Step Change (1.8°C)* scenario (TJ/d)



Shortfalls on the NQGP are not included in the reporting of shortfalls and supply gaps in southern regions that are mentioned elsewhere in this section.

[88] See https://aemo.com.au/en/energy-systems/gas/gas-bulletin-board-gbb.

[89] See https://www.epw.qld.gov.au/energyandjobsplan.

Various circumstances would exacerbate risks to supply adequacy

There are several additional risks to supply adequacy in the southern region that AEMO has explored through sensitivities. These include:

- **Infrastructure delay** – delays to the WORM or the installation of the second Winchelsea compressor are forecast to increase shortfalls in 2023, and a delay to the East Coast Grid (ECG) Stage 2 project is forecast to increase shortfalls in 2024. The second Winchelsea compressor also increases redundancy and system resilience against unplanned outages of the existing Winchelsea compressor. AEMO explored the impact of a one-year delay to each of these projects. The most impactful delay, ECG Stage 2, is shown in **Table 11**.
- **Unavailability of the Newcastle Gas Storage Facility (NGSF)** – the availability outlook for NGSF is uncertain (as described in **Section 3.1**), and unavailability of this facility is forecast to result in increased shortage risks, as well as reduced system and operational resilience.
- **Increased gas generation consumption** – gas generation is a key contributor to near-term shortfall risks, as discussed in **Section 4.1**. This GSOO explored two sensitivities that result in increased gas generation, as described in **Section 2.2.4** – delayed commissioning of new renewable generation (*VRE Delay*) and extended drought conditions akin to the water inflows from the 2006-07 millennial drought (*Dry Year*). Results from the most impactful sensitivity, VRE delay, are shown in **Table 11**. AEMO has also explored a gas generation sensitivity with higher assumed coal availability (*Improved Coal Availability)*, which is forecast to result in less gas generation consumption.
- **No electrification** – this GSOO forecasts significant fuel-switching from gas to electricity, however the rate of electrification is uncertain, and may be slower than forecast to meet net zero objectives across the economy. If the rate of electrification is slower than forecast, the risk of shortfalls will increase, as more gas consuming devices will remain operating for longer periods. Further detail on this sensitivity can be found in **Section 2.1**.

Table 11 lists the southern shortfall risks the for the *Orchestrated Step Change (1.8°C)* scenario, with committed, and committed and anticipated production, as well as the sensitivities listed above with committed production only. As outlined in **Section 3.2.3**, very little anticipated production capacity has been advised to AEMO before 2026. The table shows the lowest and highest outcomes in peak day shortfalls forecast across varying one-in-20 weather conditions, and the forecast frequency (number of days) of forecast shortfalls. The table shows that:

- Across all sensitivities, shortfall risks are infrequent from 2023 to 2026.
- The minimum shortfall forecast in most sensitivities is 0 TJ. Peak day shortfalls may be avoided under conditions where peak demand for gas generation does not align with peak demand from residential, commercial, and industrial customers. This demonstrates that the shortfall risks are primarily due to the risk of large, coincident peaks in demand. The secondary risks explored in these sensitivities are not typically enough without this extreme demand to trigger shortfalls.
  - This is highlighted by the reduction in shortfall risk that is forecast if coal availability was improved, reducing the gas required for gas generation on peak days (see the *Improved coal availability* sensitivity).
- There is little anticipated production forecast to be available from 2023 to 2026 (see **Table 5** in **Section 3.2.2** and **Figure 28** in **Section 3.2.3**). No material impact from the development of anticipated projects to reduce the magnitude or frequency of shortfall risks is forecast until 2026.
- The sensitivities investigated tend not to increase the frequency of shortfall risks, implying that underlying extreme demand conditions will be the most significant driver for shortfall risks to emerge.

Table 11 Magnitude (TJ/d) and frequency (days per year) of southern daily shortfalls across all reference years, 2023-26, one-in-20 weather conditions

	2023		2024		2025		2026	
	Magnitude	Frequency	Magnitude	Frequency	Magnitude	Frequency	Magnitude	Frequency
Orchestrated Step Change (1.8°C) – committed supply only	0-205	0-4	0-299	0-2	0-107	0-2	0-152	0-1
Orchestrated Step Change (1.8°C) – committed and anticipated supply	0-198	0-4	0-293	0-2	0-105	0-2	0-108	0-1
One year delay to ECG Stage 2 – committed supply only	0-205	0-4	0-358	0-2	0-107	0-2	0-152	0-1
Unavailability of NGSF – committed supply only	0-325	0-4	0-419	0-2	0-227	0-2	13-272	1-4
Increased gas generation – VRE delay – committed supply only	0-447	0-3	0-326	0-2	0-131	0-1	31-152	1-1
Improved coal availability – committed supply only	0-63	0-2	0-32	0-1	0-0	0-0	0-152	0-1
Orchestrated Step Change (1.8°C), No Electrification sensitivity – committed supply only	0-205	0-4	0-315	0-2	0-148	0-2	1-244	1-3

All information presented in this table assumes that the uncontracted LNG supply is made available to the domestic market when required.

Factors that may impact the volume of gas supplied

Maintenance of gas facilities

The volume of gas supplied by production facilities and storage is most impacted by planned and unplanned maintenance. Planned maintenance typically occurs in summer when demand is low, and there is sufficient remaining production capacity to satisfy forecast demand (see **Figure 34**). AEMO has modelled maintenance as published on the Gas Bulletin Board as of 1 January 2023 in the GSOO model.

Unplanned maintenance is maintenance that is carried out unexpectedly, most commonly due to equipment failure, and may result in a significant reduction in supply capacity. The reduction in supply must be met from other supply sources. Injections from deep and shallow storage and linepack[90] remain critical to respond to reductions in supply due to unplanned maintenance. Note that there is limited linepack stored in pipelines, and depending on pipeline conditions, linepack may not be able to be used.

If unplanned maintenance occurs on key production or transmission facilities during winter, peak day shortfalls may result.

Unaccounted for gas (UAFG)

UAFG is the difference between the gas entering the system and the amount of gas delivered to customers, and can result from gas leakage, or inaccuracies in gas measurement or heating values. UAFG is typically between 3% and -5%. AEMO's gas forecasts presented in **Section 2** include accommodations for UAFG.

[90] Linepack is gas stored in pipelines under pressure.

Potential actions to ensure the gas system has maximum resilience and production capability

In the short term, there is limited anticipated supply that can be developed to mitigate forecast peak day shortfall risks. Committed infrastructure and supply projects must be completed on time to minimise shortfall risks, and demand side solutions may need to be relied on to avoid shortfall risks in 2023 and 2024. It is important therefore that:

- All committed pipeline infrastructure projects are completed to schedule (including the WORM, Winchelsea compressor upgrade, and Stages 1 and 2 of the SWQP and MSP). By increasing the amount of gas that can flow from Queensland to southern consumers and removing constraints on injecting from or refilling Iona gas storage, these upgrades will increase the operability of the gas network and provide more flexibility to meet a variable and infrequent need under extreme circumstances.
- Undeveloped but committed resources, particularly in the southern regions, are developed on time to minimise shortfall risks. These projects may be subject to timing and regulatory risks, which are described in further detail in **Section 4.2**.
- Southern storages at Iona, Dandenong and Newcastle are available, including ensuring that they are at, or near, full capacity prior to winter. Through winter, operating these appropriately to avoid unnecessary depletion during periods not requiring these reserves is also important.
  - The DWGM interim LNG storage measures rule change[91] requires that AEMO contracts any uncontracted capacity in the Dandenong LNG tank from 2023 to 2025. This will ensure that the Dandenong LNG tank is full prior to winter during this period.
- Flexibility of gas consumption is encouraged, given that the lead time for new infrastructure is longer than is available before supply risks are forecasts. No additional brownfield solutions remain uncommitted. Potential demand-side flexibility includes:
  - Reducing gas generation at times of peak gas demand, with greater potential use of secondary liquid fuels (if available), or the use of alternative electricity generation (such as batteries or pumped hydro).
  - Reducing electricity demand by deploying demand response measures in the electricity market to reduce electricity demand, thereby lowering the need for gas generation.
  - Voluntary reductions in consumption from gas consumers during extreme peak day events may also be available, however incentives and processes to deliver these are less mature than in the NEM.

Beyond 2024, supply shortfall risks can be mitigated by the development of anticipated and uncertain supply, which may include the development and operation of an LNG import terminal(s). Proposed regulatory amendments are currently under consultation to extend AEMO's functions and powers to manage east coast gas supply adequacy in the near term[92]. The new powers include the ability for AEMO to direct gas flows where required to prevent shortfalls. These powers may assist with managing operational issues during times of peak demand, and will assist in ensuring there is maximum supply available for domestic demand. However, these powers will not mitigate shortfall risks where there is insufficient supply or transmission capacity available.

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

[92] Australian Government – Department of Climate Change, Energy, the Environment and Water, "Proposed regulatory amendments to extend AEMO's functions and powers to manage east coast gas supply adequacy", 26 September 2022, at https://www.energy.gov.au/government-priorities/energy-ministers/priorities/gas/proposed-regulatory-amendments-extend-aemos-functions-and-powers-manage-east-coast-gas-supply-adequacy.

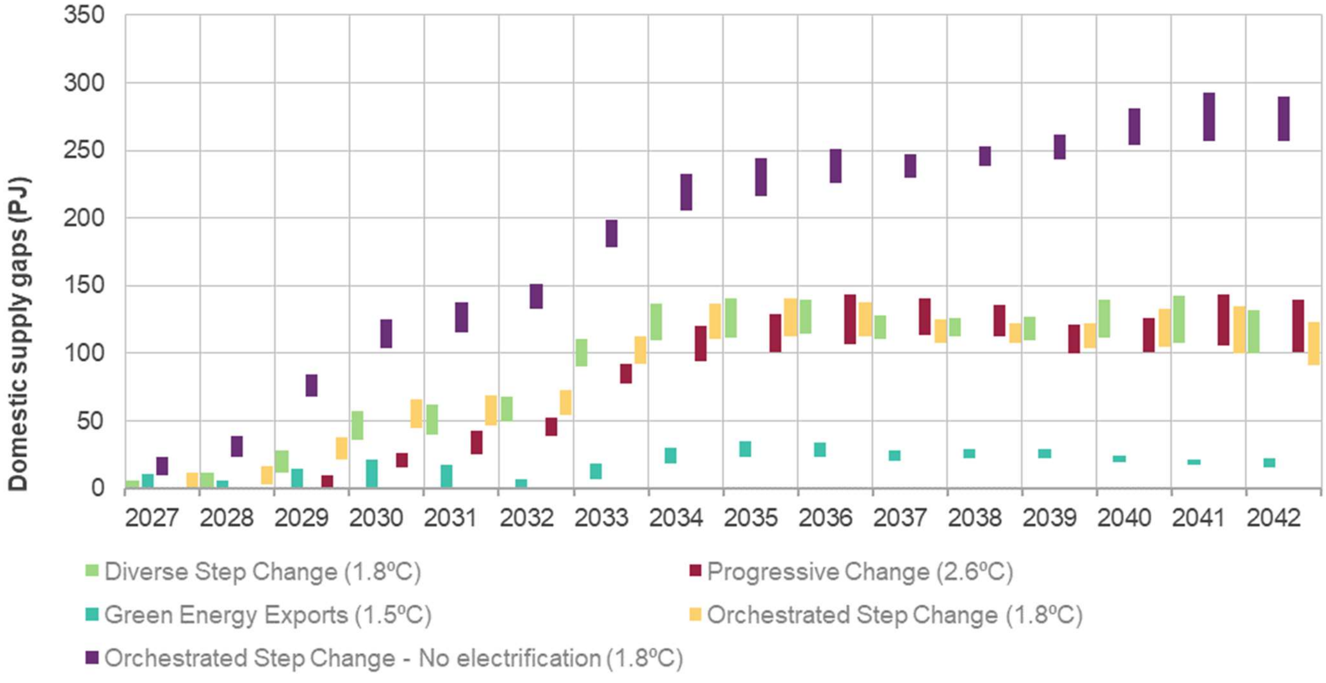
4.2 Longer-term supply adequacy

Although most scenarios forecast declining demand for gas as consumers seek alternative energy supplies to reduce emissions (via electrification, or from alternative gases such as hydrogen or biomethane), supply is projected to decline faster than forecast demand. Pipeline capacity for southern regions to access northern supply is forecast to become constrained (see **Figure 41** above) and annual southern domestic supply gaps are forecast from 2027 (see **Figure 43**).

