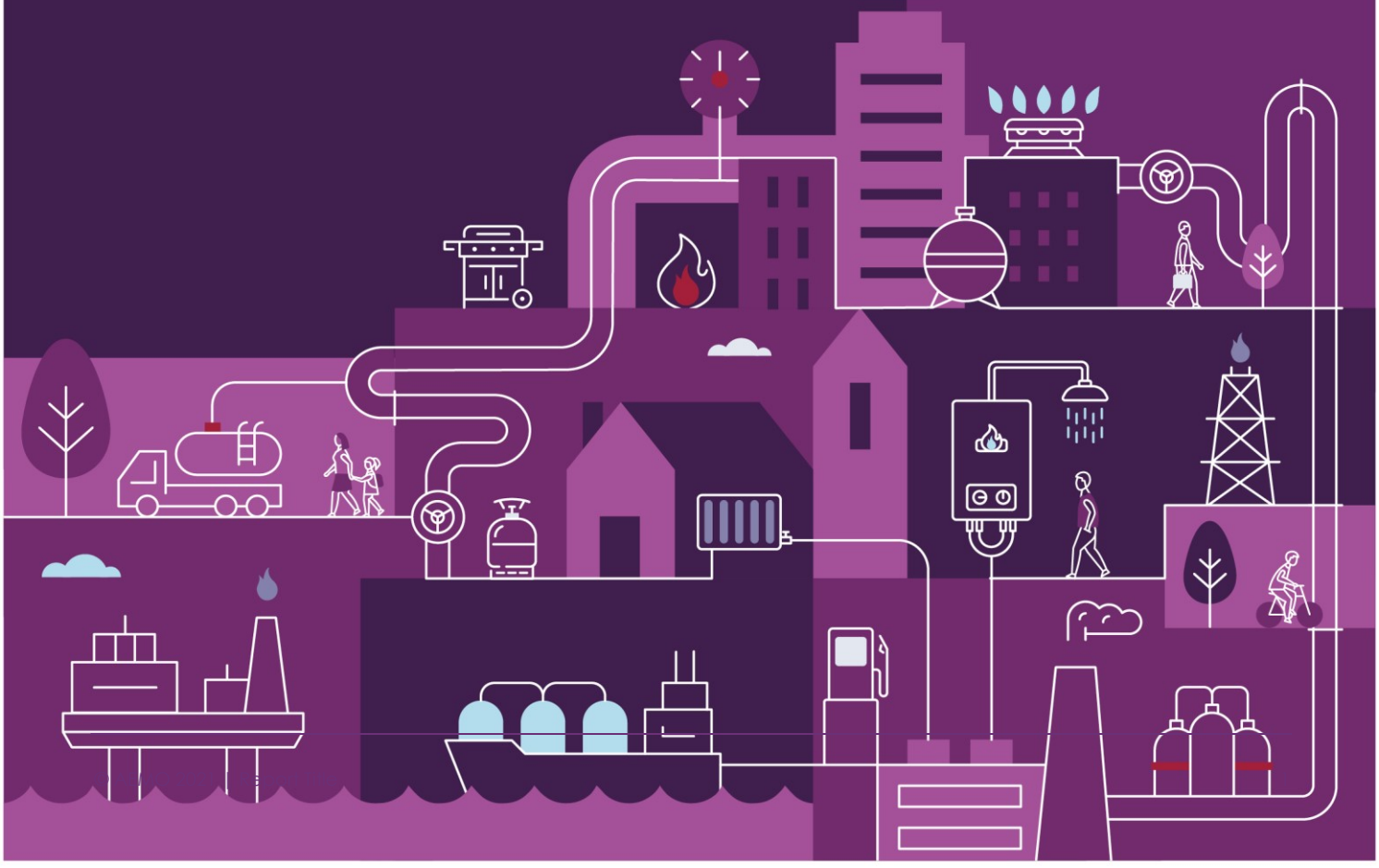
2021 Western Australia Gas Statement of Opportunities

December 2021

Market outlook to 2031

A report for the natural gas industry in Western Australia

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR



Important notice

Purpose

The purpose of this publication is to provide information about the natural gas industry in Western Australia.

AEMO publishes this Western Australia Gas Statement of Opportunities (GSOO) in accordance with Rule 103 of the Gas Services Information Rules (GSI Rules). This publication is generally based on information available to AEMO as at November 2021, unless otherwise indicated.

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Acknowledgement

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Version control

Version	Release date	Changes
1.0	14/12/2021	

Executive summary

The 2021 Western Australia (WA) *Gas Statement of Opportunities* (GSOO) presents AEMO's assessment of WA's domestic gas market for the 10-year outlook period 2022 to 2031. The WA GSOO presents forecasts of WA's domestic gas demand and potential gas supply for Low, Base and High scenarios[1], and an overview of gas infrastructure and emerging issues that affect Gas Market Participants (GMPs) and other stakeholders.

Key findings

Potential gas supply is gas that could be economically offered to the domestic market given forecast prices and production costs, capped by the availability of processing capacity and gas reserves. It does not project how much gas *will* be produced, but how much *could* be produced at the forecast price.

- Potential gas supply is sufficient to meet forecast domestic gas demand until 2024. However, reserves downgrades at existing gas production facilities have reduced potential gas supply over the outlook period.
- Between 2025 and 2027, domestic gas demand is forecast to exceed potential gas supply by 51 petajoules (PJ), at a maximum of 85 terajoules (TJ)/day. This projected supply gap could be alleviated by:
  - Gas being withdrawn from storage. WA has 78 PJ of storage capacity, which can deliver gas at up to 210 TJ/day.
  - Additional supply from existing facilities with spare production capacity (such as the Karratha Gas Plant [KGP]).
  - Development of gas fields that are not currently included in the potential gas supply forecasts, such as Corvus or Lockyer Deep.
- From 2027, Scarborough is forecast to supply up to 210 TJ/day to the domestic gas market, resulting in potential gas supply exceeding domestic gas demand until 2030. From 2031, declining production forecasts gas demand again exceeding potential gas supply.
- WA domestic gas demand is forecast to increase from 1,071 TJ/day in 2022 to 1,150 TJ/day in 2031 at an average annual rate of 0.8%.
  - Committed[2] new resources projects are expected to add approximately 33 TJ/day of gas demand by 2031.
  - Mining sector growth at existing projects is expected to add approximately 29 TJ/day of gas demand by 2031. Gas demand growth in this sector over the outlook period is driven by global demand for WA's commodities, in particular iron ore, lithium and nickel.

[1] In this executive summary, all references to forecasts are to the Base scenario, unless otherwise specified.

[2] Committed projects have achieved a positive final investment decision or are under construction and are included in all three gas demand scenarios.

- South West Interconnected System (SWIS) gas power generation (GPG) gas demand is forecast to grow by 14 TJ/day, from 129 TJ/day in 2022 to 143 TJ/day in 2031, as renewables only partly replace coal plant retirements.

WA domestic gas market is expected to be finely balanced

As shown in Figure 1 and Table 1, the WA domestic gas market is expected to be well supplied until 2024.

Between 2025 and 2027, domestic gas demand is forecast to exceed potential gas supply by 42 TJ/day in 2025, 85 TJ/day in 2026, and 13 TJ/day in 2027. The 2020 WA GSOO projected a supply gap in the outer years of the outlook period (2029 and 2030). The forecast supply reduction in the 2021 WA GSOO compared to the 2020 WA GSOO is due to reserves downgrades at the Reindeer gas field (Devil Creek gas plant) and Macedon, which will constrain these facilities' ability to supply the domestic gas market.

The commencement of Scarborough (210 TJ/day) in mid-2027 is projected to be sufficient to return the market to surplus until 2031, when there is a forecast deficit of 86 TJ/day, primarily due to declining production from existing production facilities as reserves are depleted.

Figure 1 Base scenario WA gas market balance, 2022 to 2031

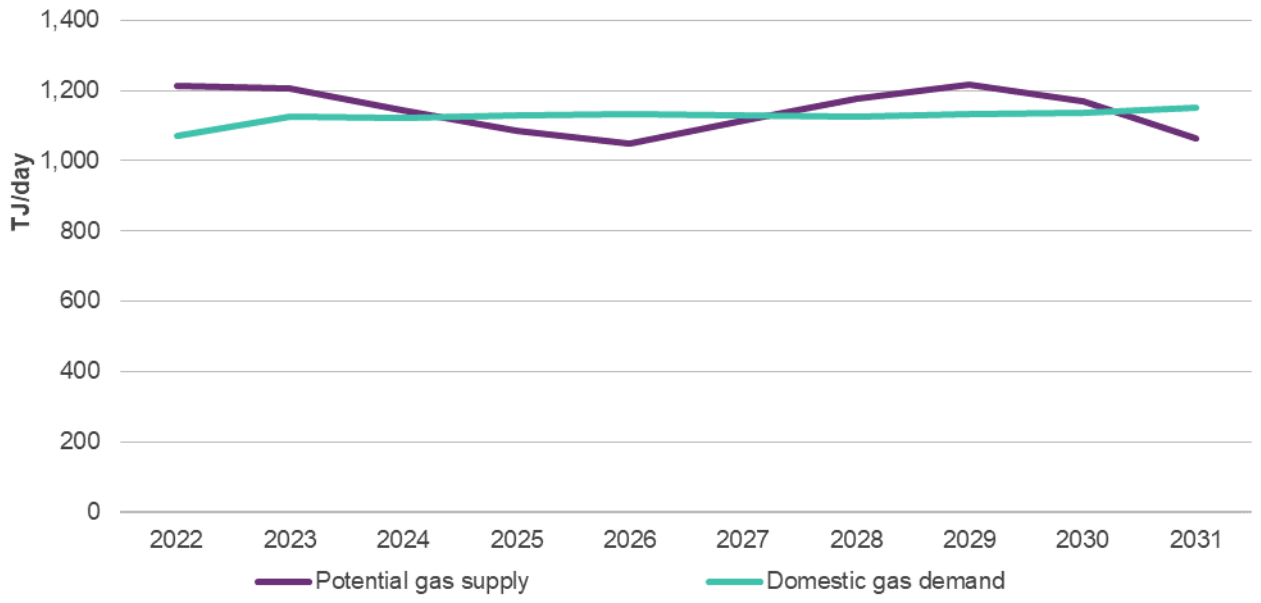


Table 1 Potential gas supply and domestic gas demand forecasts (TJ/day), 2022 to 2031

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	5-year annual average growth rate (%)	10-year annual average growth rate (%)
Potential gas supply	1,212	1,205	1,145	1,086	1,049	1,116	1,175	1,216	1,168	1,064	-3.5	-1.4
Domestic gas demand	1,071	1,125	1,122	1,129	1,133	1,129	1,127	1,134	1,137	1,150	1.4	0.8

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	5-year annual average growth rate (%)	10-year annual average growth rate (%)
Difference	141	79	23	-42	-85	-13	48	82	32	-86		

The forecast supply gap in this GSOO could be alleviated by options including the following:

- Gas could be withdrawn from storage at up to 210 TJ/day, subject to the quantity of gas in storage at the time and the duration of the requirement[3].
- Additional production could be sourced from existing facilities with spare capacity and available reserves (such as the KGP).
- Additional supply could be sourced from:
  - Backfill projects at existing facilities, such as Corvus, being developed through the Devil Creek infrastructure.
  - Expansion of existing facilities, such as Beharra Springs.
  - Undeveloped gas fields such as Lockyer Deep developed as greenfield projects.
  - Successful exploration leading to backfill opportunities at existing production facilities, like the Dancer prospect near the Devil Creek infrastructure.

