Gas Statement of Opportunities

March 2020

For eastern and south-eastern Australia

Important notice

PURPOSE

AEMO publishes the Gas Statement of Opportunities under the National Gas Law and Part 15D of the National Gas Rules.

This publication has been prepared by AEMO using information available at 31 December 2019, although AEMO has endeavoured to incorporate more recent information where practical.

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VERSION CONTROL

Version	Release date	Changes
1	March 2020	Initial release

Executive summary

In the 2020 *Gas Statement of Opportunities* (GSOO), AEMO forecasts demand and uses information from gas producers about reserves and forecast production to project the supply-demand balance and potential gaps under a range of plausible scenarios for eastern and south-eastern Australian gas markets to 2039. The 2020 *Victorian Gas Planning Report Update*[1] (VGPR Update), which complements this GSOO, provides a focused assessment of the supply-demand balance to 2024 in Victoria's Declared Transmission System (DTS).

The 2020 GSOO projects that:

- Supply from existing and committed gas developments will be sufficient to meet forecast gas demand across eastern and south-eastern Australia until at least 2023, provided that liquefied natural gas (LNG) export spot cargoes are redirected to meet domestic demand, if required.
- Southern supply from existing and committed gas developments will reduce by more than 35% (163 petajoules [PJ]) over the next five years, despite an increase in committed gas developments in the past year. Unless additional southern supply sources are developed, LNG import terminals are progressed, or pipeline limitations are addressed, gas supply restrictions and curtailment of gas-powered generation (GPG) for the National Electricity Market (NEM) may be necessary on peak winter days in southern states from 2024.
- Anticipated gas field projects (considered likely to proceed within the outlook period) are forecast to improve resource adequacy until at least 2026 if developed. However, due to the location of most of the anticipated projects within Victoria, dynamic operational pipeline constraints would limit their effectiveness in addressing the forecast peak winter day supply gaps under certain conditions[2].

Forecasting uncertainty and year-on-year variability has increased since the 2019 GSOO. Gas supply adequacy forecasts are highly uncertain, particularly between 2022 and 2024 when decline in southern field production coincides with the staged closure of Liddell Power Station. Uncertainties include:

- AEMO's Draft 2020 *Integrated System Plan* (ISP)[3] projects that investment in a portfolio of variable renewable energy (VRE), storage, and new transmission infrastructure will be the lowest-cost way of replacing Liddell's generation. Any delays in this new investment or a further decline in availability of coal-fired generation will significantly increase gas demand through increased reliance on both existing and new GPG.
- Several gas fields are forecast to cease production sometime between mid-2023 and mid-2024. If production ceases earlier, this could create peak winter day supply gaps in Victoria in 2023.
- Global oil and gas demand trends may see LNG demand varying from expectations and indirectly impacting prices and availability of domestic supply and LNG imports.
- Impacts of the COVID-19 coronavirus (not modelled) may lead to decreased levels of global LNG demand and domestic gas consumption in the short term.

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

[2] See the 2020 VGPR Update for more information.

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

- The Commonwealth and New South Wales governments have announced a proposed target to inject an additional 70 PJ of gas per year into the New South Wales market by 2022.
- The Victorian government has lifted the ban on onshore conventional gas exploration and development from July 2021, although timing of any new supply and the quantities of gas that may become available are still unclear.
- Industrial users continue to report vulnerabilities due to energy cost pressures. Any significant changes in industrial activity, whether increases or decreases, will materially impact gas and electricity demand.

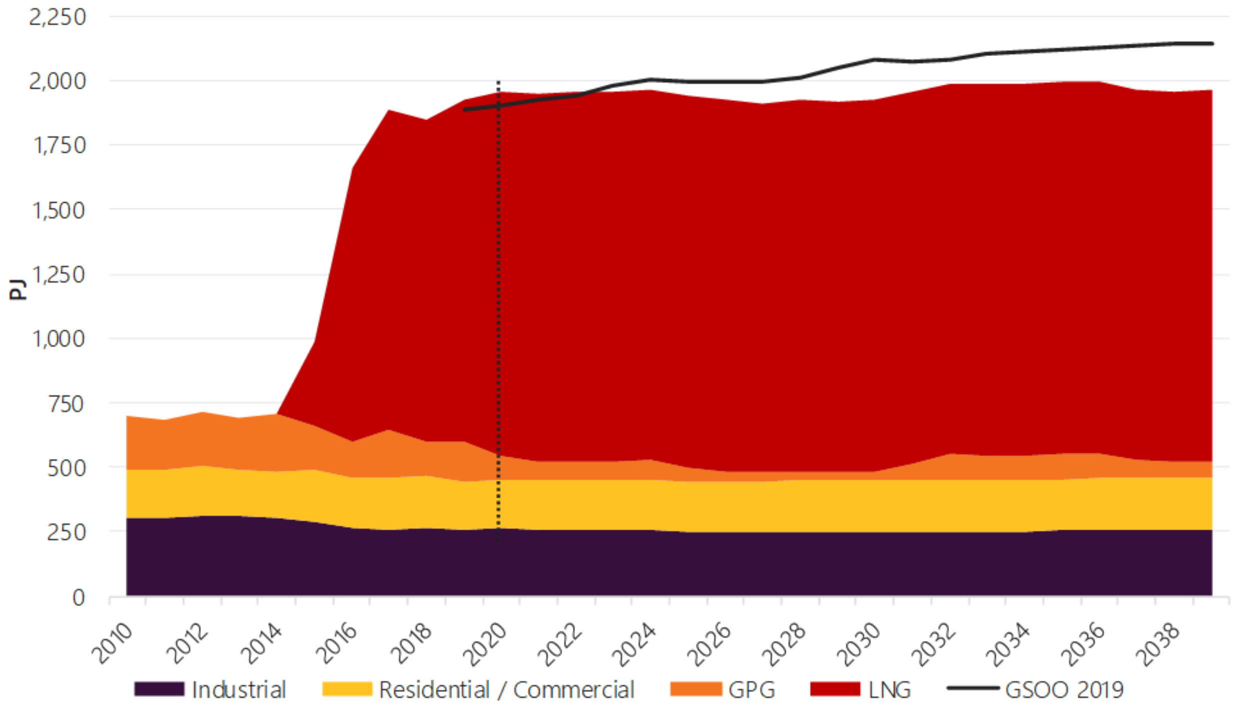
Forecast consumption

Figure 1 shows gas consumption forecasts by demand sector for the 2020 GSOO[4]. It highlights that total consumption trends continue to be driven by trends in LNG export demand, given its relative volume, constituting just over 70% of total system demand.

Short-term trends in the total east coast gas consumption forecasts are relatively flat. Total consumption is projected to be slightly higher than forecast in the 2019 GSOO, mainly due to a slightly higher forecast of LNG exports and an increase in forecast GPG for 2020, driven by delays in VRE development and deteriorating availability of ageing coal-fired generators.

Longer-term forecasts also show a flat outlook in total consumption. This is lower than was forecast in the 2019 GSOO from the mid-2020s, primarily due to a lower long-term outlook for GPG, based on projections of reduced electricity demand, greater interconnection between regions, and a higher (and more technologically diversified) new VRE build in the NEM.

Figure 1 Gas consumption actual and forecast, 2010-39, all sectors, Central scenario (PJ)



[4] Demand forecasts are available on the Forecasting Data Portal http://forecasting.aemo.com.au/. Select 'GSOO 2020' from the publication drop-down.

The scenarios studied in the 2020 GSOO, including the role for gas for GPG in the NEM, are consistent with three scenarios from the Draft ISP for the NEM[5] that provide the widest spread of outcomes from a gas perspective: the Central, Step Change, and Slow Change scenarios.

AEMO's Draft 2020 ISP was published in December 2019, and considered the needs of all energy users, both electricity and gas. The GPG scenario forecasts developed for the 2020 GSOO use the generation retirement and expansion trajectories identified by the Draft 2020 ISP.

Central scenario forecasts – short-term (to 2025)

Short-term trends in east coast gas consumption forecasts in the Central scenario are:

- LNG exports are expected to rise slightly as two of the three LNG facilities reach full nameplate capacity. This leads to higher forecast consumption than in the 2019 Neutral scenario.
- Industrial consumption is expected to remain relatively flat, as this sector is forecast to continue facing a challenging economic environment, with limited growth opportunities. AEMO's interviews with large industrial facilities indicate greater risk of closure than expansion, with potential demand reductions, due to high gas prices.
- Residential and commercial sector consumption is projected to be flat, with a similar trajectory to the 2019 GSOO. Increases in energy efficiency schemes, fuel switching away from gas appliances, and changing consumption patterns continue to put downward pressure on consumption growth, despite a growing forecast number of gas connections.
- GPG forecasts over the five-year outlook follow a similar declining trend to those in the 2019 GSOO. The forecasts for the 2020 calendar year are 17 PJ (24%) higher, due to delays in commissioning of new VRE and accounting for the deteriorating availability of an ageing coal-fired generation fleet. From 2021, GPG forecasts are slightly lower than those in the 2019 GSOO, as more utility-scale wind and solar and distributed solar "rooftop" photovoltaic (PV) generation is expected and forecast to be built in the NEM, compared to the 2019 GSOO.

The outbreak of the COVID-19 coronavirus in early 2020 is likely to lead to decreased levels of global LNG demand in 2020, and decline in economic activity in Australia for at least the short term[6]. The potential impact of this has not been included in these forecasts and could mean a lower short-term demand forecast.

Central scenario forecasts – medium-term to long-term (2025 to 2039)

In the medium to longer term:

- Forecast total gas consumption is lower than in the 2019 GSOO, with less forecast opportunity for a rebound in GPG usage with lower electricity operational consumption forecasts, increasing interconnection in the NEM enabling better sharing of renewable resources, and the inclusion of pumped hydro schemes such as the Snowy 2.0 and Battery of the Nation projects.
  - GPG is expected to continue to provide a reliability and security role to complement renewable generation in the NEM. Gas demand for GPG is forecast to drop in the medium term, as further electricity transmission means GPG is relied on less as a source of firm supply. As more coal generation retires in the long term, demand for GPG is forecast to grow back near 2020 levels.

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[5] At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp.

[6] See commentary at https://www.smh.com.au/business/the-economy/covid-19-cormann-says-stimulus-aims-to-put-economy-in-least-bad-position-20200311-p548xm.html and https://www.abc.net.au/news/2020-03-11/coronavirus-risk-aversion-uncertainty-economy-rba-guy-debelle/12044792. The potential impacts are highly uncertain. AEMO is currently updating its economic forecasts, and will continue to monitor the situation closely and seek external advice on this developing issue.

- As increasing amounts of distributed and utility-scale renewable generation are installed in the NEM, year-on-year variations in GPG demand are becoming more dependent on weather patterns.

- LNG consumption is forecast to stabilise in the longer term, at levels sufficient to meet existing contractual obligations.
- Residential and commercial consumption growth is projected to be relatively flat, from 191 PJ in 2020 to 205 PJ in 2039. Similar to the short-term trends, the effect of continuing and new energy efficiency schemes, fuel switching away from gas appliances, and assumed sustained high gas prices[7] are forecast to offset growth in domestic usage of gas from new gas connections.

Differences in Slow Change and Step Change scenario forecasts

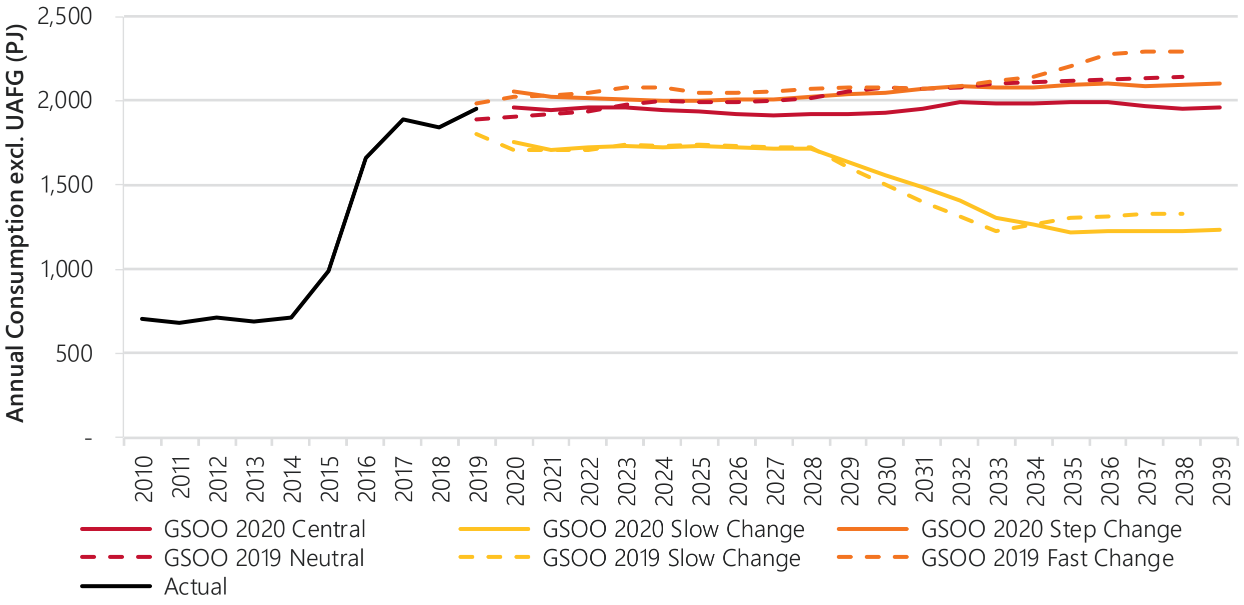
Projected consumption in other modelled plausible futures is compared to the Central scenario in Figure 2.

In the industrial sector, the relatively weak economic conditions of the Slow Change scenario are forecast to lead to gas demand declining from current levels, particularly after expiry of existing long-term contracts, with nearly a 90 PJ (or 30% of Tariff D volume) difference to the Central scenario forecast by 2040.

The Step Change scenario forecast is only slightly higher than the Central scenario, predominantly from LNG exports. The Step Change scenario highlights again that a significantly higher gas demand trajectory than the Central scenario is not necessary under a stronger decarbonisation scenario that models more energy efficiency measures and fuel-switching opportunities. Insights from large industrial users of gas indicate that this sector is unlikely to increase consumption much beyond current levels under any of the scenarios.

For LNG annual consumption, the Step Change scenario is higher, reflecting feedback from the sector on what more favourable international dynamics will mean for exports, whereas in the Slow Change scenario, feedback indicates that a fall in contract quantity can result in a decline in demand as the sector re-evaluates how remaining contract obligations will be met.

Figure 2 Gas consumption actual and forecast, 2010-39, all sectors, all scenarios, compared to equivalent 2019 GSOO scenarios (PJ)



[7] The long-term gas price outlooks used for the 2020 GSOO were developed by consultants Core Energy and are not expected to be sensitive to the current global economic conditions or other short-term shocks. These prices are at https://aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo.

Forecast supply

AEMO has been provided with updated production forecasts and gas reserve and resource information from gas producers to inform the 2020 GSOO.

Within eastern and south eastern Australia, and those fields in Northern Territory likely to supply eastern Australia, quantities of proved and probable (2P[8]) developed reserves have increased by over 2,000 PJ compared to those reported in the 2019 GSOO, indicating work has progressed over the last 12 months to increase certainty in these reserves.

In the northern states, 2P developed reserves have increased (by 1,785 PJ, from 10,452 PJ to 12,237 PJ), while 2P undeveloped reserves have decreased (a drop of 33% or 9,410 PJ) compared to quantities reported in the 2019 GSOO. Contingent (2C[9]) resources in the north are similar to those reported last year (a drop of 2%).

In the southern states, resource and reserve increases have been identified across all of 2P developed reserves, 2P undeveloped reserves, and 2C resources (from a total of 13,131 PJ to 16,933 PJ). However, despite ongoing field development activities increasing the quantities of 2P reserves, these new developments are insufficient to halt the projected decline of production in aggregate from fields in the southern states.

To access these reserves and resources, appropriate production, process, and transportation facilities need to be developed. Following stakeholder consultation, the production forecasts provided by gas producers have been assessed in this 2020 GSOO using three project commitment classifications aligned with the Society of Petroleum Engineers – Petroleum Resource Management System (PRMS)[10]:

- **Committed projects** – all necessary approvals have been obtained and implementation is ready to commence or is underway. Committed projects consist of 2P reserves (developed and undeveloped).
- **Anticipated projects** – developers consider the project to be justified on the basis of a reasonable forecast of commercial conditions at the time of reporting, and reasonable expectations that all necessary approvals (such as regulatory approvals) will be obtained and final investment decisions made. Anticipated projects typically include 2P undeveloped reserves and selected 2C resources.
- **Uncertain projects** – these projects are more uncertain or at early stages of development. Uncertain projects include uncertain 2C contingent and prospective resources that are accessible by existing pipeline and processing infrastructure.

Under this classification, a project represents a specific investment decision, with an associated quantity of recoverable reserves and resources that may be more, or less, certain. As explained in the PRMS Guidelines, "*a project may, for example, constitute the development of a single reservoir or field, or an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership*".

Table 1 shows the production forecast between 2019 and 2024 provided to AEMO by gas producers as their current best estimate of gas available and expected for production over this time, with comparisons to the forecasts provided to AEMO for the 2019 GSOO.

These production forecasts are similar to those in the 2019 GSOO, with the largest change in 2022, amounting to 59 PJ of additional gas (3% increase). Compared to last year, production forecasts in the southern states have decreased for 2020 and 2021 but are the same in 2022, despite Victorian production forecasts being higher over this same time period, compared to the 2019 GSOO.

[8] Gas reserves and resources are categorised according to the level of technical and commercial uncertainty associated with developing them. Reserves are quantities of gas which are anticipated to be commercially recovered from known accumulations, and proved and probable (2P) is considered the best estimate of commercially recoverable reserves.

[9] Contingent resources are not yet considered commercially viable, and 2C is considered the best estimate of those sub-commercial resources.

[10] See https://www.spe.org/industry/docs/PRMS_Guidelines_Nov2011.pdf.

Existing gas fields are in decline, particularly among southern fields. BHP has announced that the Minerva gas field has reached its end of life and ceased production on 3 September 2019[11]. Several of the Gippsland fields are projected to reach their end of life between mid-2023 and mid-2024, and all currently producing fields in the Otway Basin will cease production unless anticipated gas field development or plant modification projects proceed. The decline in production in southern states between 2022 and 2024, shown in Table 1, is due to total committed Victorian production reducing from 318 PJ in 2022 to 201 PJ in 2024.

Table 1 Production forecasts to 2024 (PJ) as provided by gas producers

	Commitment criteria	2020	2021	2022	2023	2024
VIC / NSW / SA[A]	Existing and committed	437	395	384	323	267
	Anticipated	22	69	72	123	106
	Total	460	464	456	447	373
	Difference from 2019 GSOO	**-15**	**-16**	**0**	**N/A**	**N/A**
QLD / NT	Existing and committed	1,566	1,525	1,489	1,371	1,261
	Anticipated	5	48	177	252	313
	Total	1,572	1,577	1,676	1,636	1,590
	Difference from 2019 GSOO	**+34**	**-20**	**+59**	**N/A**	**N/A**
Total east coast gas production		**2,031**	**2,037**	**2,122**	**2,069**	**1,947**
Difference from 2019 GSOO		**+18**	**-36**	**+59**	**N/A**	**N/A**

A. The Queensland component of the Cooper Eromanga basin appears in the SA category.

In response to declining production from southern fields, Cooper Energy's Sole project and the Esso-BHP West Barracouta project are committed and expected to start production of sales gas between 2020 and 2022. These projects alone are not sufficient to slow the decline in production, but further anticipated projects in the Otway, Gippsland, and Cooper Eromanga basins are expected to be on track to start production over the coming years. To maintain levels of production beyond 2024, gas from more uncertain field developments will need to progress.

Various new projects throughout Queensland are expected to be available to meet demand, subject to pipeline capacity. These include Senex's Project Atlas, which started producing in late 2019, and is expected to ramp up to full production capacity of 15 PJ a year by the end of 2021. Further drilling of Queensland coal seam gas (CSG) fields is forecast to continue to support the LNG export projects.

Supply-demand balance

If all anticipated projects proceed, supply from existing, committed, and anticipated gas developments is forecast to be sufficient to meet all eastern and south-eastern Australian demand until 2026 in the Central and Step change scenarios, and until 2027 in the Slow Change scenario, under most conditions.

However, this assessment does not take into account all of the detailed requirements of operating a system under peak demand and low supply conditions. Actual operational constraints, particularly within the Victorian DTS, may lead to transportation limitations throughout the system, creating potential supply gaps during peak winter days from 2024 (see the 2020 VGPR Update for more information[12]).

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[11] BHP, "BHP Operational Review for the quarter ended 30 September 2019", 17 October 2019, at https://www.bhp.com/-/media/documents/media/reports-and-presentations/2019/191017_bhpoperationalreviewforthequarterended30september2019.pdf?la=en.

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

This GSOO supply adequacy assessment includes two anticipated infrastructure projects which have been communicated to AEMO by asset owner and operator APA Group. The first is an increase to the capacity of the Moomba to Sydney Pipeline of 25 terajoules (TJ) a day. The second is the committed Western Outer Ring Main (WORM) project that will increase the refilling capacity of Iona Underground Storage (UGS) during summer months, so more gas is available in storage to be used in winter when required. If either project does not proceed, and alternative unconstrained supply options are not developed, meeting peak winter day supply in Victoria would be even more challenging, as discussed in the 2020 VGPR Update.

Figure 3 shows the expected production forecast if existing, committed, and anticipated projects are available to meet demand in the long term. Development of more uncertain reserves and resources will be required across eastern and south-eastern Australia to ensure demand is met to the end of the outlook period. There is a risk that anticipated projects, while having a reasonable expectation of progressing to production, in fact may not progress. To understand this risk, AEMO undertook GSOO analysis assuming only committed projects proceed.

Gas production from only existing and committed gas developments is forecast to provide adequate supply to meet gas demand until between 2023 and 2025 depending on scenario, provided cargoes of export LNG above contracted levels are diverted to meet domestic demand if needed. Beyond this point, existing and committed southern field projects are forecast to be insufficient to meet southern demand, and major southbound pipeline infrastructure upgrades would be required to deliver more gas from northern to southern states, particularly during winter peak days.

Figure 3 Projected eastern and south-eastern Australia gas production (export LNG and domestic) – existing projects, and committed and anticipated developments; Central scenario, 2020-39

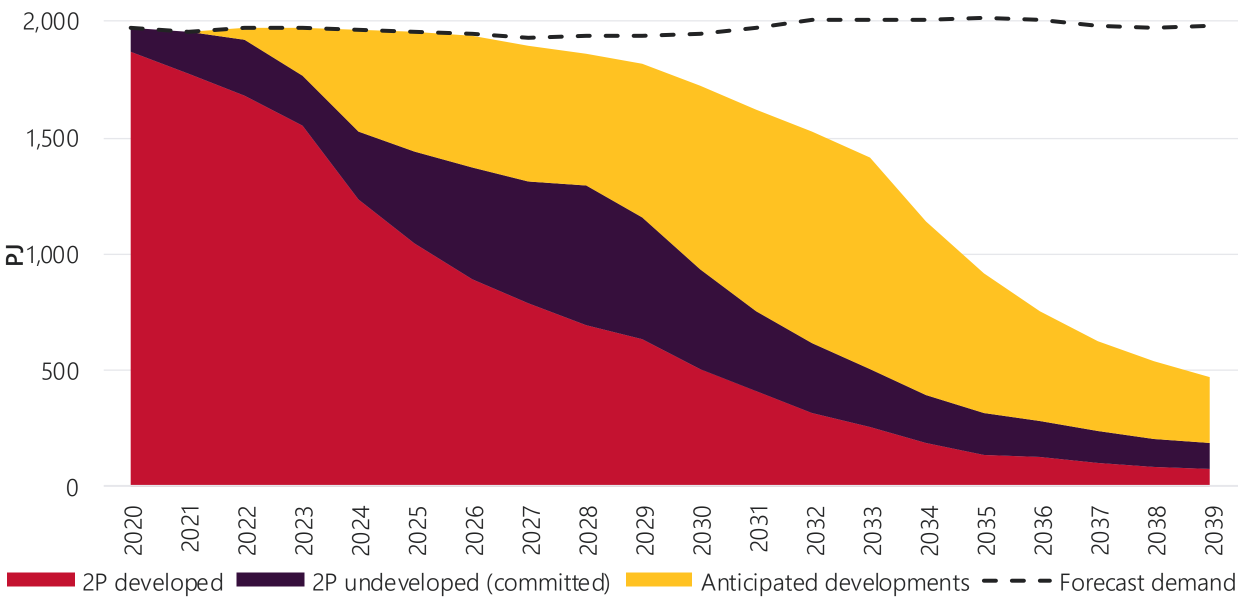
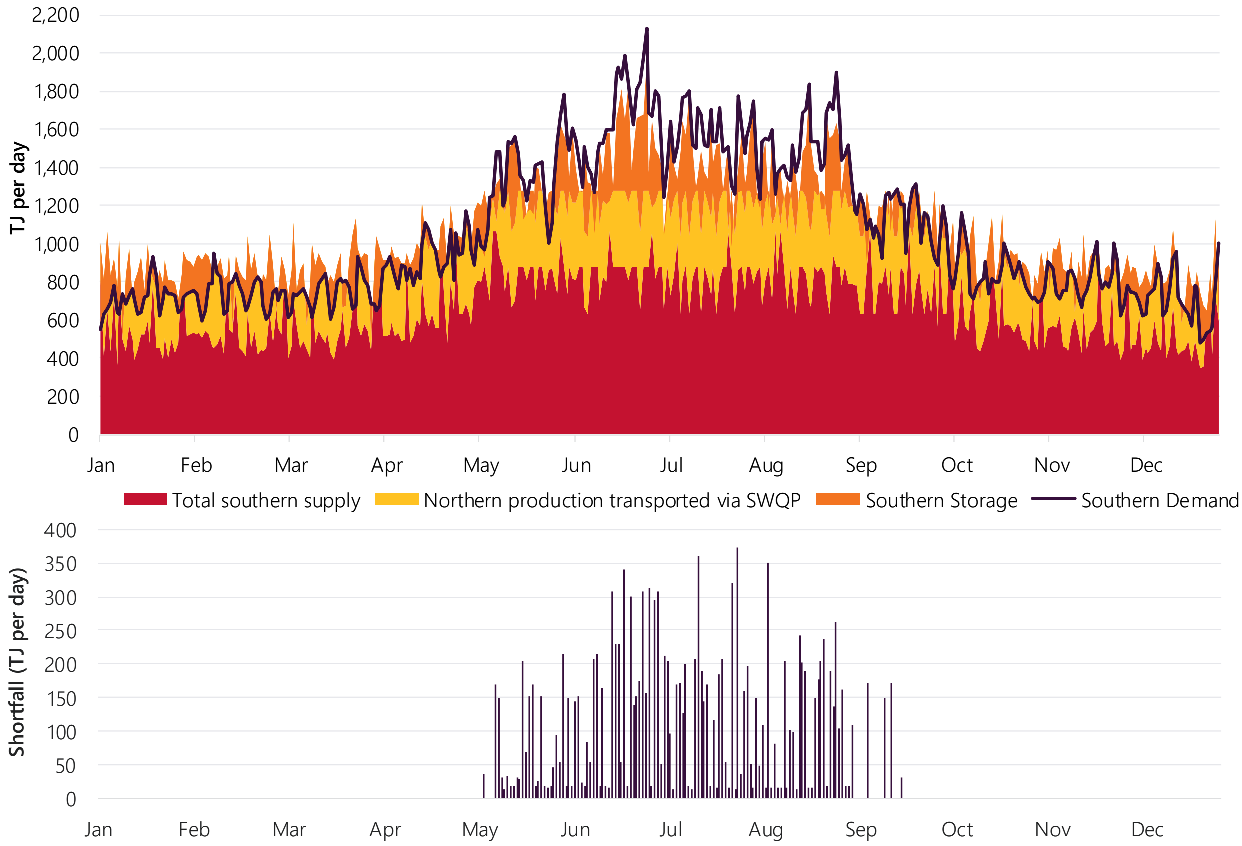


Figure 4 shows an example of a possible evolution of the daily supply-demand balance for the southern states in 2024 under the Central scenario.