The 2022 GSOO assumed that the PKET LNG import terminal was an anticipated project. As described in Section 3.3.3, PKET is the most advanced LNG import terminal with onshore infrastructure under development, but it is no longer classified as an anticipated project as there is insufficient contracted capacity to justify location and commencement of the FSRU at Port Kembla. Without the LNG import capacity that PKET provides, supply gaps are forecast six years earlier than identified in the 2022 GSOO *Step Change* scenario. The timing and scale of these supply gaps rely on excess northern production being available to southern consumers (as discussed in **Section 4.1**).

The range of supply gaps across scenarios is narrower than forecast in the 2022 GSOO, as electrification reduces gas demand more consistently in the 2023 GSOO scenarios (see **Figure 8** in **Section 2.1**).

Figure 43 Range of domestic annual supply gaps forecast in southern regions, existing, committed, and anticipated developments, all scenarios, 2027 to 2042 (PJ)



A spread of forecast supply gaps exists across the scenarios, and therefore the preferred timing, type and size of investments in new gas supply and any supporting infrastructure required remain uncertain. If the rate of electrification is slower than forecast, the timing of supply gaps is likely to be earlier, and the magnitude would likely increase, further highlighting the uncertainty in the investment needed in gas supply. The *Orchestrated Step Change (1.8°C)*, *No Electrification* sensitivity provides a conceptual upper bound to the expected demand for natural gas from residential, commercial and industrial customers, however the likelihood that no electrification were to occur is extremely low given the energy transition is already underway.

Examining forecast supply gaps in the Orchestrated Step Change (1.8°C) scenario

Figure 44 and **Figure 45** show how existing, committed, and anticipated supplies are forecast to be used in 2025 and 2030 to minimise supply gaps in the *Orchestrated Step Change (1.8°C)* scenario, as southern production declines:

- In 2025, AEMO forecasts that the amount of gas transported south via the SWQP and utilisation of storages will be sufficient to meet forecast demand on most days. Similar to the risks described in **Section 4.1** with committed only supplies in the short term, risks of peak day shortfalls are forecast under extreme demand conditions in the longer term even with anticipated developments. Outside of winter, excess production supports northerly flow on the SWQP, and refilling of storages.
- In 2030, significant seasonal supply gaps are forecast. Southern production is advised to decline significantly in comparison to 2025, and there is forecast to be insufficient flexible production and pipeline capacity to access northern gas, or to fill storage facilities ahead of winter, to meet all winter peak days.

Figure 44 Forecast gas supply options to meet southern daily demand, *Orchestrated Step Change (1.8°C)* scenario, 2025 (TJ/d)

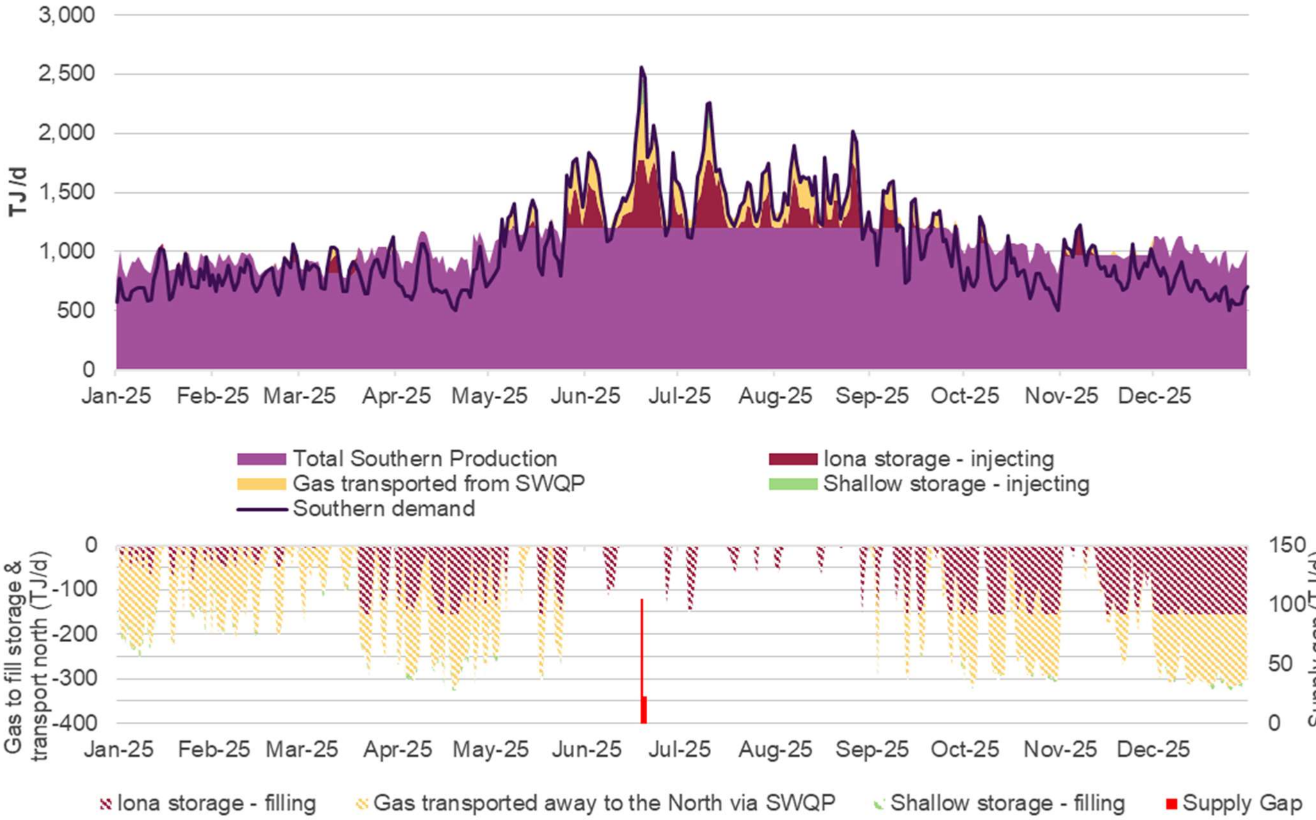


Figure 45 Forecast gas supply options to meet southern daily demand, *Orchestrated Step Change (1.8°C)* scenario 2030 (TJ/d)

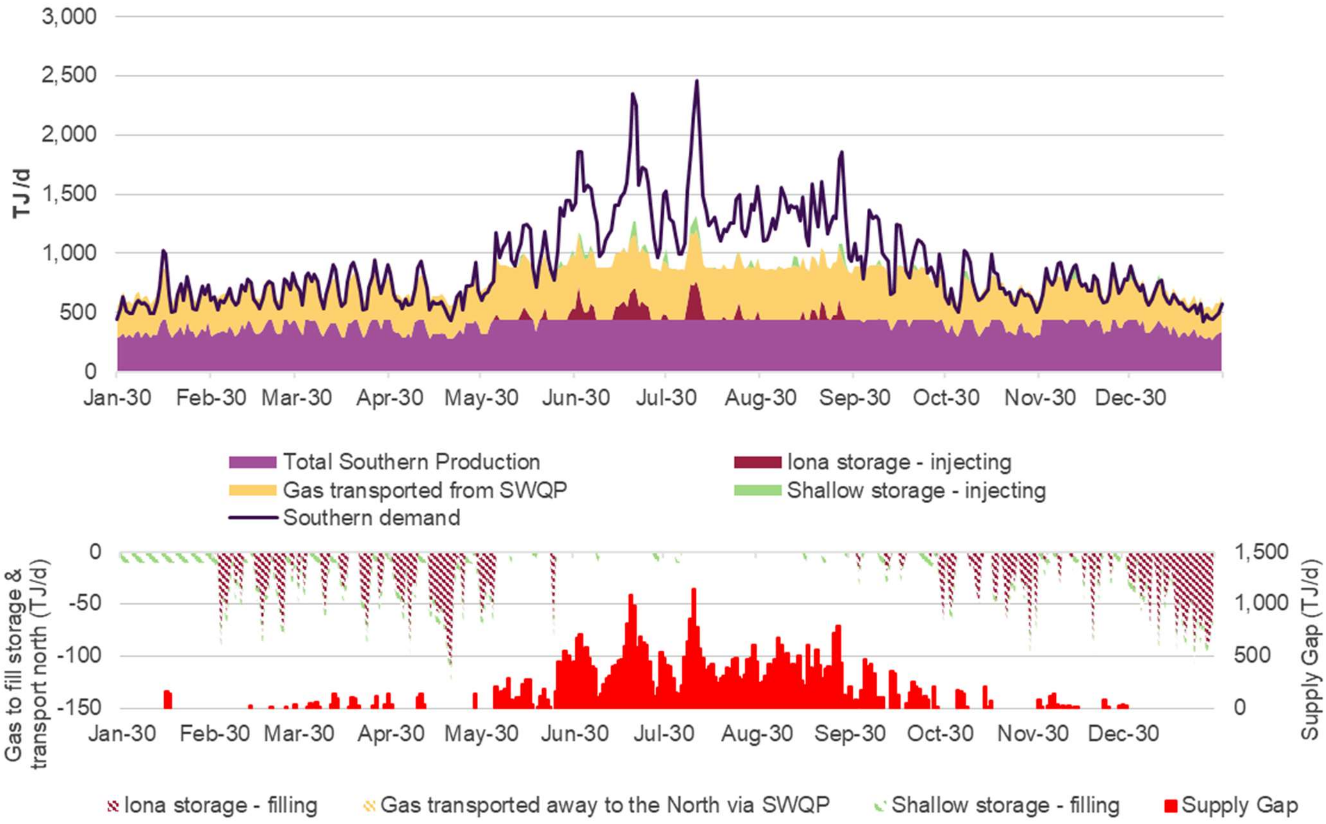


Figure 46 shows forecast annual gas supply adequacy with existing, committed, and anticipated supplies, and assuming all reserves and resources associated with these supplies are commercially recoverable to meet demand in the long term in *Orchestrated Step Change (1.8°C)*.