Potential gas supply is expected to be supported by new developments

The assumptions underpinning AEMO's potential gas supply forecasts are summarised in Table 2.

Table 2 Key assumptions for new projects in the potential gas supply forecasts

Project	Operator	Volume (TJ/day)	Available from	Notes
Scarborough	Woodside Energy	210	2027	Achieved final investment decision (FID) on 22 November 2021.
Spartan	Santos	n/a	2023	Santos is currently developing Spartan as backfill to Varanus Island. No incremental production capacity will be added.
Waitsia stage two	Mitsui E&P Australia	100	2029	Being developed for LNG export via the KGP initially, then to supply the domestic gas market at an assumed rate of 100 TJ/day from 2029.
West Erregulla	Strike Energy	87	2023	Strike Energy expects to take FID on West Erregulla by the end of 2021.

Since the 2020 WA GSOO, in addition to the reserves downgrades at the Reindeer (connected to Devil Creek) and Macedon fields, several other developments have affected the potential gas supply forecasts:

- Mitsui E&P Australia took FID on Waitsia stage two, which will export liquefied natural gas (LNG) through the KGP infrastructure at a rate of around 250 TJ/day between 2024 and 2028. During this period, the existing Xyris production facility will continue to supply up to 30 TJ/day into the

[3] Tubridgi and Mondarra have a combined storage capacity of 78 PJ and can deliver an equivalent of 210 TJ/day for four months. This assumes that both storage facilities are full and accounts for Mondarra's higher withdrawal rate and lower capacity compared to Tubridgi.

domestic gas market. From 2029, AEMO assumes that Waitsia will supply the domestic gas market at an initial rate of 100 TJ/day.

- Santos took FID on the Spartan project, which will be connected to the existing Varanus Island production facility. While this project is not expected to increase domestic gas production capacity, it will maintain potential gas supply from Varanus Island.
- Woodside Energy took FID on the Scarborough project, which will be processed through both the existing Pluto facility and a new Pluto LNG train. It will include both LNG and domestic gas production, with domestic supply of 180 TJ/day[4] to 225 TJ/day[5].

AEMO notes that there is a large volume of undeveloped gas that could supply the WA domestic market during the outlook period, but these resources are currently too speculative to include in the potential supply forecasts. These resources include, but are not limited to, Kultarr, Spar Deep, Clio-Acme, and Equus. AEMO will continue to monitor these projects for potential inclusion in future WA GSOOs.

Growth in domestic gas demand will be underpinned by major projects and mine restarts

Global commodity markets continue to recover from the COVID-19 pandemic, with prices for WA's main commodity exports like iron ore and base metals increasing strongly[6] during 2021. In 2020-21, exploration expenditure in WA reached $1.9 billion, which is the highest since 2011-12 when $2 billion was spent on exploration activities.

The mining sector is expected to be the main contributor to domestic gas demand growth over the outlook period. Overall, domestic gas demand is forecast to grow at an average annual rate of 0.8%, from 1,071 TJ/day in 2022 to 1,150 TJ/day in 2031.

Forecast growth in domestic demand is underpinned by:

- Fifteen[7] committed resources projects, that are expected to add 78 TJ/day to gas demand from 2025.
  - Two of these projects (Mineral Resources and Albemarle's Wodgina lithium mine, and Cyprium Metals' Nifty copper mine), accounting for around 16 TJ/day, are restarts of existing mines, supported by high commodity prices.
  - Three of the projects, accounting for around 47 TJ/day, are new and expanding iron ore mines (Rio Tinto's Gudai-Darri and Fortescue Metals Group's Iron Bridge).
  - The remaining projects include gold and lithium processing (such as Albemarle's Kemerton).
- SWIS GPG gas demand is forecast to grow at an average annual rate of 1.2%, from 129 TJ/day in 2022 to 143 TJ/day in 2031, as renewables only partly replace coal plant retirements.

[4] See https://www.bhp.com/news/media-centre/releases/2021/11/bhp-approves-phase-1-of-the-scarborough-project.

[5] See https://files.woodside/docs/default-source/asx-announcements/2021-asx/060.-scarborough-and-pluto-train-2-developments-approved.pdf.

[6] The iron ore price more than doubled from US$94/tonne in May 2020 to US$214/tonne in July 2021 (it fell back to $123/tonne by October 2021), due to strong growth in steel production in China, while the prices of copper, zinc, and nickel rose by 46%, 38%, and 27%, respectively between October 2020 and October 2021. See https://www.worldbank.org/en/research/commodity-markets.

[7] In comparison, seven projects totalling 40 TJ/day from 2023 were included in the 2020 WA GSOO domestic gas demand forecasts.

Contents

1 Year in review

This chapter provides a snapshot of events and initiatives which have been announced or progressed since the 2020 Western Australia (WA) Gas Statement of Opportunities (GSOO) and may facilitate future change in the WA gas market[8].

1.1 Supply projects – announced or progressed

- In December 2020, Mitsui E&P Australia sanctioned the Waitsia Stage Two project, which will deliver around 250 terajoules (TJ)/day to the Karratha Gas Plant (KGP) to be converted to liquefied natural gas (LNG) for export. As part of the field's export licence, the joint venture will deliver at least 20 TJ/day into the domestic market for the period of LNG export, and supply all remaining gas to the domestic market once LNG exports end in 2028.
- Santos made a final investment decision (FID) on Spartan to backfill Varanus Island from 2023.
- Chevron Australia announced it would proceed with the Jansz-Io Compression project, a modification of the existing Gorgon development. This will maintain gas supply from the Jansz-Io field to the three existing LNG trains and domestic gas plant.
- Woodside Energy announced FID on the Scarborough LNG and domestic gas project and Pluto LNG train two. The operator is targeting first LNG for 2026. AEMO has assumed first domestic gas supply in 2027.
- Woodside Energy commenced development of Greater Western Flank 3, a subsea tie-back to the North West Shelf (NWS) infrastructure that is estimated to contain 460 petajoules (PJ) of reserves. This will maintain gas supply to the NWS LNG and domestic gas plants.
- Exploration and development drilling projects were progressed in the Carnarvon and Perth basins, including:
  - BP drilled the Ironbark well in late 2020, with no significant hydrocarbons found.
  - Following further drilling, Strike Energy announced independently-estimated 2P[9] gas reserves of 300 PJ at West Erregulla. These reserves will underpin the planned 87 TJ/day development of West Erregulla for the domestic gas market.
  - Mineral Resources discovered gas at Lockyer Deep in the Perth Basin in September 2021. While this has the potential to be a large resource, it will need further appraisal.
- Woodside Energy announced that Pluto gas production would be accelerated through the KGP via the Pluto-KGP interconnector, producing three million tonnes (166 PJ) of LNG and 24.7 PJ of domestic gas between 2022 and 2025.

Further information on supply projects is detailed in Chapter 3.

[8] Full references for this chapter are provided in Appendix A1.

[9] Gas reserves and resources are defined in Section 3.1.1.

1.2 Infrastructure developments

- APA began construction of the 580 kilometre (km) Northern Goldfields Interconnect, which will connect the Dampier to Bunbury Natural Gas Pipeline (DBP) to the Goldfields Gas Pipeline (GGP). This will allow gas from the Perth basin to be supplied to meet gas demand in the Goldfields, centred on Kalgoorlie.
- The Pluto-KGP interconnector linking Pluto LNG and the KGP commenced construction, with start-up targeted for 2022. This will allow gas from Pluto to be processed at the KGP, securing both LNG and domestic gas supplies.
- APA commissioned two laterals off the GGP: the 56 km Karlawinda Lateral and the 26 km Lake Way Lateral, connecting two additional mines to the gas network.

1.3 Demand projects - announced or progressed

Numerous projects that may increase gas use have been announced, including gas powered generators (GPG) and processing projects. The majority of those that could increase gas use are GPG within the mining sector, while others are processing projects.

- Alinta proposed an expansion of Port Hedland Power Station, with a 60 megawatt (MW) natural gas plant plus an option for a 40 MW battery storage system.
- Australian Potash announced a 35 MW renewable microgrid, comprising a 10.7 MW gas-fired power station, solar photovoltaics (PV), wind, diesel, and battery storage at the Lake Wells Sulphate of Potash project.
- Bellevue Gold is restarting and expanding (to 200,000 ounces of gold per annum) the Bellevue Gold Project, with construction to be completed in late 2022. Both a gas power station and renewables will be installed to meet an estimated peak load of 10 MW.
- Clean Energy Fuels Australia (CEFA) signed a five-year gas sales agreement (GSA) with the Waitsia joint venture for the supply of 2 TJ/day of gas to its proposed Mid-West LNG plant at Mount Magnet.
- Mineral Resources and Albemarle will restart operations at the Wodgina Lithium Mine in the third quarter of 2022. The project includes a new 81 km gas pipeline and 64 MW gas-fired power station.
- Strike Energy proposed Project Haber in January 2021, a Mid-West ammonia and urea manufacturing facility. The facility will require more than 628 PJ of gas over 20 years.
- WA Kaolin signed a contract with CEFA for supply of LNG from the proposed Mount Magnet LNG hub to supply the Wickepin Kaolin Project for 15 years from January 2022.

However, the introduction of renewables is likely to offset gas usage.

- BHP Nickel West sanctioned the Northern Goldfields Solar Project, which comprises a 27.4 MW solar farm at Mt Keith, plus a 10.7 MW solar farm and 10.1 MW battery at Leinster. These will displace electricity currently supplied by diesel and gas. Completion is expected in early 2024.
- Rio Tinto has proposed up to 1 gigawatt (GW) of renewable energy projects in the Pilbara, which could displace 480 MW of gas-fired power generation.

Further information on demand projects is provided in Chapter 2.

1.4 Hydrogen

The WA Government has indicated its commitment to develop the hydrogen industry since 2019, when it released the WA Renewable Hydrogen Strategy. This support, along with the progress of industry-led hydrogen initiatives, has made it increasingly important to consider the potential impact of hydrogen on the WA gas market.

The hydrogen industry in WA is still emerging as a viable energy source, and most proposed projects are focused on producing hydrogen for the transport and export sectors. Since the industry is at such a nascent stage, and the sectors being targeted have limited impact on the WA domestic gas markets, AEMO has not incorporated hydrogen into the 2021 WA GSOO forecasts presented in Chapters 2 and 3.

AEMO will continue to monitor the progress of hydrogen initiatives in WA and will report on new developments in future GSOOs and at relevant industry forums.