Some supply gaps of between 13 TJ and 374 TJ are observed across winter 2024 as peak day production within southern states is insufficient to meet forecast daily demand, even with the South West Queensland Pipeline (SWQP) transporting northern gas at full capacity. Note that this is just one of many different possible evolutions from an ensemble of evolutions that have been considered in the GSOO. The *Uncertainties in gas supply adequacy* section below details the uncertainties that may lead to variations in the actual daily supply-demand balance observed in 2024, compared to the forecast.

Peak day field production in Victoria and other Victorian and South Australian pipeline infrastructure will limit the amount of further gas that could contribute to meeting southern domestic demand. The planned WORM augmentation of the Victorian DTS helps address these shortfalls by increasing the Iona UGS's refilling capacity and therefore increasing the system's peak day supply capacity. This project was originally planned to be operational by winter 2021, but is currently on hold while an Environmental Effects Statement (EES) is prepared. The GSOO assumes that the WORM will be operational before winter 2023.

Figure 4 Example evolution of daily supply-demand balance in southern states in 2024 including existing and committed projects (top) and forecast shortfalls in southern states (bottom), Central scenario



"Total southern supply" in Figure 4 includes all gas processed through Moomba processing facility, whether it comes from Moomba storage or Moomba production. This figure does not include the gas produced to refill Moomba storage.

Uncertainties in gas supply adequacy

Gas supply adequacy across the outlook is highly uncertain, particularly between 2022 and 2024 when projected tightness in the east-coast gas supply-demand balance coincides with key uncertainties in the electricity sector that may impact peak day and annual gas supply outlooks.

In the NEM, AGL has informed AEMO that it plans a staged closure of the coal-fired Liddell Power Station between 2022 and 2023. The Draft 2020 ISP forecast that a mix of existing generation, storage, and new distributed and utility-scale renewable generation will help maintain reliability at lowest cost after this closure. The Draft 2020 ISP also recommended greater interconnection between regions, to take advantage of the geographical diversity inherent in VRE, particularly wind generation, with the regions better able to share low marginal cost generation efficiently and reduce reliance on more costly local generation including GPG. If any of the investments in transmission, VRE, or storage (including Snowy 2.0) in the Draft 2020 ISP vary from the assumed timing (or are not built at all), then demand for GPG could be materially greater than forecast.

Some of the ageing thermal generation fleet is also recording declining availability, and demand for gas for GPG is highly sensitive to coal-fired generation outages. AEMO estimates that the prolonged unplanned outage of Loy Yang A2 in 2019, combined with higher demand forecasts from extended hot weather and coal quality issues at the Mount Piper Power Station, resulted in approximately 60 PJ more GPG gas usage than would otherwise have been required. Similar outages in future could increase gas demand above levels forecast in this GSOO, creating potential peak day gas shortages.

There are also key uncertainties in the gas industry, particularly between 2022 and 2024:

- In February 2020, the Commonwealth and New South Wales governments announced that additional gas supply will be secured for New South Wales consumers, injecting about 70 PJ per annum into the gas system. No clear indications have yet been given as to what this new supply may be, although the Port Kembla gas import terminal (up to 100 PJ), the Port of Newcastle gas import terminal (approximately 110 PJ), and Narrabri gas project (approximately 70 PJ) are all mentioned as priority projects in the Memorandum of Understanding[13]. This additional 70 PJ has not been included as part of the GSOO's committed or anticipated supply, but if it is available by the end of 2022, it may – depending on the location and daily maximum supply – push domestic supply gaps back by four years.
- The Victorian Government has announced that the ban on conventional gas exploration and development of Victorian onshore gas fields will be lifted from July 2021. This will allow the east coast gas market access to further sources of gas supply, but until exploration commences, the size of the resources and timing of any new supply remain unclear.
- Some existing southern gas fields are likely to cease production sometime between mid-2023 and mid-2024. Depending on the exact timing of the field depletion – which is very difficult to forecast accurately, even for field operators – this may put further pressure on meeting peak day gas demand in southern states from winter 2023.
- AGL has proposed the development of a floating LNG import terminal at Crib Point, near Hastings, and continues to progress the EES process, with an outcome expected mid-2020. If the project gains required approvals at this time, AGL projects that the import terminal should be operational by the start of 2022.
- Industrial users report continuing vulnerabilities to high domestic prices. Any significant changes in industrial activity, whether increases or decreases, will materially impact gas and electricity demand.
- Global demand for LNG is a key driver of the Queensland LNG export forecasts. Any impact to global LNG prices or the global supply chain may have impacts on the GSOO's LNG demand forecasts, with flow-on consequences on the domestic gas market. For example, early industry analysis suggests that the COVID-19 coronavirus will reduce global LNG demand for at least 2020. Depending on how much Queensland CSG producers are able to turn down their wells, this may result in excess gas in the eastern and south-eastern Australian domestic market in the next year.

In the long term, the role hydrogen may play in Australia's energy future is highly uncertain, but may also be hugely important for the transport, industrial manufacturing, electricity generation, storage, and export sectors. AEMO will continue to monitor developments and the likely impact of hydrogen on Australia's long-term energy mix. The 2021 GSOO will include a scenario reflecting a possible future where there is significant penetration of hydrogen into Australia's energy systems, and provide an assessment of potential long-term impacts of hydrogen on the gas industry.

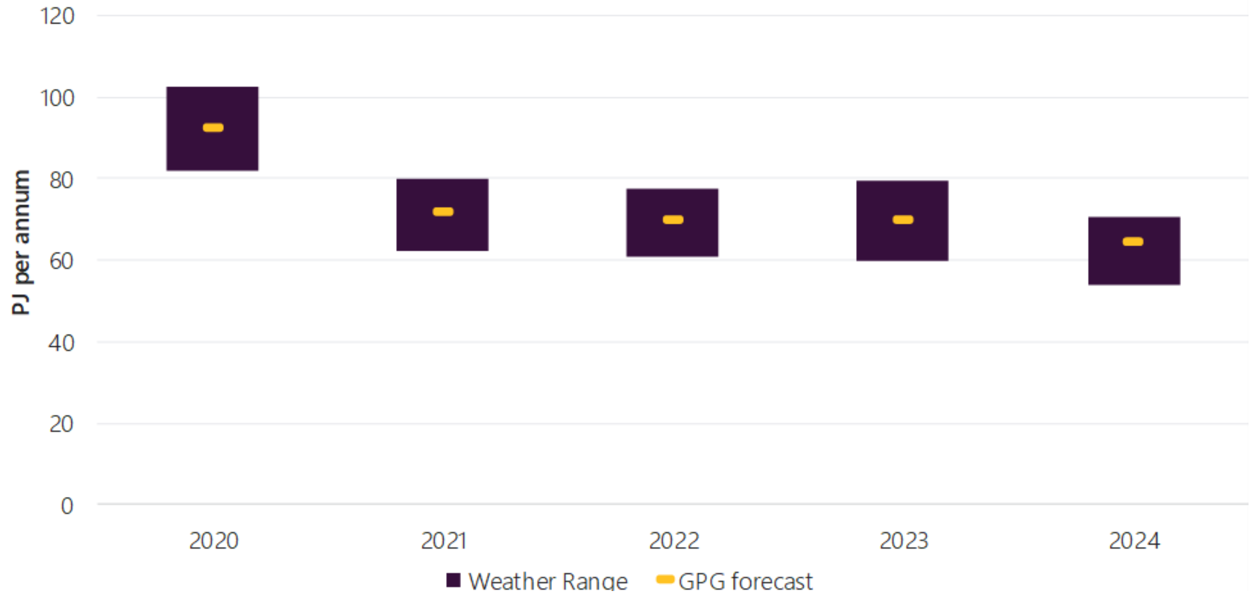
GPG, domestic gas demand, and weather variation

With increasing amounts of VRE in the NEM, annual gas demand for GPG is forecast to become increasingly sensitive to year-on-year variations in weather conditions. As part of AEMO's commitment to continuous improvement, this GSOO's GPG forecasts were developed using the actual weather patterns observed in the five most recent historical years. These weather conditions impact the amount of rainfall, wind, and solar observed in each year, as well as temperature, and thus drive variations in demand for gas and electricity, and the amount of other generation types (particularly GPG) required to flex up or down based on the impact of these weather variances on VRE.

[13] At https://energy.nsw.gov.au/media/2001/download.

Figure 5 shows possible GPG variance based on different weather patterns that might be observed. The 2020 GSOO analysis shows that under the range of GPG forecasts, domestic demand can be met from existing and committed supply until 2024, assuming no other uncertainties drive variations in the forecast.

Figure 5 Range of Central scenario GPG forecasts based on weather variation, 2020-24



The daily fluctuations of the 2020 GSOO's residential, commercial, and industrial demand forecasts were also tied to the same five most recent historical weather years. This means all forecasts for the domestic demand sectors (residential, commercial, industrial, and GPG) are driven by a consistent series of weather patterns, including historically observed coincident demand peaks within and between regions.

For example, in the Victorian DTS, on the day of peak system demand (peak residential, commercial, and industrial demand), forecasts for the next five years indicate that GPG demand can vary between 2 TJ a day and 60 TJ a day, depending on the reference weather year modelled. Of the top three peak demand days in the Victorian DTS, GPG can range between 2 TJ a day and 135 TJ a day. Depending on weather conditions, the impact of GPG on supply adequacy on peak demand days can range from trivial to significant.

AEMO is continuing to study how changes to the weather and climate may impact gas demand in the future, as all energy sectors become increasingly dependent on weather.

Contents

Tables

Figures

1. Introduction

The 2020 *Gas Statement of Opportunities* (GSOO) assesses the adequacy of eastern and south-eastern Australian gas reserves, resources, and infrastructure to meet forecast domestic gas demand while delivering expected export quantities to international markets, over a 20-year outlook period.

The GSOO analyses a range of potential futures that may impact the gas market in the next 20 years. It is focused on providing an adequacy assessment in the short to medium term and identifying longer-term development needs.

Information on the demand and supply forecasting inputs, assumptions, and methodologies used for this GSOO is available on the 2020 GSOO webpage[14].

This 2020 GSOO does not take into account the impacts the COVID-19 coronavirus may have on gas supply or demand in 2020. This situation is rapidly evolving, and at the time of writing the consequences for eastern and south eastern Australian gas supply adequacy are uncertain.

1.1 The Australian Domestic Gas Security Mechanism

The Australian Domestic Gas Security Mechanism (ADGSM)[15] was established in 2017 by way of Regulations which empower the Commonwealth Minister for Resources and Northern Australia to impose liquefied natural gas (LNG) export restrictions in a 'domestic shortfall year'. The ADGSM Guidelines[16] define a domestic shortfall year as a calendar year "*where the Minister has reasonable grounds to believe that there will not be a sufficient supply of natural gas for Australian consumers during the year unless exports are controlled, and that exports of LNG would contribute to that lack of supply*".

In deciding whether a domestic shortfall year has occurred, the Minister is informed by expert advice, including the information provided in AEMO's GSOO.

In 2019, the Commonwealth Government decided not to apply export controls for the 2020 year following its considerations under the ADGSM. A review of the ADGSM was performed in 2019 and found that the ADGSM has been working effectively to safeguard domestic gas supplies. On 24 January 2020, the Minister announced that the ADGSM will remain in place until its scheduled end in 2023[17].

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[14] AEMO's 2020 GSOO and supporting documents, and previous GSOOs, are at https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

[15] See https://www.industry.gov.au/regulations-and-standards/australian-domestic-gas-security-mechanism for information about the ADGSM.

[16] The Customs (Prohibited Exports) (Operation of the Australian Domestic Gas Security Mechanism) Guidelines 2017, at https://www.industry.gov.au/regulations-and-standards/australian-domestic-gas-security-mechanism.

[17] Commonwealth Government media release, at https://www.minister.industry.gov.au/ministers/canavan/media-releases/review-finds-gas-policy-boosts-domestic-supply-and-helps-lower.

1.2 Scenarios

The demand and supply inputs for the 2020 GSOO present three alternative futures for gas supply and demand in eastern and south-eastern Australia. These alternative futures are based on scenarios considering different rates of change impacting Australia's energy infrastructure, including Australia's eastern and south-eastern gas markets and the National Electricity Market (NEM).

The 2020 GSOO scenarios are a continuation of the themes and drivers considered in AEMO's Draft 2020 *Integrated System Plan* (ISP)[18], and include a holistic view of the pathway for energy market change as well as the transformation of the physical infrastructure required in the NEM and, where appropriate, the eastern and south-eastern gas markets to support this change. The Draft 2020 ISP was published in December 2019, and considered the needs of all energy users, both electricity and gas.

In the **Central scenario**, the pace of transition is determined by market forces under current Commonwealth and state government policies. A policy is current if it is a commitment made in an international agreement, legislated in Australia, required by regulation, in receipt of material funding from a state or Commonwealth government budget, or otherwise if the Council of Australian Governments (COAG) has advised AEMO to incorporate the policy. The Central scenario therefore incorporates:

- The NEM's share of the Commonwealth Government objective of reducing emissions by at least 26% by 2030.
- Renewable Energy Targets in Victoria (VRET, 50% by 2030) and Queensland (QRET, 50% by 2030).
- The Snowy 2.0 energy storage project, assumed to be operating by March 2025.
- All current Commonwealth or state government policies relating to distributed energy resources (DER) and energy efficiency.

The **Step Change scenario** considers stronger growth and aggressive action to address climate risks. In this scenario, commitment to more rapid decarbonisation is forecast to lead to accelerated exits of existing thermal generation. Key differences to the Central scenario include:

- Faster technological improvements leading to a greater electrification of the transport sector, energy digitalisation, and consumer-led innovation.
- Higher population and economic growth.
- More aggressive decarbonisation goals, which particularly affect the role of gas in providing electricity in the NEM, with greater penetration of renewable generation alternatives but earlier retirements of coal-fired generators.
- Technology innovation and increased DER uptake.
- Greater uptake of electric vehicles (EVs) and a stronger role for energy management solutions, including vehicle-to-home opportunities.
- A strong case for fuel switching from gas to electric appliances, particularly due to the opportunities to decarbonise energy consumption from electrification, and earlier uptake of supportive policies than in the Central scenario.
- A stronger role for energy efficiency measures in both gas and electricity appliances, and increased savings due to building code improvements that encourage the installation of better insulation and glazing, reducing the energy required for space heating.

Apart from the impacts on end-user demand forecasts, the Step Change scenario does not otherwise consider decarbonisation of the gas sector, but work is ongoing to consider this in more detail in future GSOO publications.

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[18] At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp.

The **Slow Change scenario** is characterised by a slow-down of the energy transition, reflected in slower changes in technology costs, and low political, commercial, and consumer motivation to make the upfront investments required for significant emissions reduction. Key differences to the Central scenario include:

- Lower economic growth.
- Lower overall electricity consumption.
- Less DER.
- Lower decarbonisation of the energy sector. With the reduced decarbonisation ambition, there is increased value in refurbishing ageing coal-fired generators as they approach the end of technical life, but also less development of renewable generation, resulting in a neutral impact on gas-powered generation of electricity (GPG).

Table 2 below summarises key energy drivers considered of most relevance to the gas market across the three scenarios.

Table 2 Scenario drivers of most relevance to the gas market

Driver	Slow Change scenario	Central scenario	Step Change scenario
Economic growth and population outlook	Low	Moderate	High
Energy efficiency improvement	Low	Moderate	High
Fuel switching – from gas to electric appliances	Weak economic case for fuel switching	Average economic case for fuel switching	Strong economic case for fuel switching
Gas price	Low gas prices	Medium gas prices	Medium gas prices
Commodity price	Low	Medium	Medium
Foreign Exchange Rate – AUD to USD	Weak	Medium	Strong
Large-scale renewable generation uptake	Low	Moderate	High

1.3 Improvements for 2020 GSOO

In a change since the 2019 GSOO, the Australian Capital Territory region was modelled separately from the New South Wales region. This allowed AEMO to develop richer insights into the key trend drivers for both regions and identify structural and behavioural changes and model energy policy impacts separately.

Survey information from gas distribution networks has improved the growth rate calculations for the commercial gas users.

With increasing amounts of variable renewable energy (VRE) in the NEM, annual gas demand for GPG is forecast to become increasingly sensitive to year-on-year variations in weather conditions. As part of AEMO's commitment to continuous improvement, this GSOO's GPG forecasts were developed using the actual weather patterns observed in the five most recent historical years[19]. These weather conditions impact wind, solar, rainfall and temperature, and thus drive both demand for gas and electricity and the amount of other

[19] A full set of historical data across residential, commercial, and industrial gas demand in all GSOO geographical locations was only available for the most recent five historical years. This GSOO's GPG forecasts therefore only considered these same five historical years to maintain consistency across the full suite of demand forecasts, despite having access to the nine historical weather years of data that was used in the Draft 2020 ISP.

generation types (particularly GPG) required to flex up or down based on the impact of these weather variances on VRE.

The daily fluctuations of GSOO's residential, commercial, and industrial demand forecasts were also tied to the same five most recent historical weather years. This means all forecasts for domestic demand sectors (residential, commercial, industrial, and GPG) are driven by a consistent series of weather patterns, including historically observed coincident demand peaks within and between regions.

AEMO is working closely with CSIRO and the Bureau of Meteorology (BOM) through the Electricity Sector Climate Information (ESCI) project[20] to understand the likely and possible impacts of climate change as they relate to the electricity sector. This project will improve information on the likely future changes to extreme weather events, including concurrent and/or compounding events to inform analysis on long-term climate risk. This work will improve AEMO's ability to forecast supply adequacy across gas, electricity, and the intersection between the two sectors, as all energy sectors become increasingly dependent on weather.

The GSOO's supply adequacy assessment has been modelled across all five historical weather years. Any annual assessment given is an average across the five weather outcomes, while any daily assessments or figures will refer to a single weather outcome, unless otherwise specified.

Further improvements to demand forecasting have been made, and are discussed in detail in Section 2.3.1.

1.4 Supplementary information

Supporting material including supply input data files, methodology reports, and figures and data is available on AEMO's website at https://www.aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo, 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. These files also provide an update of reserves and resources and cost estimates used for the GSOO modelling.

Additional material is listed in Table 3 below.

Table 3 Supplementary information

Information source	Website address and link
CORE Energy wholesale gas price outlook	Report: https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2019/core-energy-delivered-wholesale-gas-price-outlook-2020-2050_report.pdf?la=en&hash=4D53CA4DD239E0A075336D0B572462C7 Databook: https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2019/core-energy-delivered-wholesale-gas-price-outlook-2020-2050_databook.xlsx?la=en&hash=5260BC9179F0328EB4C26D796980EFF1
Deloitte Access Economics long term economic scenarios forecast	https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2019/long-term-economic-scenario-forecasts---deloitte-access-economics.pdf?la=en&hash=46C9F0C5ED8EF6C6E42FE1988D0D16FB
AEMO Forecasting portal	http://forecasting.aemo.com.au/
Gas Bulletin Board – Map and Reports	https://www.aemo.com.au/energy-systems/gas/gas-bulletin-board-gbb

[20] For more information on the ESCI project, see https://www.environment.gov.au/climate-change/adaptation.

2. Consumption forecasts

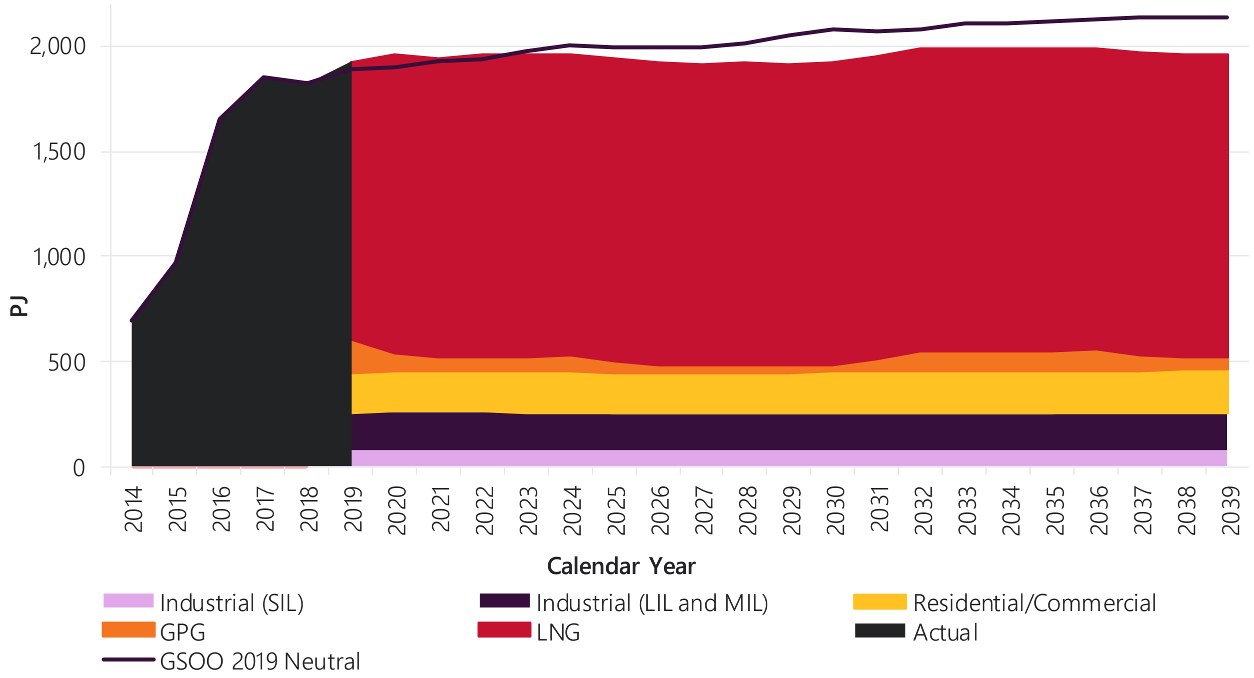
2.1 Total eastern and south-eastern gas consumption forecasts

Key trends

- Gas consumption trends continue to be driven by LNG export demand, given its relative volume.
- Short-term trends in total east coast gas consumption forecasts are relatively flat, and slightly higher than the forecast in the 2019 GSOO, mainly due to slightly higher forecasts for LNG exports and an increase in forecast GPG for 2020.
- Longer-term forecasts show a reduction in total projected gas consumption, and a lower total forecast than in the 2019 GSOO from the mid-2020s, primarily due to the lower GPG forecast.

Figure 6 shows the 20-year total consumption forecast for eastern and south-eastern gas markets under the Central scenario, and the breakdown of the forecast by consumer types. Gas demand forecasts for the 2020 GSOO are available on the AEMO Forecasting data portal[21].

Figure 6 Gas consumption actual and forecast, 2014-39, all sectors, Central scenario (PJ)



Note: LIL, MIL, and SIL are large, medium, and small industrial loads.

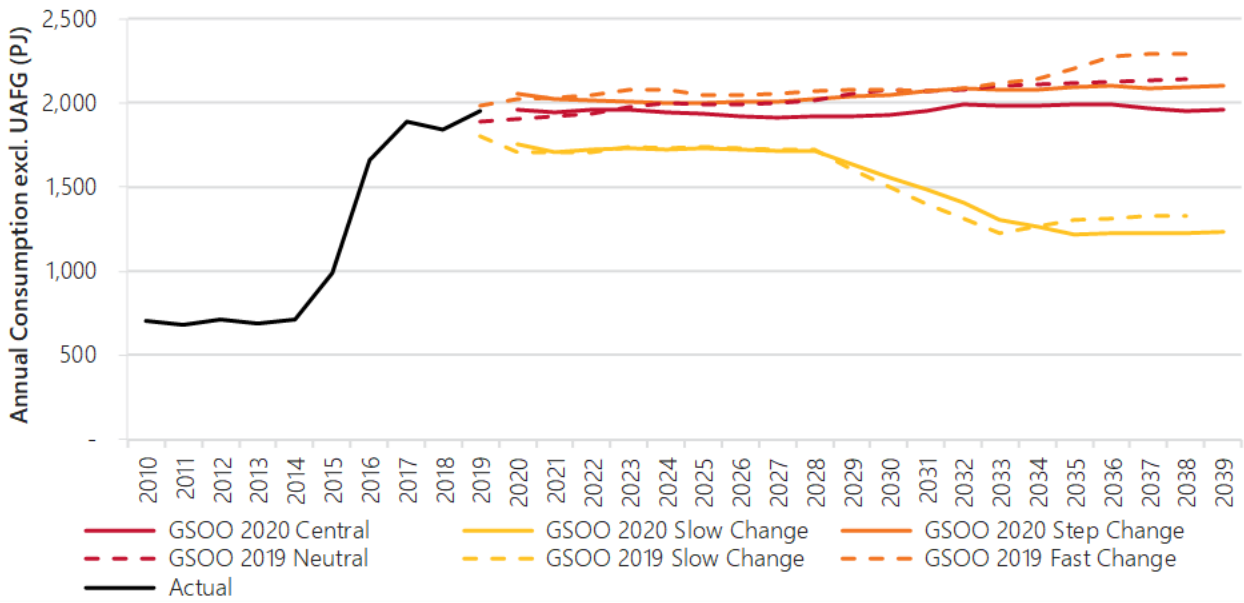
[21] At http://forecasting.aemo.com.au/. Select 'GSOO 2020' from the publication drop-down.

2.1.1 Comparison of 2020 GSOO and 2019 GSOO consumption forecasts

Figure 7 compares the 2020 GSOO and 2019 GSOO forecasts for annual consumption across all three scenarios. In the Central scenario, differences include:

- In the short term, gas consumption is expected to be slightly higher than in the 2019 GSOO, with LNG exports expected to rise slightly, as two of the three LNG facilities push towards full nameplate capacity, and GPG consumption increases in 2020, driven by delays in VRE development and the declining availability of ageing thermal generators.
- In the medium to longer term, forecast total gas demand is lower than in the 2019 GSOO, due to less forecast growth in GPG usage. GPG is still expected to continue to provide a reliability and security role in the NEM to complement VRE and coal-fired generation. GPG consumption is forecast to stabilise in the medium term, then grow slightly in the longer term as further coal generation retires. Compared to the 2019 GSOO, Central GPG forecasts feature more VRE and energy storage projects, and greater NEM transmission interconnection augmentations, allowing greater resource-sharing between regions.

Figure 7 Gas consumption actual and forecast, 2010-39, all sectors, all scenarios, compared to equivalent 2019 GSOO scenarios (PJ)



2.2 Trends in consumption drivers

2.2.1 Economic and demographic outlook

Gross State Product and industrial production

AEMO engaged Deloitte Access Economics (Deloitte) to develop long-term economic forecasts for each Australian state and territory as a key input to AEMO's demand forecasts, and consistent with the scenarios outlined in Section 1.2.

In Deloitte's central scenario (aligned to the 2020 GSOO Central scenario), Gross State Product (GSP) is forecast to grow at 3.1% annually on average across the NEM regions in the short term (0-5 years), spurred by public expenditure and a low Australian dollar. GSP is then forecast to transition to an average long-term growth rate of 2.7% annually, driven by labour force and productivity growth. Productivity is expected to lift and wage growth is expected to pick up in the longer term, with broad unemployment measures down and rates of underemployment starting to return to longer-term averages. Deloitte's central scenario also forecasts industrial production shrinking as a proportion of Australia's economic output as the manufacturing sector continues its long-term decline. Industrial production is forecast to grow at 2.3% per annum in the short term and remain at a long term average annual rate of 2.2%.