Figure 46 Projected annual adequacy in southern regions *Orchestrated Step Change (1.8°C)* scenario, with existing, committed and anticipated developments, 2023-42 (PJ)

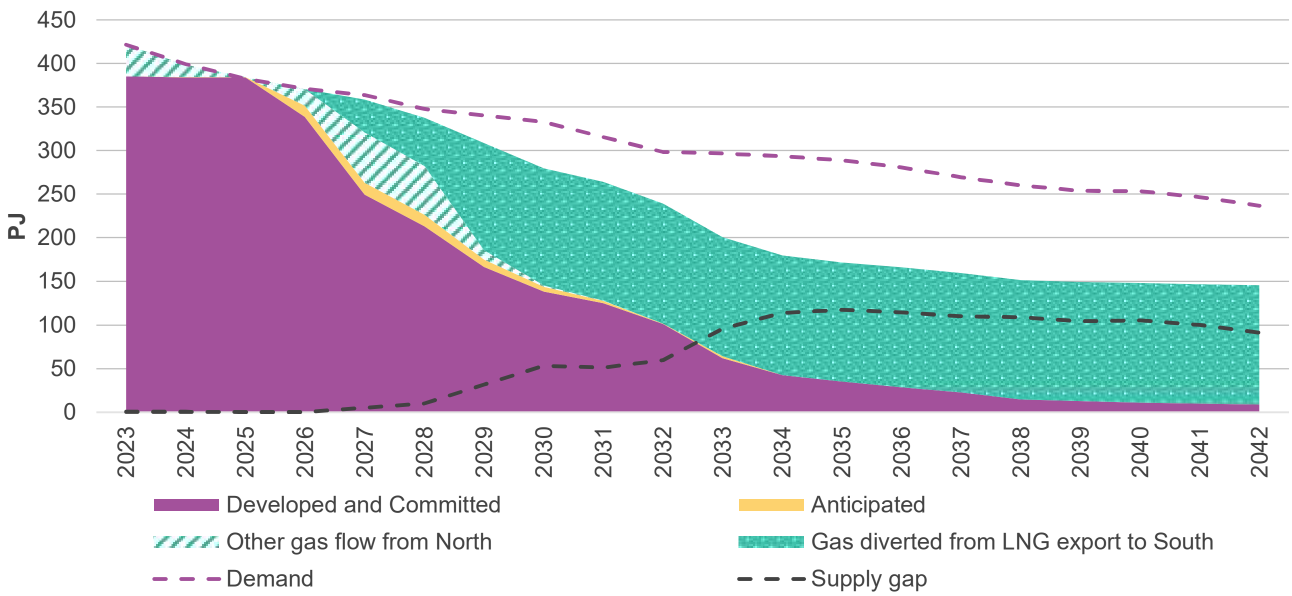


Figure 46 shows that:

- New supply options are forecast to be required to meet southern demand from 2027 to the end of the horizon. The forecast supply gap in 2027 is forecast to be between 0 PJ and 12 PJ, depending on weather conditions.
- Increasing gas otherwise contracted for LNG export is required to be diverted to domestic consumers from 2027 to maintain domestic supply adequacy (causing LNG supply shortages). From 2030, all supply from the north to the south is from the LNG exporters. Development of new supply options would reduce the level of LNG supply shortage.

Opportunities exist for large volumes of LNG imports in the long term

There are many options to address the annual supply gaps, including increased southern production, increased pipeline capacity to access increased northern supply and the development of LNG import terminals.

While no east coast import terminal now meets 'committed' or 'anticipated' commitment status in this 2023 GSOO, the potential impact of LNG import terminals on annual supply gaps is explored in this section, using PKET as an example. Complementing **Figure 44** and **Figure 45**, **Figure 47** and **Figure 48** show how existing, committed and anticipated supplies, and PKET, are forecast to be utilised in 2026 (when PKET is assumed to be operational in this sensitivity analysis) and 2030 to minimise supply gaps in the *Orchestrated Step Change (1.8°C)* scenario.

Figure 47 Forecast gas supply options to meet southern daily demand, with committed and anticipated supplies, and PKET, *Orchestrated Step Change (1.8°C)* scenario 2026 (TJ/d)

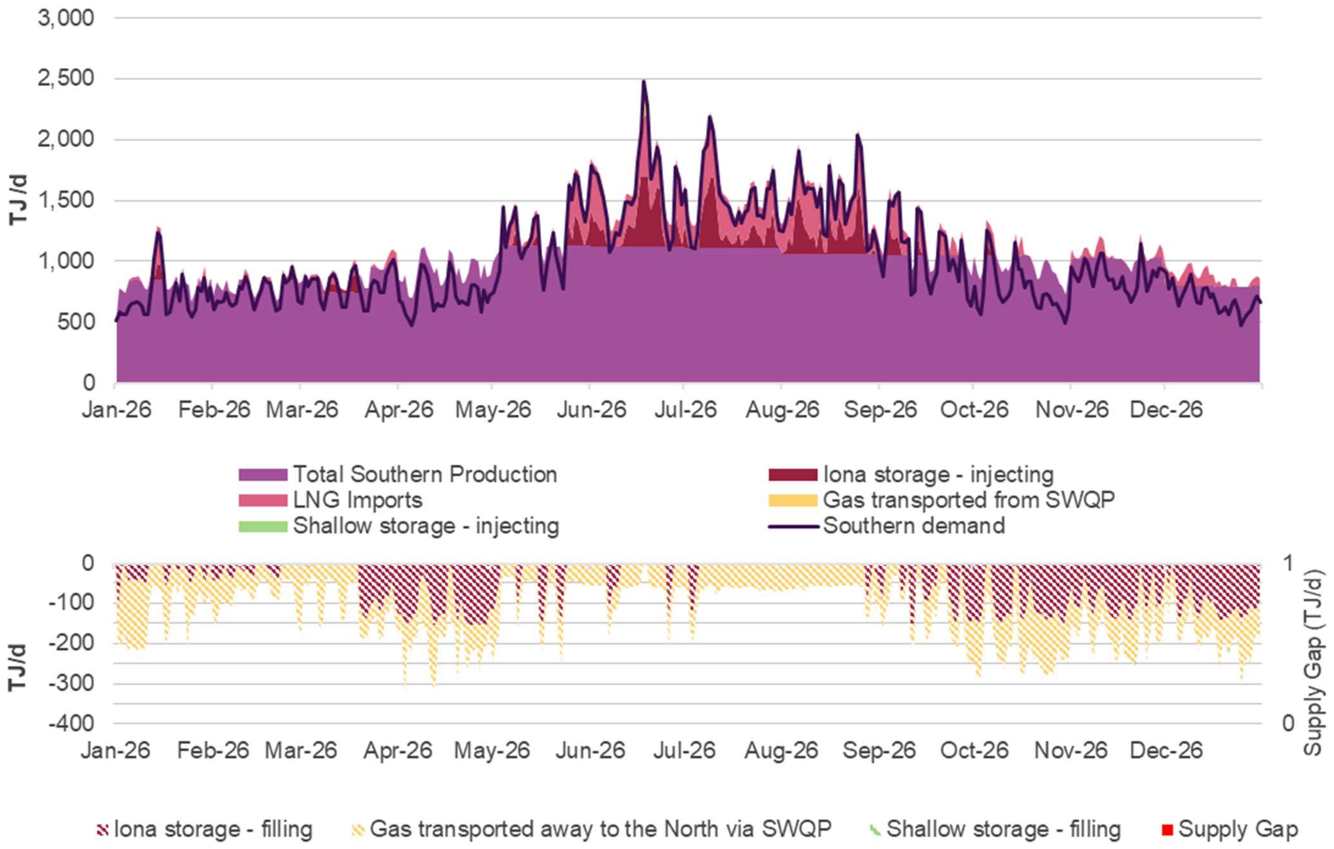


Figure 48 Forecast gas supply options to meet southern daily demand, with committed and anticipated supplies, and PKET, *Orchestrated Step Change (1.8°C)* scenario 2030 (TJ/d)

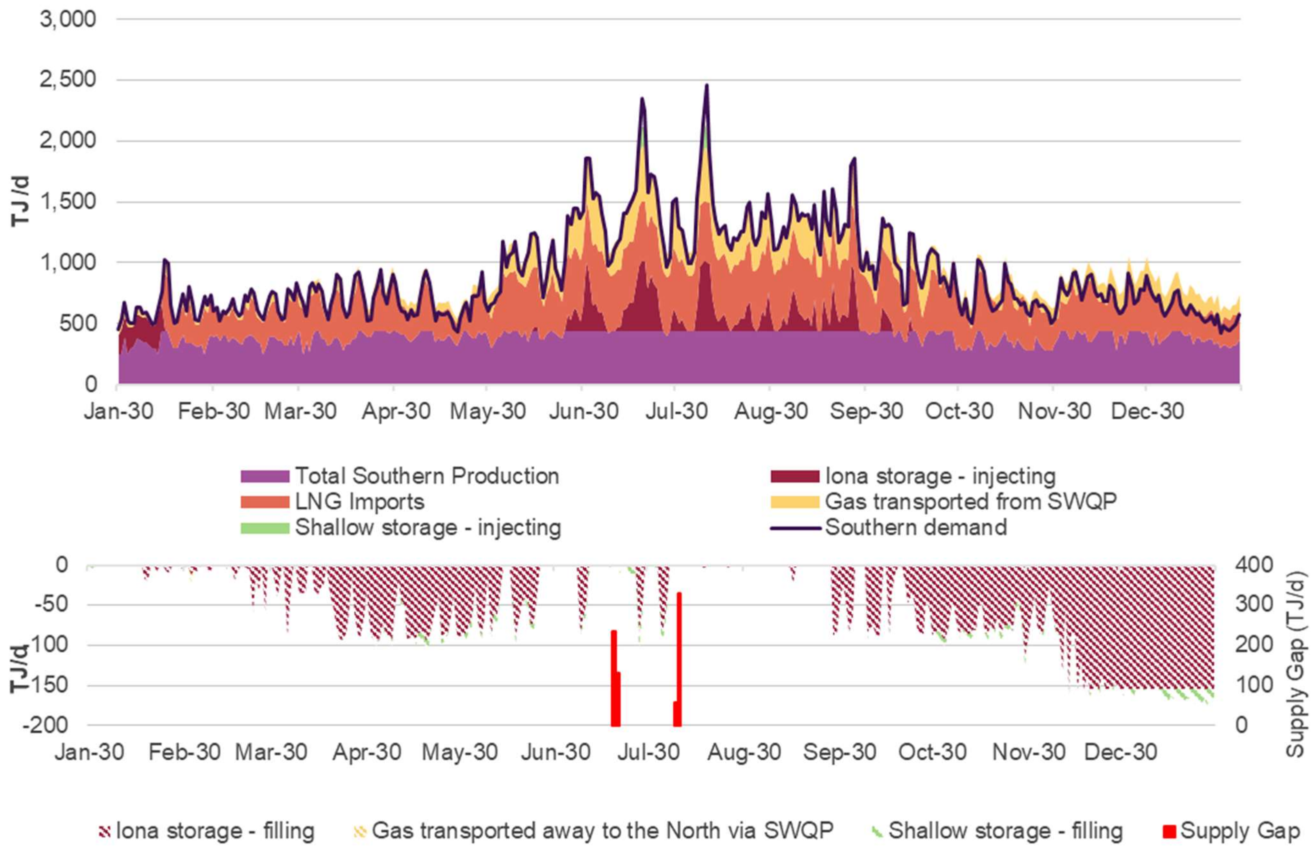


Figure 47 and **Figure 48** highlight that:

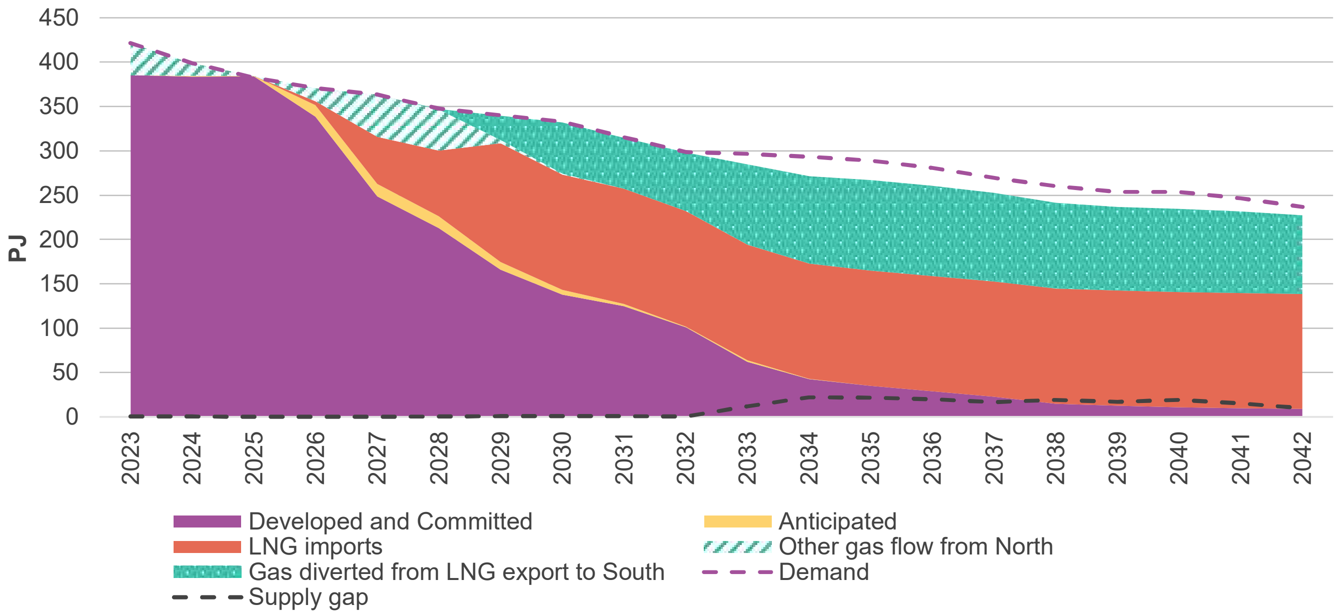
- In 2026, LNG imports will be needed with committed and anticipated supplies to provide limited supply in winter to maintain peak day supply adequacy[93]. With PKET operating, no peak day shortfalls are forecast in 2026.
- In 2030, LNG imports are relied on during the winter months to meet peak seasonal demand. Even with full availability of the PKET facility, peak day shortfalls are forecast on a few extreme days without additional uncertain developments. PKET is utilised outside of winter to support domestic demand, and filling storages.