Key initiatives announced in 2021 include:

- Additional funding for the development of the hydrogen industry was announced in the 2021-22 State Budget. This included $50 million to stimulate local demand for hydrogen (particularly targeting the transport and industrial sectors) and $4 million to develop a plan for the activation of the Oakajee Strategic Industrial Area as a renewable hydrogen hub.
- A further $117.5 million was announced in November 2021 to establish the Mid West Clean Hydrogen Hub at Oakajee Strategic Industrial Area and the Pilbara Hydrogen Hub (hydrogen or ammonia pipeline connecting the Maitland and Burrup strategic industrial areas).
- As part of its Renewable Hydrogen Fund, the WA Government awarded grants to the following projects:
  - ATCO's Hydrogen Blending Project, which will investigate blending hydrogen into natural gas pipeline networks.
  - APA's feasibility study into blending hydrogen into the Parmelia Gas Pipeline.
  - BP's Kwinana Clean Fuels Hub feasibility study.
  - Global Energy Ventures' Compressed Hydrogen Export Project feasibility study.
- The Australian Government announced an additional $150 million for hydrogen project grants, extending its prospective network of clean hydrogen hubs to each of Australia's states. The Pilbara was the only WA region identified by the Australian Government. The Clean Hydrogen Industrial Hubs program is to co-locate hydrogen production facilities with industrial users, building on pre-existing industry infrastructure and regional workforces.

Industry has responded with the following initiatives since the 2020 WA GSOO:

- BP began a feasibility study into the production of green hydrogen at the Kwinana refinery site, which closed in 2020.
- Hazer Group commenced construction of the Hazer Commercial Demonstration Project at the Woodman Point Water Recovery Facility.
- Pilot Energy commenced a feasibility study into carbon capture and storage, as well as production of blue hydrogen, in the Kwinana Strategic Industrial Area.
- Province Resources progressed its HyEnergy green hydrogen project near Carnarvon.

- Woodside Energy announced the H2Perth project, which aims to produce up to 1,500 tonnes a day of hydrogen for export in the Kwinana Strategic Industrial Area.

1.5 Regulatory update

On 1 April 2021, the Economic Regulation Authority (ERA) published its final decisions on DBNGP (WA) Transmission Pty Ltd's proposed revised access arrangement for the DBP. The ERA did not approve the proposed changes to the access arrangement and published a revised access arrangement and access arrangement information on its website[10].

The Gas Advisory Board (GAB) function moved from the Rule Change Panel (RCP) to Energy Policy WA (EPWA) on 30 June 2021. While topics associated with LNG trucking and consideration of a gas hub have been discussed at the GAB, no rule changes have been proposed at this stage.

[10] See: https://www.erawa.com.au/gas/gas-access/dampier-to-bunbury-natural-gas-pipeline/access-arrangements.

2 Gas demand

In the Base scenario, WA domestic gas demand is forecast to increase from 1,071 TJ/day in 2022 to 1,150 TJ/day in 2031 at an average annual rate of 0.8%. Most of this gas demand is expected to come from growth at existing facilities in the mining sector, which contributes 29 TJ/day of additional gas demand by 2031. Committed new resources projects are expected to add approximately 33 TJ/day to gas demand by 2031.

All data in this chapter is presented in calendar years unless otherwise stated.

2.1 Historical WA domestic gas demand

2.1.1 Overview

WA's unique combination of geographic isolation and very large gas resources provides a backdrop for remotely located LNG developments. WA Government policy promoted the development of gas fields in the NWS area during the 1980s. The State Energy Commission of WA signed a large gas supply contract with the NWS partners in 1980 and completed construction of the DBP in 1984.

The WA domestic gas market is characterised by:

- Large gas reserves that are generally located offshore and developed mainly to supply the global LNG market.
- A limited number of large suppliers and consumers.
- Bilateral, commercial and long-term take-or-pay gas sales contracts.
- Residential, commercial, and small industrial consumers comprising around 15% of total demand.
- Small volumes of short-term and spot gas sales.
- A small number of pipelines and interconnectors, with limited surplus pipeline capacity.
- Limited information about supply that is available to be contracted, potential buyers, and gas contract pricing.
- Storage capacity of 78 PJ, that can receive gas at up to 160 TJ/day and supply gas at up to 210 TJ/day.

2.1.2 Large customers supplied through the transmission network

The majority of large customers[11] are supplied directly through the transmission network (such as the DBP and the GGP).

[11] Gas consumers using 10 TJ/day or more.

Based on WA Gas Bulletin Board (GBB) data[12], in 2021, large customers[13] accounted for around 85% of WA's domestic gas demand. This 85% was split between minerals processing (32%), mining (27%), electricity generation (25%), industrial (12%) and other (5%) sectors.

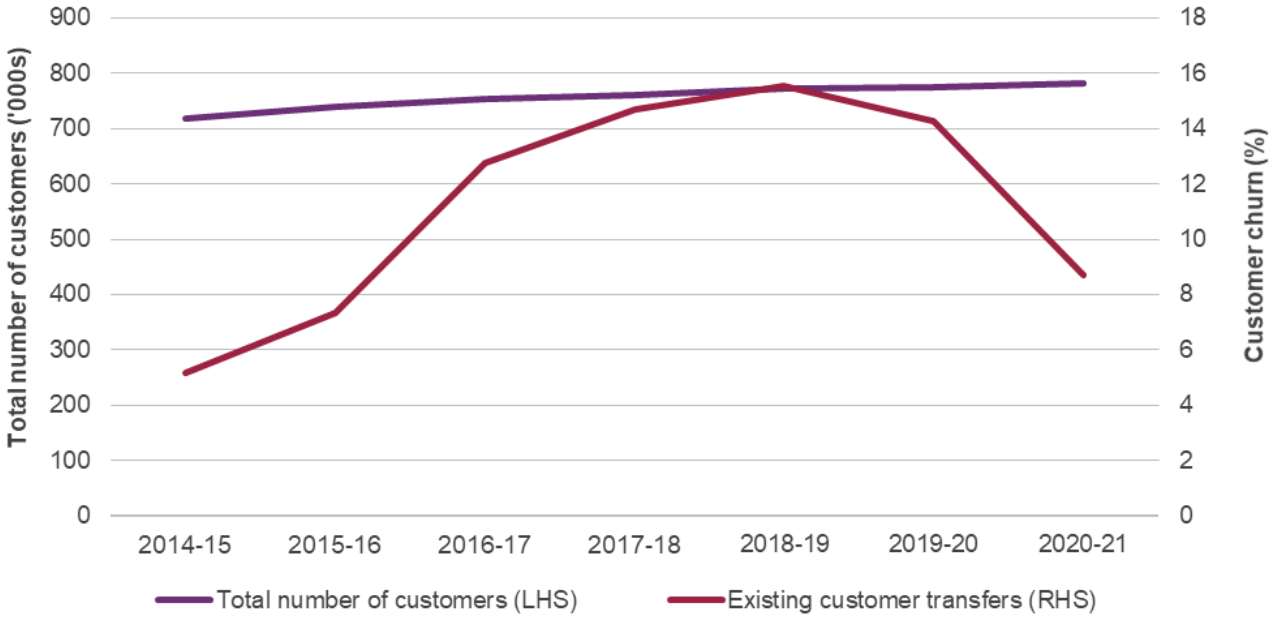
2.1.3 Customers supplied through the distribution network

Customers supplied through the retail distribution network account for 8% of WA's total domestic gas consumption.

The data in Section 2.1.3 is presented in financial years.

Before 2013-14, Alinta Energy was the only small residential and business retailer. The distribution gas market has since expanded to nine retail licensees[14], with the addition of AGL, Amanda, Esperance Gas Distribution Company, Kleenheat, Origin Energy, Perth Energy, Simply Energy, and Synergy. With growing availability of retailer choice in the market, customer churn increased from 5% in 2014-15 to peak at 16% in 2018-19 before falling, as shown in Figure 2. Over the same period, the total number of customers increased at an average annual rate of 1.5%, from 717,439 in 2014-15 to 782,360 in 2020-21.

Figure 2 Total number of customers[A] and churn rate[B], 2014-15 to 2020-21



A. Includes both residential and non-residential customers.
B. Calculated by dividing the number of customers who changed retailer by the total number of customers for a given financial year.

The gas market moratorium[15] prevents Synergy from competing for customers supplied through the retail distribution network who use less than 0.18 TJ each year. The moratorium covers 97% of residential customers and 77% of business customers.

Alinta Energy's market share of customers covered by the gas market moratorium has steadily declined from a monopoly in 2013-14 to 60% in 2019-20. Kleenheat captured most of the customers

[12] See https://gbbwa.aemo.com.au.

[13] Excludes gas consumed by petroleum and LNG processing, which is not reported to the GBB.

[14] See https://www.erawa.com.au/cproot/21649/2/Annual-data-report---Energy-retailers-2019-20.pdf.

[15] See https://www.wa.gov.au/organisation/energy-policy-wa/gas-industry.

who changed retailers, increasing its market share to 28% in 2019-20. AGL has the next largest market share at 9% in 2019-20, with Origin Energy and Perth Energy accounting for the remaining 3%.

2.2 WA domestic gas demand forecasts

2.2.1 Forecasting scenarios

AEMO has developed WA domestic gas demand forecasts for the outlook period for three scenarios – Low, Base, and High. These scenarios reflect varying views on the economic outlook, commodity production, gas prices, and population growth (see Appendix A3 for more information on scenario assumptions).

In developing the 2021 WA GSOO, AEMO considered the role that hydrogen may play in the future domestic gas market. However, there is insufficient information at the time of publication to confirm that hydrogen will create demand for natural gas (to produce blue hydrogen) or will become a supply source that displaces natural gas (green hydrogen)[16]. Given this uncertainty, AEMO has excluded hydrogen from the gas demand forecasts for this WA GSOO. AEMO will continue to monitor the progress of hydrogen technology for possible inclusion in future WA GSOOs.

Mining and minerals processing

Fifteen[17] committed mining and minerals processing projects are forecast to contribute a net 78 TJ/day to gas demand from 2025 as follows:

- Albemarle Corporation's Kemerton lithium refinery is expected to be fully operational (train one and train two) by the end of 2022[18].
- Capricorn Metals' Karlawinda gold mine was commissioned in the September 2021 quarter[19] and is forecast to operate at full capacity during 2022.
- CEFA's Mid-West LNG hub is expected to commence operation by the end of 2021[20].
- Covalent Lithium's Kwinana lithium hydroxide refinery is expected to commence operations in the second half of 2024[21].
- Cyprium Metals has announced its intention to restart the Nifty copper mine in early 2023[22].
- At Fortescue Metals Group's Iron Bridge (stage two), first production is expected by the end of 2022[23].
- Kalium Lakes' Beyondie sulphate of potash project is completing commissioning[24]. It is expected to ramp up production and gas use during 2022.