Deloitte's weak economic outlook (aligned to the 2020 GSOO Slow Change scenario) assumes countries reduce their international engagement, resulting in less efficient allocation of resources. With a long-term annual average growth rate of 2.0%, economic growth is lower relative to the Central scenario. Lower real household disposable income growth flows through the economy affecting industry with an annual average growth rate of 1.6%.

In contrast, Deloitte's strong economic outlook (aligned to the 2020 GSOO Step Change scenario) is based on an increase in global economic growth, increase in population growth in Australia, productivity gains from skilled migration, and increases in international trade of goods and services. Economic growth is higher relative to Deloitte's central scenario, with a long-term average annual growth rate of 3.3%. Improvements in global growth and a relatively subdued impact on the exchange rate also create positive dividends for industrial production industries, with a long-term average annual growth rate of 2.7%.

Economic impacts of COVID-19 coronavirus

Deloitte's economic forecasts were developed in April 2019, before the COVID-19 coronavirus outbreak and summer bushfires. AEMO is currently updating its economic forecasts for 2020-21 publications. The updated forecasts will consider the effects of these shocks, particularly the coronavirus affecting various economic sectors, including services trade, supply chain disruptions, equity markets, energy, and fuel. Near-term economic activity is expected to be lower than was captured in the Deloitte forecasts, with at least a short-term significant drag on tourism, accommodation, food services, wholesale and retail trade, and transport services. At the time of this GSOO publication, the magnitude of such economic disruption is highly uncertain, including the time it will take for the economy to recover.

Population and connections

The 2020 GSOO updates the gas connection forecasts with a higher population forecast than the 2019 GSOO and considers recent growth rates in gas connections. In the Central scenario, approximately 170,000 additional new gas connections by 2038 are forecast compared to the 2019 GSOO, the majority of which are in New South Wales. This reflects the greatest realignment to recently observed connections growth. Other regions have similar or lower projections compared to the 2019 GSOO.

2.3 Consumption forecasts by sector

2.3.1 Residential and commercial consumption

Key trends

- Residential and commercial sector gas consumption in the Central scenario is projected to grow from 191 petajoules (PJ) in 2020 to 205 PJ in 2039. Over the 20-year outlook, this is similar to the 2019 Neutral forecast of 201 PJ by 2038, although the underlying drivers have varied.
- The lower trajectory of the 2020 Slow Change scenario compared to the 2020 Central Scenario reflects a lower assumed outlook for the sector, with lower connections forecast and less economic activity.
- The 2020 Step Change scenario reflects higher assumed population and connections growth, tempered by greater potential for gas-to-electric fuel switching (gas heating to reverse-cycle air-conditioning, and gas to electric hot water systems) and higher energy efficiency impacts, compared to the 2020 Central scenario. The net effect of these consumption drivers results in a relatively similar consumption forecast to the 2020 Central scenario in the medium term.

AEMO has developed forecasts of residential and commercial gas consumption using forward estimates of consumption on a per connection basis. The type and forecast number of new connections therefore drives the growth trajectory, subject to other behavioural influences, such as in response to pricing stimuli, appliance fuel switching, and broader energy efficiency impacts.

Table 4 summarises the estimated impact of changes in key drivers on the residential gas demand forecasts, compared to the 2019 GSOO forecast.

Table 4 Estimated impact on forecasts due to changes to residential and commercial drivers for the Central scenario

Driver	Estimated impact on forecasts by 2039 (PJ)	Explanation
Consumer trends and connection forecasts	-22	Updated split of commercial and residential usage with a lower growth rate now forecast for commercial gas connections, despite growth forecast in connection numbers. Reflecting this update, the Central scenario forecast (for this component) has decreased by approximately 22 PJ in 2038, compared to the 2019 GSOO forecast.
Energy efficiency, fuel switching and price response	+24	AEMO has identified a decreased potential of approximately 24 PJ in the Central scenario compared to the 2019 GSOO, reflecting updated methodologies and forecast.
Net impact on residential forecasts	+2	

Energy efficiency and gas to electric fuel-switching continue to show high potential in reducing future usage of gas, with reductions forecast of 27 PJ, 29 PJ, and 45 PJ in the Slow Change, Central, and Step Change scenarios respectively by 2039.

Details of factors reducing projected consumption that have been updated in the 2020 GSOO are:

- Commercial sector growth rate – a key model update this year was new information obtained from surveys to the gas distributors focused on the commercial and residential sectors, to receive both the usage differences between the two sectors and the relative year-on-year growth in connections. Previously, AEMO had assumed new commercial connections grew at the same rate as new residential connections. The updated survey information shows year-on-year growth for the commercial sector to be lower than previously assumed. Incorporating the historical trends has resulted in a downwards revision of the commercial sector's gas consumption for Tariff V by approximately 15 PJ by 2038 in the 2020 Central scenario when compared to the 2019 Neutral scenario.
- Energy efficiency impacts – these are linked to current or planned energy efficiency schemes, as forecast for AEMO by Strategy.Policy.Research[22]. The Central scenario impact is approximately 13.5 PJ less gas consumption in 2039 compared to the 2019 GSOO, while the Slow Change and Step Change impacts in 2039 are lower gas consumption by approximately 11.1 PJ and 11.5 PJ, respectively. The reduction in forecast energy efficiency consumption savings is due to changes in the consultant's input and modelling assumptions, revised estimates of the impact from state schemes for the 2020 GSOO, and post-model adjustments made by AEMO for the 2019 GSOO.
- Gas to electric fuel-switching – the negative impact on consumption from fuel-switching has decreased in the Central and Slow Change scenarios by 4.2 PJ and 8.2 PJ respectively in 2039, compared to the 2019 GSOO, driven by methodological changes to estimate fuel-switching behaviour for water heating. In the

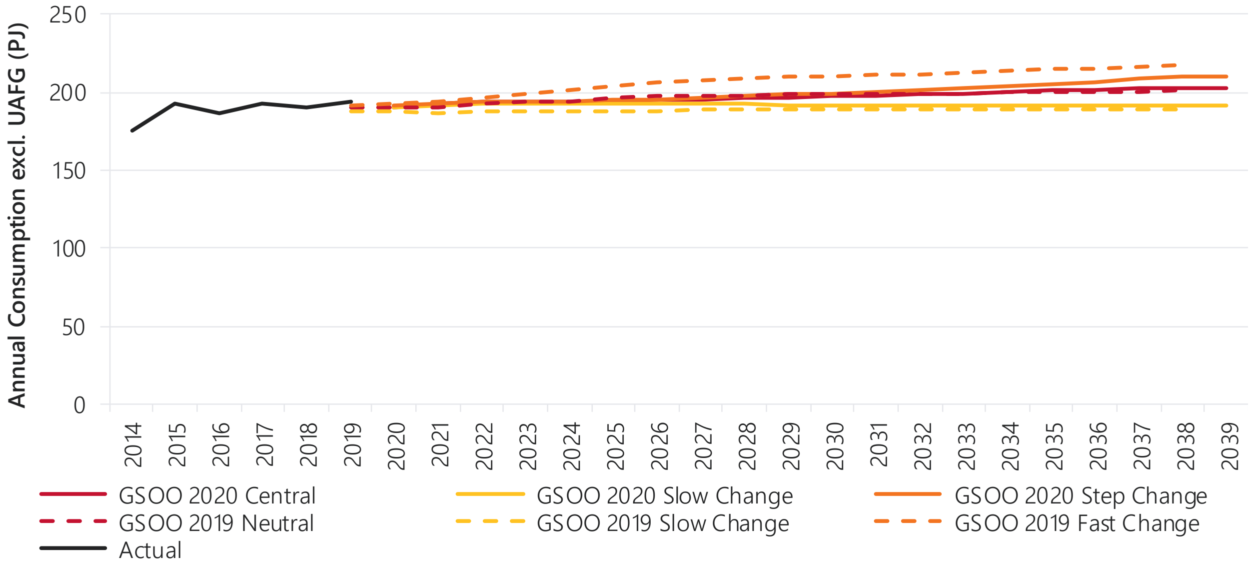
[22] Strategy.Policy.Research, *Energy Efficiency Forecasts: 2019 – 2041: Final Report*, July 2019, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/StrategyPolicyResearch_2019_Energy_Efficiency_Forecasts_Final_Report.pdf.

2019 GSOO, this was modelled on a transition from 3-star to 5-star gas water heating, but in the 2020 GSOO, it was derived from estimates of the impact of relevant policy measures on water and space heating, based on data from the Commonwealth Department of Environment and Energy. The Step Change scenario shows a higher impact (an additional 8.8 PJ), which would lower the gas consumption forecast, reflecting the greater potential for a transition from gas heating to reverse-cycle air-conditioning under this scenario.

- Gas price impacts – while high gas prices are forecast to have a negative impact on gas consumption, the impact is approximately 6 PJ less by 2038 for the Central scenario, relative to the 2019 GSOO forecasts. This reduced impact is due mainly to a revised retail price model more closely benchmarked to current retail offers, lowering the price elasticity of demand.

Figure 8 shows forecast residential/commercial gas consumption for the three scenarios, and compared to the 2019 GSOO demand forecast.

Figure 8 Residential/commercial annual consumption actual and forecast, 2014-39, all scenarios, and compared to 2019 GSOO



2.3.2 Industrial consumption

Key trends

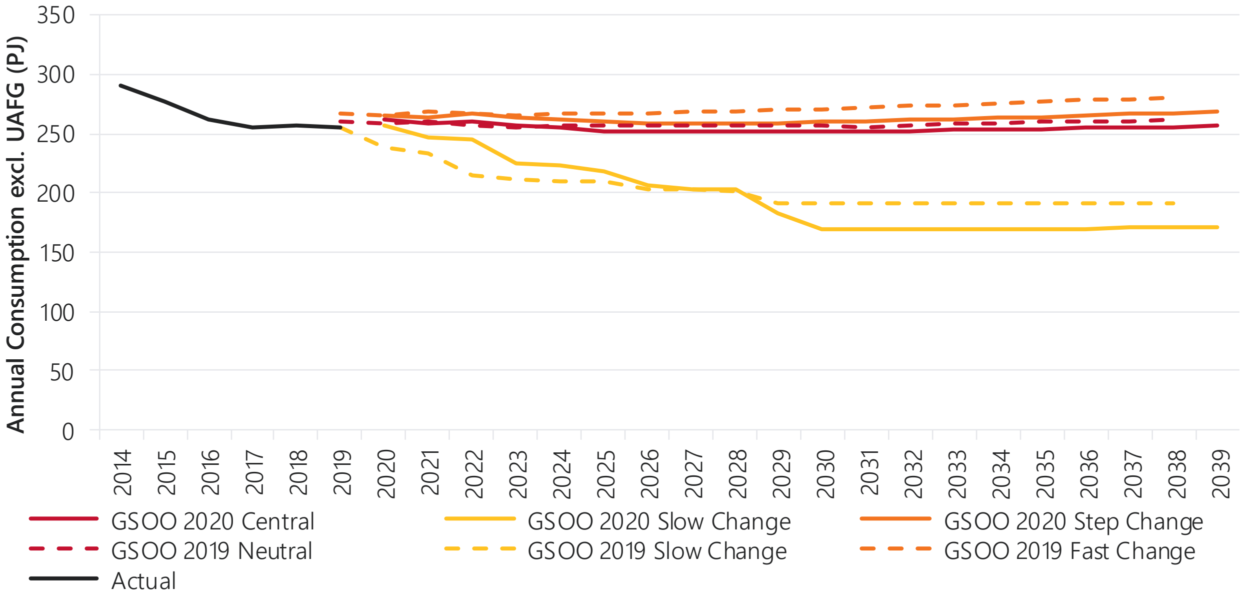
- The 2020 GSOO Central scenario industrial consumption forecast is very similar to the 2019 Neutral forecast over the 20-year outlook, with total consumption projected to be 256 PJ in 2039 compared to 255 PJ last year.
- The Slow Change scenario forecasts a decline in industrial consumption in the short to medium term (2019-29), reflecting risks of closures and demand destruction resulting from gas price increases and a subdued economic outlook.
- The similar industrial consumption trajectories of the 2020 GSOO Step Change and Central scenarios reflects the lack of strong upside opportunities forecast for the sector. Industry feedback from large customers interviewed suggests continued concern exists regarding the impact of relatively high gas prices, particularly for those customers with only shorter-term gas supply agreements in place.

AEMO forecasts the consumption of the industrial sector based on two categories:

- Large and Medium Industrial Loads (LILs and MILs) – these facilities were forecast individually. LILs are generally categorised as facilities that have consumed more than 800 terajoules (TJ) a year at least once historically, while MILs typically consume 500-800 TJ a year. Typically, LILs and MILs include aluminium and steel producers, glass plants, cement plants, paper and chemical producers, oil refineries, some larger food processors, and on-site GPG that is not included in GPG forecasts.
- Small Industrial Loads (SILs) – these facilities are forecast in aggregate. SILs consume more than 10 TJ but less than 500 TJ annually at individual sites, and include customers such as food manufacturing, casinos, shopping centres, hospitals, stadiums, and universities. This sector shows a moderate growth outlook in the Central and Step Change scenarios. However, these new connections, on average, use much less gas than existing industrial users of gas, so the impact on future gas consumption growth is lower than it has been in the past for newly connecting facilities. For example, in Victoria since 2012, there has been a net increase in connections of approximately 4%, but the total consumption for this sector has remained flat at approximately 31, 000 TJ a year. This is largely due to the average consumption for all SILs dropping steadily from 41 TJ a year to 39 TJ a year during the period.

Figure 9 shows the overall trend in forecast industrial gas consumption for the three scenarios, and compared to the 2019 GSOO demand forecast.

Figure 9 Industrial annual consumption actual and forecast, 2014-39, all scenarios, and compared to 2019 GSOO



Interviews and surveys with industrial gas consumers still indicate that concern exists regarding the impact of relatively high gas prices, maintaining a continued risk of closures and demand destruction. The sector is also forecast to face an increasingly challenging economic environment (due to lower international competitiveness given the relatively high cost of domestic gas, for example), with limited growth opportunities. As a result, industrial consumption is forecast to remain relatively flat in both the Central and Step Change scenarios, with a lack of strong upside opportunities for growth.

By comparison, the 2020 Slow Change scenario shows more downside risk associated with the potential closure of LILs and declining production due to weakening global and domestic demand. Compared to the 2019 Slow Change scenario, more customers have now entered new gas contracts, firming up the outlook for the first 10 years of the forecast.

Any significant changes in industrial activity, whether increases or decreases, will materially impact gas and electricity demand. In addition, several LIL industrial customers indicated they are actively looking at efficiency projects to reduce their gas consumption and/or fuel switching to either biomass or coal where feasible.

2.3.3 GPG

Key trends

- In the short term, increasing VRE capacity and transmission infrastructure augmentation in the NEM is forecast to lead to a near-term decline in demand for GPG, similar to the trend in the 2019 GSOO.
  - The forecasts for 2020 are 17 PJ (24%) higher than last year, due to delays in commissioning of new VRE and accounting for the declining availability of the ageing coal-fired generation fleet.
  - From 2021, GPG forecasts are lower than those in the 2019 GSOO, as more utility wind and solar and distributed solar "rooftop" photovoltaic (PV) generation is now expected to be built in the NEM, particularly in response to increased state renewable energy targets.
  - In total, the Draft 2020 ISP forecasts approximately 6,300 megawatts (MW) of new renewable generation to be constructed and start operating in the NEM by mid-2026, including the Snowy 2.0 pumped hydro project.
- Based on forecasts of the evolution of the NEM in the Draft 2020 ISP, GPG is expected to continue to provide a reliability and security role to complement VRE, but gas consumption for GPG is forecast to reduce in the medium term. Further electricity transmission interconnection and the inclusion of energy storage projects such as the Snowy 2.0 project lead to increased sharing of renewable resources and less reliance on GPG as a source of firm supply.
- As more coal-fired generation retires in the long term, gas consumption for GPG in the NEM is forecast to grow again, recovering to levels similar to those forecast for the 2020 calendar year.

Variations in forecast GPG consumption highlight that these forecasts are uncertain and highly dependent on factors including changes in the NEM's generation technology mix, particularly coal-fired generation retirements, and the timing, location, and scale of new transmission infrastructure or augmentations in the NEM. All NEM outcomes used in 2020 GSOO modelling are consistent with AEMO's Draft 2020 ISP.

Stakeholder consultation after the 2018 ISP identified improvements to inputs and assumptions, which AEMO used in developing the Draft 2020 ISP. A number of these impact GPG annual consumption forecasts, as outlined below.

Compared to the 2018 ISP (which was used to develop the 2019 GSOO forecasts), the Draft 2020 ISP modelled:

- Approximately 2,560 MW of additional capacity from utility solar, storage, and wind projects which are under development or have started generating in the NEM earlier than forecast in the 2018 ISP, and an observed faster pace of development in distributed renewable energy generation.
- A stronger legislated VRET, based on stronger targets from the Victorian Government[23], driving more renewable energy in Victoria out to 2030.
- The Snowy 2.0 energy storage project as committed (in the 2018 ISP, this was considered as an alternative scenario).
- Updates to the forced outage rate and maintenance assumptions for thermal generation based on recent historical performance, resulting in brown-coal fired generation being less reliable.

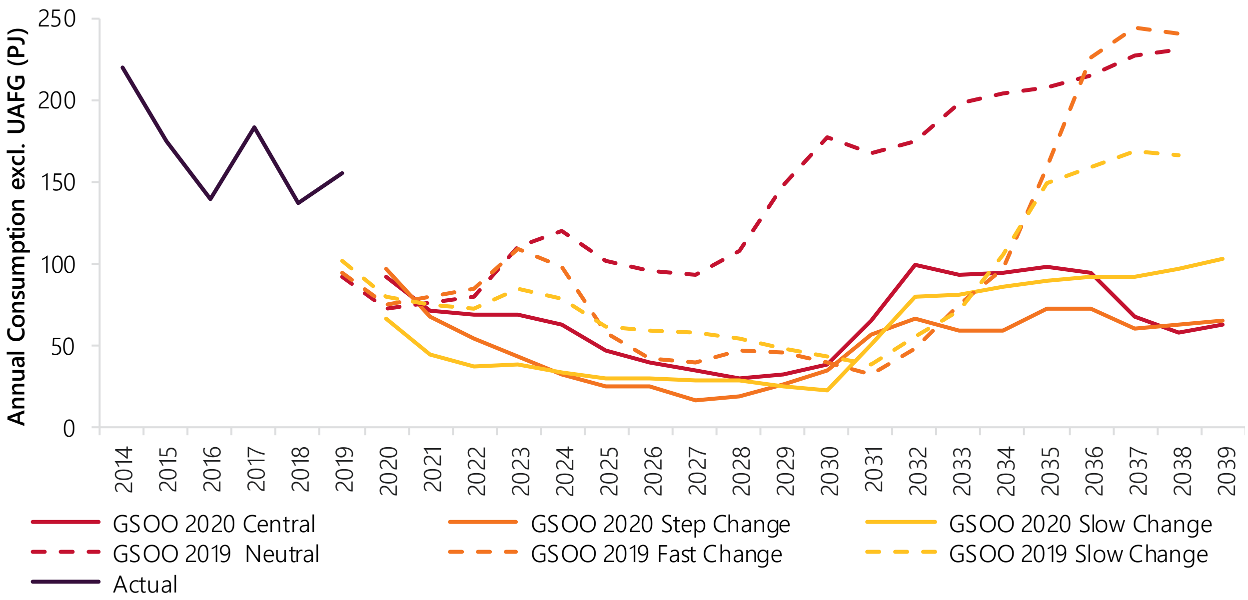
[23] See https://www.energy.vic.gov.au/renewable-energy/victorias-renewable-energy-targets.

AEMO also introduced GSOO modelling improvements to capture and address some key weather-related uncertainties. A more comprehensive assessment of weather variability was implemented, with the GSOO supply adequacy assessment studying GPG outcomes across multiple reference years. This change:

- Better captured the projected effects of weather on the system and the variable operation of wind, solar, and hydro generation (and consequently GPG).
- Led to the 2020 ISP scenarios tending to present a more even distribution of solar, wind, and storage installations on a capacity basis than the 2018 ISP.
- Incorporated hydro inflow variability and the impact of this variability on hydro generation (and subsequent demand for GPG). GPG will help compensate for hydro generation reductions during drought conditions, and demand for GPG decreases during wetter conditions.

Figure 10 shows the actual and forecast annual consumption for GPG, and a comparison to the 2019 GSOO demand forecast, across each of the scenarios.

Figure 10 GPG annual consumption actual and forecast, 2014-39, all scenarios, and compared to 2019 GSOO



The Draft 2020 ISP forecast increasing VRE capacity in the NEM, to meet various Commonwealth and state government policies, driving a continued drop in GPG consumption from historical levels. Based on information available to AEMO at August 2019[24], the Draft 2020 ISP forecast that over 2,800 MW of new renewable generation (committed or under construction) would be generating in the NEM by mid-2021, while nearly 3,500 MW more renewable generation was either committed or forecast by mid-2026, including the Snowy 2.0 pumped hydro project.

Six new major transmission augmentation projects that were recommended by the Draft ISP as either Group 1 priority grid projects or Group 2 near-term grid projects have been assumed to progress for these GPG forecasts:

- Queensland – New South Wales Interconnector (QNI) minor by 2021-22 and Victoria – New South Wales Interconnector (VNI) minor by 2022-23, to provide increased supply between Queensland, New South Wales, and Victoria.

[24] Based on AEMO's Generator Information, August 2019 release, at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

- EnergyConnect by 2023-24, to link South Australia and New South Wales.
- HumeLink by 2024-25, to increase transfer capacity between the Snowy Hydro scheme and New South Wales load centres.
- VNI West and QNI Medium from 2026-27, to provide larger increases in supply between Queensland, New South Wales, and Victoria.

As each of these new transmission projects is commissioned, the ability for NEM regions to share resources (particularly geographically diverse VRE) is increased, and therefore demand for GPG is forecast to decrease.

By the early 2030s, further coal-fired generation retirements are expected, at which point GPG is forecast to increase to support the variability of increasing amounts of VRE.

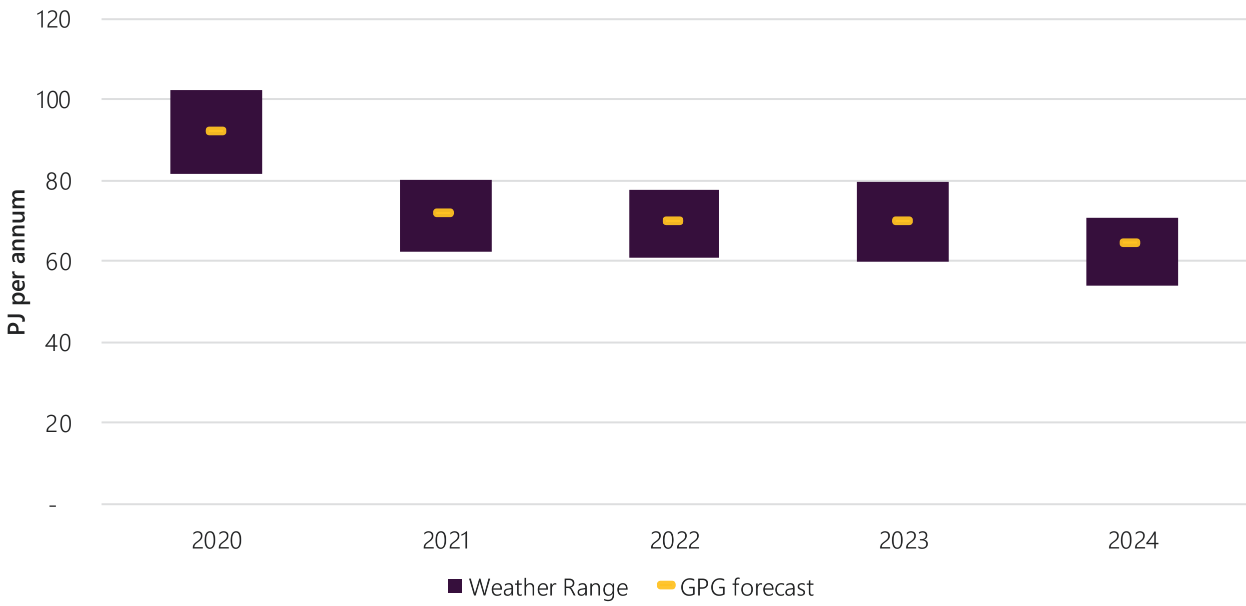
Under the Central scenario, Marinus Link was forecast to be commissioned mid-2036. With surplus renewable generation from Tasmania then available to the mainland NEM, GPG is forecast to again decline in this scenario, despite continuing coal-fired generation retirements.

GPG forecasts are becoming increasingly uncertain, and contain key assumptions around coal generation fleet reliability and retirements, the timing and cost of generation technologies, and the major NEM transmission augmentation projects. If any of these vary from the assumptions, GPG forecasts may vary. Further discussion on these, and other, uncertainties can be found in Chapter 5.

GPG forecasts also vary depending on the weather. If wind or solar generation suddenly drops off, GPG is often the technology most able to quickly ramp up to replace the missing generation. With increasing amounts of VRE forecast to be installed in the NEM, annual gas demand for GPG is forecast to become increasingly sensitive to year-on-year variations in weather conditions. For example, in a year that faces weather patterns conducive to regular strong wind conditions and clear, sunny skies, GPG is likely to be dispatched less in the NEM. Conversely, in a year with low wind and regular cloudy conditions, or hydro droughts, GPG may be called upon regularly.

As mentioned in Section 1.3, this GSOO's GPG forecasts were developed using the actual weather patterns observed in the five most recent historical years. Figure 11 shows the possible GPG variance for the next five years, based on the different weather patterns that have been explored. Based on the range in weather conditions observed in the past five years, demand for GPG can vary by approximately +/- 15%. The GPG forecasts in Figure 10 correspond to an average GPG consumption across all five historical weather patterns. All GSOO supply adequacy outcomes have been tested against all five historical weather years.

Figure 11 Range of Central scenario GPG forecasts based on weather variation, 2020-24



2.3.4 LNG

AEMO surveyed the LNG consortium following the 2019 GSOO, and assessed long-term global trends to update the LNG forecasts used in the 2020 GSOO. The forecasts are shown in Figure 12 for all scenarios, and with a comparison to the 2019 GSOO forecasts.