Figure 49 shows forecast annual gas supply adequacy with existing, committed, and anticipated supplies, including PKET, in the long term in *Orchestrated Step Change (1.8°C)*. It highlights that, in comparison to **Figure 46**:

- Reliance on northern supply to meet annual domestic consumption is forecast to be reduced. Although all gas from the north is diverted from LNG export from 2029 (resulting in LNG supply shortages), the volumes are reduced meaning that more is available for export.
- Annual supply gaps are projected to be delayed until 2033, and their magnitude reduced significantly. Annual supply gaps are approximately 20 PJ/y from 2034 and remain flat across the remainder of the horizon.

[93] This analysis does not consider the potential high cost of operating an FSRU to provide only peak day supply support.

Figure 49 Projected annual adequacy in southern regions *Orchestrated Step Change (1.8°C)* scenario, with existing, committed and anticipated developments, and PKET, 2023-42 (PJ)



Investments in additional gas supply are needed but must consider uncertainty and peakiness

While consumption uncertainty is highlighted by differences across scenarios, increasing "peakiness" of gas demand is a common trend, and new supply developments will therefore need increasing operational flexibility. Conversely, demand response from gas consumers could potentially play a growing role in managing peak gas demand, as it does in the NEM. Greater use of the contingency gas mechanism in the Short Term Trading Markets (STTMs) or new tools to manage gas reliability (equivalent to the NEM's RERT), may need to be developed over time to help enable greater operational control of loads to reduce gas demand during extreme demand events. In addition, some large gas users may choose to enter into interruptible gas supply contracts in exchange for lower supply costs.

AEMO recognises that the current investment environment for projects is challenging and highly uncertain. Key uncertainties impacting project timelines and likelihood of completion include:

- **Russia-Ukraine conflict** – the Russian invasion of Ukraine in February 2022 has caused shocks in the global energy markets causing high international energy prices. The conflict is also driving up demand for electrolysers and FSRUs as Europe is driven to seek gas from sources other than Russia.
- **Inflation** – higher inflation in Australia and overseas, combined with rising rates to combat inflation, has increased high borrowing costs. Some project costs are not keeping pace with long-term gas price projections.
- **Financing** – natural gas is becoming unpalatable for some investors who are screening investments on the basis of environment, social and governance (ESG) issues and want to limit exposure to fossil fuels.
- **COVID-19** – ongoing impacts of the COVID-19 pandemic have caused prolonged project timelines and delays procuring or the complete unavailability of specialist equipment and skilled resources.

- **Regulatory approvals –** environmental approvals for gas projects are becoming increasingly stringent. Industry has advised that the December 2022 Federal Court decision to set aside NOPSEMA's approval of Santos's Barossa Gas Project Environmental Plan[94] has increased industry uncertainty.
- **Market uncertainty** – from 23 December 2022, the Federal Government imposed a $12/GJ price cap to new domestic wholesale gas contracts for 12 months[95]. The Federal Government is also implementing a mandatory code of conduct that will apply to contracts between gas producers and their consumers on the east coast[96].
- **Competing investment interests for renewable gases** – policy and investment into renewable gases in other jurisdictions has been significant. Examples include the US Department of Energy's US$7 billion hydrogen hubs program[97], US$750 million clean hydrogen technology package[98] and clean hydrogen production tax credits[99] and the European Union's REPowerEU Plan[100]. This may lead to Australia being a less appealing investment option for renewable gas projects.

4.2.1 Northern Territory gas adequacy

AEMO has collected production data for the Northern Territory voluntarily for the 2023 GSOO and produced approximate demand forecasts[101]. The Northern Territory is connected to the east coast network via the NGP (see **Figure 32** in **Section 3.3**). The NGP is unidirectional and supports flow from the Northern Territory to Queensland when there is a production excess, but does not support flow from Queensland to the Northern Territory.

As flow from Queensland is unable to support Darwin demand in the event of unplanned outages, Power and Water Corporation (PWC, which manages large wholesale gas supply and transportation) may purchase gas from the LNG export facilities in Darwin under emergency circumstances[102]. This arrangement is useful to mitigate shortfall risks, but is not viable to respond to annual supply gaps. PWC is reported to have used this mechanism in 2022 to respond to supply issues from the Yelcherr gas plant[103].

ENI, operator of the Blacktip field which supplies the Yelcherr gas plant, plans to drill development wells in the Blacktip field to return production capacity to normal rates in early 2023. If this is unsuccessful, less supply than forecast will be available to flow along the NGP to the east coast, and emergency supply from the LNG export facilities may be required to meet Northern Territory demand at peak times. **Section 4.1** describes the impact of lower NGP flow on the east coast network.

[94] Santos, "Full federal court decision for the Barossa Gas Project", 2 December 2022, at https://www.santos.com/news/full-federal-court-decision-for-the-barossa-gas-project/.

[95] Hon Katy Gallagher (Acting Treasurer), Treasury Portfolio, "Gas price cap to take effect", 22 December 2022, at https://ministers.treasury.gov.au/ministers/jim-chalmers-2022/media-releases/gas-price-cap-take-effect.

[96] Hon Dr Jim Chalmers (Treasurer), Treasury Portfolio, 'Responsible and meaningful action on gas prices", 9 December 2022, at https://ministers.treasury.gov.au/ministers/jim-chalmers-2022/media-releases/responsible-and-meaningful-action-gas-prices.

[97] Department of Energy, "Biden-Harris Administration Announces Historic $7 Billion Funding Opportunity to Jump-Start America's Clean Hydrogen Economy", 23 September 2022, at https://www.energy.gov/articles/biden-harris-administration-announces-historic-7-billion-funding-opportunity-jump-start.

[98] Department of Energy, "Biden-Harris Administration Announces $750 Million to Accelerate Clean Hydrogen Technologies", 16 December 2022, at https://www.energy.gov/articles/biden-harris-administration-announces-750-million-accelerate-clean-hydrogen-technologies.

[99] Department of Energy - Hydrogen and Fuel Cell Technologies Office, "Financial Incentives for Hydrogen and Fuel Cell Projects", at https://www.energy.gov/eere/fuelcells/financial-incentives-hydrogen-and-fuel-cell-projects.

[100] European Commission, "REPowerEU Plan", 18 May 2022, at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2022%3A230%3AFIN&qid=1653033742483.

[101] The supply adequacy assessment for the Northern Territory used data voluntarily provided from some producers, however the full supply demand balance for Northern Territory relied on greater estimation than is typical of AEMO's gas forecasting.

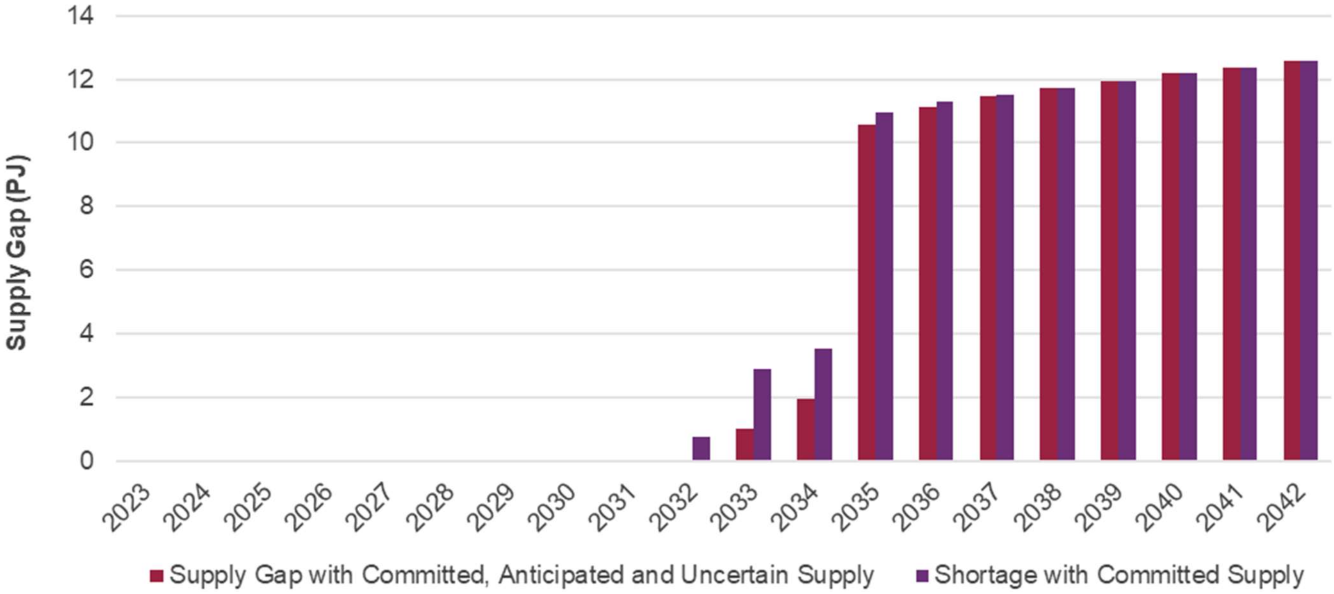
[102] Detail on this arrangement can be found at https://www.aemc.gov.au/sites/default/files/2019-08/Information%20sheet.pdf.

[103] ABC, "NT's Power and Water Corporation buys gas from LNG exporters", 25 June 2022, at https://www.abc.net.au/news/2022-06-25/nt-power-and-water-gas-supply-problems-electricity/101178154.

Figure 50 shows that annual supply gaps are forecast to emerge in the Northern Territory from 2032 with committed supply, and from 2033 with committed, anticipated and uncertain supply. Mitigating these annual shortfall risks would require:

- Additional supply developed in the Northern Territory, and/or
- Pipeline transportation capacity developed from the east coast to the Northern Territory, and/or
- Additional alternative energy sources developed (such as VRE), reducing the Northern Territory's reliance on gas for power generation, consequently reducing and/or delaying annual supply gaps.

Figure 50 Forecast annual supply gaps in the Northern Territory 2023-42 (PJ)



A1. Forecast accuracy

Assessing historical forecasting performance and the existence of any bias in recent forecasts is critical to future forecasting improvements, including understanding of forecast risks. AEMO publishes data detailing its forecasting accuracy to help inform its approach to continuous improvement and build confidence in the forecasts it produces.