[16] See https://www.wa.gov.au/government/publications/western-australian-renewable-hydrogen-strategy-and-roadmap.
[17] The 2020 WA GSOO included seven committed projects.
[18] See https://www.albemarle.com/news/albemarle-reports-third-quarter-sales-growth-of-11-and-increases-guidance.
[19] See https://capmetals.com.au/wp-content/uploads/2021/10/2021.10.05-Quarterly-Activities-Sep-2021-Final-1.pdf.
[20] See https://www.cefa.com.au/cefa-signs-5-year-contract-with-beach-energy-and-mitsui-ep-australia/.
[21] See https://www.wesfarmers.com.au/docs/default-source/asx-announcements/2021-full-year-results.pdf.
[22] See https://wcsecure.weblink.com.au/pdf/CYM/02456000.pdf.
[23] See https://www.fmgl.com.au/about-fortescue/our-operations.
[24] See https://app.sharelinktechnologies.com/announcement/asx/0cd40524b9e7316239c553773e69d447.

- Mineral Resources announced it would restart the Wodgina spodumene mine by the end of 2022[25].
- Rio Tinto's Gudai-Darri mine has been delayed, with production now expected to commence in the first quarter of 2022[26].
- At Tianqi Lithium Energy Australia's (TLEA) lithium hydroxide facility, construction on train two has recommenced and is expected to be completed in 2022[27].
- Western Areas' Odysseus nickel project includes refurbishment and expansion of the existing Cosmos concentrator and is expected to commence in 2023[28].
- Two other projects were identified through the confidential 2021 Formal Information Request (FIR) process.

In addition to the projects that will expand gas consumption, there are two projects included in the forecasts that are expected to reduce gas demand as follows:

- BHP Nickel West's Northern Goldfields Solar Project will include a 27.4 MW solar farm at Mount Keith, and a 10.7 MW solar farm and 10.1 MW battery at Leinster, both scheduled to be completed during 2023[29].
- Hazer Group Limited's biogas to hydrogen and graphite project is expected to be commissioned during the first quarter of 2022[30].

GPG gas demand

Scenario assumptions specific to South West interconnected system (SWIS[31]) GPG gas demand are dependent on the electricity demand forecasts presented in the 2021 Wholesale Electricity Market (WEM) *Electricity Statement of Opportunities* (ESOO)[32], as well as the expected generation mix in the SWIS over the outlook period.

In all scenarios, non-SWIS GPG (including towns like Port Hedland, Karratha, Carnarvon, and Exmouth but excluding mining GPG) represents roughly 20% of total GPG gas usage (3.2% of total domestic gas demand). However, limited growth has been identified in this area because electricity consumption in these towns is expected to remain relatively stable. Further discussion on the projected outlook for individual gas use sectors is provided in Section 2.2.3.

Further information relating to the methodology and assumptions underpinning the GPG and gas demand scenarios is in Appendix A3 and in the commodity forecast[33] and SWIS GPG forecast modelling reports[34].

[25] See https://clients3.weblink.com.au/pdf/MIN/02440344.pdf.

[26] See https://www.riotinto.com/-/media/Content/Documents/Invest/Financial-news-and-performance/Production/RT-Third-Quarter-Operations-Review-2021-pdf.pdf.

[27] See https://www.igo.com.au/site/PDF/cc348eaf-7541-4491-9124-a9c4c41dd8df/September2021QuarterlyActivitiesReport.

[28] See http://clients2.weblink.com.au/news/pdf_1%5C02448779.pdf.

[29] See https://www.bhp.com/news/media-centre/releases/2021/07/two-new-solar-farms-and-battery-to-help-power-mines-at-bhps-nickel-west.

[30] See https://hazergroup.com.au/wp-content/uploads/2021/11/211112-ASX-Announcement-Hazer-Commercial-Demonstration-Project-Update.pdf.

[31] The SWIS comprises the electricity transmission and distribution networks in the south west area of Western Australia and extends from Albany to Kalbarri and to Kalgoorlie in the east. The non-SWIS area includes all towns and mine sites outside of the SWIS (see Appendix A3 for further information).

[32] See https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/wem-forecasting-and-planning/wem-electricity-statement-of-opportunities-wem-esoo.

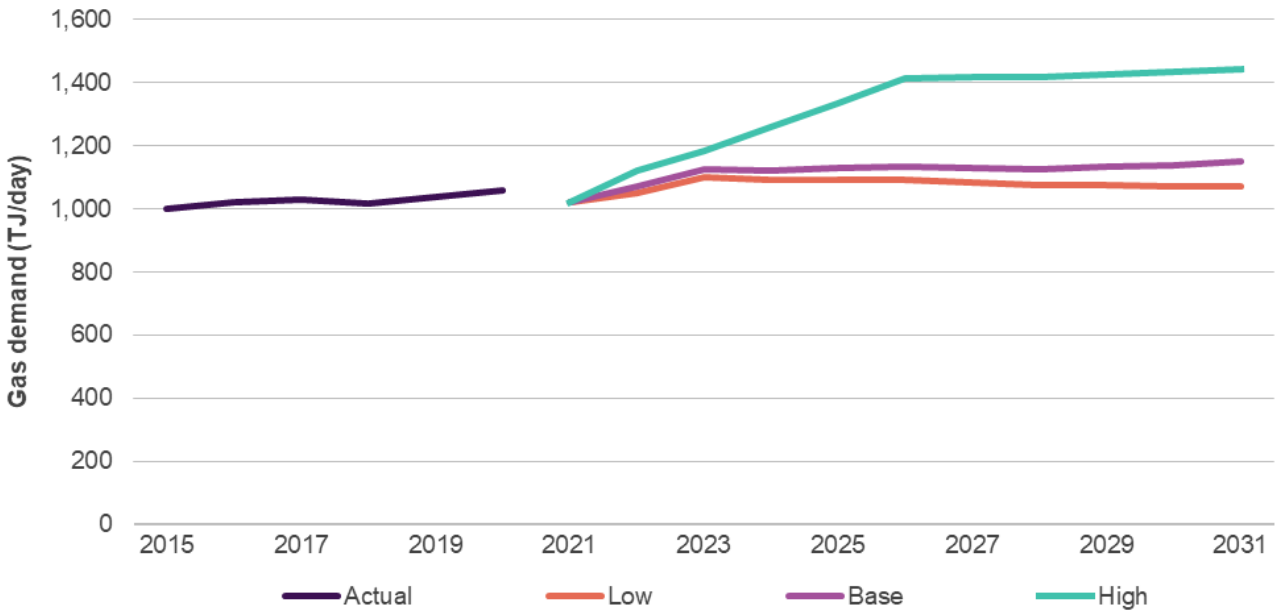
[33] See https://aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/wa-gas-statement-of-opportunities-wa-gsoo.

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

2.2.2 Domestic gas demand forecasts by scenario

Figure 3 presents the domestic gas demand forecasts under the Low, Base, and High scenarios.

Figure 3 Domestic gas demand – actual data from 2014 to 2019 and forecasts under three growth scenarios from 2022 to 2031



In summary, over the outlook period:

- In the Low scenario, domestic gas demand is forecast to grow at an average annual rate of 0.3%. Compared to the Base scenario, the Low scenario reflects a weaker commodity outlook, which drives lower gas demand in the mining sector.
- In the Base scenario, domestic gas demand is forecast to grow at an average annual rate of 0.8%, driven by:
  - Strong global commodity markets encouraging expansion of mining activity in WA, leading to mining-sector gas consumption growth at an average annual rate of 1.7%.
  - Average annual growth of 0.7% in the minerals processing sector as new lithium refinery projects increase consumption.
  - Growth in residential and small business connections, which contribute to average annual growth of 0.7% in the distribution networks.
  - SWIS GPG gas demand increasing at an average annual rate of 1.2% due to the retirement of two units at the coal-fired Muja Power Station by 2024, which is expected to increase GPG use.
- In the High scenario, domestic gas demand is forecast to grow at an average annual rate of 2.8%. Compared to the Base scenario, the High scenario includes 12 prospective demand projects which could add up to 216 TJ/day to demand by 2026.

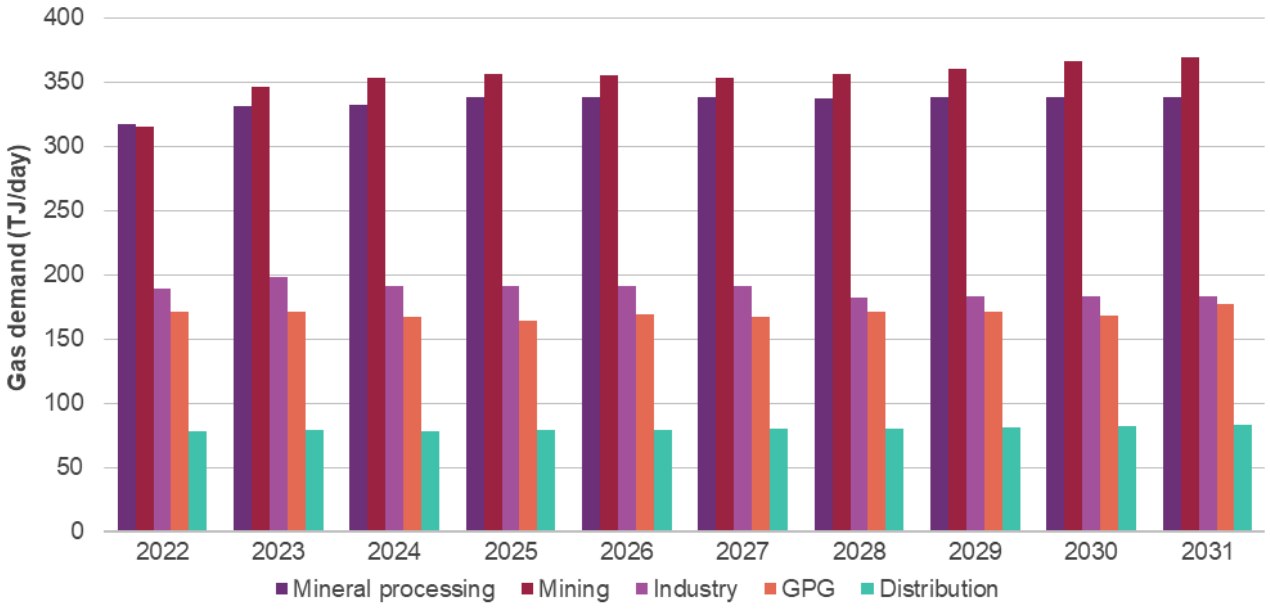
2.2.3 Domestic gas demand forecasts by usage category

The gas demand forecasts are disaggregated into the following five major usage categories[35]:

- Minerals processing.
- Mining.
- GPG (SWIS and non-SWIS).
- Industrial (major users such as ammonia, fertiliser, and liquified petroleum gas production).
- The distribution network.

This breakdown is shown for the Base scenario in Figure 4.

Figure 4 Domestic gas demand forecasts by usage category, Base scenario, 2022 to 2031



Drivers of trends in the different scenarios are:

- Gas demand in the minerals processing sector[36] is forecast to increase at an average annual rate of 0.7% between 2022 and 2031, despite a decrease in consumption from Alcoa's Wagerup alumina refinery that is expected to continue until 2022. For the remainder of the outlook period, committed lithium refineries (Albemarle's Kemerton, Covalent Lithium's Kwinana, and TLEA's Kwinana) support gas demand growth. This is a similar annual growth rate to the 0.6% forecast in the 2020 WA GSOO.
- In the mining sector, gas demand is projected to grow at an average annual rate of 1.7% over the outlook period compared to 1.6% in the 2020 WA GSOO. This marginally higher growth rate can

[35] Usage categories are defined in this way because each category is affected by different external and internal influences. Appendix A5 has a complete breakdown of how gas consumers were categorised. The mining and minerals processing sectors include GPG located at remote mine sites or minerals processing facilities.