Figure 12 LNG annual consumption actual and forecast, 2014-39, all scenarios, and compared to 2019 GSOO

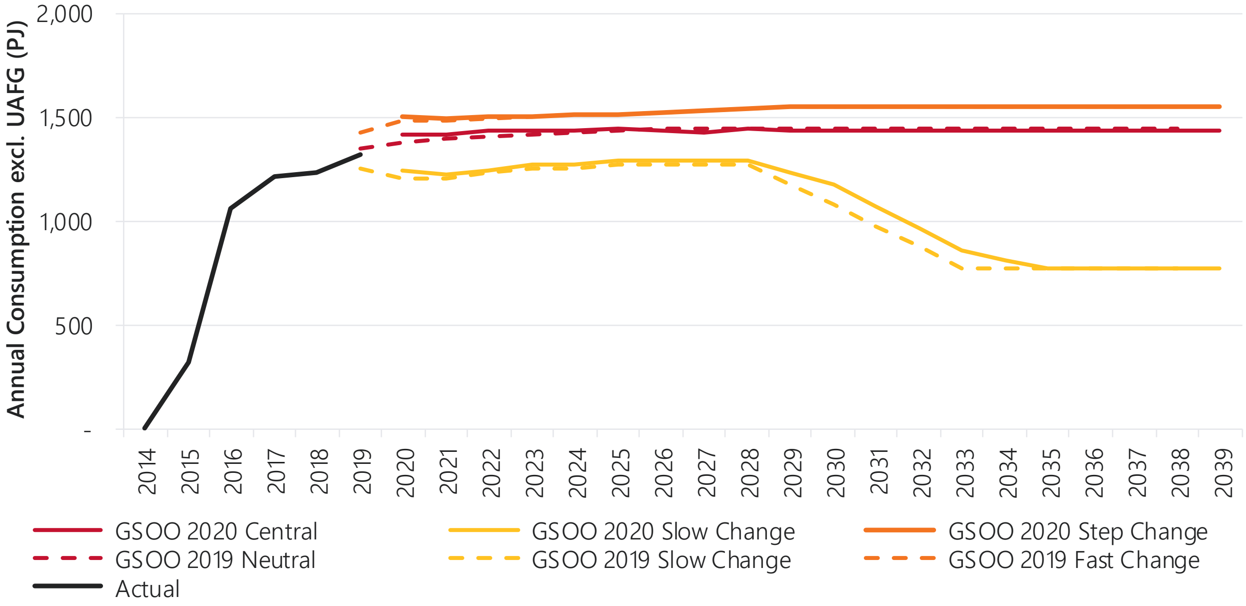


Figure 12 shows that:

- In the short term (2020-25), demand in the Central scenario is expected to rise slightly, as two of the three LNG facilities push towards full nameplate capacity. Forecast demand is marginally higher than the 2019 GSOO Neutral scenario.
- The 2020 GSOO Slow Change scenario captures a fall in contract quantity, similar to the 2019 Slow Change scenario but with a slightly lower decline, reflecting facility onsite gas usage and an updated estimate of remaining contract obligations. In the long term, forecasts for the Central scenario are projected to remain flat at levels sufficient to meet contractual obligations. Increasing global competition reduces the incentive to increase production to capitalise on further spot market opportunities.
- The Step Change scenario assumes that all three projects reach full capacity.

It has been assumed that any increase in LNG export demand above the Central scenario will be driven by a corresponding increase in new Queensland CSG production, as it is unlikely that increased contracts for export demand would be agreed upon without a related source of gas supply.

The impact of the COVID-19 coronavirus on the global economy from early 2020 is likely to lead to reduced global LNG demand for at least 2020. The potential impact of this has not been modelled in these forecasts, and could mean a lower LNG demand forecast in the short term. The precise timing, duration, and materiality of impacts of COVID-19 are yet to be determined, and are inherently uncertain.

2.4 Maximum daily demand forecasts

Key trends

- The forecast maximum daily demand, excluding GPG, is forecast to decline marginally in Queensland, South Australia, and Victoria from 2020-25. This short-term downward trend is attributed to increases in gas consumption due to new connections growth being offset by reductions in consumption due to energy efficiency, gas-to-electricity fuel switching, and behavioural price response impacts. In New South Wales and Tasmania, the impact from new connections growth is not forecast to be outweighed by these consumption reduction drivers.
- In the medium to long term (2025-39), maximum daily demand, excluding GPG, is forecast to increase in all states except South Australia. This is primarily the result of projected increases in consumption, due to new connections growth being forecast to start outweighing reductions due to other drivers in household, commercial, and industrial consumption. In South Australia, growth drivers are not forecast to outweigh these other drivers, leading to forecast reductions.

For most regions in eastern and south-eastern Australia, maximum daily demand is determined by weather driving households and commercial businesses and, to a varying degree depending on region, industrial businesses, to consume more gas for heating in winter. Maximum daily demand is measured at the regional level, because demand peaks at different times in different regions. There is no system-wide coincident maximum against which supply is assessed.

Key regional observations in the maximum demand forecasts are:

- Maximum daily demand in **New South Wales** is projected to increase in the first five years, driven by new connections. The connections growth effect is then projected to be moderated by energy efficiency and fuel-switching impacts after 2025, resulting in a relatively flat long-term trend to the end of the forecast horizon.
- Maximum daily demand in **Queensland**:
  - Excluding GPG and LNG, is forecast to decline to 2025, due to projected reductions in industrial consumption, then to increase slightly for the remainder of the 20-year forecast horizon, due to a rise in industrial production and household and commercial business consumption (from new connections growth).
  - For LNG, at the time of system peak, is forecast to increase modestly until 2022. Beyond 2022, the forecast is expected to remain at a stable level. For more detail, see Section 2.3.4.
- In **South Australia**, the maximum daily demand (excluding GPG) is forecast to be relatively flat to 2024, then to decline from 2024 to 2025 due to fuel-switching in some business facilities. The medium- to long-term forecast trend remains flat to the end of the forecast horizon, with projected reductions (due to energy efficiency, gas to electric appliance-switching, and behavioural price response impact) expected to balance against the impact of increases due to growth in new connections.
- A slight upward trend is forecast in **Tasmania**. The projected increase is primarily driven by forecast new connections growth in households and commercial businesses. Large industrial consumption at the time of regional peak is also expected to increase in the short term, then remain relatively flat until the end of the forecasting horizon.
- In **Victoria**, the maximum daily demand (excluding GPG) is projected to be flat to 2025, due to improvements in energy efficiency and publicly announced industrial closures. In the medium to long term, peak day gas demand is expected to increase, as new connection points continue to grow while energy efficiency in gas-fuelled appliances becomes saturated.

Over the forecast horizon, compared to the 2019 GSOO, maximum daily demand forecasts in the 2020 GSOO are higher in Queensland, New South Wales, and Tasmania, but lower in Victoria and South Australia. This is due to the net effect of revisions in demand drivers impacting both Tariff V and Tariff D, including:

- A greater impact of new connections on household and commercial business gas consumption at the time of maximum daily demand in most regions, with the exception of Victoria. These changes reflect a revision and update in connections forecast utilising gas metering identification reference number (MIRN), the recently updated Australian Bureau of Statistics (ABS) population and household data, and an updated view of the residential – commercial usage proportion.
- Other demand drivers, including region-specific revisions to large industrials' current and future outlook, energy efficiency, and fuel switching in household and commercial business consumption.

In 2020, GPG daily demand at time of regional coincident peak ranged from 44 to 67 TJ a day in Queensland and Victoria, 9 to 25 TJ a day in New South Wales, and 133 to 143 TJ a day in South Australia.

Table 5 and Table 6 show the seasonal forecasts[25] for all sectors combined, excluding GPG[26]. These forecast totals include unaccounted for gas (UAFG) that is lost while being transported through the network[27].

The tables show that:

- The difference between 1-in-2 and 1-in-20 forecasts is smaller in Queensland and Tasmania than other regions, because Queensland and Tasmania are less sensitive to weather at the time of regional peaks, having proportionally higher demand from large industrial loads.
- Victoria and South Australia have a greater degree of weather sensitivity, due to the proportionally higher residential and commercial demand.

Table 5 Total 1-in-2 and 1-in-20 forecast maximum demand, summer, all sectors excluding GPG, including UAFG (TJ a day)

	NSW		QLD (incl LNG)		QLD (excl LNG)		SA		TAS		VIC	
	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
2019[A]	263		4,408		336		98		18		388	
2020	295	319	4,358	4,379	342	363	105	112	20	21	435	570
2024	296	320	4,406	4,425	336	355	105	112	19	21	428	562
2029	300	326	4,408	4,428	330	350	101	109	20	22	430	565
2039	306	330	4,418	4,439	335	356	101	109	21	22	448	593

A. 2019 is actual maxiumum demand.

25 Maximum daily demand is forecast with a probability of exceedance (POE), meaning the likelihood the forecast will be met or exceeded. A 1-in-20 (or 5% POE) forecast is expected to be exceeded, on average, only once in 20 years, while a 1-in-2 (50% POE) forecast is expected, on average, to be exceeded every second year.

26 All maximum daily demand forecasts can be accessed from the Forecasting Data Portal, at http://forecasting.aemo.com.au/. Select 'GSOO 2020' from the publication drop-down.

27 UAFG is metered entering the network but does not reach consumers.

Table 6 Total 1-in-2 and 1-in-20 forecast maximum demand, winter, all sectors excluding GPG, including UAFG (TJ a day)

	NSW		QLD (incl LNG)		QLD (excl LNG)		SA		TAS		VIC[B]	
	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
2019[A]	452		4,424		352		155		22		1,203	
2020	469	496	4,366	4,386	350	370	157	167	21	23	1,140	1,254
2024	476	505	4,413	4,433	343	363	158	168	22	23	1,136	1,251
2029	478	505	4,416	4,435	338	357	154	163	22	24	1,149	1,263
2039	482	510	4,417	4,447	344	364	153	162	23	25	1,205	1,331

A. 2019 is actual maxiumum demand.
B. The Victorian 1-in-2 and 1-in-20 maximum demand forecasts in Table 6 are larger than those reported in the VGPR Update, because the VGPR Update forecasts report the maximum demand forecasts for the Victorian Declared Transmission System (DTS) only. The Victorian maximum demand outside of the DTS peaks at between 4 TJ a day and 5 TJ a day.

3. Gas supply and infrastructure

This chapter provides a brief overview of the historical operation of the eastern and south-eastern Australian gas system, an assessment of the changes in reserves and resources compared to the 2019 GSOO, and the outlook for gas supply (provided by gas producers) for the next five years.

Key insights

- Traditional sources of gas supply are declining, driving a change in where gas is produced and how it is transported.
- Southern supply from existing and committed gas developments will reduce by more than 35% over the next five years (a reduction of 163 PJ), despite an increase in committed gas developments in the last year.

3.1 The eastern and south-eastern Australian gas system

Historically:

- Gas production to meet demand in the southern states has primarily come from the Victorian gas basins – Gippsland, Otway, and Bass basins – with production from Victorian gas fields typically well in excess of Victorian demand.
- Prior to the LNG export projects, gas production to meet demand in Queensland was primarily met from conventional gas reserves within the Bowen Surat basins and the Cooper Eromanga at the western end of the South West Queensland Pipeline (SWQP).
- Coal seam gas (CSG) within the Bowen Surat basins has driven gas production for LNG export from Curtis Island since 2014.
- The SWQP, the only link between the northern and southern gas systems, has been used to shift excess supply or meet peak demands in either system, being used to help meet southern peak demand days in winter, and to send excess southern gas north during summer or shoulder periods.

The gas basins and pipeline infrastructure that supply gas to eastern and south-eastern Australian gas consumers are shown in Figure 13.

Figure 13 Gas producing basins and infrastructure supplying eastern and south-eastern Australia

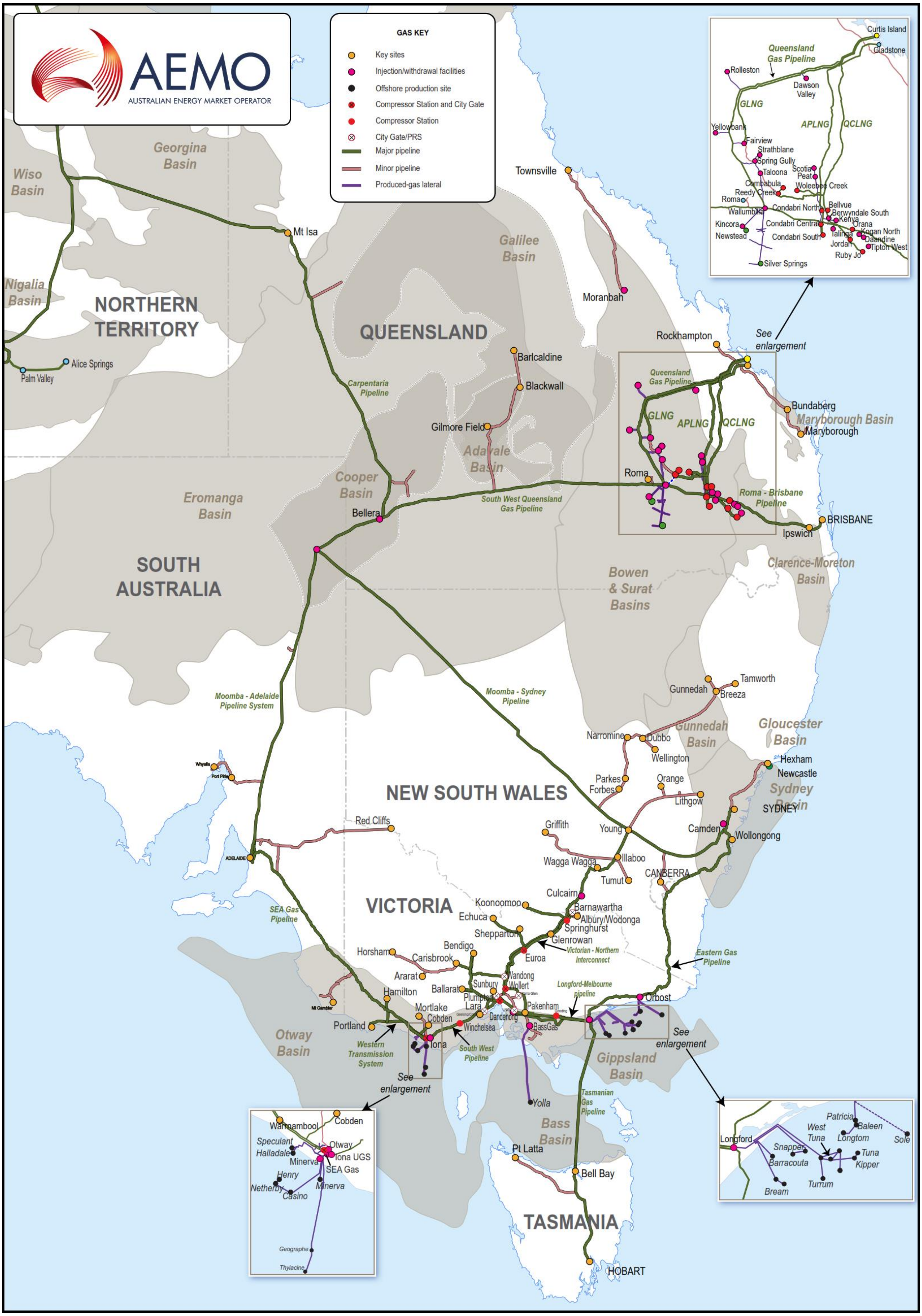
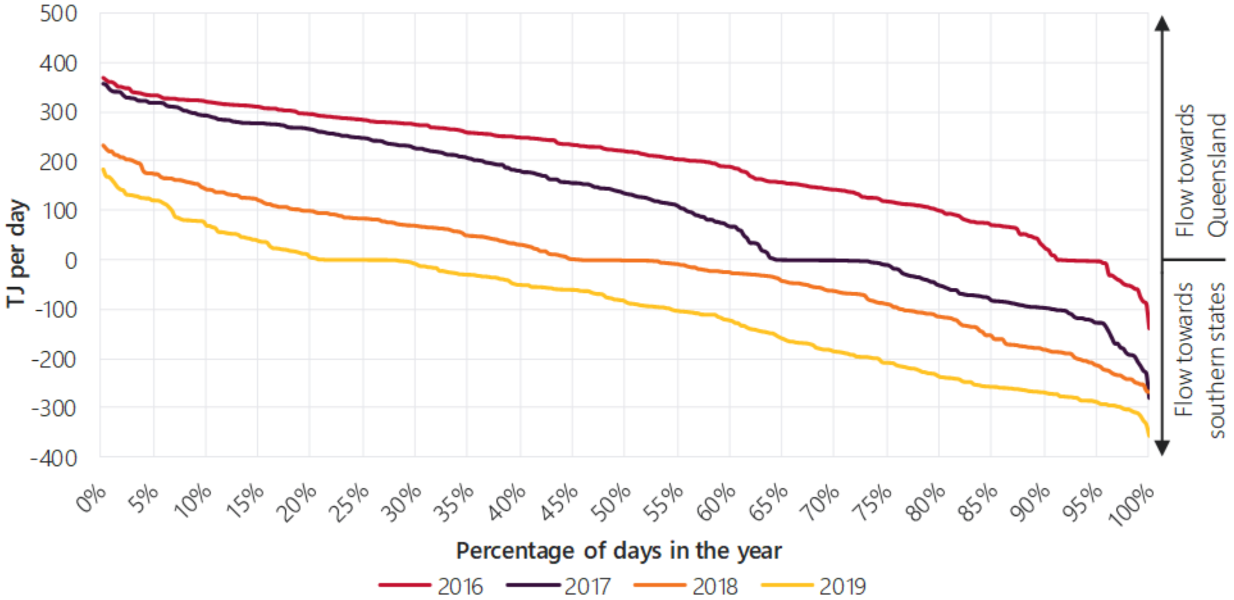


Figure 14 shows the daily flow duration curves for the SWQP each year since 2016, where the flow in each individual year is ordered from highest to lowest to assess the percentage of time the flow was at or above a certain level. It highlights that the SWQP has been increasingly used to help meet demand in the southern states, with flows ranked from most positive (flow towards Queensland) to most negative (flow towards the southern states). A marked shift has occurred, with gas transported towards the southern states on over 70% of days in 2019, compared to fewer than 10% of days in 2016. The quantity of gas transported south has also increased, with gas transported south exceeding 200 TJ on approximately 25% of days in 2019. compared to fewer than 10% of days in 2018.

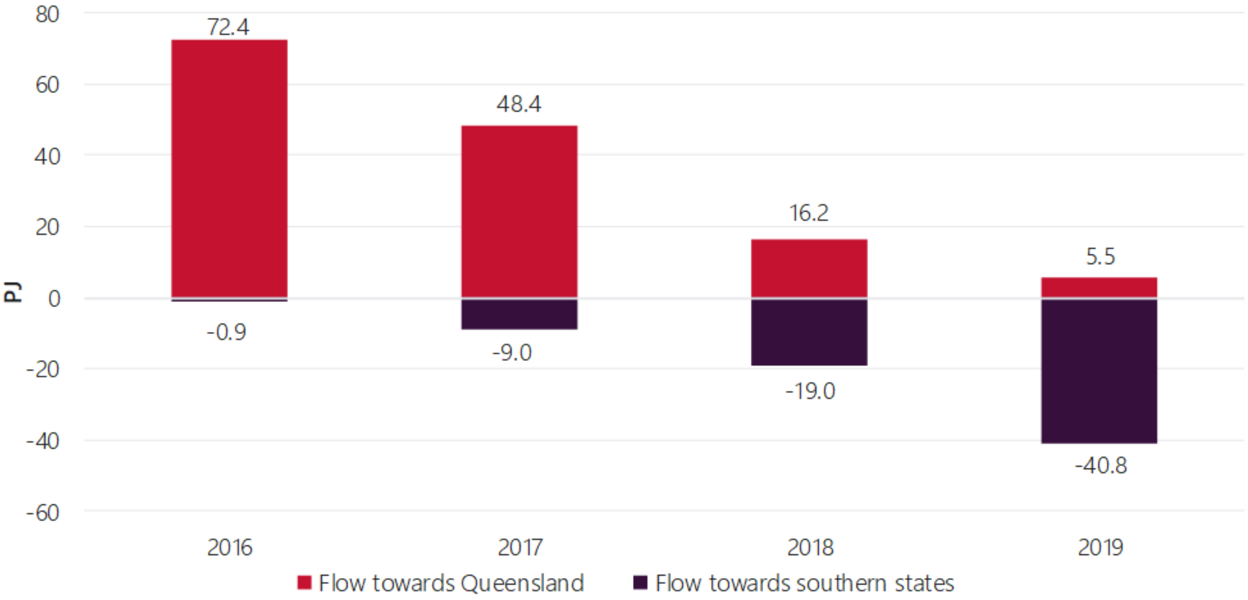
Figure 15 shows that the total quantity of gas transported south has more than doubled between 2018 (19 PJ) and 2019 (40.8 PJ).

Figure 14 Cumulative distribution of flows along the SWQP from 1 January 2016 to 31 December 2019



Source: Gas Bulletin Board (GBB)

Figure 15 Total flows along the SWQP from 1 January 2016 to 31 December 2019



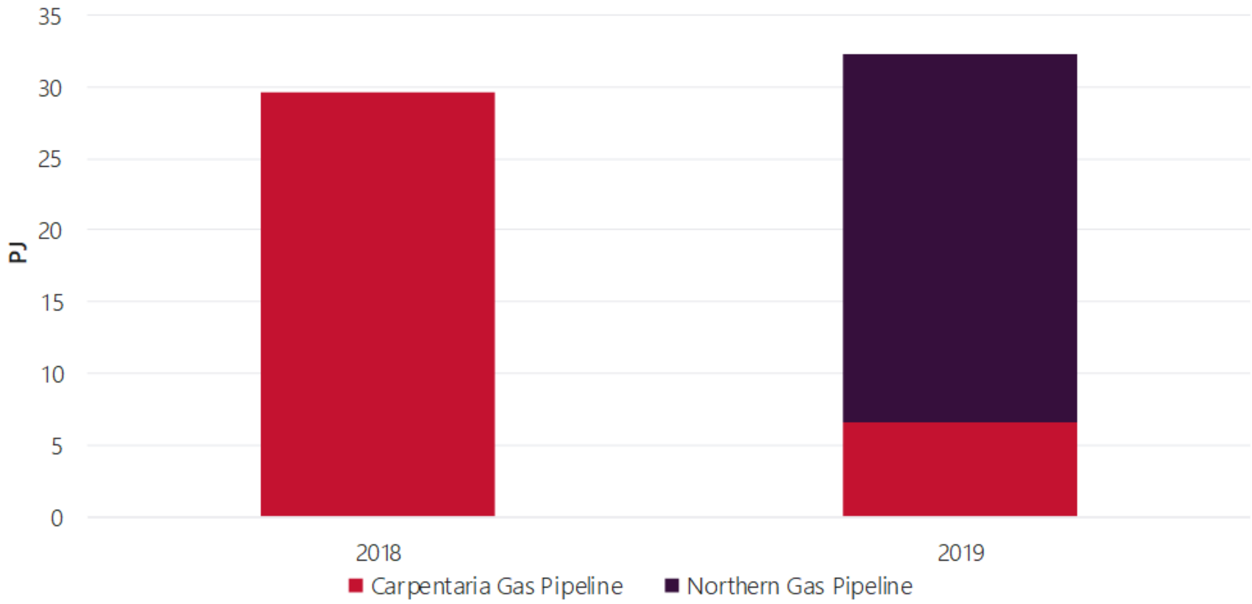
Source: Gas Bulletin Board (GBB)

The increased ability of the SWQP to deliver gas to southern states is in part due to the introduction of the Northern Gas Pipeline (NGP), which began commercial operation on 3 January 2019, supplying up to 90 TJ a day from Tennant Creek to Mount Isa. Prior to the NGP, Mt Isa demand was supplied via the Carpentaria Gas Pipeline (CGP), which in turn required supply from the SWQP.

Figure 16 shows that approximately 30 PJ of gas was supplied to Mt Isa via the CGP in 2018, whereas the CGP accounted for only 6.5 PJ in 2019, with the balance being supplied by the NGP. As a result, in 2019 more capacity was available on the SWQP to deliver gas to southern states.

Also during 2019, record levels of LNG were exported from Curtis Island (1,346 PJ in 2019 compared to 1,238 PJ in 2018), leading to record levels of gas production within Queensland (1,485 PJ) to meet both domestic and LNG export demand.

Figure 16 Gas flows towards Mt Isa along the CGP and NGP, 2018 and 2019



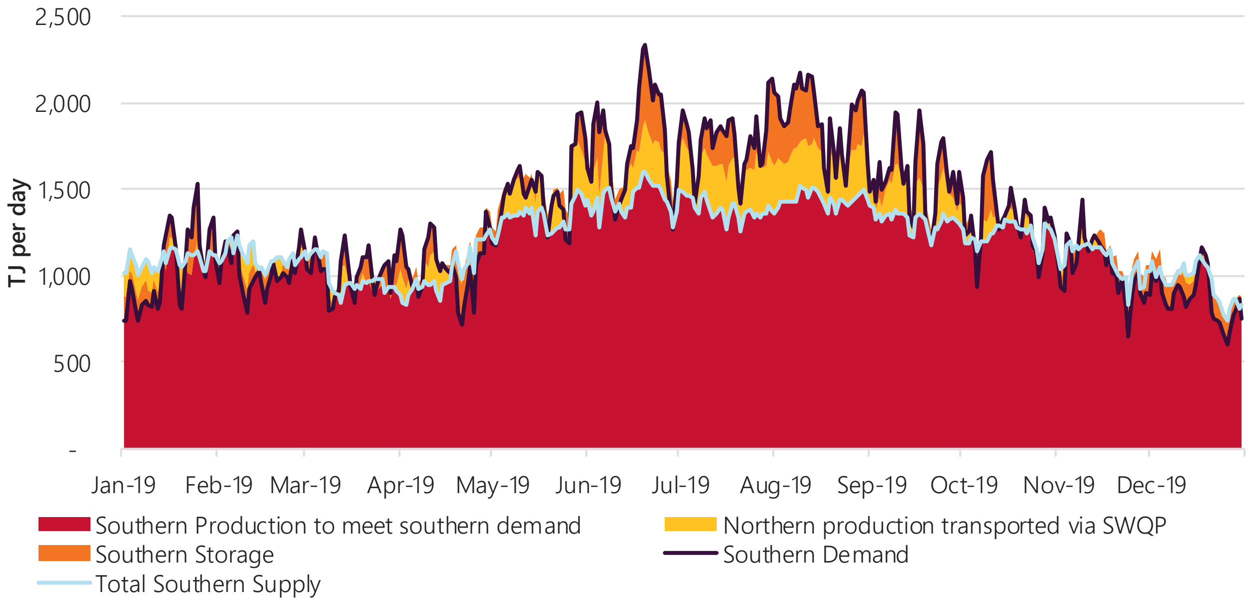
Source: Gas Bulletin Board (GBB)

Figure 17 shows the daily profile of how southern demand was actually met across 2019, by a combination of:

- Production from fields within the southern states.
- Gas produced within fields from the northern states sent south via the SWQP.
- Supply from gas storages within the southern states.

During times of excess supply, southern production can be used to fill southern storages, and further excess gas can be sent north via the SWQP.

Figure 17 Historical actual daily supply and demand balance in the southern states, 2019



"Total southern supply" and "Southern production" in Figure 17 includes all gas processed through Moomba processing facility, whether it comes from Moomba storage or Moomba production. This figure does not include the gas produced to refill Moomba storage.

3.2 Reserves and resources connected to eastern and south-eastern Australian gas markets

Gas reserves and resources 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, or overcoming geological challenges.

The following categories are applied across the industry:

- **Reserves** are quantities of gas which are anticipated to be commercially recovered from known accumulations.
  - **Proved and probable reserves (2P)** are considered the best estimate of commercially recoverable reserves. When probabilistic methods are used, 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. The 2P reserves can be classified as either **Developed**, meaning supply from existing wells, or **Undeveloped**, meaning wells are yet to be drilled.
- **Contingent resources** are considered less viable than reserves, either due to current economics or other contingent factors that need to be overcome. Contingent resources may include, for example, accumulations for which there is currently no viable market, or where commercial recovery is dependent on the development of new technology, or where evaluation of the accumulation is still at an early stage.
  - **2C resources** are considered the best estimate of those sub-commercial resources.
- **Prospective resources** are estimated volumes associated with undiscovered accumulations of gas. These resources are estimated to exist in the prospect areas, but have not yet been proven by drilling.