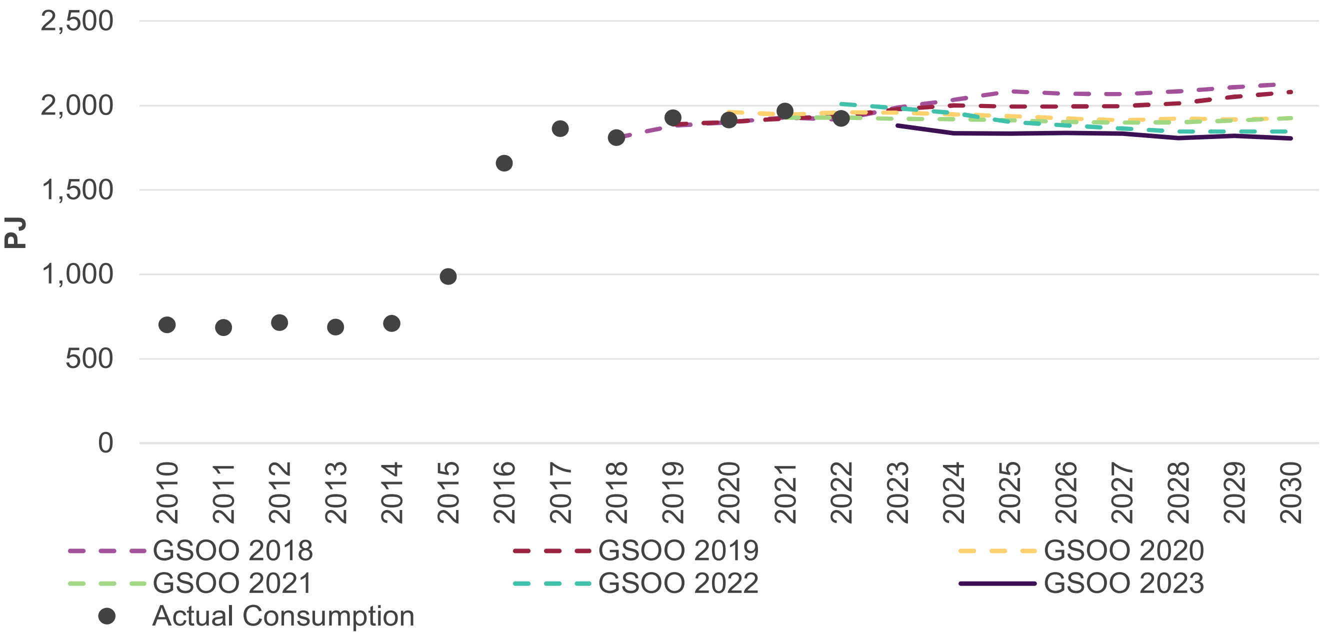
The following charts show AEMO's gas consumption forecasts since 2018, compared to actual recorded consumption. These charts can be used to assess the performance of the forecasts by comparing actual consumption against forecasts in each year. Only the historical *Central/Neutral* scenario forecasts are presented. For the 2023 GSOO, the *Orchestrated Step Change (1.8°C)* scenario is presented.

Actual gas consumption is partly driven by weather conditions in a given year. 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 that assumes typical weather conditions, so some misalignment between forecast and actual consumption is expected in years that are particularly hot or cold.

A1.1 Total gas consumption forecasts

Figure 51 shows total gas consumption forecasts, including consumption for LNG export.

Figure 51 Total gas annual consumption forecast comparison



Key observations include:

- The 2018 GSOO and 2019 GSOO both forecast gas consumption for calendar year 2018 and 2019 reasonably well, whereas the 2020 GSOO over-estimated gas consumption in the 2020 calendar year, mainly due to the LNG market disruption that occurred in 2020 because of COVID-19.

- 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 (discussed in **Section 2.2.4**).
- The 2022 GSOO over-estimated consumption in the 2022 calendar year. The variance mainly came from the lower than forecast LNG consumption.

Table 12 provides an overview of the forecast accuracy of the calendar year immediately following the forecast. Forecast accuracy in this case is measured as the percentage error, and calculated as:

Percentage error = (Forecast - Actual) / Actual

A positive number represents an over-forecast, that is, where the forecast was higher than the actual turned out to be. Due to the large size of the LNG sector (which represents approximately 70% of total gas consumption), small changes in operations from individual facilities make a large contribution to forecast error.

Table 12 Year ahead historical forecast accuracy, total consumption (PJ)

	2018	2019	2020	2021	2022
Year ahead forecast	1,810	1,889	1,959	1,928	2,009
Actual consumption	1,811	1,928	1,914	1,966	1,924
Forecast accuracy	-0.1%	-2.0%	2.4%	-1.9%	4.4%
Source	2018 GSOO	2019 GSOO	2020 GSOO	2021 GSOO	2022 GSOO

The following sections break down gas forecast accuracy into the individual sectors to enable a closer inspection of the individual drivers contributing to forecast uncertainty.

A1.2 Residential and commercial segment consumption forecasts

Figure 52 shows AEMO's residential and commercial gas consumption forecasts.

Figure 52 Gas annual consumption forecast comparison, residential/commercial

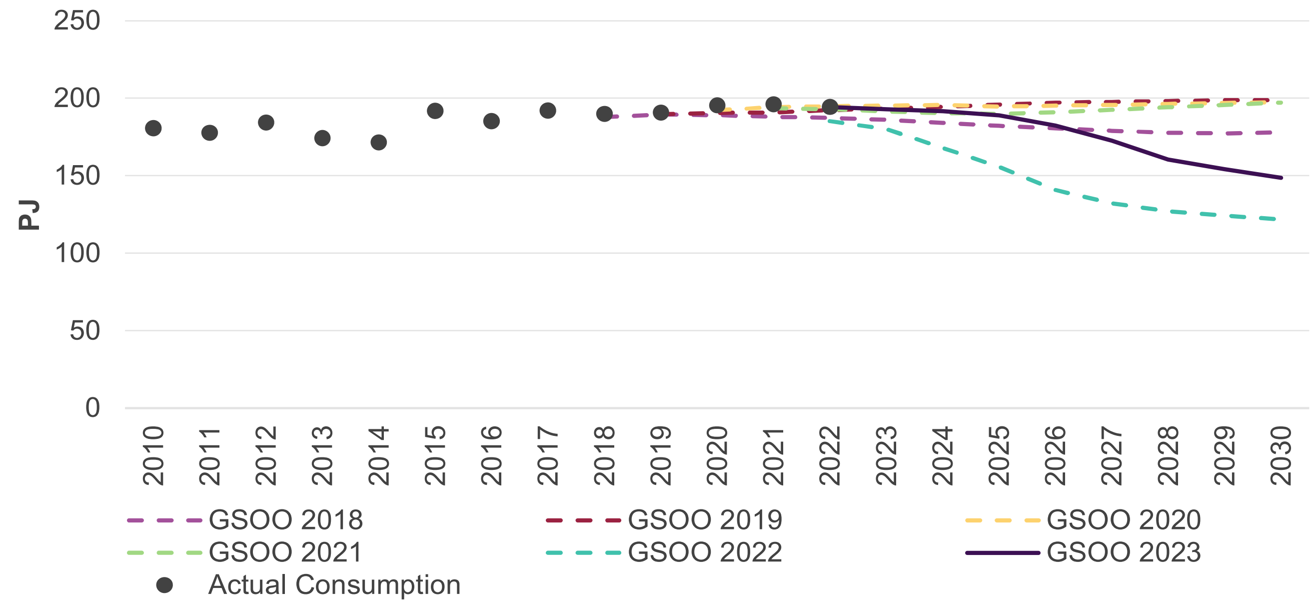


Table 13 provides an overview of the residential and commercial gas consumption forecast accuracy of the calendar year immediately following the forecast. AEMO's 2022 GSOO residential and commercial projection was 4.7% lower than actual consumption levels in calendar year 2022. A large part of this variance was due to weather conditions being inconsistent with the typical conditions that are forecast, with Victoria experiencing a colder than average autumn and spring[104], resulting in nearly 3 PJ of extra consumption compared to a median weather year[105]. In assessing the forecast accuracy, AEMO has identified that the 2022 GSOO residential and commercial model was calibrated on consumption data with some missing values, resulting in a lower starting point in the forecasts; this year's forecast has since been recalibrated. The projected decline in residential and commercial consumption was also smaller than forecast, potentially reflecting a slower rate of fuel-switching (including electrification) in this sector.

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

	2018	2019	2020	2021	2022
Year ahead forecast	188	190	191	194	185
Actual consumption	190	191	195	196	194
Forecast accuracy	-0.9%	-0.4%	-2.3%	-1.4%	-4.7%
Source	2018 GSOO	2019 GSOO	2020 GSOO	2021 GSOO	2022 GSOO

A1.3 Industrial segment consumption forecasts

Figure 53 shows AEMO's industrial gas consumption forecasts. AEMO's industrial consumption projection is based on two categories – large industrial loads (LIL) and small to medium industrial loads (SMIL) – and incorporates assumptions on forecast changes in economic drivers and data obtained by surveying large gas users. The two categories and assumption factors are described in more detail in **Section 2.2.2**.

Table 14 provides an overview of the industrial gas consumption forecast accuracy of the calendar year immediately following the forecast.

[104] See Bureau of Meteorology climate summaries, at http://www.bom.gov.au/climate/current/season/vic/archive/202205.summary.shtml and http://www.bom.gov.au/climate/current/season/vic/archive/202211.summary.shtml.

[105] AEMO uses an Effective Degree Day (EDD) weather standard. The median EDD from 2000-2022 is 1,387 adjusting for climate change. In 2022 the calculated EDD was 1,431. Refer to the AEMO Gas Methodology Paper for details on the EDD formulation, historical climate change adjustment, and use as a weather standard.

Figure 53 Gas annual consumption forecast comparison, industrial

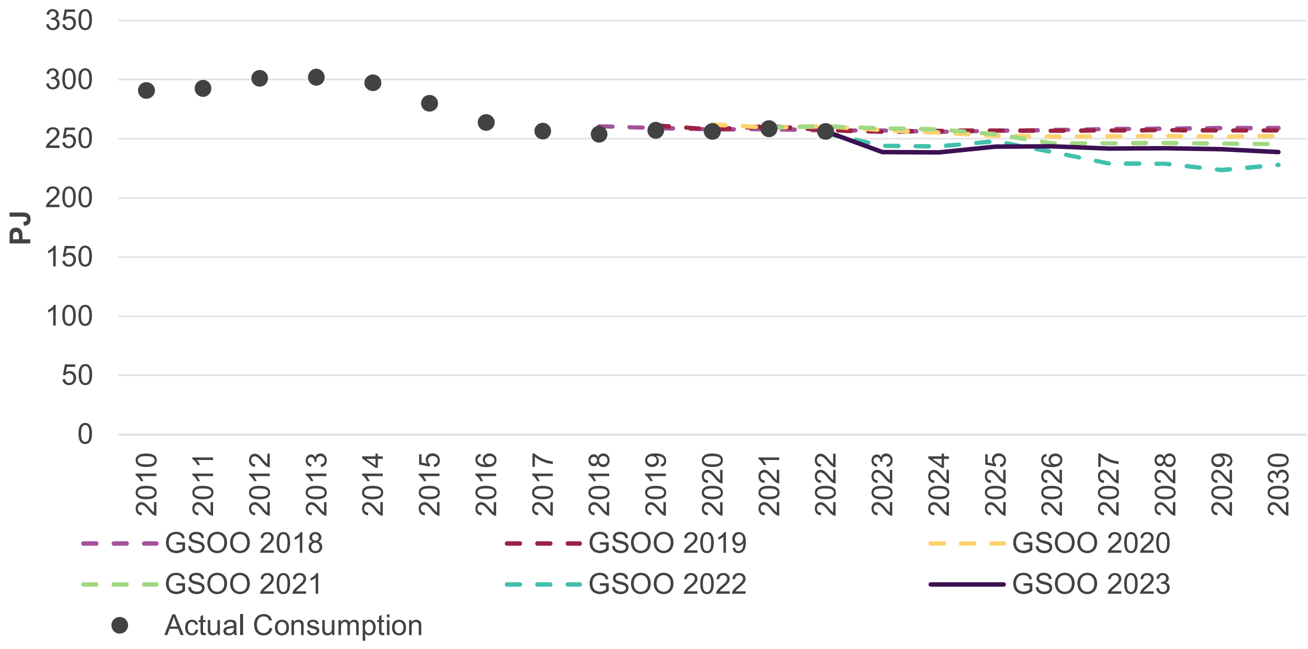


Table 14 Year ahead historical forecast accuracy, industrial total consumption (PJ)

	2018	2019	2020	2021	2022
Year ahead forecast	260.4	261.0	261.7	259.6	254.3
Actual consumption	253.9	257.1	256.3	258.6	256.4
Forecast accuracy	2.6%	1.5%	2.1%	0.4%	-0.8%
Source	2018 GSOO	2019 GSOO	2020 GSOO	2021 GSOO	2022 GSOO

Since the 2018 GSOO, AEMO has forecast a long-term flattening trend in industrial demand, informed by surveys and interviews, which often has suggested increased vulnerability of industrial load to higher gas prices and potential disruption to gas loads as the sector transforms and contributes to net zero emissions objectives. Approximately 70% of industrial consumption (by volume) is surveyed, with the remaining forecast applying AEMO's forecasting methodologies (including allowance for potential fuel-switching to electricity and hydrogen from gas, informed by multi-sector modelling undertaken by consultants CSIRO and ClimateWorks).