[36] Pinjarra Power Station was reclassified as GPG for the 2021 WA GSOO from minerals processing in the 2020 WA GSOO. This has decreased the minerals processing forecasts compared to the 2020 WA GSOO. Comparison is based on recalculated 10-year average growth rate of 0.9% for minerals processing accounting for the reclassification for 2020 WA GSOO.

be attributed to new projects that have become committed during 2021, including Western Areas' Odysseus nickel mine.

- Despite the contribution of new projects (Kalium Lakes' Beyondie and CEFA's Mid-West LNG hub), gas demand in the industrial sector is forecast to decline at an average annual rate of 0.3% over the outlook period, primarily due to a decline in gas demand from existing projects. This trend is similar to the 2020 WA GSOO forecast.
- Gas demand for GPG[37] is forecast to grow at an average annual rate of 0.4% across the outlook period. This contrasts with the 2020 WA GSOO, which forecast no growth in GPG gas demand. In the SWIS, an increase in gas use following the retirement of two units at the coal-fired Muja Power Station by 2024 is partially offset by increased renewable penetration, the entry of the East Rockingham waste-to-energy facility in 2022 and battery storage displacing GPG. Non-SWIS GPG gas demand is expected to fall at an average annual rate of 2.2% over the outlook period.
- Increasing customer numbers in the distribution network is forecast to offset a decline in average gas consumption per connection, resulting in average annual growth of 0.7% across the outlook period. This is similar to the trends observed in the 2020 WA GSOO.

2.2.4 Domestic gas demand forecasts by area

In line with previous WA GSOO reports, gas demand has been disaggregated into two areas, SWIS and non-SWIS, as shown in Figure 5.

Consistent with the 2020 WA GSOO, forecast growth in gas demand outside the SWIS exceeds the expected growth rate within the SWIS. Both non-SWIS and SWIS demand growth is projected to be marginally higher than the 2020 WA GSOO forecast.

SWIS gas demand is projected to increase at a faster rate over the outlook period (0.7% on average) compared to the 2020 WA GSOO (0.4%). This is largely due to the addition of two committed lithium refinery projects (Covalent Lithium's Kwinana and TLEA's Kwinana). In contrast, gas demand growth in the non-SWIS area has fallen compared to the 2020 WA GSOO, from projected average annual growth of 1.1% to 0.9%. This decline in growth is partly due to BHP Nickel West's Northern Goldfields Solar Project, which will reduce minerals processing demand outside of the SWIS, combined with a decline in industrial demand.

[37] Pinjarra Power Station was reclassified as GPG for the 2021 WA GSOO from minerals processing in the 2020 WA GSOO. This has increased the GPG forecasts compared to the 2020 WA GSOO. Comparison is based on recalculated 10-year average growth rate of -0.4% for GPG accounting for the reclassification for 2020 WA GSOO.

Figure 5 Domestic gas demand forecasts by area, Base scenario, 2022 to 2031

2.2.5 Domestic gas demand forecasts by region

WA domestic gas forecasts have been split into three demand regions:

- East (includes the GBB Zones of Goldfields and Kalgoorlie).
- North (includes the GBB Zones of Karratha, Dampier, Pilbara, and Telfer).
- Metro/South West (includes the GBB Zones of Mid-West, Parmelia, Metro, and South West)[38].

Figure 7 presents the expected domestic gas demand forecasts by region for the Base scenario.

Of the three regions, most of the growth is forecast to occur in the North, particularly during the first half of the outlook period. The 2.5% average annual growth is predominantly due to new gas consuming projects related to iron ore and nickel, which are expected to add 33 TJ/day to gas consumption from 2023. Growth in this region is projected to decline after 2025.

In the Metro/South West region, forecast average annual gas demand growth of 0.7% over the outlook period is expected to be supported by new lithium refining projects and general growth in the distribution network. This is partly offset by slow growth in SWIS GPG (see Section 2.2.3).

Growth in gas demand in the East region is expected to be supported by gold mining projects, partly offset by declining consumption at BHP Nickel West's Mount Keith and Leinster operations due to replacement of gas with renewables (see section 2.2.1). As a result, gas demand in this region is forecast to grow at an average annual rate of 0.9% over the outlook period

[38] Note that this zoning classification does not match the SWIS area presented in Section 2.2.1, footnote 31.

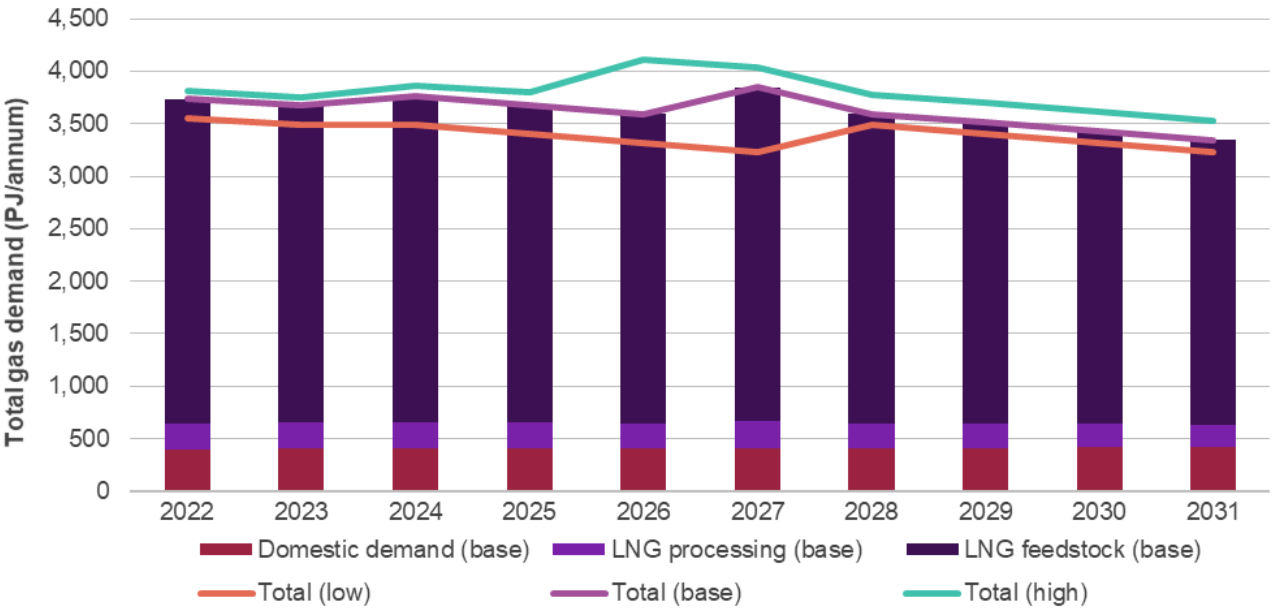
Figure 6 Domestic gas demand forecasts by region, Base scenario, 2022 to 2031

2.2.6 Total gas demand forecasts

Total gas demand is based on the assumptions outlined in Appendix A4 and is the aggregate of forecasts for domestic gas demand, LNG export feedstock, and gas use in LNG processing.

Figure 7 shows the total gas demand forecasts for the Low, Base, and High scenarios.

Figure 7 Total gas demand forecasts under the Low, Base, and High scenarios, 2022 to 2031



In summary:

- In the Low scenario, total gas demand is projected to decline at an average annual rate of 2.6% over the outlook period. This scenario assumes the KGP is backfilled by Waitsia stage two and

Pluto, with Scarborough as an expansion of the Pluto LNG project from 2028. It illustrates a reduction in production for the KGP from 2022, as spare processing capacity emerges due to reserves depletion.

- In the Base scenario, total gas demand is projected to decline moderately at an average annual rate of 1.2% over the outlook period. Small projected increases in total gas demand starting from 2022 driven by backfill for the KGP from both Waitsia stage two and Pluto are insufficient to offset the depletion from the NWS fields. From 2027 to 2030, despite additional gas from Scarborough, total gas demand falls as a result of further production declines at the NWS project.
- Compared to the Base scenario, the High scenario includes Gorgon producing at nameplate (increasing from 14.7 million tonnes per annum [mtpa] to 15.6 mtpa), and earlier commencement of Scarborough and Pluto train two (mid-2026 instead of mid-2027). This results in a slower average annual decline rate of 0.8% over the outlook period.

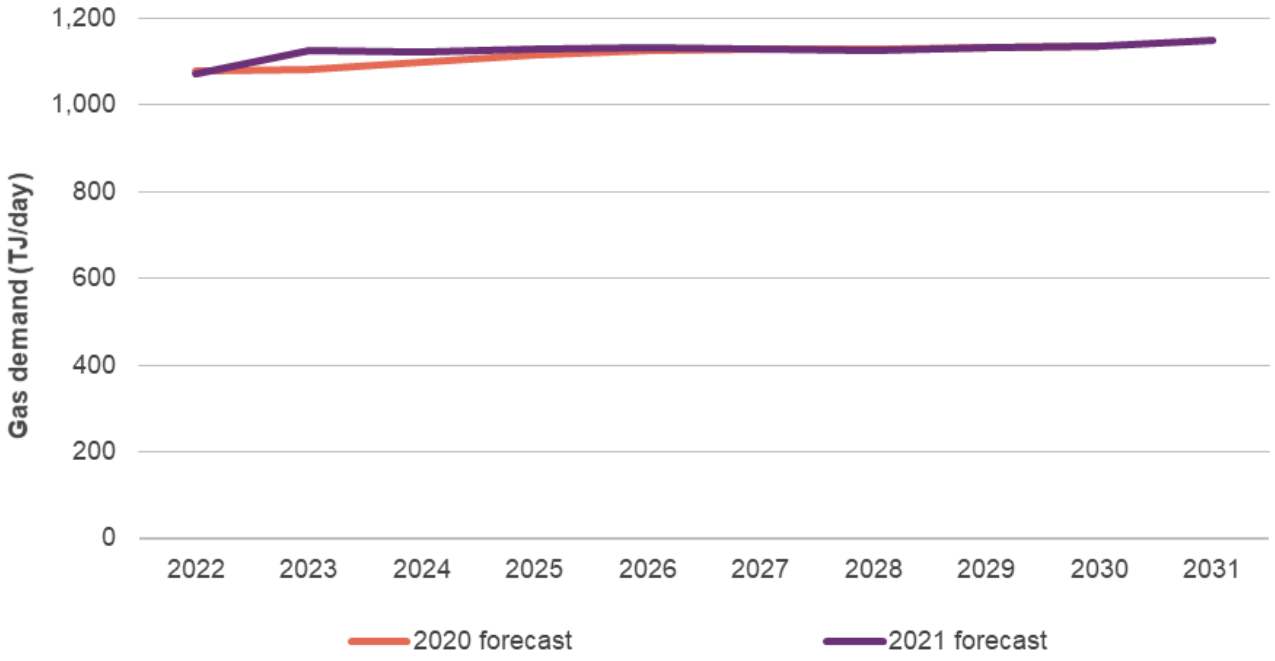
A further breakdown for total gas demand forecasts into domestic gas demand, LNG feedstock, and LNG processing for the Low, Base, and High scenarios is included in Appendix A4.