AEMO's natural gas reserve and resource estimates combine information from gas producers with estimates from Core Energy Group[28]. Within eastern and south-eastern Australia, and those fields in Northern Territory likely to supply eastern Australia, natural gas 2P reserves (developed and undeveloped) have decreased by

[28] Core Energy Group estimates are published with the GSOO at https://aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo.

5,239 PJ (12.3%) from the 2019 GSOO estimates. Over the same time, 2C contingent resources have increased by 1,337 PJ (2.3%), as some 2P reserves have been downgraded as less economical, and some prospective resources have been explored and are now more certain.

Figure 18 provides a breakdown of 2P developed and undeveloped reserves and 2C contingent resources reported in the 2019 GSOO and this 2020 GSOO, and shows a slight decline in total reserves and resource estimates of 3,903 PJ.

Figure 18 Reserves and resources reported in the 2019 GSOO and 2020 GSOO

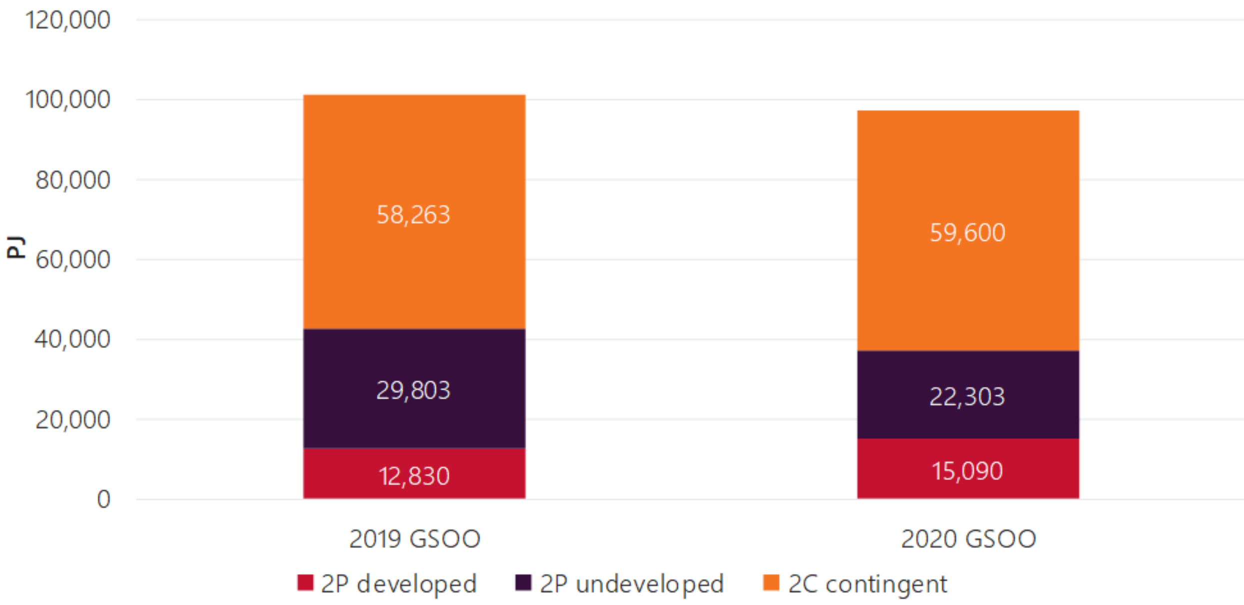
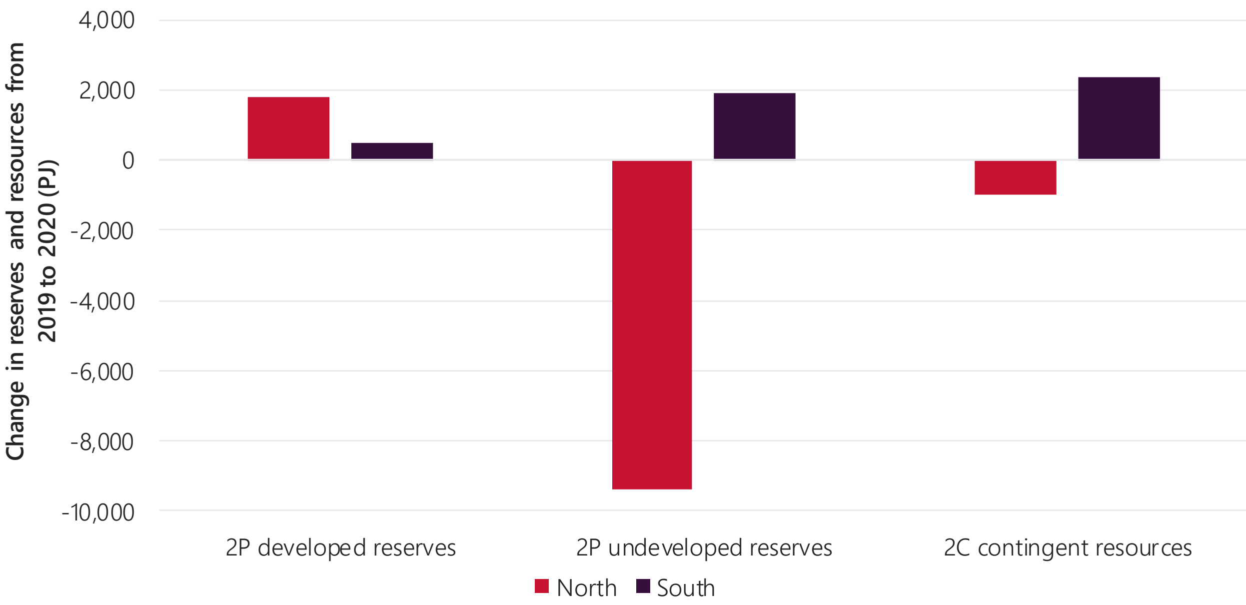


Figure 19 indicates that the decrease in 2P reserves is driven by a decrease of 9,410 PJ (33%) in northern 2P undeveloped reserves, partially offset by an increase in southern 2P undeveloped reserves and an increase in northern and southern 2P developed reserves.

Figure 19 Change in reserve and resource quantities from northern and southern natural gas reserves, 2020 GSOO compared to 2019 GSOO



The increase in southern 2P reserves indicates that some 2C contingent resources have been successfully converted to 2P reserves, while the increase in southern 2C contingent resources indicates that exploration and development of resources is continuing.

The probability of gas existing in the ground and being considered commercially viable is not the only uncertainty related to future production. To access these reserves and resources, appropriate production, process, and transportation facilities need to be developed. Therefore, AEMO has further considered the level of certainty around whether gas supply and infrastructure projects will proceed to develop the identified volumes of reserves or resources.

Following stakeholder consultation, AEMO has defined three gas supply and infrastructure project commitment classifications aligned with the Society of Petroleum Engineers – Petroleum Resource Management System[29] (PRMS) project maturity sub-classes:

- **Committed projects** – all necessary approvals have been obtained and implementation is ready to commence or is underway. Committed projects consist of 2P reserves, both developed and undeveloped. This category encompasses the PRMS project maturity sub-classes *On Production* and *Approved for Development*.
- **Anticipated projects** – developers consider the project to be justified on the basis of a reasonable forecast of commercial conditions at the time of reporting, and reasonable expectations that all necessary approvals (such as regulatory approvals) will be obtained and final investment decisions made. Anticipated projects typically include 2P undeveloped reserves and selected 2C resources. This category includes the PRMS project maturity sub-classes *Justified for Development* and *Development pending*.
- **Uncertain projects** – these projects are more uncertain or at early stages of development. Uncertain projects include uncertain 2C contingent and prospective resources that are accessible by existing pipeline and processing infrastructure. This category includes all remaining PRMS project maturity sub-classes.

Under this classification, a project represents a specific investment decision, with an associated quantity of recoverable reserves and resources that may be more, or less, certain. As explained in the PRMS Guidelines, "*a project may, for example, constitute the development of a single reservoir or field, or an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership*".

The 2020 GSOO is the first time AEMO has classified reserves and resources by PRMS commitment classifications. These classifications were used when modelling outcomes for the 2020 GSOO, and future iterations of the GSOO will include year-on-year comparisons of reserves and resources accessible by facilities on this classification basis.

Table 7 shows the production forecast between 2019 and 2024 provided to AEMO by gas producers as their current best estimate of gas available and expected for production over this time, with comparisons to the forecasts to 2022 provided to AEMO for the 2019 GSOO.

These production forecasts are similar to those provided in the 2019 GSOO, with the largest change in 2022, amounting to 59 PJ of additional gas, or 3%. Compared to last year, production forecasts in the southern states have decreased for 2020 and 2021 but are the same in 2022, despite Victorian production forecasts being higher over this same time period, compared to the 2019 GSOO. The declining production in southern states between 2022 and 2024, shown in Table 7, is driven by total committed Victorian production reducing from 318 PJ in 2022 to 201 PJ in 2024.

[29] See https://www.spe.org/industry/docs/PRMS_Guidelines_Nov2011.pdf.

Table 7 Production forecasts to 2024 (PJ) as provided by gas producers

	Commitment criteria	2020	2021	2022	2023	2024
VIC / NSW / SA[A]	Existing and committed	437	395	384	323	267
	Anticipated	22	69	72	123	106
	Total	460	464	456	447	373
	Difference from 2019 GSOO	**-15**	**-16**	**0**	**N/A**	**N/A**
QLD / NT	Existing and committed	1,566	1,525	1,489	1,371	1,261
	Anticipated	5	48	177	252	313
	Total	1,572	1,577	1,676	1,636	1,590
	Difference from 2019 GSOO	**+34**	**-16**	**+69**	**N/A**	**N/A**
Total east coast gas production		**2,031**	**2,041**	**2,132**	**2,083**	**1,963**
Difference from 2019 GSOO		**+18**	**-32**	**+69**	**N/A**	**N/A**

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

Despite ongoing field developments and increases in 2P developed reserves, production from existing gas fields is in decline, particularly among southern fields. BHP has announced that the Minerva gas field has reached its end of life, and ceased production on 3 September 2019[30]. Several of the Gippsland fields are projected to reach their end of life between mid-2023 and mid-2024, production from Camden Gas Plant is expected to cease in 2023, and all currently producing fields in the Otway Basin will cease production unless anticipated gas field development or plant modification projects proceed.

In southern fields, Cooper Energy's Sole project and the Esso-BHP West Barracouta project are committed, with the gas producers informing AEMO that production of sales gas is expected to commence between 2020 and 2022. These projects alone are not sufficient to reverse the decline in production. Even with further anticipated projects in the Otway, Gippsland, and Cooper Eromanga basins that are expected to start production over the coming years, forecast supply from existing, committed, and anticipated southern fields in 2024 is 87 PJ lower than in 2020.

As previously discussed, gas produced in the Northern Territory has been flowing through Jemena's NGP since December 2018, supplying approximately 26 PJ of gas to meet east coast demand in 2019 and displacing Queensland production previously used to supply demand at Mt Isa.

Various new projects throughout Queensland are expected to be available to meet demand, including Senex's Project Atlas, which started producing in late 2019 and is expected to ramp up to full production capacity of 15 PJ a year by the end of 2021. Further drilling of the Queensland CSG fields is forecast to continue to support the LNG export projects.

Total gas expected to be produced over the next three years shows an increase from current levels, with decreases expected in 2023 and 2024. To maintain production levels beyond 2022, exploration and development of more uncertain fields will be required.

Several uncertain field projects have been identified by gas producers as having the potential to produce within the next five years, and may be available as early as 2021, with 5 PJ forecast to be produced. By 2024, forecast production from these Uncertain fields increases to nearly 200 PJ, with the majority (92%) of this flagged uncertain production is located within southern gas basins.

[30] BHP, "BHP Operational Review for the quarter ended 30 September 2019", 17 October 2019, at https://www.bhp.com/-/media/documents/media/reports-and-presentations/2019/191017_bhpoperationalreviewforthequarterended30september2019.pdf?la=en.

4. Supply-demand balance

This chapter presents the supply adequacy outlook for eastern and south-eastern Australia in the next 20 years, considering existing, committed, and anticipated projects.

Key insights

- Supply from existing and committed gas developments will be sufficient to meet gas demand across eastern and south-eastern Australia until at least 2023, provided that LNG export spot cargoes are redirected to meet domestic demand if required.
- If anticipated gas field projects (considered likely to proceed within the outlook period) are developed, resource adequacy improves until at least 2026. However, due to the location of most of the anticipated projects within Victoria, dynamic operational pipeline constraints would limit their effectiveness in addressing the forecast peak winter day supply gaps under certain conditions
- Daily field production and pipeline limitations are important in assessing gas supply adequacy and are projected to be the first factors contributing to projected supply gaps.

4.1 Supply adequacy from existing, committed, and anticipated gas developments

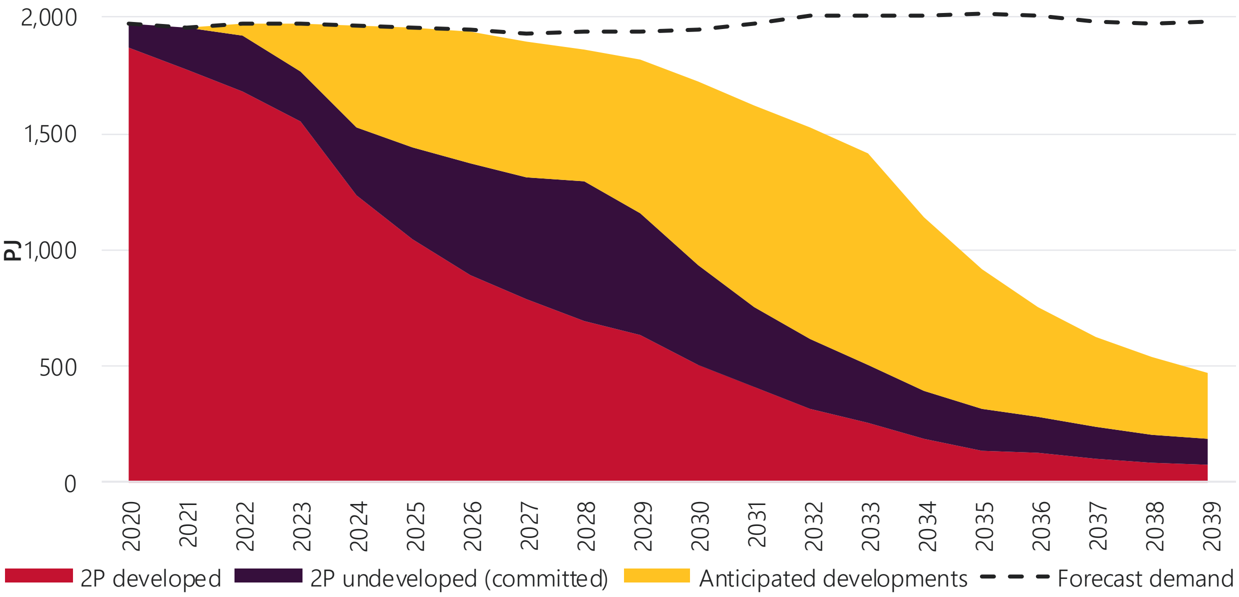
Supply from existing, committed, and anticipated gas developments (if they are developed) is projected to be sufficient to meet all eastern and south-eastern Australian demand until 2026 in the Central and Step Change scenarios, and until 2027 in the Slow Change scenario. Supply adequacy until 2026 relies on anticipated projects that are not yet committed.

Figure 20 shows the expected production forecast in the Central scenario if existing, committed, and anticipated projects are available to meet demand in the long term and GPG is in line with forecasts.

It highlights that:

- Development of more uncertain reserves and resources will be required to meet demand to 2039.
- Supply gaps are forecast from 2026, with 6 PJ of demand unmet, particularly around during winter peak periods. This supply gap increases to over 200 PJ in 2030, with a gap of up to 1,515 PJ by 2039 if further new supply is not developed.

Figure 20 Projected eastern and south-eastern Australia gas production (export LNG and domestic), 2020-39 – existing projects, and committed and anticipated developments, Central scenario



In assessing daily supply adequacy, the GSOO modelling takes into account major gas transmission pipeline and compression limitations, processing plant and storage facility daily capacities, and, where known, gas field daily production limitations, particularly important in the case of fields nearing their end of life.

This assessment does not take into account all of the detailed requirements of operating a system under peak demand and low supply conditions such as the dynamic variability of pipeline limitations due to system pressure changes, or intraday operations. Actual operational constraints, particularly within a strongly interconnected gas system such as the Victorian Declared Transmission System (DTS), may lead to transportation limitations throughout the system that are unable to be captured in this GSOO modelling, creating potential supply gaps during peak winter days from 2024 (see the 2020 VGPR Update for more information[31]).

This GSOO supply adequacy assessment includes two anticipated infrastructure projects which have been communicated to AEMO by APA:

- An increase to the capacity of the Moomba to Sydney Pipeline of 25 TJ a day.
- The committed Western Outer Ring Main (WORM) project that will increase Iona Underground Storage (UGS) refilling capacity during summer months and increases the capacity of the SWP to support peak day demand, so more gas is able to be injected into storage and can be used in winter when required.

If either project does not proceed, and alternative unconstrained supply options are not developed, meeting peak winter day supply in Victoria would be even more challenging, as discussed in the 2020 VGPR Update.

4.2 Supply adequacy risks if anticipated field development projects do not proceed

There is a risk that anticipated field development projects, while they have a reasonable expectation of progressing to production, in fact may not eventuate. By 2024, production forecasts from anticipated field

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

development projects account for approximately 20% and 25% of total production in Queensland and southern states respectively (see Table 7).

If gas supply forecasts are limited to existing and committed developments only:

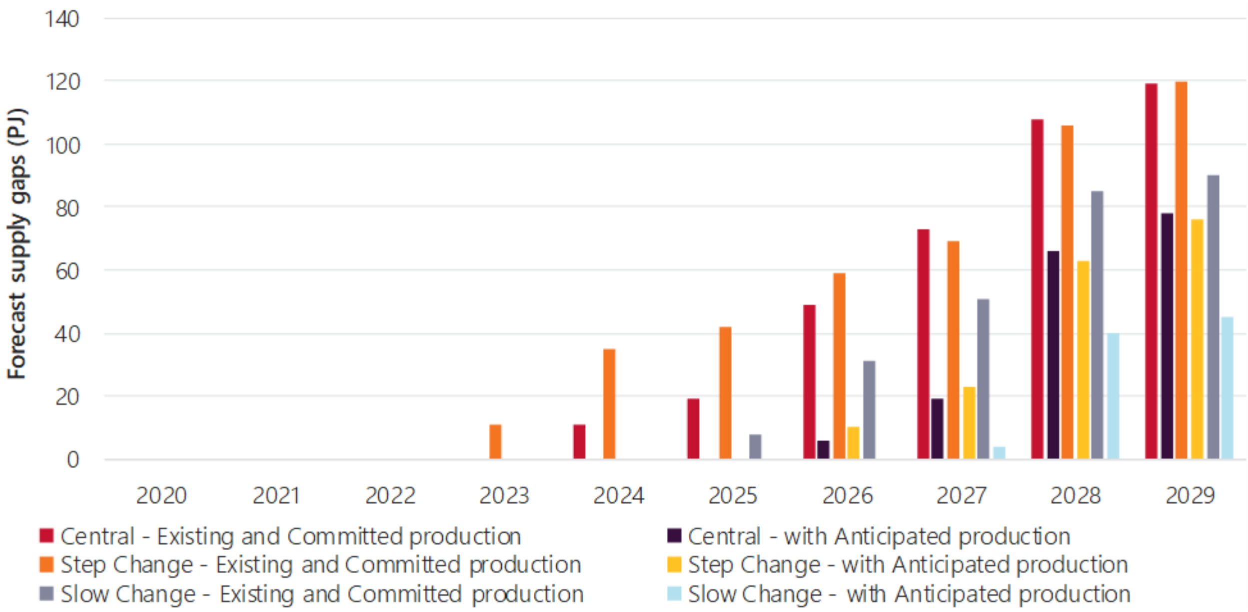
- Assuming cargoes of export LNG above contracted levels can be diverted to meet domestic demand, or export demand commitments are otherwise able to be sourced internationally, there is forecast to be enough pipeline capacity to meet all domestic demand until between 2023 and 2025, depending on scenario.
- Without diversion of LNG cargoes, supply gaps for eastern and south-eastern Australia are forecast from 2022 under all scenarios.

The range of domestic supply gaps forecast across the three scenarios, considering a) existing and committed supply, and b) existing, committed, and anticipated supply, is shown in Figure 21.

Under Central scenario demand, if anticipated projects do not proceed, by 2024:

- Production from existing and committed gas fields, particularly peak day field production within Victoria, is projected to decline such that pipeline constraints within Victoria, New South Wales, and South Australia limit the gas that can be supplied from northern fields to meet forecast demand.
- If no further sources of gas or alternative infrastructure are developed, supply gaps can be expected in the southern states from 2024 onwards.

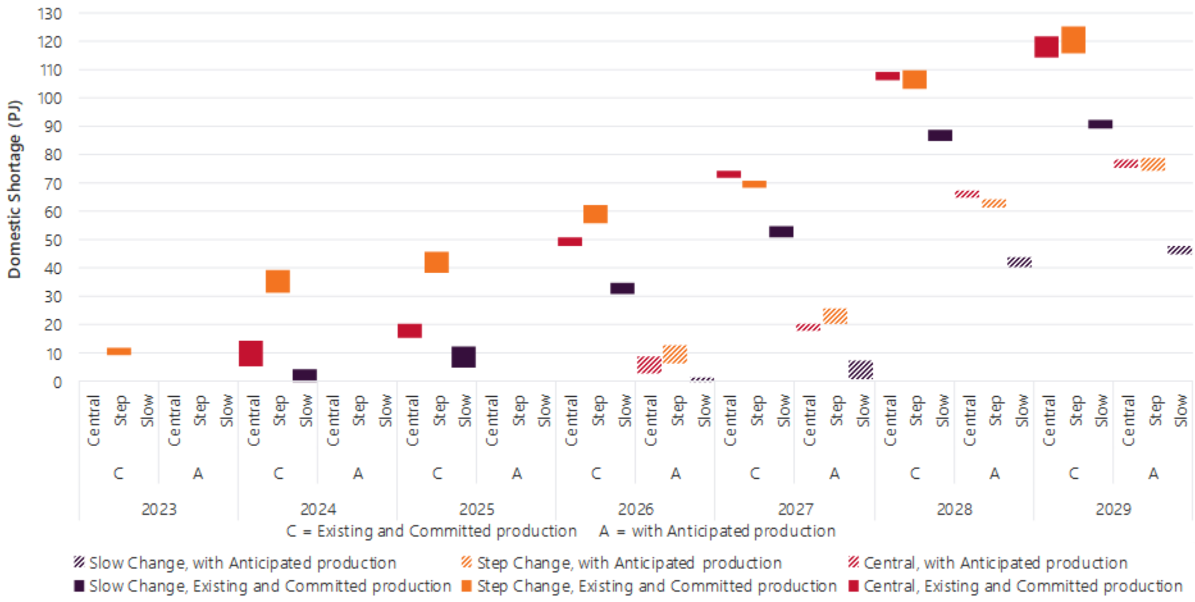
Figure 21 Domestic supply gaps forecast under Central, Step Change, and Slow Change scenarios, considering existing and committed, and anticipated supply, 2020-29



As discussed in Chapter 2, forecast demand varies by scenario (Central, Step Change, and Slow Change), and also across weather years and POE (in this case, 1-in-2 and 1-in-20). Consequently, the supply demand balance and any forecast shortfalls also vary across weather years and POE.

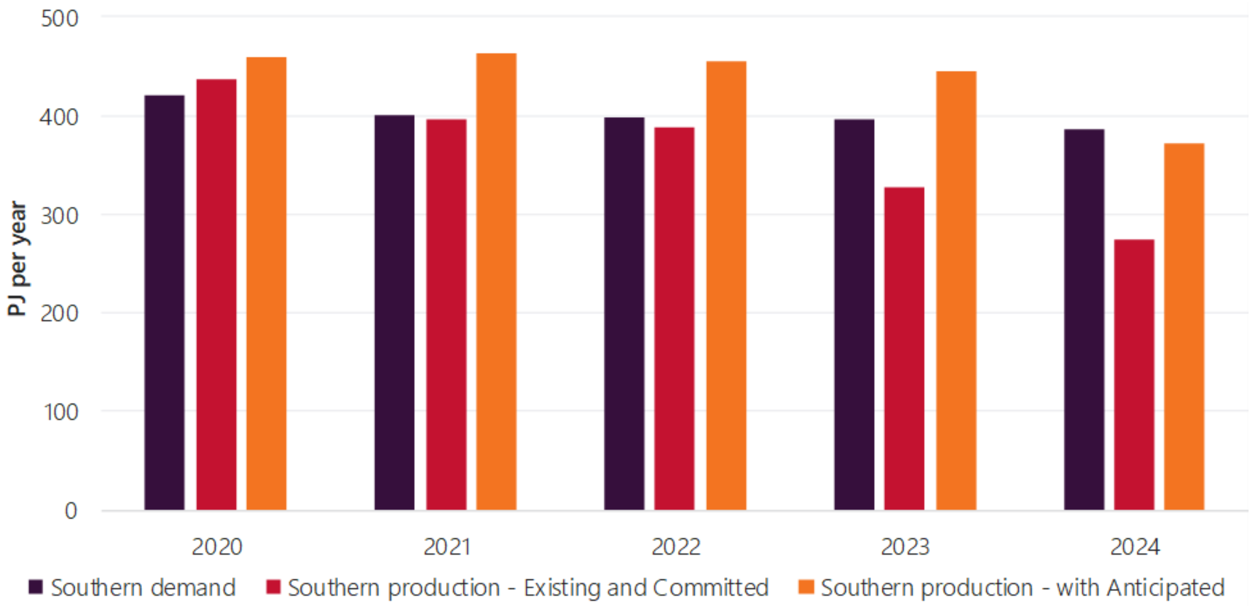
Figure 21 above shows the forecast domestic shortfalls averaged across the weather years and POE. Figure 22 below displays the possible range of domestic shortfalls for each scenario and supply type. For example, in 2024, the annual domestic shortfall for the Central scenario with existing and committed supply is forecast to vary between a minimum of 5 PJ and maximum of 15 PJ. These variations demonstrate the effect of weather and POE on gas consumption, in particular for GPG.

Figure 22 Range of domestic shortfalls forecast under Central, Step Change, and Slow Change scenarios, considering existing and committed, and anticipated supply, 2023-29



When comparing annual southern consumption forecasts against southern field production forecasts using simple mass balance equations, Figure 23 indicates that there is sufficient production from southern fields to meet southern consumption in 2020 and almost all of 2021 with existing and committed fields producing, and sufficient production until 2023 with anticipated fields producing. However, when assessing supply adequacy, it is important to take into consideration both annual and daily field production limitations. As fields decline, the maximum flow rate – the maximum amount of gas able to be extracted from the field – also declines.

Figure 23 Annual demand and field production for southern states (VIC/NSW/SA/TAS); Central scenario, 2020-24 (production forecasts provided by gas producers)



In comparing daily demand against maximum daily field production limits, Figure 24 highlights the seasonality of southern demand and the inability of southern fields to meet peak southern demand in winter. In aggregate, the southern states are forecast to face up to 1,822 TJ difference between maximum and minimum demand across the year. Both storage and the SWQP are therefore forecast to play an important role in meeting peak day southern demand, even in years where there appears to be sufficient forecast production on an annual level.