Variations from forecasts to actual industrial consumption arise primarily due to unpredictable factors such as weather variations, market shocks, or operational issues that result in unforeseen changes in industrial loads, both temporary and permanent.

AEMO's 2022 GSOO industrial projection was 0.8% lower than actual consumption in the 2022 calendar year, with the difference attributed to:

- In the SMIL sector, elevated consumption levels due to heightened post-pandemic activities and to a lesser extent by colder than average spring and autumn weather conditions.
- In the LIL sector, lower than forecast consumption in South Australia, Queensland, and Victoria, slightly offset by higher than forecast consumption in New South Wales.

- While there is insufficient means to assess the rate of electrification, AEMO suspects that slower electrification investments may be occurring than has been forecast previously.

A1.4 LNG export segment consumption forecasts

The largest proportion of gas consumption in the GSOO is consumed by LNG facilities in Queensland. LNG consumption is driven by factors including:

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

Figure 54 and **Table 15** compare LNG forecasts against actual consumption by LNG facilities. The LNG forecasts in the 2022 GSOO are based on survey responses from LNG producers (see **Section 2.2.3** for further details). The comparison shows that:

- The forecasts over-estimated consumption for all years except for 2018 and 2021.
- The 2018 and 2019 forecasts were reasonably accurate, both being within 3% of actuals.
- In 2020, LNG exports reduced markedly, due to COVID-19 lowering economic activity around the globe. As a result, actuals were 5.8% under the 2020 GSOO forecast.
- The 2021 GSOO produced a far closer forecast of LNG consumption in 2021, under-forecasting by less than 0.9% in the continued global pandemic.
- The 2022 GSOO over-estimated gas consumption in that calendar year by 6.4%.

Figure 54 Gas annual consumption forecast comparison, LNG

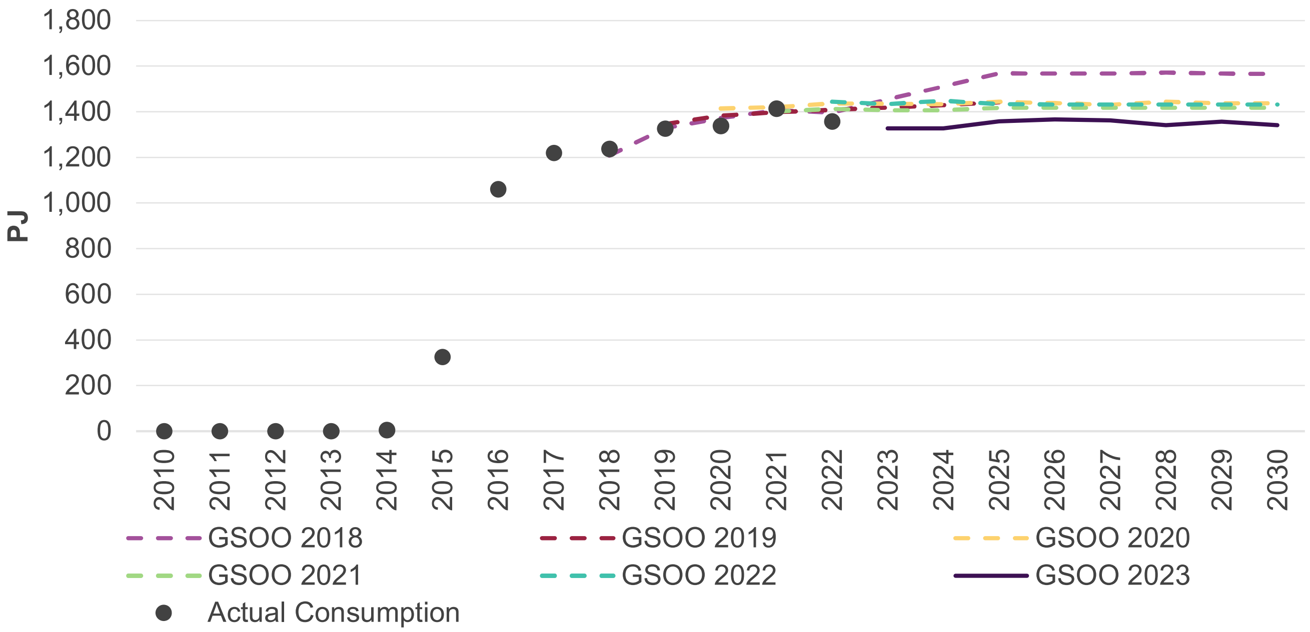


Table 15 Year ahead historical forecast accuracy, all Queensland LNG facilities total consumption (PJ)

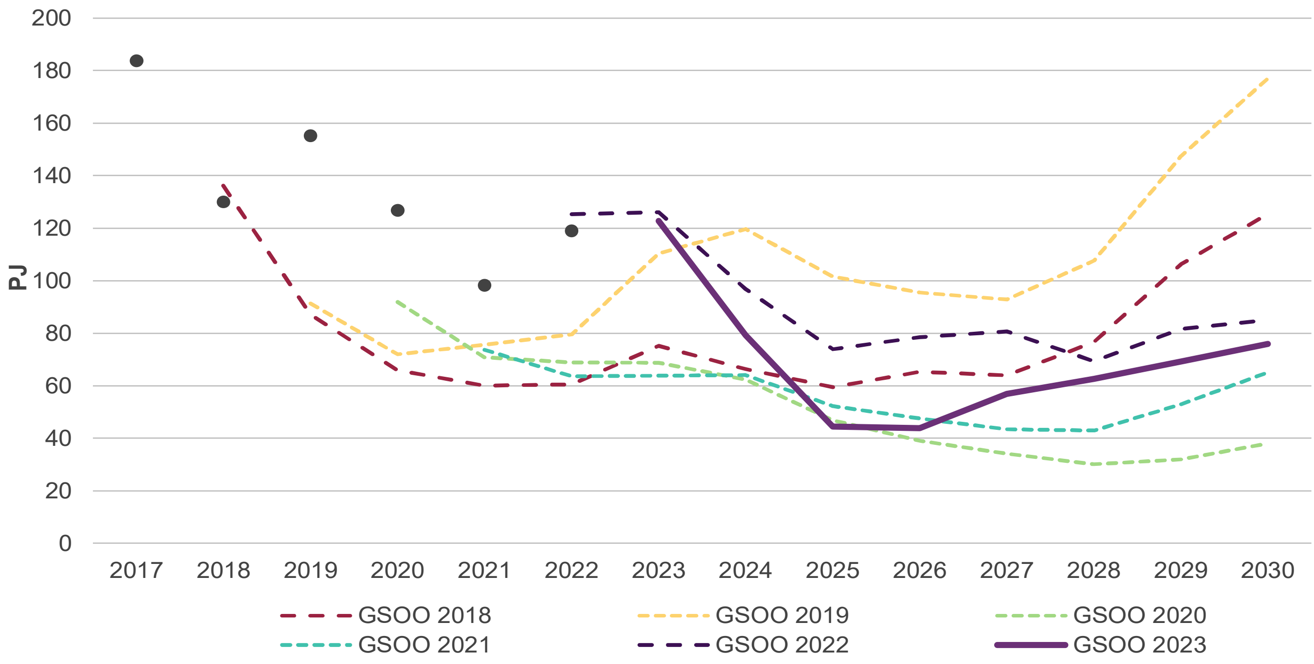
	2018	2019	2020	2021	2022
Year ahead forecast	1,208.1	1,346.4	1,414.8	1401.0	1444.4
Actual consumption	1,237.4	1,325.4	1,337.5	1413.7	1357.6
Forecast accuracy	-2.4%	1.6%	5.8%	-0.9%	6.4%
Source	2018 GSOO	2019 GSOO	2020 GSOO	2021 GSOO	2022 GSOO

A1.5 Gas generation consumption forecasts

Forecasting consumption of gas for electricity generation is challenging because gas generation is often significantly affected by events, such as extreme weather or outages of major electricity generators, that can be difficult to predict and can lead to significant variations in forecasts.

Figure 55 compares AEMO's gas generation forecast accuracy against actual consumption. It shows that all forecasts prior to the 2022 GSOO had significantly under-estimated annual consumption, however the 2022 GSOO slightly over-forecast consumption.

Figure 55 Gas annual consumption forecast comparison, gas generation



As discussed in **Section 2.2.4**, the volume of gas generation has been affected by events in recent years, including interconnector failures, long duration outages at coal power stations, coal supply disruptions, weather-driven events such as heatwaves, floods, and bushfires, and global geopolitical events affecting thermal fuel prices. Appendix Section A1.5 of the 2022 GSOO has more details on these events and their materiality on the error of historical gas generation forecasts.

The 2022 GSOO's *Step Change* scenario forecast was 9.8 PJ (8.5%) higher than actual 2022 total consumption for gas generation inclusive of all GSOO regions:

The 2022 GSOO over-forecast gas generation in the summer months, and under-forecast gas generation between May and July (when significant unforeseen market disruption occurred). Milder summer conditions contributed to the over-forecast of that season, while across winter significant energy limits affecting coal supplies, flooding events affecting hydro availability, and extreme fuel pricing affecting both gas and coal prices all contributed to a significant under-forecast over that season.

Table 16 provides an overview of the forecast accuracy since 2018 of the calendar year immediately following the forecast. The volatility in gas generation forecasts reflects the difficulty to capture the pace and impact of electricity supply transformation. The improved accuracy in the 2022 GSOO reflects the greater consideration for coal unavailability contained within the forecast; as described in the 2022 GSOO, significant coal disruptions had occurred in almost every year since 2017.

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

	2018	2019	2020	2021	2022
Year ahead forecast	136.2	91.4	91.9	73.7	125.3
Actual consumption	129.9	154.6	125.5	98.2	115.5
Forecast accuracy	4.8%	-40.9%	-26.8%	-24.9%	8.5%
Source	2018 GSOO	2019 GSOO	2020 GSOO	2021 GSOO	2022 GSOO

A2. Monthly demand forecast for 2023

Table 17 details the monthly demand forecast by region and sector for 2023. Forecast are provided for the *Orchestrated Step Change (1.8°C)* scenario, 2019 reference year, with potential variation due to weather shown in brackets.