For the Base scenario, LNG feedstock is forecast to account for around 80% of the total gas demand throughout the outlook period, with domestic gas demand accounting for around 10% of total gas demand.

2.3 WA domestic gas demand forecasts compared to 2020 WA GSOO

The Base scenario gas demand forecasts developed for the 2020 and 2021 WA GSOOs are compared in Figure 8.

Figure 8 Comparison of 2020 and 2021 WA domestic gas demand forecasts, Base scenario, 2022 to 2031



The WA domestic gas demand forecasts presented in this 2021 WA GSOO are mostly higher than the 2020 WA GSOO for the entire outlook period. Higher demand in the 2021 WA GSOO forecast is largely due to seven additional committed projects that are expected to be operational by 2025 (see

Section 2.2.1). The ramp-up of new projects at the start of the outlook period increases the difference from 9 TJ/d less than the 2020 WA GSOO in 2022 to 44 TJ/day more in 2023. Once these projects are onstream, the forecasts become more aligned.

2.4 Reconciliation of previous WA GSOO domestic gas demand forecasts vs actuals

Reconciliation of previous WA GSOO domestic gas demand forecasts against actual average gas using data sourced from the WA GBB is shown in Table 3. Forecasting methodology improvements, access to FIR data and augmentation of GBB data have contributed to the accuracy of the forecasts over time.

The reconciliation of actuals and previous WA GSOO domestic gas demand forecasts indicates that:

- Among the five forecast years considered, the percentage difference between the forecast and actual gas demand varies between -1.3% to 5.1%, with a tendency to over-forecast.
- There have been some improvements in demand forecast accuracy. For example, the percentage difference between forecast and actual gas demand for the first forecast year shows an absolute difference of less than 1.8% for 2020 and 2021, while it ranges between 2.7% and 3.2% for 2016, 2017, and 2018.

Table 3 Reconciliation of previous WA GSOO domestic gas demand forecasts (% deviance of forecast from actual)[A], 2013 to 2020

	2017 actual	2018 actual	2019 actual	2020 actual	2021 actual[B]	Average over-forecast series (absolute terms)
December 2016 GSOO forecast deviance (%)	2.7	5.1	2.6	0.4	1.9	2.5
December 2017 GSOO forecast deviance (%)		3.2	1.8	0.3	1.3	1.7
December 2018 GSOO forecast deviance (%)			3.0	1.6	3.3	2.6
December 2019 GSOO forecast deviance (%)				-1.3	1.5	1.4
December 2020 GSOO forecast deviance (%)					1.8	1.8

A. Percentage difference is calculated as (forecast demand – actual demand)/actual demand.
B. Using data from 1 January 2021 to 16 November 2021.

3 Gas supply

Potential gas supply is projected to decrease at an average annual rate of 1.4% over the outlook period. This decrease is driven by natural depletion and reserves downgrades at the Reindeer gas field (Devil Creek gas plant) and Macedon domestic-only gas production facilities, partially offset by the development of Scarborough, Spartan, and West Erregulla.

AEMO forecasts the potential availability of gas supply to the WA domestic market, or "potential gas supply". Potential gas supply is defined as supply that could be economically offered to the domestic gas market[39], given forecast prices, production costs and domestic market obligations (DMOs), subject to the availability of processing capacity and gas reserves.

All data in this chapter is presented in calendar years unless otherwise stated.

3.1 Profile of upstream gas production

3.1.1 Reserves and resources

Gas has been categorised into either reserves or resources, based on the level of commercial and technical uncertainties associated with extraction[40]. These terms are broadly defined below:

- Reserves are quantities of gas that are anticipated to be commercially recoverable from known accumulations. Proved and probable (2P) reserves are considered the best estimate of commercially recoverable reserves[41].
- Contingent (2C) resources are considered less commercially viable than reserves. These can be considered roughly the equivalent of reserves with one or more commercial or technical uncertainties impacting the likelihood of development. 2C resources are considered the best estimate of sub-commercial resources[42].

Third-party estimates of WA total conventional gas resources[43] are summarised in Table 4.

Table 4 WA conventional and unconventional gas resources and reserves (PJ), August 2021[44,45]

Type	2020	2021
Conventional 2P gas reserves	64,441	66,337

[39] The exception to this rule is that DMOs must be offered to the market, regardless of financial viability.

[40] These uncertainties could include securing finance, obtaining government approvals, negotiating contracts, or overcoming geological challenges. The terms 'resources' and 'reserves' are not interchangeable: reserves constitute a subset of resources.

[41] The 2P reserves categorisation indicates there is a reasonable probability that 50% or more of the gas is recoverable and economically profitable. Proved reserves (1P) indicate that this probability is higher than 90%. Gas producers generally sign gas supply sales contracts based on 1P reserves.

[42] The resources are estimated to exist in prospective areas but are not currently commercial.

[43] 'Conventional' refers to formations that are relatively straightforward to extract, and 'unconventional' refers to formations that are much more difficult to extract, in some cases requiring specialised techniques. Both conventional and unconventional gas formations may contribute to reserves and resources, depending on the economic viability of extraction. For more details, refer to Appendix A3.3.

[44] See https://www.wa.gov.au/government/publications/western-australias-economy-and-international-trade.

[45] See https://jtsi.wa.gov.au/docs/default-source/default-document-library/wa-lng-profile---september-2020.docx.

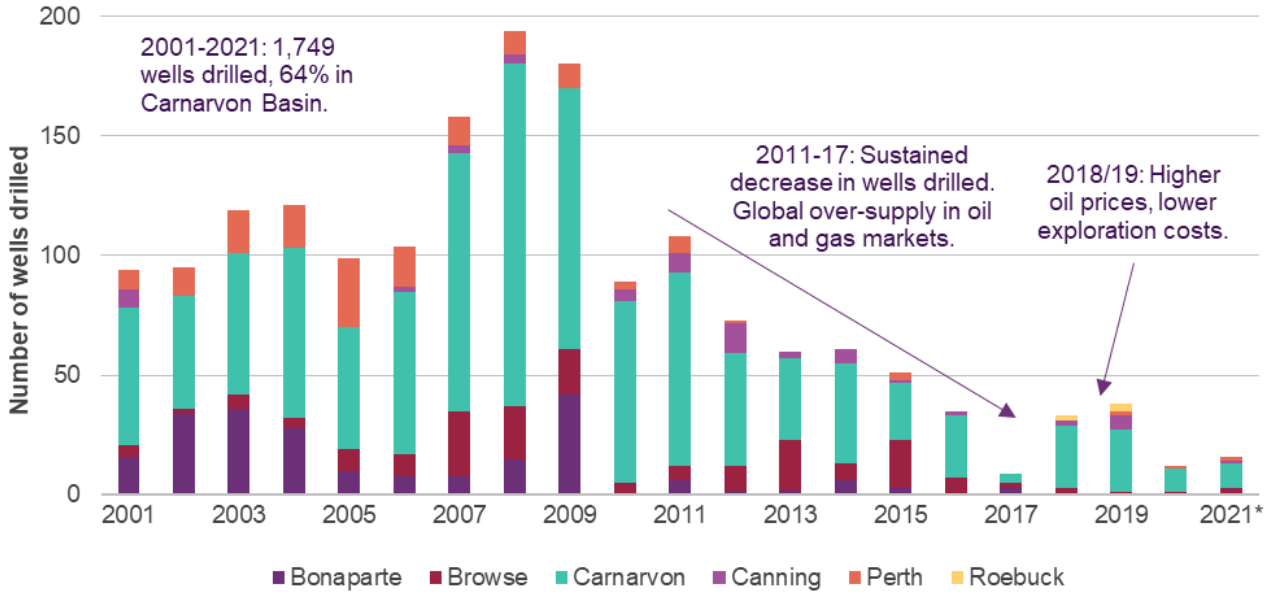
Type	2020	2021
Conventional 2C gas resources	79,426	74,427

In addition to conventional gas, WA has unconventional gas resources (shale and tight gas), mostly located in the Canning and Perth basins. Geoscience Australia has estimated 438,599 PJ of shale gas could ultimately be recoverable from the Canning Basin[46]. There has been no commercial production of unconventional gas in WA to date.

3.1.2 Exploration

Gas supply to the WA domestic market relies on the ongoing development of gas discoveries. The number of exploration and development wells drilled in WA remains subdued, with only 17 wells drilled so far in 2021 compared to 194 at the peak in 2008, as shown in Figure 9.

Figure 9 Exploration and development wells drilled, 2001 to 2021 (year to date)[47,48,49]



Domestic gas production is not expected from the Bonaparte, Browse, Canning, or Roebuck basins during the outlook period.

3.1.3 Gas production

There are currently nine gas production facilities supplying the WA domestic gas market, with a total nameplate capacity of about 1,851 TJ/day[50]. The KGP maintains the largest capacity at 630 TJ/day.

[46] See https://www.ga.gov.au/digital-publication/aecr2021/gas.

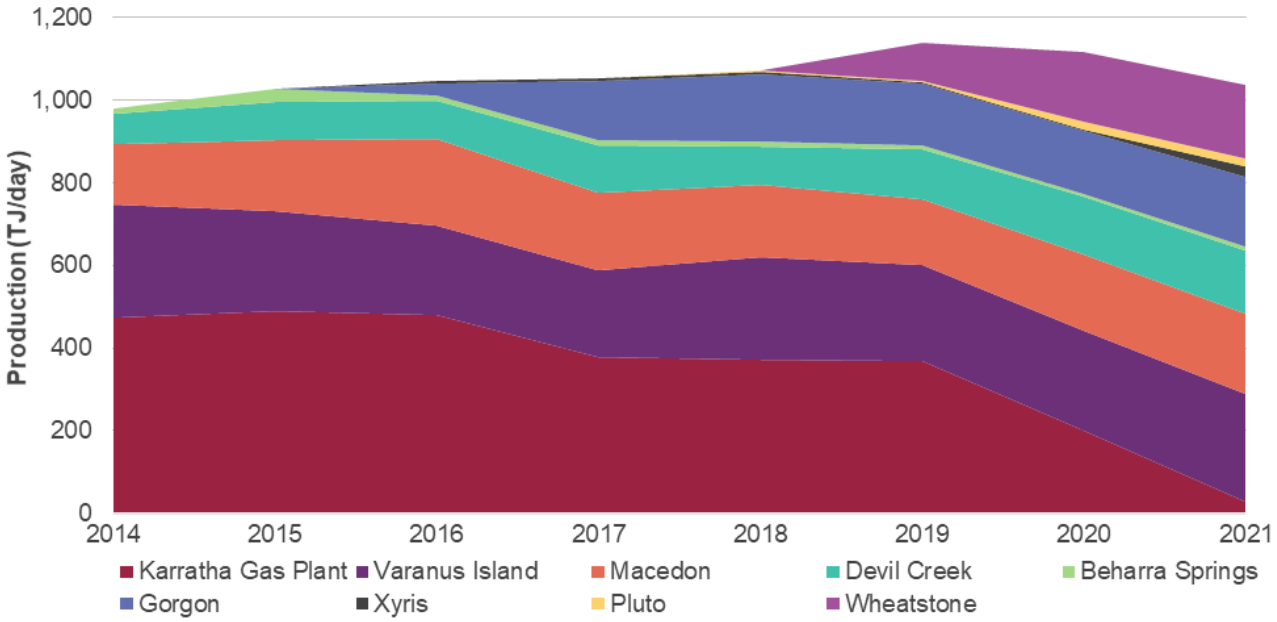
[47] Data is correct to 31 October 2021.