Figure 24 Daily demand and field production limits for southern states (VIC/NSW/SA/TAS); Central scenario, 2020-24 (daily production limits provided by gas producers)

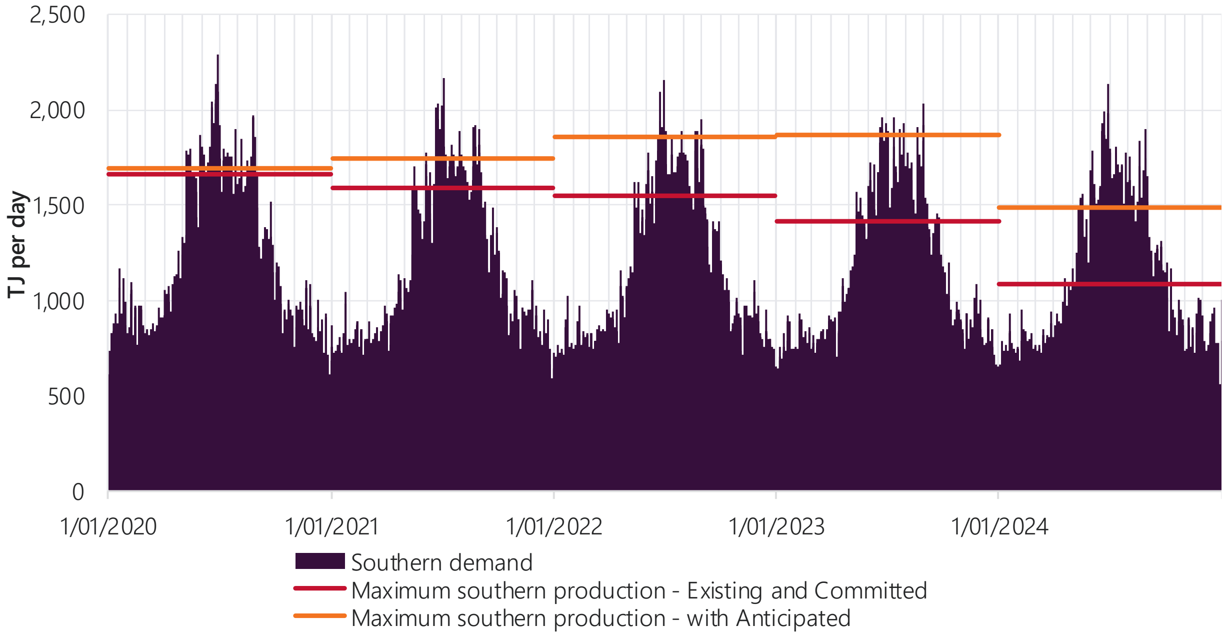
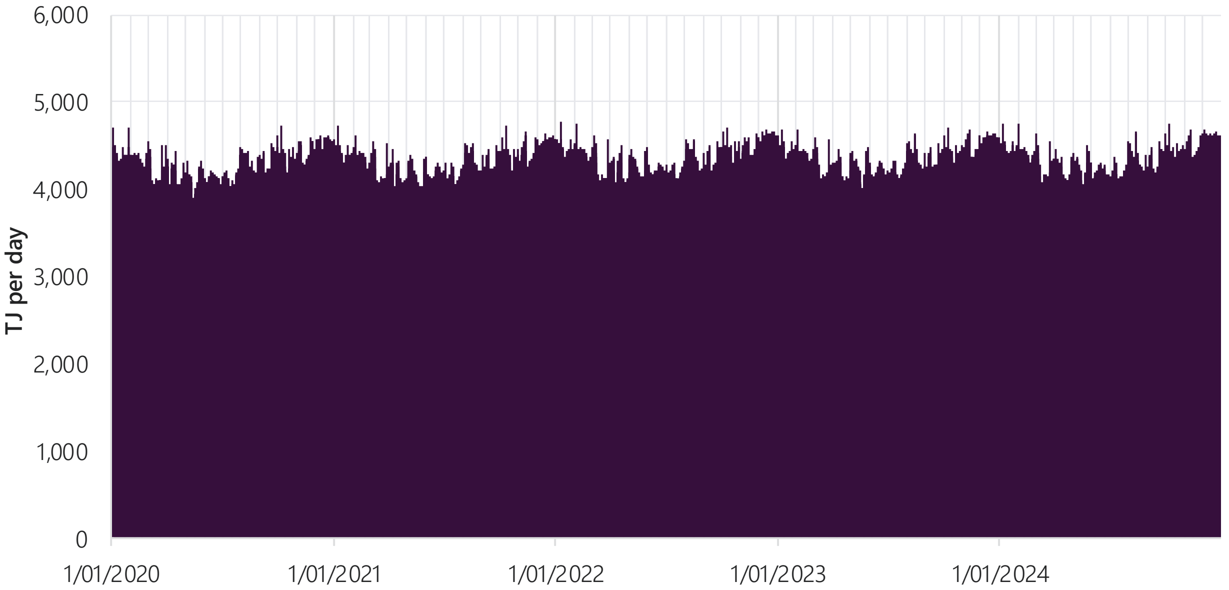


Figure 25 highlights that Queensland gas demand (including export LNG demand) has much less seasonal variation, so the northern fields' ability to meet peaks and troughs in daily demand is much less of a concern than in the southern states. LNG export demand typically peaks over the summer months as the global demand for LNG peaks during the northern hemisphere's winter season. This offsets Queensland's domestic demand peaks which typically occur over winter, with Queensland facing approximately 200-300 TJ difference between maximum and minimum demand across the year. In aggregate, Queensland seasonal demand peak is forecast to occur over summer, and southern demand peaks are forecast to continue to occur in winter.

Figure 25 Daily Queensland demand (domestic and export LNG demand); Central scenario, 2020-24



4.3 Daily supply adequacy with production only from existing and committed fields

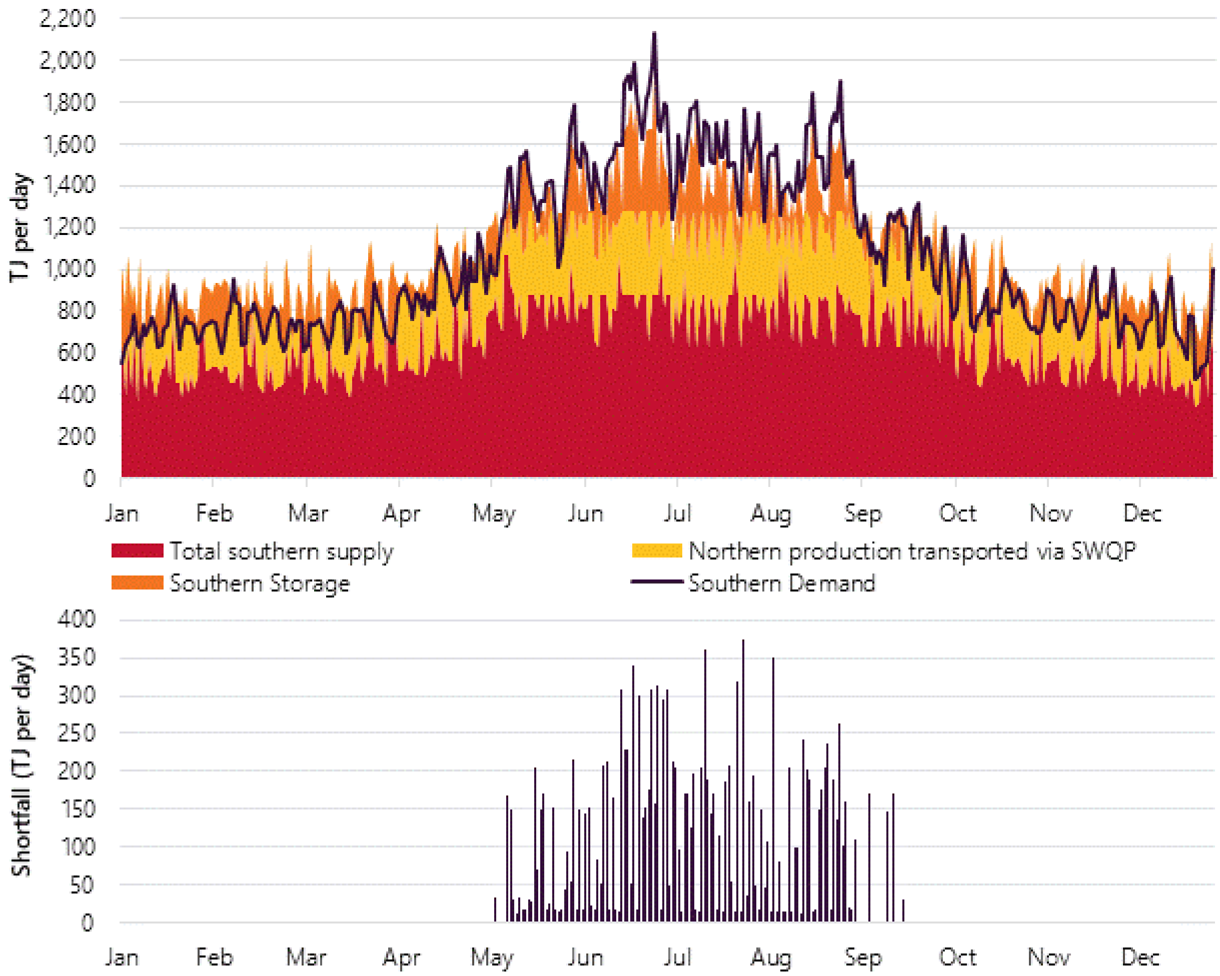
Figure 26 shows a sample possible evolution of the daily supply-demand balance for southern states in 2024 under the Central scenario. The exact daily demand pattern will be driven by the specific weather conditions experienced in 2024, as well as by events in the NEM that may vary GPG and drive demand up or down on a daily basis.

Some supply gaps are observed across winter 2024, as peak day production within southern states is forecast to be insufficient to meet forecast daily demand, even with the SWQP transporting northern gas at full capacity. Projected peak day supply gaps nearly reach 400 TJ a day across the southern domestic market. This is just one of many different possible results from an ensemble of evolutions that have been considered in 2020 GSOO modelling, with five different weather series considered.

Detailed pipeline system operational issues were not considered in this GSOO, so, depending on daily operational conditions, shortfalls may be higher than forecast.

Chapter 5 below details the uncertainties that may lead to variations between the forecast and the actual daily supply-demand balance in 2024.

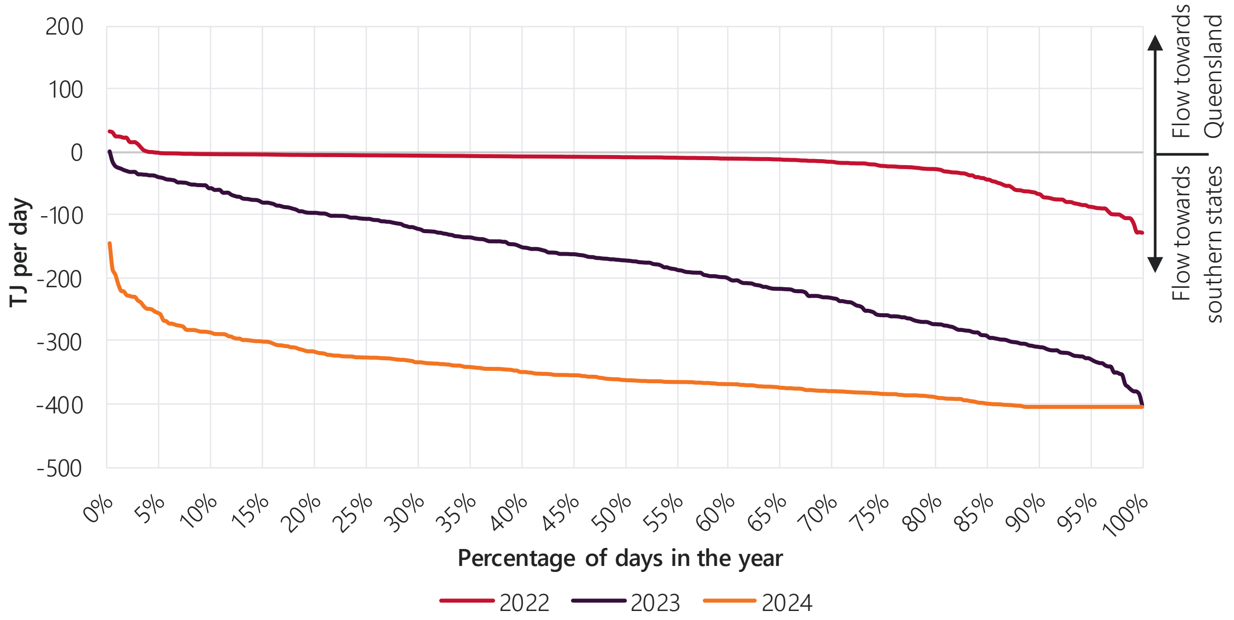
Figure 26 Example evolution of daily supply and demand balance in southern states in 2024 including existing and committed projects (top) and forecast shortfalls in the southern states (bottom); Central scenario



Total southern supply in Figure 26 includes all gas processed through Moomba processing facility, whether it comes from Moomba storage or Moomba production. This figure does not include the gas produced to refill Moomba storage.

Figure 27 shows that flows along the SWQP are forecast to be towards the south for approximately 95% of days in 2022, and for all days in 2023 and 2024. This highlights the southern states' dependence on gas from northern fields if southern anticipated fields are not developed when expected.

Figure 27 Forecast cumulative distribution of flows along the SWQP for years 2022 to 2024; Central scenario, existing and committed projects



5. Increasing uncertainty

This chapter highlights some of the uncertainties that may impact supply adequacy in the short term, particularly between 2022 and 2024 when a decline in southern field production coincides with major changes to the resource mix and consequently demand for GPG in the NEM. It also explains why these uncertainties are greater now than they were in the 2019 GSOO, and why year-on-year variability in supply adequacy is increasing.

5.1 Tightening linkages between gas and electricity

While the gas and electricity markets have been historically inter-linked, the markets have transitioned from a period of abundant gas reserves and an over-supplied NEM to a situation where the supply-demand balance is tight in both gas and electricity markets. Adequacy issues in one sector are now increasingly likely to drive adequacy issues in the other.

Forecasting uncertainty and year-on-year variability have increased since the 2019 GSOO. A range of events in both the gas and electricity sectors increase uncertainty, particularly in the short term when supply adequacy is already tight, fields are in decline, the NEM generation fleet is ageing, and generation and transmission investment to replace the retirement of a major coal-fired power station is not yet committed. In this rapidly changing environment, any single event, or combination of events, may significantly impact the forecast outlook.

5.1.1 Gas sector uncertainties

Gas supply adequacy across the outlook is highly uncertain, particularly between 2022 and 2024 with projected tightness in the east-coast gas supply-demand balance. Key uncertainties may change the forecast supply adequacy outlook, and highlight the need to plan for multiple possible eventualities:

- Existing fields in the Gippsland basin and Camden in the Sydney basin are likely to cease production sometime between 2023 and mid-2024, as mentioned in Chapter 3. The exact timing of field depletions and flow rates in the months before ceasing production are very difficult to forecast accurately, even for field operators. If these fields cease production earlier than advised, this will put further pressure on meeting peak day gas demand in southern states from winter 2023.
- The Commonwealth Government and New South Wales Government have announced the setting of a target to inject an additional 70 PJ of gas a year into the New South Wales market, and agreed to a gas market review if this target is not met by 2022. The potential impact of this additional supply is studied further in Section 5.2.
- On 17 March 2020, the Victorian Government announced that the ban on conventional gas exploration and development of Victorian onshore gas fields will be lifted from July 2021. Given the lead times required for exploration and development of projects, new supply from these onshore fields is unlikely to be available in the short term, and until exploration commences, the size of the resources and thus the potential impact on supply adequacy remains uncertain.
- Large industrial customers interviewed by AEMO continue to raise concerns about the impact of relatively high gas prices, particularly for customers with only shorter-term gas supply agreements in place. Any industrial closures would significantly affect demand for gas and for electricity (and hence GPG).

- Global demand for LNG is a key driver of the Queensland LNG export forecasts. Any impact to global LNG prices or the global supply chain may have impacts on the GSOO's LNG demand forecasts, with flow-on consequences on the domestic gas market. For example, early industry analysis suggests that the COVID-19 coronavirus will reduce global LNG demand for at least early 2020. Depending on how much Queensland CSG producers are able to turn down their wells, this may result in excess gas in the eastern and south-eastern Australian domestic market in the next year. At the time of writing, it is unclear how long or how much this virus will impact the global economy.

5.1.2 Electricity sector uncertainties that may impact the gas sector

Between 2022 and 2024, there are also key uncertainties in the electricity sector that may impact peak day and annual gas supply outlooks.

Uncertainties related to the electricity market which could affect demand for gas for GPG and therefore gas supply adequacy include the following:

- The Draft 2020 ISP forecasts that a mix of existing generation, storage, and new distributed and utility-scale renewable generation will help maintain reliability at lowest cost after the planned staged closure of the coal-fired Liddell Power Station between 2022 and 2023. If the development of new renewable generation is delayed, or if more GPG were to be built instead, there may be greater reliance on GPG to meet electricity demand in the wake of Liddell's retirement than forecast.
- Greater interconnection between regions is also part of the least-cost future NEM, to take advantage of the geographical diversity inherent in renewable generation, with NEM regions better able to share low marginal cost generation efficiently and reduce reliance on more costly local generation, including GPG (see Section 2.3.3 for more information). If the timing of any of the forecast investments in transmission, VRE, or storage (including Snowy 2.0) vary from that assumed in the Draft 2020 ISP (or any are not built at all), demand for GPG could be materially greater.
- As the thermal generation fleet ages, some units are becoming less reliable, and demand for gas for GPG is highly sensitive to coal-fired generation outages. The 2019 GSOO's GPG forecasts for the 2019 calendar year were approximately 60 PJ (41%) lower than the GPG gas usage actually required, with the difference driven by a combination of the prolonged unplanned outage of Loy Yang A2 in 2019, higher summer electricity demand from extended hot weather, and coal quality issues at the Mount Piper Power Station. Similar outages in future, or other significant NEM events, could increase gas demand above levels forecast in this GSOO, compounding potential peak day gas shortages.
- Weather, and in particular, changing weather uncertainty, impacts gas demand for GPG, with the range of studied weather uncertainty detailed in Section 2.3.3. AEMO is continuing work to further understand the weather uncertainties and the long-term impacts of climate change on the energy sector, as discussed in Section 1.3.

These gas and electricity sector uncertainties, if compounded, could have significant consequences to supply adequacy, and will need to be monitored closely. An updated GSOO will be issued if new information becomes available that could materially impact the current GSOO forecasts.

Between now and the end of 2024, if gas consumption is higher than the Central scenario forecast, due to any combination of uncertainties, GSOO analysis suggests that:

- An increase in consumption of up to 30 PJ in 2020 could be met without any adverse impact to the supply-demand balance.
- For up to a 60 PJ demand increase, if cargoes of export LNG above contracted levels are able to be diverted to meet domestic demand, or export demand commitments are otherwise able to be sourced internationally, then there is still sufficient pipeline capacity to meet demand without causing additional domestic demand shortfalls before 2024.
- If actual consumption increases by more than 60 PJ in any year, (or, conversely, if demand is as forecast but fields deplete more rapidly than forecast and gas production decreases by more than 60 PJ; or some

combination of these two options) then domestic shortfalls are likely to occur. To put this in perspective, 60 PJ is only approximately 3% of total gas consumption in eastern and south-eastern Australia.

This assessment depends on the location of the increase in demand, and local pipeline constraints involved in transporting supply to meet this increased demand.

Many new supply options are currently under consideration by the gas industry. AEMO has assessed the impact of some of these proposed projects on supply adequacy in sections 5.2 to 5.4.2, particularly considering if supply from anticipated projects is not available to meet demand.

5.2 The understanding between the Commonwealth and New South Wales governments

On 31 January 2020, the Commonwealth Government and New South Wales Government signed a Memorandum of Understanding (MOU)[32], agreeing that they will work together to develop options to increase gas supply for New South Wales. The New South Wales Government will set a target to inject an additional 70 PJ of gas a year into the New South Wales market.

The priority projects identified by this MOU are the:

- Port Kembla gas import terminal (up to 100 PJ) – granted planning approval in April 2019.
- Port of Newcastle gas import terminal (approximately 110 PJ) – declared New South Wales Critical State Significant Infrastructure in August 2019.
- Narrabri Gas Project (approximately 70 PJ) – to be determined by the Independent Planning Commission.

The MOU also says that, if the projects outlined above do not proceed, or do not inject 70 PJ of gas into the east coast market by 2022, the governments will conduct a gas market review to address barriers to bringing on new gas supply and to identify how the target can be achieved. As an action, the New South Wales Government will facilitate, within its established rules and limitations, investment opportunities for gas infrastructure in New South Wales, as well as working with the Commonwealth Government to explore options to free up gas demand through electrification, fuel-switching, and energy efficiency.

New South Wales' annual gas consumption is approximately 115 PJ a year. Less than 5% of that demand is currently met by production within the state, and this production (at Camden) is expected to cease from 2023. A new gas supply of 70 PJ a year would increase New South Wales' security of supply in the face of declining southern reserves, meeting over 60% of demand, and delaying potential supply gaps within New South Wales until at least 2034.

To improve the supply outlook for other southern states, these projects would need to not only provide sufficient annual volumes of new gas supply, but also have the flexibility to increase daily supply to meet winter peak demands. As noted in Section 4.1, the difference between maximum and minimum demand in the southern states can be quite large. In 2024, for example, demand in New South Wales is forecast to vary between 170 TJ a day and 500 TJ a day, and demand in Victoria is forecast to vary between 270 TJ a day and 1,200 TJ a day.

The Narrabri Gas Project is estimated to be capable of producing a maximum of approximately 200 TJ a day[33], while an import terminal, whether at Port Kembla or Port of Newcastle, may be capable of producing around 500 TJ a day[34]. Jemena has informed AEMO that if an import terminal was constructed at Port Kembla, the Eastern Gas Pipeline (EGP) can be modified to allow the transport of gas in both a northerly and southerly direction, so any excess gas could flow south from Sydney to Melbourne, if required.

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[32] See https://energy.nsw.gov.au/media/2001/download.

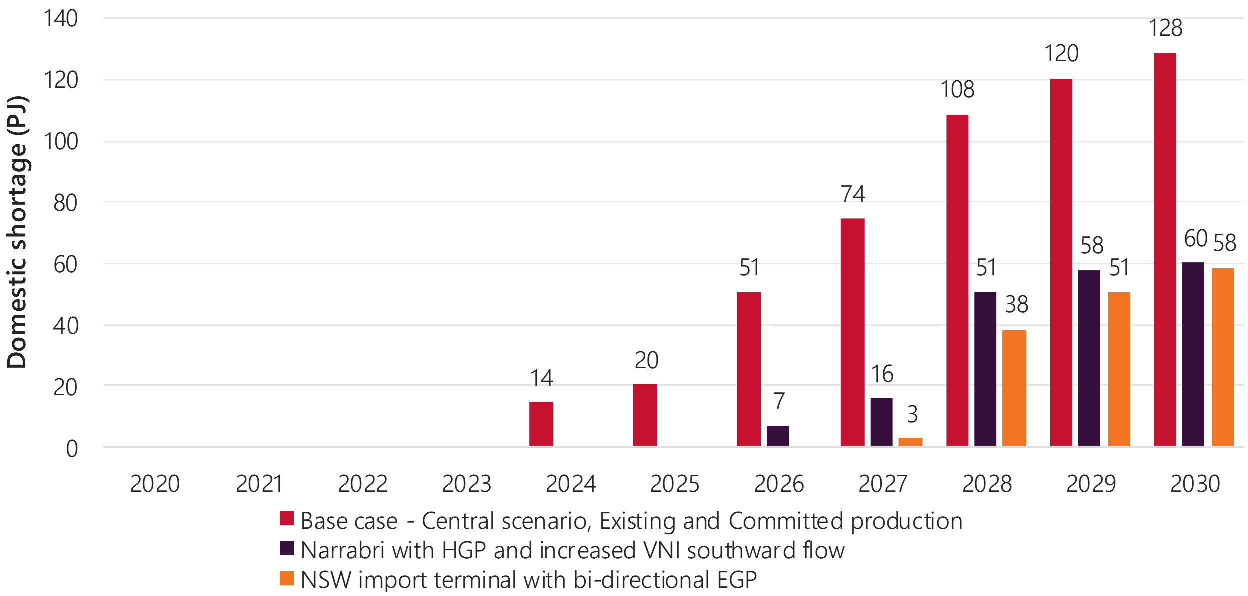
[33] Narrabri Gas Project, Environmental Impact Statement, at http://majorprojects.planning.nsw.gov.au/index.pl?action=view_job&job_id=6456.

[34] Port Kembla Gas Terminal Proposed Modification Environmental Assessment, at https://majorprojects.planningportal.nsw.gov.au/prweb/PRRestService/mp/01/getContent?AttachRef=SSI-9471-MOD-1%2120191128T233407.251%20GMT.

If Narrabri is paired with the Hunter Gas Pipeline, or a similar pipeline project links Narrabri with the Moomba to Sydney Pipeline (MSP), and capacity is increased along the Victoria – New South Wales Interconnector, southern shortfalls are estimated to be delayed until 2026, or two years relative to the base case (existing and committed supplies only). It is worth noting that in the base case in 2026 the annual southern shortfall is estimated to be 51 PJ, lower than the estimated production from Narrabri of 70 PJ, yet Narrabri cannot entirely eliminate this shortfall due to the difficulty of meeting peak day demand.

If a New South Wales import terminal, producing 70 PJ a year and 550 TJ a day, is paired with bi-directional flow along the EGP, southern shortfalls are estimated to be delayed till 2027, or three years relative to the base case. This information is summarised in Figure 28.

Figure 28 Comparison of forecast shortfalls across New South Wales supply options, 2020-29



5.3 Victorian import terminal

AGL has proposed the development of a floating LNG import terminal at Crib Point in Victoria, with injection capabilities up to 550 TJ a day and connecting to the Victorian gas system at an existing pipeline near Pakenham. AGL continues to progress the Environmental Effects Statement (EES) process, with an outcome expected mid-2020. Should the project gain the required approvals at this time, AGL projects that the import terminal should be operational by the beginning of 2022.

With this supply, if only existing and committed projects are otherwise available, then this import terminal in Victoria can support declining southern resources and is forecast to push back any forecast supply gaps by up to six years to 2030 in the Central scenario.

5.4 Further southern field production

AEMO has also considered further gas projects within Victoria and South Australia:

- GB Energy's Golden Beach production and storage facility project is expected to produce up to 100 TJ a day for up to three years before being used as a storage reservoir. Should approvals, funding, and construction progress as planned, production from this project could be available by 2022.
- Leigh Creek Energy proposes to use the existing but unused Leigh Creek coalfield in South Australia to produce energy from the coal using in-situ gasification (ISG) to produce synthetic gas. In the initial stage of the Leigh Creek Energy project, a demonstration plant will be run to inform the design of a

commercial scale facility. If all approvals, funding, and construction of a commercial-scale plant progress as planned, this facility may inject up to 60 PJ of gas into the South Australian gas system by 2024.

- Exploration and field development projects within Victoria are continuing, in:
  - The Gippsland Basin, including the Manta and Longtom field projects.
  - The Bass Basin, including the Trefoil field project.
  - The Otway Basin, including the Annie, La Bella, and Henry field projects.
- Further development in the Cooper and Eromanga Basin has also been identified.

More detail on the Victorian projects, and other more uncertain exploration projects, can be found in the 2020 VGPR Update.

None of these projects alone are likely to change the timing of the supply gaps forecast in the southern states in the short term, but in combination, are likely options for the ongoing development required to fill the increasing shortfalls forecast beyond 2024.

5.4.1 New northern supply

Exploration continues in the Beetaloo Basin in the Northern Territory, with several different exploration projects ongoing across 2019 and 2020. Should this exploration produce favourable outcomes, significant amounts of new supply could be available for transport to the eastern gas markets (Core Energy Group estimates a prospective resource of approximately 70,000 PJ). The Commonwealth Government is supporting this development, with the Commonwealth Budget including funding for feasibility studies to accelerate gas supplies from the Northern Territory to the east coast market.