Table 17 Forecast monthly demand by region and sector (gas generation [GPG], and residential, commercial and industrial [RC&I]) for each month in 2023 (PJ)

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Northern Territory	GPG	1.8 [+0,-0]	1.8 [+0,-0]	1.9 [+0,-0]	1.6 [+0,-0]	1.5 [+0,-0]	1.5 [+0,-0]	1.6 [+0,-0]	1.6 [+0,-0]	1.5 [+0,-0]	1.8 [+0,-0]	1.8 [+0,-0]	2.1 [+0,-0]
	RC&I	0.3 [+0,-0]	0.2 [+0,-0]	0.3 [+0,-0]	0.3 [+0,-0]	0.2 [+0,-0]	0.3 [+0,-0]	0.3 [+0,-0]	0.3 [+0,-0]	0.3 [+0,-0]	0.2 [+0,-0]	0.3 [+0,-0]	0.3 [+0,-0]
Queensland	GPG	5.8 [+2,-1]	4.4 [+0,-1]	6.2 [+1,-1]	4.7 [+1,-1]	4 [+0,-0]	5 [+1,-1]	4.2 [+0,-0]	3.6 [+0,-1]	2.1 [+0,-0]	2.3 [+0,-1]	3 [+0,-1]	3 [+0,-1]
	RC&I	9 [+0,-0]	7.8 [+0,-0]	8.1 [+1,-0]	7.8 [+1,-0]	8.7 [+0,-0]	9 [+0,-1]	8.7 [+0,-1]	8.1 [+1,-0]	8.1 [+1,-0]	9 [+0,-1]	9 [+0,-1]	9 [+0,-1]
Total Northern		**16.9 [+2,-1]**	**14.2 [+0,-0]**	**16.5 [+2,-0]**	**14.3 [+2,-0]**	**14.5 [+0,-0]**	**15.8 [+1,-1]**	**14.7 [+0,-1]**	**13.6 [+0,-0]**	**12 [+1,-0]**	**13.4 [+0,-1]**	**15.2 [+0,-1]**	**14.3 [+0,-1]**
New South Wales	GPG	2.2 [+1,-0]	1.3 [+0,-0]	1.9 [+1,-1]	1.6 [+1,-1]	1.6 [+0,-0]	4.8 [+0,-3]	2.6 [+0,-1]	1.5 [+0,-0]	0.6 [+0,-0]	0.8 [+0,-1]	1.2 [+0,-0]	0.7 [+1,-0]
	RC&I	6.9 [+0,-0]	7.2 [+0,-1]	8.6 [+0,-2]	7.4 [+0,-1]	11 [+0,-1]	11.9 [+0,-1]	11.6 [+2,-0]	12.2 [+1,-1]	9.7 [+1,-0]	7.4 [+1,-0]	7.2 [+1,-0]	6.8 [+1,-0]
Victoria	GPG	1.8 [+0,-0]	1.2 [+0,-0]	2.1 [+0,-1]	1.6 [+0,-1]	2 [+0,-1]	3 [+0,-1]	2.3 [+0,-1]	1.3 [+1,-0]	1.5 [+0,-1]	1.2 [+1,-1]	1.5 [+0,-1]	1 [+0,-1]
	RC&I	9.2 [+1,-0]	9.5 [+0,-1]	10.7 [+1,-1]	10.4 [+2,-1]	16.8 [+6,-0]	25.9 [+0,-2]	26.3 [+3,-0]	27.9 [+0,-2]	18.6 [+1,-0]	13.1 [+0,-3]	13.6 [+0,-2]	11.3 [+0,-2]
South Australia	GPG	3.3 [+1,-1]	2.3 [+2,-0]	3.5 [+1,-1]	2.8 [+2,-0]	3.4 [+1,-1]	4.5 [+1,-1]	3.5 [+1,-1]	2.6 [+2,-0]	2.8 [+0,-1]	2.4 [+0,-1]	2.7 [+0,-1]	2.3 [+0,-1]
	RC&I	2.3 [+0,-0]	2.4 [+0,-0]	2.8 [+0,-0]	2.5 [+0,-0]	3.6 [+0,-0]	3.9 [+0,-0]	3.9 [+0,-0]	4.1 [+0,-0]	3.2 [+0,-0]	2.7 [+0,-0]	2.7 [+0,-0]	2.6 [+0,-0]
Tasmania	GPG	0 [+0,-0]	0 [+0,-0]	0 [+0,-0]	0 [+0,-0]	0 [+0,-0]	0 [+0,-0]	0 [+0,-0]	0 [+0,-0]	0 [+0,-0]	0 [+0,-0]	0 [+0,-0]	0 [+0,-0]
	RC&I	0.4 [+0,-0]	0.4 [+0,-0]	0.4 [+0,-0]	0.4 [+0,-0]	0.5 [+0,-0]	0.7 [+0,-0]	0.6 [+0,-0]	0.6 [+0,-0]	0.6 [+0,-0]	0.7 [+0,-0]	0.5 [+0,-0]	0.5 [+0,-0]
Total Southern		**26.1 [+1,-0]**	**24.2 [+0,-2]**	**29.9 [+0,-5]**	**26.5 [+5,-3]**	**38.9 [+7,-2]**	**54.8 [+0,-9]**	**50.8 [+5,-0]**	**50.2 [+0,-2]**	**37.1 [+2,-0]**	**28.3 [+0,-3]**	**29.5 [+0,-1]**	**25.2 [+0,-2]**
Total Domestic		**42.9 [+2,-1]**	**38.4 [+0,-2]**	**46.4 [+1,-6]**	**40.8 [+8,-3]**	**53.4 [+7,-3]**	**70.5 [+0,-10]**	**65.6 [+4,-0]**	**63.8 [+0,-2]**	**49.1 [+3,-0]**	**41.7 [+0,-3]**	**44.8 [+0,-2]**	**39.5 [+0,-3]**
Queensland	LNG	114 [+3,-1]	103 [+4,-1]	113 [+0,-1]	111 [+6,-1]	109 [+0,-0]	104 [+0,-1]	107 [+0,-0]	106 [+1,-1]	111 [+4,-0]	120 [+2,-1]	113 [+2,-0]	115 [+4,-1]
Total		**157 [+5,-2]**	**141 [+4,-1]**	**159 [+0,-6]**	**152 [+9,-0]**	**163 [+3,-7]**	**175 [+0,-14]**	**173 [+1,-2]**	**170 [+0,-3]**	**160 [+6,-0]**	**162 [+0,-6]**	**157 [+1,-1]**	**155 [+1,-2]**

Data is shown for the 2019 reference year. Data in the brackets represents differences in forecast demand for that component of demand due to weather variation. Totals may not add up due to rounding. Variation due to weather for total rows (i.e., 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 MMLI for QLD and NT), because these values may not occur in the same reference year.

Figure 56 and **Figure 57** show forecast monthly demand in petajoules a month (PJ/m) for 2023, for the 2019 reference year, by region and by sector respectively.

Figure 56 Forecast monthly domestic demand by region for 2023, *Orchestrated Step Change (1.8°C)* scenario, reference year 2019 (PJ/m)

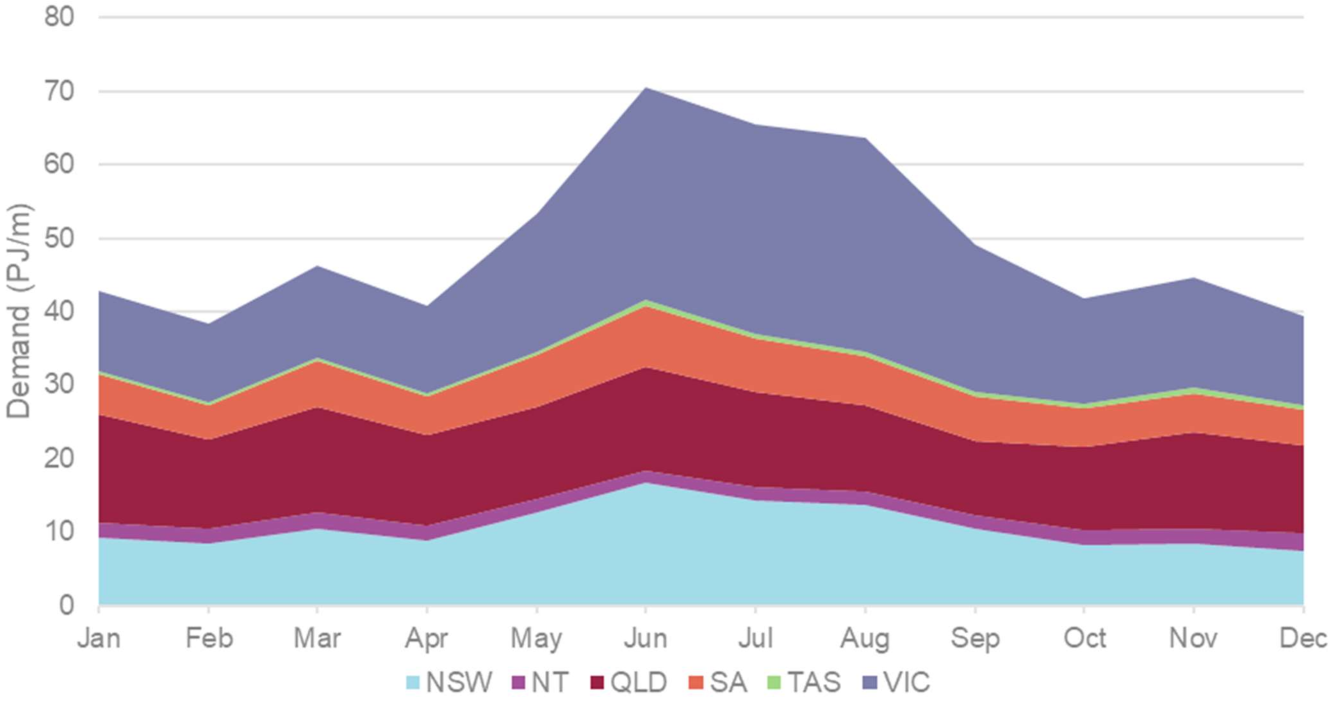


Figure 57 Forecast monthly demand by sector for 2023, *Orchestrated Step Change (1.8°C)* scenario, reference year 2019 (PJ/m)