[48] See http://www.ga.gov.au/nopims.

[49] See https://wapims.dmp.wa.gov.au/WAPIMS/Search/Wells.

[50] Dongara has not operated since Q3 2017 and has therefore been excluded. The nameplate capacity value has been calculated based on data available from the WA Gas Bulletin Board as at 30 June 2021. Refer to Appendix A3.5 for further information on domestic gas production facility average production and capacity utilisations.

Figure 10 Gas production by facility, 2014 to 2021 (year to date)



As shown in Figure 10, the following trends were observed between 2014[51] and 2021[52]:

- Since 2014, gas supply in WA has diversified.
- In 2016, Gorgon started supplying its first tranche of 182 TJ/day[53] and Xyris came online at 10 TJ/day after being refurbished[54].
- In 2018, Pluto started supplying the domestic gas market via a 25 TJ/day pipeline gas facility[55].
- In 2019, Wheatstone commenced domestic gas production (205 TJ/day capacity[56]), while Pluto's 15 TJ/day LNG truck-loading facility began operating[57].
- Xyris was expanded to 20 TJ/day in mid-2020[58] and 28 TJ/day in early 2021[59].
- The KGP's market share declined from 48% in 2014 to under 3% in 2021, due to several GSAs expiring.
- The Beharra Springs facility's production peaked in 2015 at 5.8 PJ (1.6% of total gas production), then steadily declined to 2.2 PJ (0.5% of total gas production) in 2020. The Beharra Springs Deep gas field was connected to the existing facility in early 2021[60], which has increased production to 3.6 PJ (0.9% of total gas production).

[51] 2014 is the first year for which a full year's set of GBB data is available for comparison.

[52] Year to date between 1 January 2021 and 31 October 2021.

[53] See https://gbbwa.aemo.com.au/#capacities.

[54] See https://mitsuiepmidwest.com.au/what-we-do/the-process-of-making-gas/.

[55] See https://www.wa.gov.au/government/publications/implementation-of-the-wa-domestic-gas-policy.

[56] See https://gbbwa.aemo.com.au/#capacities.

[57] See https://www.wa.gov.au/government/publications/implementation-of-the-wa-domestic-gas-policy.

[58] See https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/2A1258293/BPT_Quarterly_report_for_the_period_ended_30_September_2020.pdf.

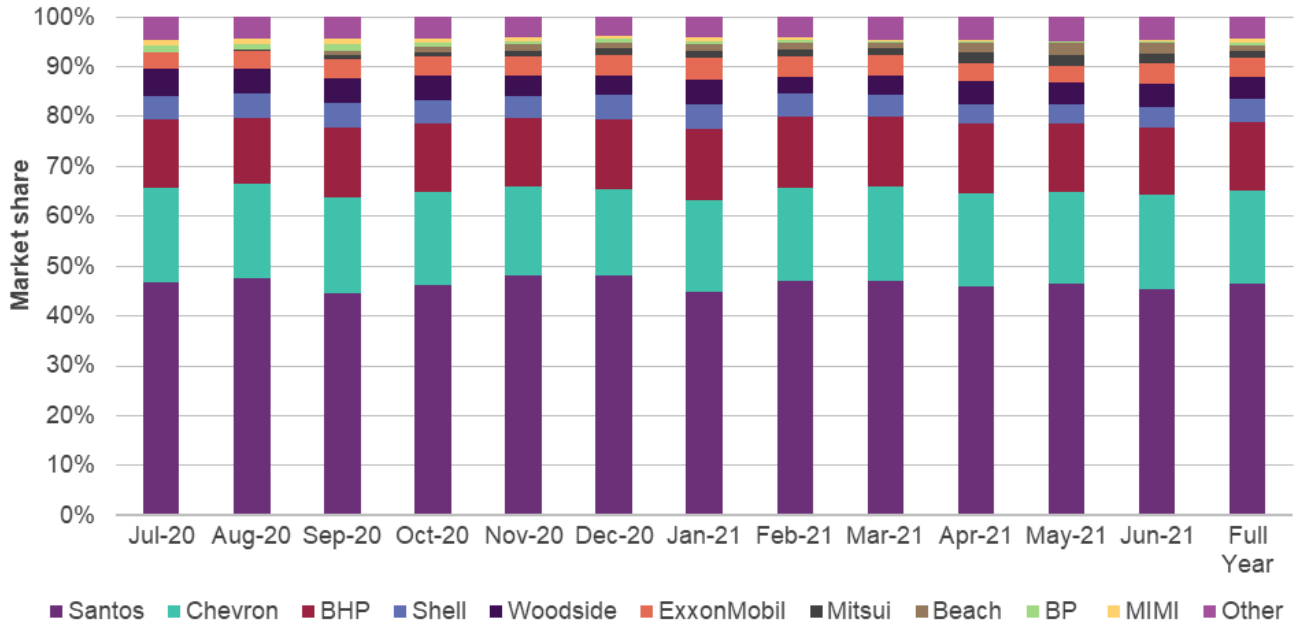
[59] See https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/2A1295285/BPT_Quarterly_report_for_the_period_ended_31_March_2021.pdf.

[60] See https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/2A1310912/BPT_Quarterly_report_for_the_period_ended_30_June_2021.pdf.

- Production from the Devil Creek, Macedon, and Varanus Island production facilities has been stable over the outlook period, with minor fluctuations.

When comparing the average gas production market share by company (see Figure 11) for the 2020-21 financial year, Santos was the largest producer (46%), followed by Chevron (19%) and BHP (14%). Both Japan Australia LNG (MIMI) and BP's share each decreased over the period from 1.2% in July 2020 to 0.2% in June 2021, while Mitsui and Beach Energy's market share each increased to 2.1% in June 2021, due to the expansion of the Xyris facility in August 2020[61]. The remaining companies maintained stable market shares for the outlook period.

Figure 11 Gas production market share by company, 2020-2021 financial year



On 17 August 2021, Woodside Energy and BHP announced a merger of their oil and gas businesses[62]. AEMO estimates that this could increase the merged entity's expected market share in 2022 to 18%, behind Santos (34%m – decreasing due to Reindeer downgrade) and Chevron (23% – increasing due to Gorgon tranche two).

3.2 Potential gas supply model assumptions

AEMO forecasts the potential availability of gas supply to the WA domestic market, or "potential gas supply". Potential gas supply is defined as supply that could be economically offered to the domestic gas market[63], given forecast prices, production costs and DMOs, subject to the availability of processing capacity and gas reserves.

The model does not project how much gas *will* be produced, but how much *could* be produced if there was demand at the forecast price. It distinguishes between existing, committed[64], and

[61] See https://www.beachenergy.com.au/wp-content/uploads/2021/01/BPT_Quarterly_report_for_the_period_ended_30_September_2020.pdf.

[62] See https://files.woodside/docs/default-source/asx-announcements/2021-asx/woodside-and-bhp-to-create-a-global-energy-company.pdf.

[63] See footnote 39.

[64] Expansions to production capacity that have achieved FID.

prospective projects[65] by triggering prospective projects when the forecast price (WA domestic gas price or Asian LNG price) exceeds production costs.

For further information about the methodology and features of the model, see Appendix A3.3.

3.2.1 Forecasting scenarios

AEMO developed the potential gas supply forecasts for the Low, Base, and High scenarios for the outlook period. The input assumptions used in the three scenarios are:

- Domestic gas demand forecasts, domestic gas price forecasts, and Asian LNG netback forecasts for the Low, Base, and High scenarios were matched to the relevant gas supply scenario.
- Production costs, DMO volumes, and gas reserves were the same for the three scenarios.

Forecasts for domestic gas prices, Asian LNG netback, and production cost estimates were sourced from EnergyQuest. Gas reserves and sales were sourced from the 2021 FIR process. Existing DMO volumes were sourced from the WA Department of Jobs, Tourism, Science and Innovation (DJTSI[66]), while prospective projects' DMO volumes were calculated by AEMO. Market intelligence was gathered via informal and formal gas stakeholder engagement and information publicly available on these projects.

The hydrogen industry is at a nascent stage, and the sectors currently targeted by industry have limited impact on the WA domestic gas market over the outlook period. As such, AEMO has not incorporated hydrogen in the potential gas supply forecasts. However, AEMO will continue to monitor the progress of hydrogen for potential inclusion in future WA GSOOs and provide relevant updates in future industry forums.

3.2.2 Key modelling assumptions

WA has a Domestic Gas Policy[67] that aims to secure the state's long-term energy needs by ensuring that LNG export project developers make gas available to the WA domestic market. The policy seeks to reserve the equivalent of 15% of LNG exports for WA consumers. In August 2020, the WA Government clarified that it would not agree to gas exports through the WA pipeline network, and that supply of gas to Australia's east coast would be treated as an export for the purposes of the policy[68].

The full DMO quantity associated with an LNG-linked supply source is assumed to be available to the WA domestic gas market, as gas reserves and infrastructure are developed over the outlook period. The modelling also assumes the maximum potential gas supply from domestic gas only projects is available to the market, subject to remaining gas reserves.

Full details of the domestic market obligations in force, including gas produced and outstanding commitments, are available via DJTSI[69].

3.2.3 Key modelling assumptions in the Low scenario

The Low scenario includes only existing and committed production capacity. For existing and committed production capacity, the forecast assumptions are as follows:

[65] New projects that have not yet achieved FID and have not been excluded from the modelling for one of the reasons listed in Section 3.3.1.

[66] See https://www.wa.gov.au/government/publications/western-australian-domestic-gas-policy.

[67] See https://www.wa.gov.au/government/publications/wa-domestic-gas-policy.

[68] See https://www.mediastatements.wa.gov.au/Pages/McGowan/2020/08/Revised-policy-to-secure-domestic-gas-supply-and-create-jobs.aspx.

[69] See https://www.wa.gov.au/government/publications/implementation-of-the-wa-domestic-gas-policy.

- Beharra Springs, Devil Creek, Gorgon (tranche one), Macedon, Varanus Island and Wheatstone were modelled as existing production facilities.
- Pluto was modelled as an existing facility at 40 TJ/day, which includes the LNG truck-loading facility (15 TJ/day) and direct pipeline injection capacity (25 TJ/day).
- The KGP is assumed to make supply available at 65 TJ/day until 2031.
- The second tranche from Gorgon (118 TJ/day) was modelled as being available from 2022, taking Gorgon's total capacity to 300 TJ/day.
- Waitsia[70] will supply 250 TJ/day to the KGP for export as LNG between 2024 and 2028, with at least 20 TJ/day from the existing Xyris production facility continuing to be made available to domestic gas consumers during this period[71]. From 2029, AEMO assumes that Waitsia makes gas available at up to 100 TJ/day.
- Spartan was modelled as backfill to Varanus Island, delivering 35 TJ/d from 2023[72].
- Scarborough has been modelled with a 12 month delay, delivering 210 TJ/day from mid-2028[73].