Exploration is also ongoing in the Galilee Basin in Queensland as a new source of supply within the east coast.

Jemena has an interest in pipeline projects in bringing new supply to the east coast gas markets from both the Northern Territory and the Galilee Basin, eventually connecting near Wallumbilla. Jemena has indicated[35] that the capacity of the NGP could be increased to 700 TJ a day (255 PJ a year) if required by the market.

Depending on the size and timing of these projects, new supply from either Beetaloo or Galilee basins may push back total supply gaps and improve Queensland's supply adequacy. Any new supply from the north would, however, have limited impact on southern domestic shortfalls unless further infrastructure projects are developed.

5.4.2 Pipeline expansion options

APA has advised AEMO that, if required by the market, several key pipelines could be upgraded:

- The SWQP could provide an additional 130 TJ a day of capacity in both directions.
- The MSP could provide an additional 230 TJ a day towards Sydney.
- The Victoria – New South Wales Interconnector could provide 125 TJ a day additional capacity towards Victoria.

Projects proposing further pipeline linkages between Queensland and New South Wales (such as the Queensland Hunter Gas Pipeline) – connecting Wallumbilla to Newcastle or along the MSP – are being considered as options to increase the southern states' access to northern gas supplies.

Any expansion to existing pipelines or further connection between New South Wales and Queensland would allow any new northern supply to further support the southern gas system.

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[35] See: https://jemena.com.au/about/newsroom/media-release/2018/missing-gas-pipeline-link-complete.

6. Gas industry evolution

This chapter considers the possible role hydrogen might play in Australia's long-term energy mix, with impacts to the gas industry considered further in the 2021 GSOO, and highlights upcoming changes to gas transparency following reviews from the Australian Energy Market Commission, the Australian Competition and Consumer Commission, and the Gas Market Reform Group.

6.1 The potential long-term role of hydrogen in Australia's energy mix

The recently released national hydrogen strategy[36] outlines Australia's potential to produce low-emissions hydrogen for both export and domestic markets. Hydrogen has the potential to help meet global long-term climate objectives by decarbonising hard-to-abate sectors such as heavy transport and industrial manufacturing. The value of hydrogen to Australia lies not only in domestic applications but also in the potential export market.

Global demand for low-emissions hydrogen is expected to rise as decarbonisation efforts increase. Several countries have developed national hydrogen strategies, with demand in the Asia Pacific region stemming primarily from applications in transport, industry, and power generation[37,38,39]. In some of these applications – particularly industrial heat, chemicals manufacturing, and power generation – hydrogen is viewed as a replacement for natural gas in the long term.

That means natural gas and hydrogen markets will eventually interact as hydrogen gradually meets an increasing share of global energy demand growth.

Hydrogen production to meet projected export demand may require a range of low-emissions technologies including, but not limited to, electrolysis of water using renewable electricity, steam methane reforming with carbon capture and storage (CCS), and coal gasification with CCS. These technologies have different feedstocks and characteristics, so the impact on Australia's energy mix and resources will vary depending on their relative dominance.

Domestically, hydrogen has the potential to decarbonise sectors including residential heat, cars and heavy transport, industrial heat, and chemicals and fertiliser manufacturing[36]. Multiple state governments have

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[36] Commonwealth of Australia, "Australia's National Hydrogen Strategy", November 2019, at https://www.industry.gov.au/data-and-publications/australias-national-hydrogen-strategy.

[37] Japanese Ministry of Economy, Trade and Industry, "Formulation of a New Strategic Roadmap for Hydrogen and Fuel Cells", March 2019, at https://www.meti.go.jp/english/press/2019/0312_002.html.

[38] Government of Korea, "Hydrogen Economy Roadmap of Korea", January 2019, at https://docs.wixstatic.com/ugd/45185a_551e67dca75340569e68e37eea18f28e.pdf.

[39] Strategy Advisory Committee of the Technology Roadmap for Energy Saving and New Energy Vehicles (China), "Hydrogen Fuel Cell Vehicle Technology Roadmap", October 2016, at https://docs.wixstatic.com/ugd/45185a_e975e82743f3496ca41fe3ccc94c6228.pdf.

published hydrogen strategies and/or action plans[40,41,42,43], with blending of up to 10% hydrogen (by volume) in natural gas distribution networks featuring significantly. Hydrogen may be used in electricity generation as a way to shift excess renewable generation by storing it as hydrogen, which is then used to power GPG at a later time when generation resources are low.

Current projects include feasibility studies into blending 10% hydrogen into Victorian and South Australian distribution networks[44], a trial to produce renewable hydrogen for blending into the western Sydney distribution network[45], and feasibility studies into production of ammonia from renewable hydrogen[46,47]. Australian governments will complete a review of the National Gas Law and impacts on gas networks by the end of 2020. This will be submitted to the COAG Energy Council with recommendations on safe limits for hydrogen in existing gas pipelines.

The National Hydrogen Strategy noted that energy market bodies will need to account for possible effects of hydrogen in their planning. As AEMO's Draft 2020 ISP noted, an emerging hydrogen economy could potentially have long-term impacts on Australia's future energy mix. Large-scale take-up of hydrogen technologies in Australia will depend on the rate of cost reduction, state and federal policy measures, competing water priorities, and social acceptance of hydrogen as a fuel in domestic and transport applications.

AEMO will continue to monitor developments in the hydrogen space as policy, economic, and technological change progresses, and the likely impact of hydrogen on Australia's long-term energy mix. The 2021 GSOO will provide a scenario reflecting a possible future where there is significant penetration of hydrogen into Australia's energy systems, and provide an assessment of the long-term impacts of hydrogen on the gas industry.

6.2 Gas market transparency measures

Between 2017 and 2019, the Australian Energy Market Commission (AEMC), the Australian Competition and Consumer Commission (ACCC), and the Gas Market Reform Group (GMRG) established by the COAG Energy Council conducted independent reviews of Australia's gas markets.

These reviews identified a range of information gaps and asymmetries that they suggested are adversely affecting the efficient operation of the eastern and northern Australian gas markets.

The reviews independently recommended several measures to address these information deficiencies[48] by addressing two key elements of the National Gas Law (NGL) and National Gas Rules (NGR):

- Changes to the GSOO – strengthening AEMO's information-gathering powers to create greater transparency. This includes amending the NGR to allow AEMO to collect GSOO information on a mandatory basis and including the Northern Territory within the scope of the GSOO.

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[40] Government of South Australia, "South Australia's Hydrogen Action Plan", September 2019, at https://www.renewablessa.sa.gov.au/topic/hydrogen/hydrogen-action-plan.

[41] Queensland Government, "Queensland Hydrogen Industry Strategy 2019 – 2024", May 2019, at https://www.dsdmip.qld.gov.au/resources/strategy/queensland-hydrogen-strategy.pdf.

[42] Tasmanian Government, "Tasmanian Renewable Hydrogen Action Plan", March 2020, at https://www.stategrowth.tas.gov.au/energy_and_resources/energy/hydrogen/tasmanian_renewable_hydrogen_action_plan.

[43] Government of Western Australia, "Western Australia Renewable Hydrogen Strategy", July 2019, at http://www.drd.wa.gov.au/Publications/Documents/wa_renewable_hydrogen_strategy.pdf.

[44] See https://arena.gov.au/projects/australian-hydrogen-centre/.

[45] See https://arena.gov.au/projects/jemena-power-to-gas-demonstration/.

[46] See https://arena.gov.au/projects/yara-pilbara-renewable-ammonia-feasibility-study/.

[47] See https://arena.gov.au/projects/feasibility-study-for-a-green-hydrogen-and-ammonia-project/.

[48] COAG Energy Council, Measures to Improve Transparency in the Gas Market, COAG Regulation Impact Statement for consultation, August 2019, at http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/Measures%20to%20Improve%20Transparency%20in%20the%20Gas%20Market%20-%20Regulatory%20Impact%20Statement%20-%2020190808.pdf.

- Changes to the Gas Bulletin Board (GBB) – using the GBB to collect GSOO information, and including new GBB information such as Large Users and LNG Facilities.

The COAG Energy Council released a Regulation Impact Statement (RIS) for consultation which examined various options, seeking to minimise costs to participants while maximising the potential benefits. The Consultation closed on 27 September 2019.

Subject to COAG Energy Council endorsement at each step, the process is expected to be:

- Amendments to the NGL, NGR, and Regulations to give effect to the preferred option will be prepared for public consultation after the March 2020 COAG Energy Council meeting.
- Outcomes from this consultation will be considered by the COAG Energy Council by mid-2020.
- Changes to the NGL, NGR, and Regulations will be completed by the end of 2020.
- Once system and reporting changes occur, actual implementation would be in 2021-22 with the 2022 GSOO benefiting from greater information transparency facilitated through these reforms.

A1. Forecast accuracy

Assessing forecasting performance and understanding any propensity for bias is critical to AEMO's ability to improve its future forecasting accuracy and better identify the forecast uncertainty. AEMO publishes data detailing its forecasting accuracy to help inform its approach to continuous improvement and build confidence in the forecasts it produces.

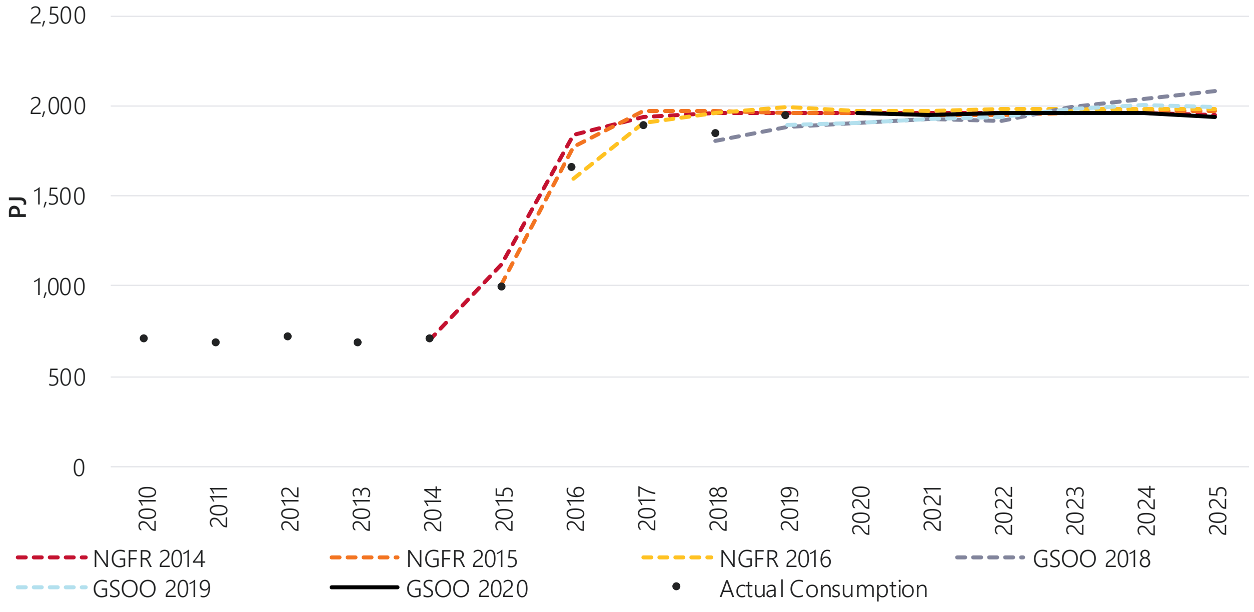
The following charts show AEMO's gas consumption forecasts since 2014 (published in the *National Gas Forecasting Report* [NGFR] until 2016, and the GSOO from 2018 onwards[49]), compared to actual recorded consumption since 2010. These charts can be used to assess the performance of the forecasts by comparing actual consumption against forecasts in each year. Only the Central/Neutral scenario forecasts are 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 the 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 may be expected in years that are particularly hot or cold.

Total gas forecasts for eastern and south-eastern Australia

Figure 29 shows total gas consumption forecasts for eastern and south-eastern Australia, including consumption for LNG export.

Figure 29 Gas annual consumption forecast comparison, total for eastern and south-eastern Australia



[49] The 2016 NGFR was published December 2016, so the GSOO – published each March – did not publish demand forecasts until the 2018 edition.

Key observations include:

- Steep growth in gas consumption was seen between 2014 and 2016 as LNG facilities ramped up in Queensland.
- There was some overestimation of gas consumption in the 2014 NGFR and 2015 NGFR forecasts for 2016 and 2017, largely driven by slower than expected ramp-up of LNG exports.
- The 2020 gas consumption forecast is lower than all previous forecasts from 2023 onwards, largely reflecting a reduced outlook for the LNG sector, along with a muted outlook for GPG as new utility-scale renewable capacity forecasts are higher than previously forecast (refer to Section 2.3.3).

Table 8 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 the difference between the forecast and the actual, divided by the actual. From the 2016 NGFR onwards, (that is, after the significant LNG ramp) total gas consumption forecasts have performed reasonably well, with actual gas consumption falling within 3% of the year ahead forecasts.

Table 8 Year ahead historical forecast accuracy, total for eastern and south-eastern Australia

	2015	2016	2017	2018	2019
Year ahead forecast	1,122.7	1,773.4	1,903.4	1,809.6	1,888.6
Actual consumption	987.6	1,658.4	1,885.3	1,844.5	1,947.9
Forecast accuracy	13.7%	6.9%	1.0%	-1.9%	-3.0%
Source	2014 NGFR	2015 NGFR	2016 NGFR	2018 GSOO*	2019 GSOO

* The 2018 GSOO was published in June 2018, considering data available until early April 2018. As such, the year ahead forecast included actual consumption from January to March inclusive.

LNG export segment consumption forecasts

Figure 30 shows AEMO's forecast of annual gas consumption by the Queensland LNG consortia. Since LNG production began to plateau in 2016, forecast accuracy has improved, helped through greater input from the consortia since 2018. AEMO's 2019 GSOO LNG projection aligns well with actual consumption levels in 2019.

Figure 30 Gas annual consumption forecast comparison, LNG

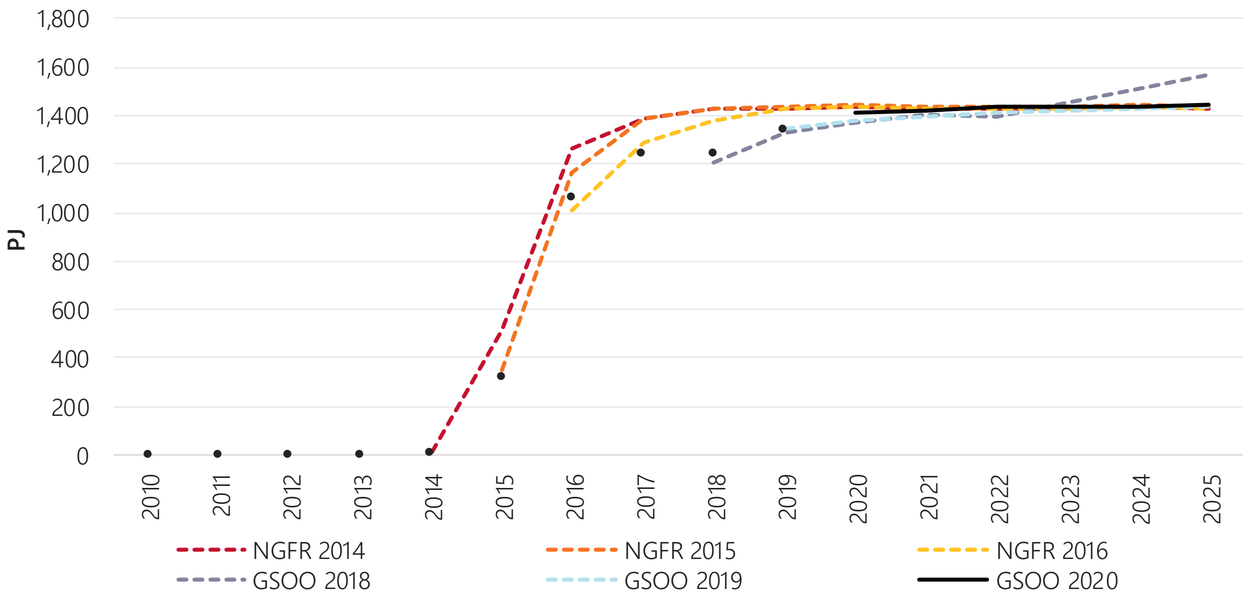


Table 9 provides an overview of the forecast accuracy of the calendar year immediately following the forecast. Like Figure 30, this table highlights improving forecast accuracy for the year ahead forecasts of LNG demand.

Table 9 Year ahead historical forecast accuracy, LNG

	2015	2016	2017	2018	2019
Year ahead forecast	511.3	1,167.9	1,291.5	1,208.1	1,346.4
Actual consumption	324.7	1,059.9	1,241.6	1,242.9	1,325.0
Forecast accuracy	57.5%	10.2%	4.0%	-2.8%	1.6%
Source	2014 NGFR	2015 NGFR	2016 NGFR	2018 GSOO*	2019 GSOO

* The 2018 GSOO was published in June 2018, considering data available until early April 2018. As such, the year ahead forecast included actual consumption from January to March inclusive.

Residential and commercial segment consumption forecasts

Figure 31 shows AEMO's residential and commercial gas consumption forecasts. The starting point of the 2020 GSOO forecast is calibrated to recent consumption data, with the overall trend reflecting AEMO's assumptions relating to connections and population growth and the impacts of energy efficiency, gas to electric fuel-switching, gas prices, and climate change.

Table 10 provides an overview of the residential and commercial gas consumption forecast accuracy of the calendar year immediately following the forecast.

AEMO's 2019 GSOO residential and commercial projection was 0.7% higher than actual consumption levels in calendar year 2019. This variance is likely due to a combination of weather, connection, and usage changes.

Figure 31 Gas annual consumption forecast comparison, residential/commercial

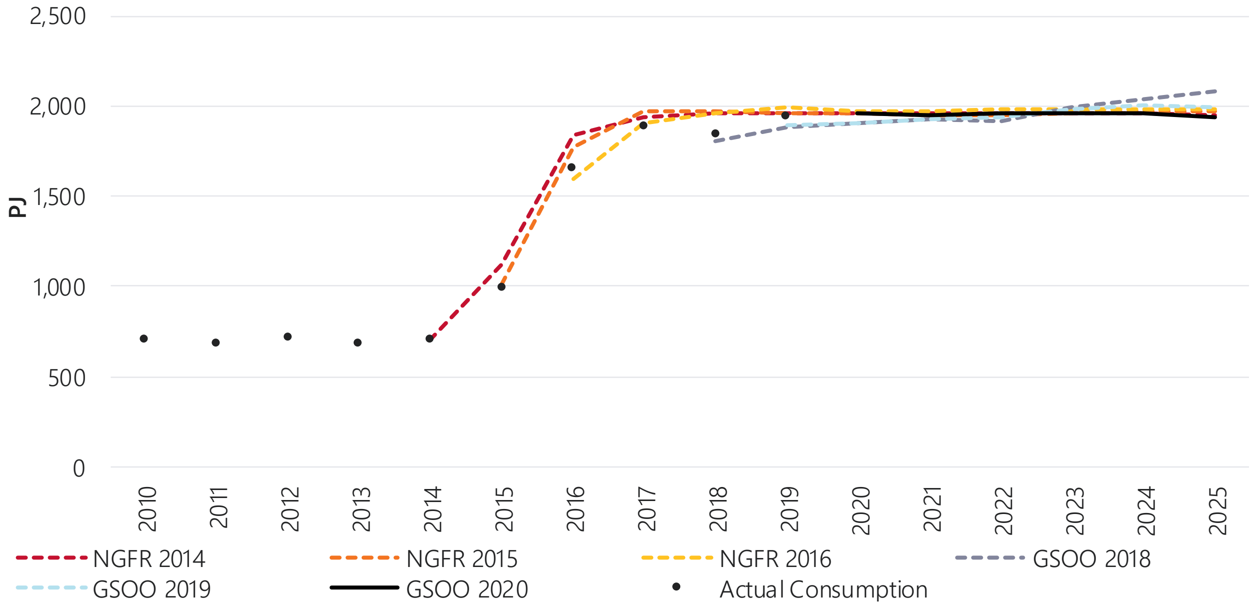


Table 10 Year ahead historical forecast accuracy, residential/commercial

	2015	2016	2017	2018	2019
Year ahead forecast	175.3	188.0	190.5	187.9	189.8
Actual consumption	198.9	192.9	199.5	196.9	188.5
Forecast accuracy	-11.8%	-2.5%	-4.5%	-4.6%	0.7%
Source	2014 NGFR	2015 NGFR	2016 NGFR	2018 GSOO*	2019 GSOO

* The GSOO 2018 was published in June, considering data available until early April 2018. As such, the year ahead forecast included actual consumption from January to March inclusive.

Industrial segment consumption forecasts

Figure 32 shows AEMO's industrial gas consumption forecasts, incorporating AEMO's assumptions on forecast changes in economic drivers and data obtained by surveying large gas users.

Figure 32 Gas annual consumption forecast comparison, industrial

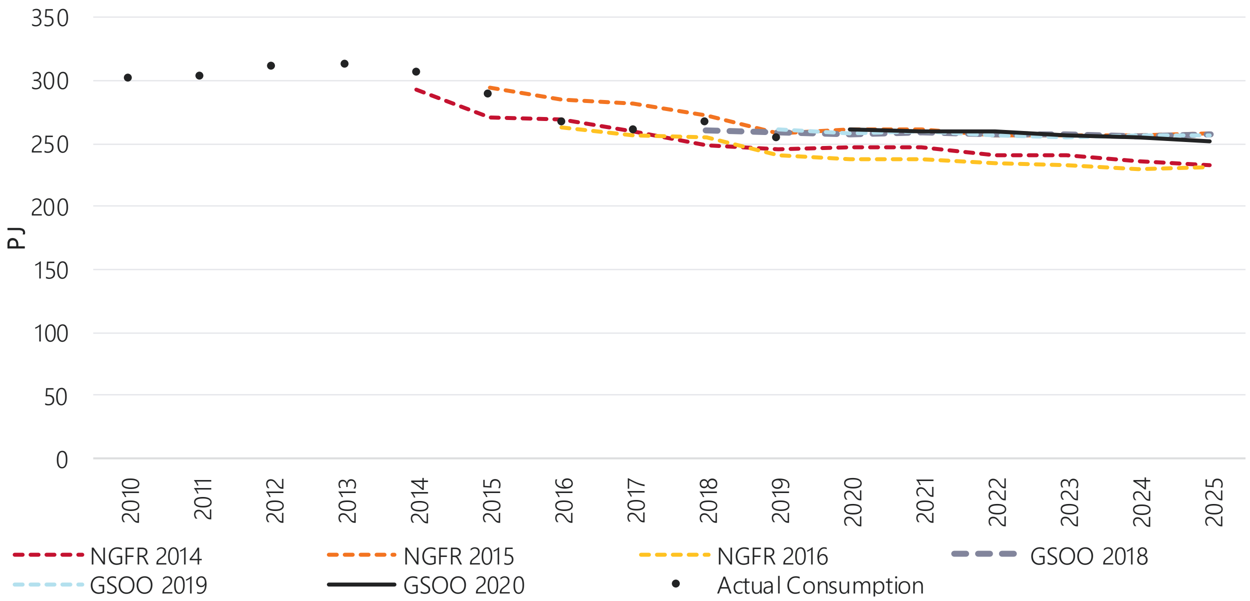


Table 11 provides an overview of the industrial gas consumption forecast accuracy of the calendar year immediately following the forecast.

Table 11 Year ahead historical forecast accuracy, industrial

	2015	2016	2017	2018	2019
Year ahead forecast	271.6	285.7	257.4	260.4	261.0
Actual consumption	289.1	266.5	260.4	267.1	255.1
Forecast accuracy	-6.1%	7.2%	-1.2%	-2.5%	2.3%
Source	2014 NGFR	2015 NGFR	2016 NGFR	2018 GSOO*	2019 GSOO

* The 2018 GSOO was published in June 2018, considering data available until early April 2018. As such, the year ahead forecast included actual consumption from January to March inclusive.

In the 2014 NGFR, AEMO correctly predicted an inflection point in industrial consumption. Key to identifying this inflection point in consumption trends was AEMO's increased engagement with large industrial users. This process has helped AEMO develop richer insights into the key trend drivers for this sector and identify structural and behavioural changes. This 2020 GSOO has further increased the number of surveys, interviews, and separate customer forecasts and now covers 70% of Tariff D consumption. The 2019 GSOO and 2020 GSOO both forecast a long-term flattening trend in industrial demand, reflecting an increased vulnerability of industrial load to higher gas prices, as continually reported in surveys and interviews.

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

AEMO's 2019 GSOO industrial projection over-forecast actual consumption in 2019 by 5.9 PJ (2.3%). This variation was largely driven by lower usage from transmission-connected load in Queensland, Victoria, and South Australia. During discussions in preparation for the 2020 GSOO with large facilities on their fall in recent consumption, LILs indicated that this lower usage in 2019 was related to specific operational issues faced by certain facilities and not indicative of any structural change in consumption from these facilities.

GPG consumption forecasts

Forecasting gas consumption for GPG is challenging because it is driven by events, such as extreme weather or generation outages, that can be difficult to predict and which lead to significant variations in forecasts.

Figure 33 compares AEMO's GPG forecasts since 2014 against actuals. It highlights that declining trends have been reasonably well anticipated, although all forecasts since 2014 have underestimated actual GPG consumption in the past five years due to event-driven increases in GPG reliance. Events over the last five years include the Basslink interconnector outage in 2015, the sudden closure of Hazelwood coal power station in 2017, the extended outage of Yallourn in November 2017, and the Loy Yang A2 and Mortlake unit outages in 2019. Increasing renewable generation developments in the NEM are expected to continue to drive down system normal demand for GPG, although the absolute level of event-driven GPG in any given year is difficult to predict. A backcast exercise was performed for the 2019 calendar year (discussed further below), testing the GPG forecast had the Loy Yang A2 and Mortlake unit prolonged outages been explicitly included in the GSOO model. This can be seen as the red cross in Figure 33.