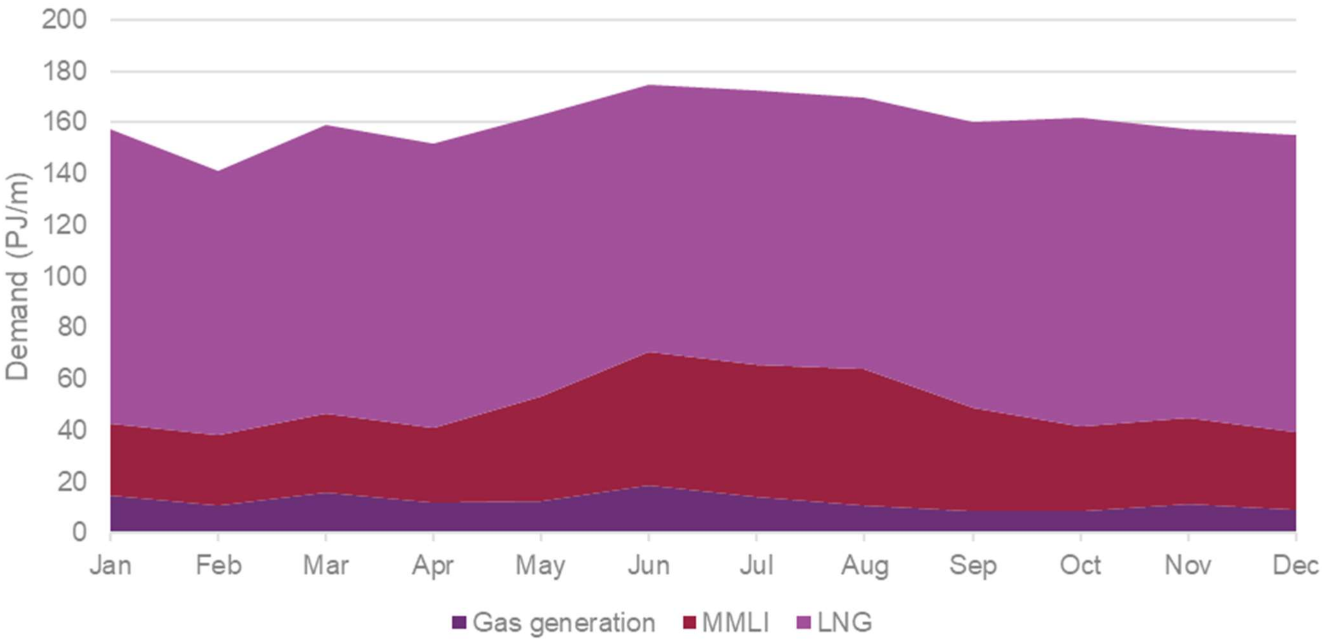
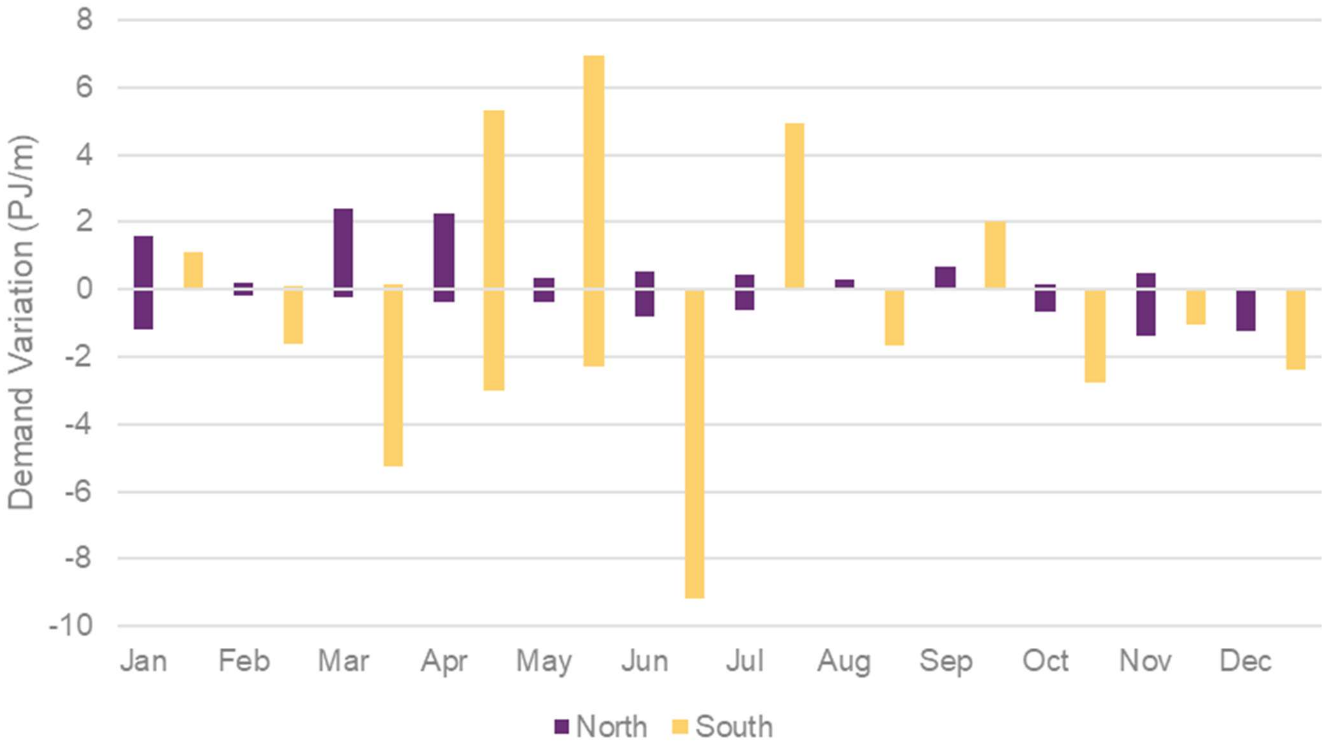


Figure 58 visualises the monthly variation in demand in relation to the 2019 reference year, for the northern and southern regions.

Figure 58 Variation on monthly forecast demand by region in relation to the 2019 reference year, *Orchestrated Step Change (1.8°C)* scenario (PJ/m)



A3. Glossary, measures and abbreviations

Units of measure

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

Abbreviations

Term	Definition
2C	best estimate of contingent resources
2P	proved and probable
ACCC	Australian Competition and Consumer Commission
ADGSM	Australian Domestic Gas Security Mechanism
AEMO	Australian Energy Market Operator
AGP	Amadeus Gas Pipeline
BLP	Brooklyn–Lara Pipeline
BGP	Bonaparte Gas Pipeline
CCS	carbon capture and storage
CGP	Carpentaria Gas Pipeline
CSG	coal seam gas
DTS	Declared Transmission System
DWGM	Declared Wholesale Gas Market
ECG	East Coast Grid
EES	Environmental Effects Statement
EGP	Eastern Gas Pipeline
ESG	Environment, Social and Governance
FID	final investment decision
FSRU	floating storage regasification unit
GSOO	*Gas Statement of Opportunities*
LGA	Lewis Grey Advisory
IASR	*Inputs, Assumptions and Scenarios Report*
ISP	*Integrated System Plan*
LIL	large industrial load
LMP	Longford Melbourne Pipeline
LNG	liquefied natural gas

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

Glossary

This document uses many terms that have meanings defined in the National Gas Rules (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.

Term	Definition
Anticipated projects	Gas field and production facility projects that developers consider justified on the basis of a reasonable forecast of commercial conditions at the time of reporting, and reasonable expectations that all necessary approvals (such as regulatory approvals) will be obtained and final investment decision (FID) made.
Augmentation	The process of upgrading the capacity or service potential of a transmission (or a distribution) pipeline.
Biomethane	Methane captured from biological processes such as wastewater treatment, landfill or biodigesters (also known as biogas) and purified to meet gas quality standards. Biomethane can be used interchangeably with natural gas.
Commercial customers	See residential and commercial customers.
Committed projects	Gas field and production facility projects that have obtained all necessary approvals, with implementation ready to commence or already underway.
Consumption	Gas consumed over a period of time, usually a year but sometimes a month.
curtailment	The interruption of a customer's supply of gas at the customer's delivery point, which occurs when a system operator intervenes, or an emergency direction is issued.
Customer	Any party who purchases and consumes gas at particular premises. Customers can deal through retailers (who are registered market customers in the Declared Wholesale Gas Market [DWGM]) or may be registered as market participants in their own right.
Declared Transmission System	The Victorian gas Declared Transmission System (DTS) refers to the principal gas transmission pipeline system identified under the *National Gas (Victoria) Act*, including augmentations to that system. Owned by APA Group and operated by AEMO, the DTS serves Gippsland, Melbourne, Central and Northern Victoria, Albury, the Murray Valley region, and Geelong, and extends to Port Campbell.
Declared Transmission System constraint	A constraint on the gas Declared Transmission System.
Declared Wholesale Gas Market	The market administered by AEMO under Part 19 of the NGR for the injection of gas into, and the withdrawal of gas from, the DTS and the balancing of gas flows in or through the DTS.
Demand	The amount of gas used on a daily basis. The maximum across a season is referred to as maximum demand or peak day demand.
Distribution	The transport of gas over a combination of high-pressure and low-pressure pipelines from a city gate to customer delivery points.
Eastern Gas Pipeline (EGP)	The east coast pipeline from Longford to Sydney.
Effective Degree Day (EDD)	A measure of coldness that includes temperature, sunshine hours, wind chill and seasonality. The higher the number, the colder it appears to be and the more energy that will be used for area heating purposes. The EDD is used to model the daily relationship between weather and gas demand.
Facility operator	Operator of a gas production facility, storage facility, or pipeline.
Gas generation	Where electricity is generated from gas turbines (combined cycle gas turbine [CCGT] or open cycle gas turbine [OCGT]).
Gas Statement of Opportunities	Demand forecasts (over a 20-year horizon) and supply adequacy assessment for eastern and south-eastern Australia published annually by AEMO.
Industrial customers (Tariff D)	The gas transportation tariff applying to daily metered sites with annual consumption greater than 10,000 GJ or maximum hourly quantity (MHQ) greater than 10 GJ and that are assigned as being on demand tariffs (Tariff D) in the AEMO meter installation register. Each site has a unique Metering Identity Registration Number (MIRN).
Injection	The physical injection of gas into the transmission system.
Lateral	A pipeline branch.
Linepack	The pressurised volume of gas stored in the pipeline system. Linepack is essential for gas transportation through the pipeline network throughout each day, and is required as a buffer for within-day balancing.
Liquefied Natural Gas (LNG)	Natural gas that has been converted to liquid for ease of storage or transport. The Melbourne LNG storage facility is at Dandenong.
Natural gas	A naturally occurring hydrocarbon comprising methane (CH4) (between 95% and 99%) and ethane (C2H6).
Participant	A person registered with AEMO in accordance with the National Gas Rules (NGR).
Petajoule	An International System of Units (SI) unit. One PJ equals 1 x 10^{15} joules.

Term	Definition
Pipeline	A pipe or system of pipes for or incidental to the conveyance of gas, including part of such a pipe or system.
Prospective resources	Estimated volumes associated with undiscovered accumulations of gas, highly speculative and not yet proven by drilling.
Probability of Exceedance (POE)	The statistical likelihood that a peak demand forecast will be met or exceeded.
Renewable gases	Carbon-neutral natural gas substitutes that do not generate additional greenhouse gas emissions when burnt. Renewable gases include biomethane and hydrogen.
Reserves	Quantities of gas expected to be commercially recovered from known accumulations.
Residential and commercial customers (Tariff V)	The gas transportation tariff applying to consumers on volume-based tariffs (Tariff V). This includes residential and small to medium sized commercial gas consumers.
Resources	Less certain, and potentially less commercially viable sources of gas, than reserves.
Retailer	A seller of bundled energy service products to a customer.
Shoulder season	The period between low (summer) and high (winter) gas demand. It includes the calendar months of March, April, May, September, October, and November.
South West Pipeline	The 500 mm pipeline from Lara (Geelong) to Iona.
Storage facility	A facility for storing gas, including the Dandenong LNG storage facility and Iona Underground Gas Storage (UGS) in Victoria, and Newcastle Gas Storage Facility (NGSF) in New South Wales.
Summer	December to February.
System demand	Demand from Tariff V (residential, small commercial and industrial customers nominally consuming less than 10 TJ of gas per annum) and Tariff D (large commercial and industrial customers nominally consuming more than 10 TJ of gas per annum). It excludes gas generation demand, exports, and gas withdrawn at Iona.
Tasmanian Gas Pipeline (TGP)	The pipeline from VicHub (Longford) to Tasmania.
Terajoule	An International System of Units (SI) unit. One TJ equals 1×10^{12} joules.
Unaccounted for Gas (UAFG)	The difference between metered injected gas supply and metered and allocated gas at delivery points, comprising gas losses, metering errors, timing, heating value error, allocation error, and other factors.
Uncertain projects	Gas field and production facility projects that are at earlier stages of development or face challenges in terms of commercial viability or approval.
Underground Gas Storage (UGS)	A storage facility which reinjects gas into depleted gas reservoirs, which can be withdrawn out at a later date.
VicHub	The interconnection between the Eastern Gas Pipeline (EGP) and the gas DTS at Longford, facilitating gas trading at the Longford hub.
Winter	June to August.

A4. List of tables and figures

Tables

Figures