Figure 33 Gas annual consumption forecast comparison, GPG

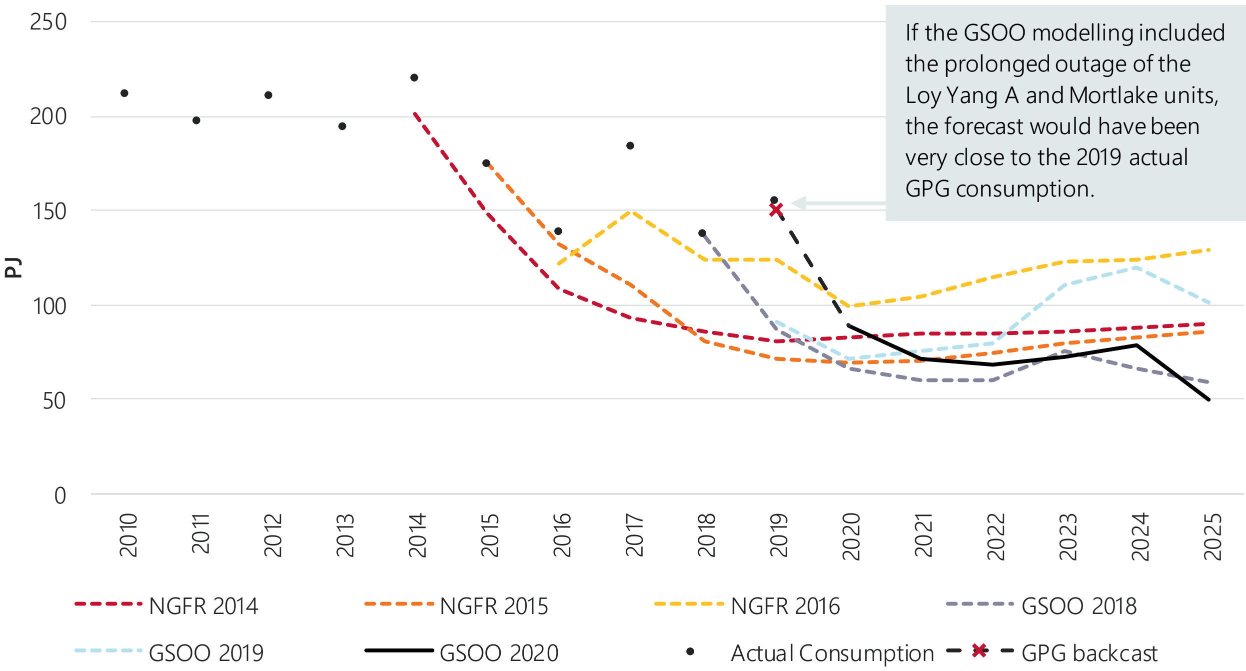


Table 12 provides an overview of the forecast accuracy of the calendar year immediately following the forecast. The GPG forecast accuracy ranges from a 1% underforecast for the 2018 calendar year up to a 41.1% underforecast for the 2019 calendar year. The GPG backcast results can also be seen within brackets in the 2019 calendar year column.

Table 12 Year ahead historical forecast accuracy, GPG

	2015	2016	2017	2018	2019 (GPG backcast)
Year ahead forecast	149.0	131.8	150.1	136.1	91.4 (152.1)
Actual consumption	175.0	139.1	183.8	137.5	155.3
Forecast accuracy	-14.9%	-5.2%	-18.3%	-1.0%	-41.1% (-2.1%)
Source	2014 NGFR	2015 NGFR	2016 NGFR	2018 GSOO*	2019 GSOO

* The 2018 GSOO was published in June 2018, considering data available until early April 2018. As such, the year ahead forecast included actual consumption from January to March inclusive.

AEMO's 2019 GSOO GPG projection significantly underforecast actual consumption in 2019, by 64 PJ. This was primarily due to extended unit outages in the NEM:

- The coal-fired Loy Yang A2 unit was damaged following an electrical short internal to the generator and was out of service from May 2019, only returning to normal service in January 2020.
- Mortlake, Victoria's newest and most efficient GPG, faced a six-month outage of one unit between July and December 2019 after the unit was damaged by an electrical fault.

Additionally, extreme weather events, particularly extended hot weather across January 2019, led to a slightly higher electricity consumption than forecast (the energy equivalent is approximately 10 PJ).

AEMO determined that these factors were key in the forecast inaccuracy by running a backcast model, that is, a GPG model with:

- The half-hourly demand exactly reflecting the actual 2019 electricity operational demand.
- The weather patterns driving wind and solar generation exactly as observed in 2019.
- Loy Yang A2 and Mortlake unit 2 out of service during the times observed in 2019.

This model forecast that under these conditions, the NEM would have required 152 PJ of gas for GPG, 3 PJ lower than the actual requirements observed. This GPG backcast is also shown in Figure 33, as the red cross at the 2019 calendar year. The reduced coal quality experienced by Mount Piper Power Station in 2019 was not included in this assessment. This highlights that GPG is highly uncertain and can be significantly impacted by unforecast events; however, the backcast model strongly suggests that the underlying GPG modelling methodology is robust, given inputs used.

The following sections provide a regional breakdown of the GPG forecasts, which allows NEM event patterns to be more clearly understood. The GPG backcast forecasts can also be seen in each of the regions' charts.

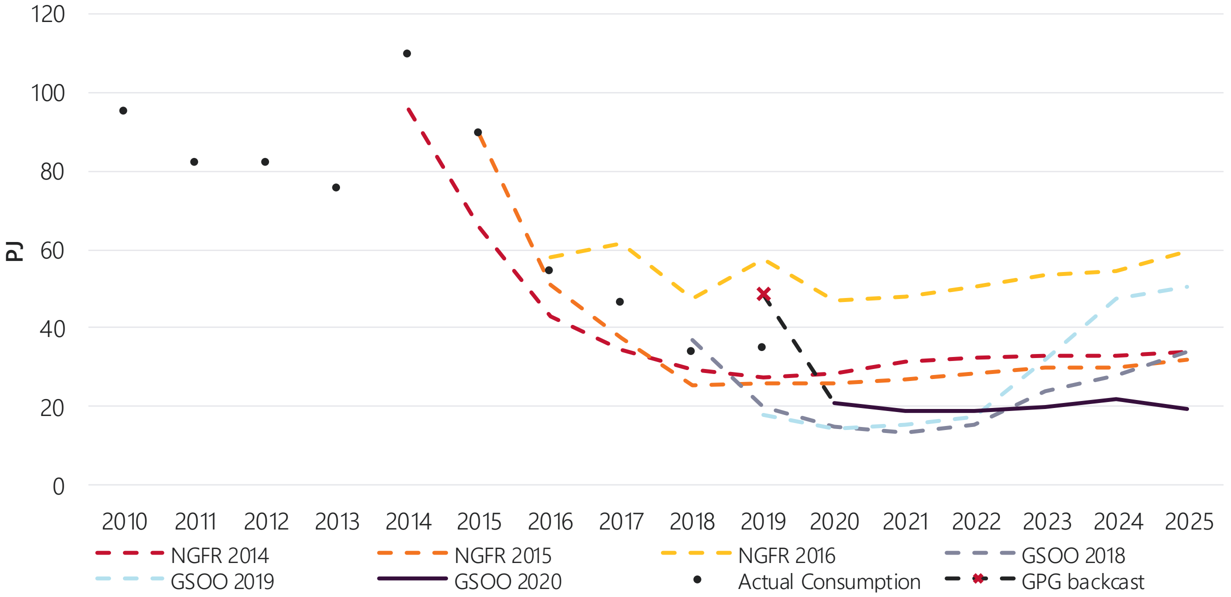
Queensland GPG forecasts

As shown in Figure 34, the Queensland GPG forecast has been tracking actual consumption outcomes fairly accurately and has effectively captured the timing and volume of the reduction in GPG since 2015.

The Queensland coal fleet is the newest in the NEM on average and recorded the highest level of availability in 2019 (for example, the amount of time Queensland coal generation was available to produce electricity was

7.3% higher than the coal fleet in New South Wales over the same period[50]). More reliable coal generation reduces the inherent uncertainty of GPG forecasts. In addition, as noted in the 2019 *Electricity Statement of Opportunities*[51], Queensland currently has a capacity surplus and a relatively large pipeline of committed and proposed renewable generation development, which means GPG is comparatively less likely to be required to meet demand under extreme events than regions with lower capacity surplus.

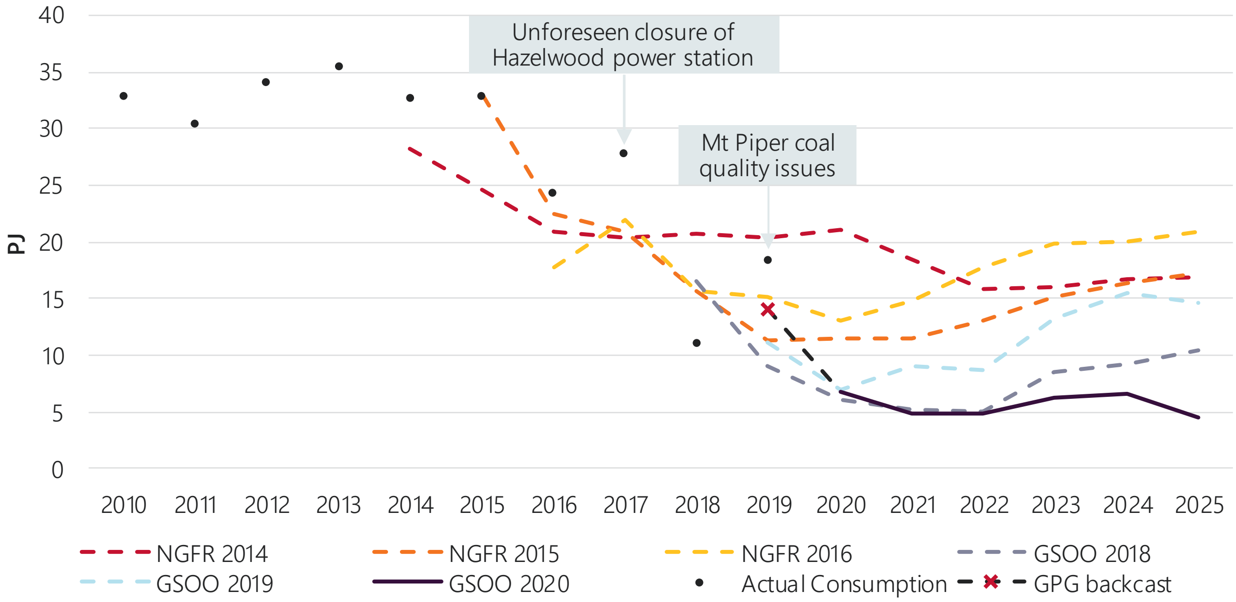
Figure 34 Gas annual consumption forecast comparison for Queensland, GPG



New South Wales GPG forecasts

Figure 35 shows GPG forecasts and actual GPG gas consumption since 2010 for New South Wales.

Figure 35 Gas annual consumption forecast comparison for New South Wales, GPG



[50] Based on calculations from NEM market data.

[51] At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo

The forecasts have generally been trending downwards since 2014, as new renewable generation is forecast to enter the NEM.

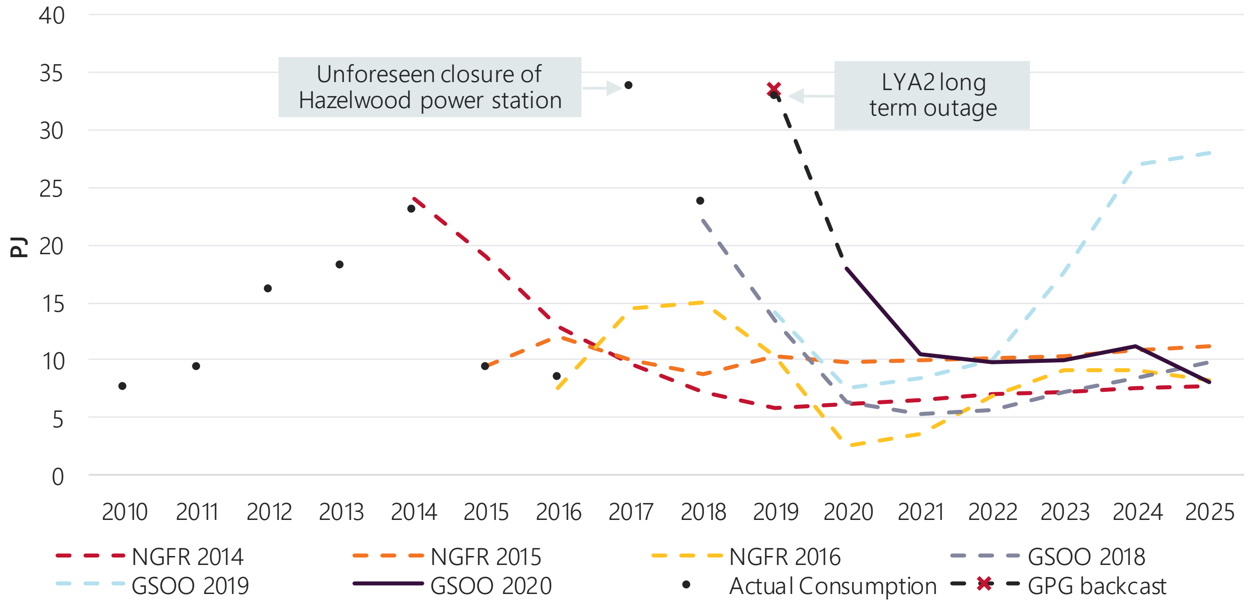
The 2017 calendar year recorded the previously unforeseen retirement of Hazelwood Power Station in Victoria, with increased generation from GPG required in New South Wales to support lost coal generation capacity. Actual GPG consumption in 2018 was particularly low compared to earlier historical values, largely driven by new renewable generation starting operation across 2018. This included 180 MW of solar generation that had not been included in the 2018 GSOO forecast, and 270 MW of wind generation that had been included but began generating nearly six months earlier than forecast. Additionally, 2018 did not experience any prolonged, unexpected coal-fired generation outages, which reduced the region's reliance on GPG.

This downward trend in GPG was not observed in 2019, as the Mount Piper Power Station experienced coal quality issues, which drove increased GPG to replace the lost generation. New South Wales also provided some support for the loss of Loy Yang A2 across 2019.

Victoria GPG forecasts

Figure 36 shows GPG forecasts and actual GPG gas consumption for Victoria. Following five years of sustained growth in GPG usage in Victoria, the period since 2015 has recorded large swings in inter-yearly GPG consumption. These swings have largely been event-driven, with upside pressure on the GPG forecast directly impacted by issues affecting the Victorian brown coal fleet. GPG consumption is forecast to trend downward due to increasing renewable generation capacity but, as noted in Section 5.1.2, there is considerable uncertainty around this forecast as the Victorian brown coal fleet is ageing and its availability is declining.

Figure 36 Gas annual consumption forecast comparison for Victoria, GPG



Victorian GPG forecasts are heavily event-driven, as it is the only state with no combined cycle gas turbines (CCGTs) in its GPG fleet. Open cycle gas turbines (OCGTs) are more expensive to run, and are therefore typically dispatched only during highest demand periods when most other generation sources are already generating at high load. This makes their operation much more volatile and less predictable than that of CCGTs.

In 2017, Victoria faced the unexpected (and unforecast) closure of the coal-fired Hazelwood Power Station, which resulted in a roughly 25 PJ (290%) increase from the 2016 actual GPG consumption, and a 19 PJ increase from the 2016 NGFR forecast.

The 2019 GSOO underforecast Victorian GPG for the 2019 calendar year by 18 PJ (57%), due primarily to the coal-fired Loy Yang A2 tripping and being out of service from May 2019, only returning to normal service in January 2020.

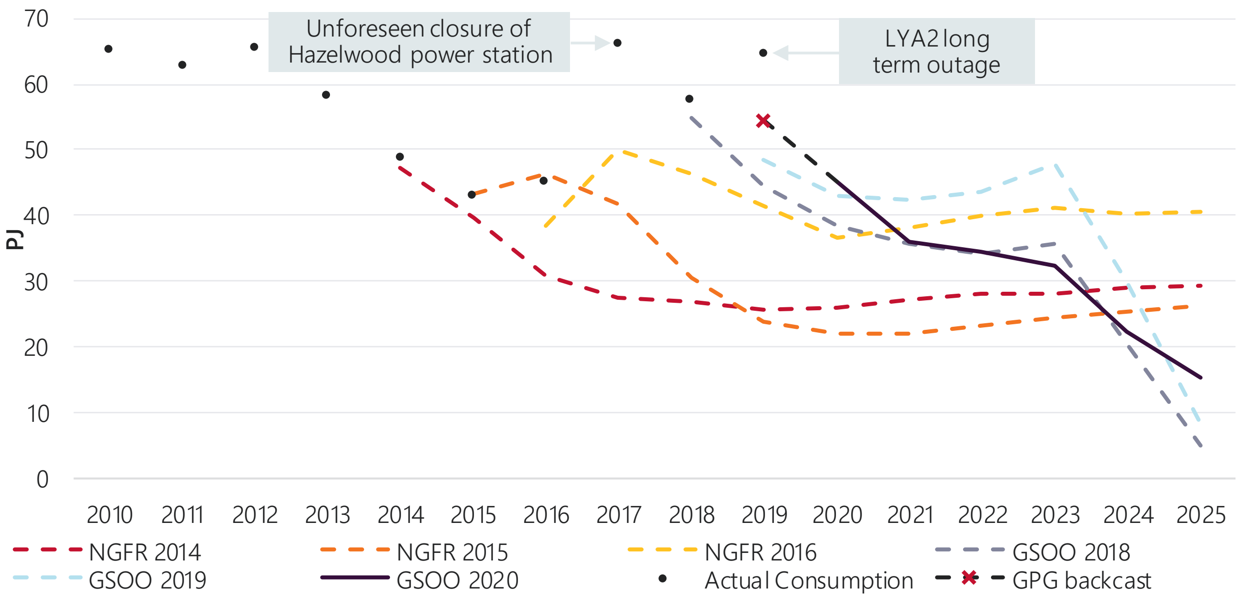
South Australia GPG forecasts

The South Australian GPG forecasts and actual GPG consumption since 2010 can be seen in Figure 37. The forecast's downward trend is due to forecast new renewable generation, balanced by South Australia's more recent system strength requirements. Following the South Australian black system event in September 2016, generation operation procedures changed to require more GPG operating to ensure the system remained secure.

As discussed above, 2017 saw the unforecast closure of Hazelwood Power Station. AEMO has observed that an outage of the coal fleet can impact GPG in adjacent regions of the NEM. The outage of Loy Yang A2 served to increase GPG consumption in South Australia, which AGL explicitly noted: "*We will use our generation portfolio in the adjacent regions of South Australia and New South Wales to support Victorian electricity requirements over the interconnectors*"[52].

While this response from South Australian GPG was underforecast in the 2019 backcast model, the long-term Loy Yang A2 outage in 2019 still led to increased South Australian GPG consumption of about 12% in the backcast.

Figure 37 Gas annual consumption forecast comparison for South Australia, GPG



Tasmania GPG forecasts

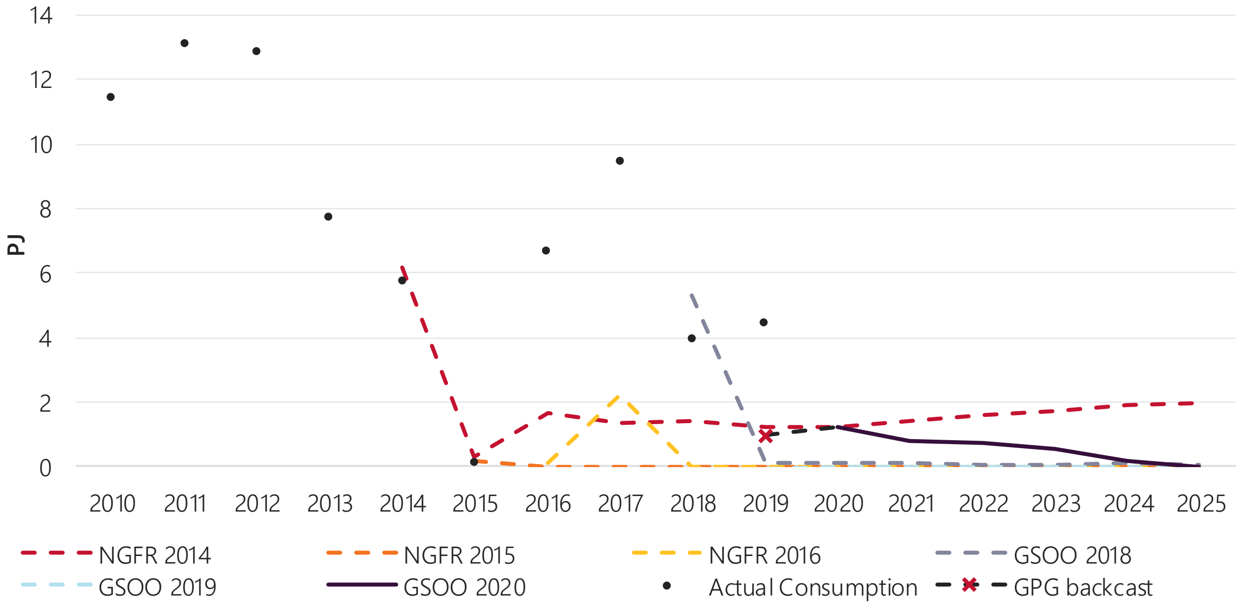
The Tasmania GPG forecasts and actual GPG consumption since 2010 can be seen in Figure 38.

While actual GPG consumption in Tasmania was in decline between 2011 and 2015, the outage of the Basslink interconnector between Tasmania and Victoria in December 2015 (not restored until mid-2016) drove up GPG demand in the short term. Tamar Valley CCGT is currently not in regular service, but may return to service at

[52] ABC News, "AGL holds off plans to mothball gas-fired Torrens Island Power Station ahead of summer", 12 July 2019, at https://www.abc.net.au/news/2019-07-12/agl-holds-off-plans-to-mothball-torrens-island-power-station/11303268.

its discretion with less than three months' lead time[53]. GPG in Tasmania is likely to continue to be used when hydro reservoirs are low, or when renewable generation is not available.

Figure 38 Gas annual consumption forecast comparison for Tasmania, GPG



[53] As advised by AETV, and reported in AEMO's Generation Information page: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information

Measures and abbreviations

Units of measure

Abbreviation	Full name
MW	megawatts
PJ	petajoules
TJ	terajoules

Abbreviations

Abbreviation	Full name
2P	proved and probable
ACCC	Australian Competition and Consumer Commission
ADGSM	Australian Domestic Gas Security Mechanism
AEMC	Australian Energy Market Commission
CCS	carbon capture and storage
CGP	Carpentaria Gas Pipeline
COAG	Council of Australian Governments
CSG	coal seam gas
DER	distributed energy resources
DTS	Declared Transmission System (Victoria)
EE	energy efficiency
EES	Environmental Effects Statement
EGP	Eastern Gas Pipeline
EVs	electric vehicles
GBB	Gas Bulletin Board
GDP	Gross Domestic Product
GMRG	Gas Market Reform Group

Abbreviation	Full name
GPG	gas-powered generation
GSOO	Gas Statement of Opportunities
GSP	Gross State Product
ISG	in-situ gasification
ISP	Integrated System Plan
LIL	Large Industrial Load
LNG	liquefied natural gas
MIL	Medium Industrial Load
MOU	Memorandum of Understanding
MSP	Moomba to Sydney Pipeline
NEM	National Electricity Market
NGFR	National Gas Forecasting Report
NGL	National Gas Law
NGP	Northern Gas Pipeline
NGR	National Gas Rules
POE	probability of exceedance
PRMS	Petroleum Resource Management System
PV	photovoltaic
QNI	Queensland – New South Wales Interconnector
QRET	Queensland Renewable Energy Target
RIS	Regulation Impact Statement
SIL	Small Industrial Load
SWQP	South West Queensland Pipeline
UAFG	unaccounted for gas
UGS	Underground Storage
VGPR	Victorian Gas Planning Report
VNI	Victoria – New South Wales Interconnector
VRE	variable renewable energy
VRET	Victorian Renewable Energy Target
WORM	Western Outer Ring Main

Glossary

Term	Definition
1-in-2	The 1-in-2 maximum 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	The 1-in-20 maximum 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.
2C contingent resources	Best estimate of contingent resources – equivalent to 2P reserves, except for one or more contingencies or uncertainties currently impacting the likelihood of development. Can move to 2P classification once the contingencies are resolved.
2P reserves	The sum of proved and probable estimates of gas reserves. The best estimate of commercially recoverable reserves, often used as the basis for reports to share markets, gas contracts, and project economic justification.
annual consumption	Gas consumption reported or forecast for a given year.
basin	A geological formation that may contain coal, gas, and oil.
coal seam gas (CSG)	Gas found in coal seams that cannot be economically produced using conventional oil and gas industry techniques. See unconventional gas. Also referred to in other industry sources as coal seam methane (CSM) or coal bed methane (CBM).
consumption	The measure of gas usage over time, typically one year.
contingent resources	Gas resources that are known but currently considered uncommercial based on one or more uncertainties (contingencies) such as commercial viability, quantities of gas, technical issues, or environmental approvals.
conventional gas	Gas that is produced using conventional or traditional oil and gas industry practices. See also unconventional gas.
demand	Capacity or gas flow on an hourly or daily basis, or the electrical power requirement met by generating units.
developed reserves	Gas supply from existing wells.
domestic gas	Gas that is used within Australia for residences, businesses, power generators, etc. This excludes gas demand for LNG exports.
gas-powered generation (GPG)	The generation of electricity using gas as a fuel for turbines, boilers, or engines.
initial reserves	On a given assessment date (such as 31 December 2010), the total quantity of gas expected to be recovered from a reservoir over its entire productive life (for example, from 1975 to 2025). See also remaining reserves.
large industrial	A segment of the gas market defined to include businesses that consume more than 10 TJ a year. See also mass market.
liquefied natural gas (LNG)	Natural gas that has been converted into liquid form for ease of storage or transport.

Term	Definition
LNG netback price	AEMO follows the ACCC definition of LNG Netback price (see "Gas Enquiry Interim Report 2017-2020", April 2018, https://www.accc.gov.au/system/files/Gas%20inquiry%20April%202018%20interim%20report.pdf): "*A pricing concept based on an effective price to the producer or seller at a specific location or defined point, calculated by taking the delivered price paid for gas and subtracting or 'netting back' costs incurred between the specific location and the delivery point of the gas. For example, an LNG netback price at Wallumbilla is calculated by taking a delivered LNG price at a destination port and subtracting, as applicable, the cost of transporting gas from Wallumbilla to the liquefaction facility, the cost of liquefaction and the cost of shipping LNG from Gladstone to the destination port*."
LNG train	A unit of gas purification and liquefaction facilities found in a liquefied natural gas plant.
market segments	For purposes of developing gas demand projections, gas consumers are grouped into domestic market segments (residential/commercial, large industrial, and gas demand for GPG), and gas demand for LNG export.
National Electricity Market (NEM)	The wholesale market for electricity supply in Queensland, New South Wales, the Australian Capital Territory, Victoria, Tasmania, and South Australia.
probability of exceedance (POE)	Refers to the probability that a forecast electricity maximum demand figure will be exceeded. For example, a forecast 5% probability of exceedance (POE) maximum demand will, on average, be exceeded only one year in every 20, and is equivalent to 1-in-20 terminology.
probable reserves	Estimated quantities of gas that have a reasonable probability of being produced under existing economic and operating conditions. Proved-plus-probable reserves added together make up 2P reserves.
production	In the context of defining gas reserves, gas that has already been recovered and produced.
prospective resources	Gas volumes estimated to be recoverable from a prospective reservoir that has not yet been drilled. These estimates are therefore based on less direct evidence than other categories.
proved and probable	See 2P reserves.
proved reserves	Estimated quantities of gas that are reasonably certain to be recoverable in future under existing economic and operating conditions. Also known as 1P reserves.
remaining reserves	On a given assessment date (such as 31 December 2010), the total quantity of gas expected to be recovered from a reservoir over its remaining productive life (for example, 1 January 2011 to 2025). See also initial reserves.
reserves	Reserves are quantities of gas which are anticipated to be commercially recovered from known accumulations.
reservoir	In geology, a naturally occurring storage area that traps and holds oil and/or gas. Iona Underground Storage (UGS) is also referred to as a reservoir for gas storage.
resources	More uncertain and less commercially viable than reserves. See contingent resources and prospective resources.
scenario analysis	Identifying and projecting internally consistent political, economic, social, and technological trends into the future and exploring the implications.
sensitivity analysis	A technique used to determine how different values of an independent variable will impact a particular dependent variable under a given set of assumptions. For example, in the GSOO, new supply options are tested as a sensitivity to the Neutral scenario.
unconventional gas	Gas found in coal seams, shale layers, or tightly compacted sandstone that cannot be economically produced using conventional oil and gas industry techniques. See also conventional gas.
undeveloped reserves	Gas supply from wells yet to be drilled.