3.2.4 Key modelling assumptions in the Base scenario

In addition to the facilities in the Low scenario forecast, West Erregulla has been included in the Base scenario forecast as a prospective supply source. West Erregulla is expected to achieve FID by the end of 2021 and deliver 87 TJ/day from 2023. This volume and timing has been updated since the 2020 GSOO (80 TJ/day from 2022). AEMO has made assumptions about the commencement date for this project based on information publicly announced by the project proponents and previous history of major project developments. Further information about West Erregulla is in the following section.

West Erregulla

The West Erregulla field was discovered in 2019 and is located onshore in the Perth basin, approximately 230 km north of Perth. The field is owned by Strike Energy (50%, operator) and Warrego Energy (50%).

Phase one of the project is expected to produce 87 TJ/day, reflecting gas sales agreements with Alcoa of Australia[74] and CSBP (subsidiary of Wesfarmers)[75]. FID is targeted for the second half of 2021[76]. AEMO has modelled West Erregulla as a domestic gas only prospective project available from mid-2023 at 87 TJ/day.

Scarborough

The Greater Scarborough gas fields are located approximately 375 km west-northwest of the Burrup Peninsula and are estimated to hold 13 trillion cubic feet (tcf), or 13,780 PJ of dry gas. The Greater Scarborough gas fields include Thebe (1.4 tcf, 1,484 PJ), Jupiter (0.5 tcf, 530 PJ) and Scarborough

[70] See https://mitsuiepmidwest.com.au/what-we-do/development/waitsia-stage-2/.
[71] See https://www.wa.gov.au/government/publications/implementation-of-the-wa-domestic-gas-policy.
[72] See https://www.santos.com/wp-content/uploads/2021/02/2020-Full-Year-Results-Announcement-and-Presentation.pdf.
[73] See https://files.woodside/docs/default-source/asx-announcements/2021-asx/061.-scarborough-fid-teleconference-and-investor-presentation.pdf.
[74] See http://asx.warregoenergy.com/site/PDF/842f238a-4ee7-4ce6-95bc-ddbb6ffdd25a/UpdatedWarregoandAlcoaSignLargeScaleLongTermGSA.
[75] See https://asx.api.markitdigital.com/asx-research/1.0/file/2924-02274277-6A993558.
[76] See https://warregoenergy.com/uploads/RBC%20Warrego%20March%202021%20Quarter%20210421.pdf.

(11.1 tcf, 11,660 PJ)[77]. The Scarborough gas field is owned by Woodside Energy (73.5%, operator) and BHP (26.5%)[78].

AEMO modelled Scarborough as an LNG-linked project, developed through a second LNG train at Pluto. In March 2020, Woodside Energy announced it would delay FID on Scarborough and Pluto train two until the second half of 2021[79]. On 22 November, Woodside Energy announced FID on the Scarborough LNG and domestic gas project and Pluto LNG train two. The operator is targeting first LNG for 2026. AEMO has assumed first domestic gas supply in 2027. Woodside Energy has increased the volume for Scarborough to 8 mtpa of LNG, with 5 mtpa to Pluto train two, and up to 3 mtpa as backfill to Pluto train one[80].

Woodside Energy intends to increase domestic gas production capacity at Pluto to 250 TJ/day, from 25 TJ/d of pipeline gas and 15 TJ/d of trucked LNG capacity, as part of the Scarborough development[81].

3.2.5 Key modelling assumptions in the High scenario

There are substantial undeveloped gas reserves located in WA that could provide domestic gas in the future, either through new or existing production facilities. AEMO modelled three discovered gas fields, described further in the following sections, that could deliver gas into the WA market before 2031 (see Appendix A3.4 for further information about the selection criteria for these projects). These projects have been included in the High scenario only. AEMO has treated these fields as prospective domestic gas only projects, where domestic gas prices exceed the estimated cost of development and production. AEMO will monitor development of these projects for potential inclusion in the Base scenario of future WA GSOOs.

Beharra Springs expansion

The Beharra Springs Deep gas field, located in the Perth basin, was tied into the Beharra Springs gas plant in 2021[82]. The field is owned by Beach Energy (50%, operator) and Mitsui E&P Australia (50%).

Beach Energy has proposed an expansion to the gas plant, supported by the additional reserves. AEMO has assumed that this expansion will be from 18.5 TJ/day to 70 TJ/day, developed by 2025[83].

Corvus

The Corvus gas field is located offshore in the Carnarvon basin, approximately 90 km northwest of Dampier. The field is 100% owned and operated by Santos.

Santos has identified Corvus as potential backfill for either Devil Creek or Varanus Island[84]. AEMO has modelled Corvus as backfill for Devil Creek from 2028.

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[77] Resources quoted for Scarborough, Thebe, and Jupiter are 2C. PJs are calculated at 1.06 PJ/bcf.

[78] See https://files.woodside/docs/default-source/our-business---documents-and-files/burrup-hub---documents-and-files/scarborough---documents-and-files/scarborough-overview.pdf.

[79] See https://files.woodside/docs/default-source/asx-announcements/2020-asx/response-to-market-conditions.pdf.

[80] See https://files.woodside/docs/default-source/asx-announcements/2021-asx/061.-scarborough-fid-teleconference-and-investor-presentation.pdf.

[81] See https://files.woodside/docs/default-source/asx-announcements/2020-asx/investor-briefing-day-2020.pdf.

[82] See https://yourir.info/resources/0c5a441cf54ff229/announcements/bpt.asx/2A1310912/BPT_Quarterly_report_for_the_period_ended_30_June_2021.pdf.

[83] See https://www.beachenergy.com.au/wp-content/uploads/2020/08/FY20-Results-and-Outlook-Presentation.pdf.

[84] See https://www.santos.com/news/successful-corvus-2-appraisal-well-discovers-significant-offshore-resource/.

Lockyer Deep

Lockyer Deep was discovered in September 2021[85]. It lies 10 km north of the West Erregulla project and 15 km east of the Waitsia project. The field is owned by Energy Resources Limited (80%, operator), and Norwest Energy NL (20%). AEMO has assumed the project could come online by 2028.

3.3 Potential gas supply forecasts

Depending on the various input assumptions for the Low, Base, and High scenarios, prospective supply sources and backfill for existing production facilities are triggered to commence if:

- Forecast WA domestic gas prices exceed the cost of production, for domestic gas projects.
- Forecast Asian LNG prices exceed the cost of production, for LNG-linked projects. If the project commences, AEMO assumes that an associated DMO will be offered to the domestic gas market.

AEMO's potential gas supply forecasts for the three scenarios are shown in Table 5 and Figure 12. Potential gas supply forecasts in all three scenarios are lower than the total nameplate production capacity expected to be available over the outlook period.

In summary:

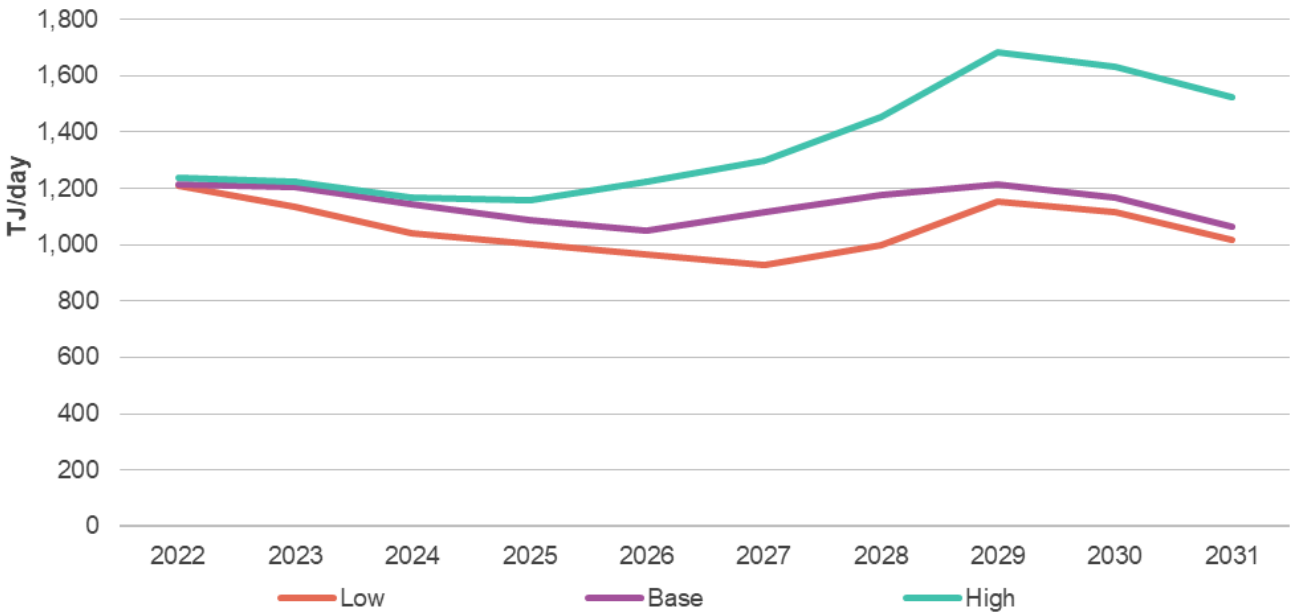
- In the Base scenario, potential gas supply is projected to decrease at an average annual rate of 1.4% between 2022 and 2031.
  - Decrease is driven by natural depletion and reserves downgrades at the Reindeer gas field and Macedon domestic-only gas production facility, partially offset by the development of Scarborough, Spartan, and West Erregulla.
- Volumes are similar in the Base and High scenarios between 2022 and 2024, reflecting a similar mix of production facilities being available during this period.
- In the High scenario, potential supply increases from 2026 as Beharra Springs expansion, Corvus and Lockyer Deep are brought onstream.
- In all three scenarios, potential supply increases from 2026 (High scenario), 2027 (Base scenario) and 2028 (Low scenario) due to Scarborough coming online.

Table 5 Potential gas supply forecasts (TJ/day), 2022 to 2031

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	5-year average growth pa (%)	10-year average growth pa (%)
Low	1,211	1,136	1,039	1,002	965	927	997	1,153	1,114	1,017	-5.5	-1.9
Base	1,212	1,204	1,145	1,086	1,049	1,116	1,175	1,216	1,168	1,064	-3.5	-1.4
High	1,237	1,223	1,169	1,159	1,225	1,296	1,451	1,683	1,632	1,525	-0.2	2.4

[85] See https://clients3.weblink.com.au/pdf/MIN/02419018.pdf.

Figure 12 Potential gas supply forecasts, 2022 to 2031



3.4 Comparison of 2020 and 2021 WA GSOO potential gas supply forecasts

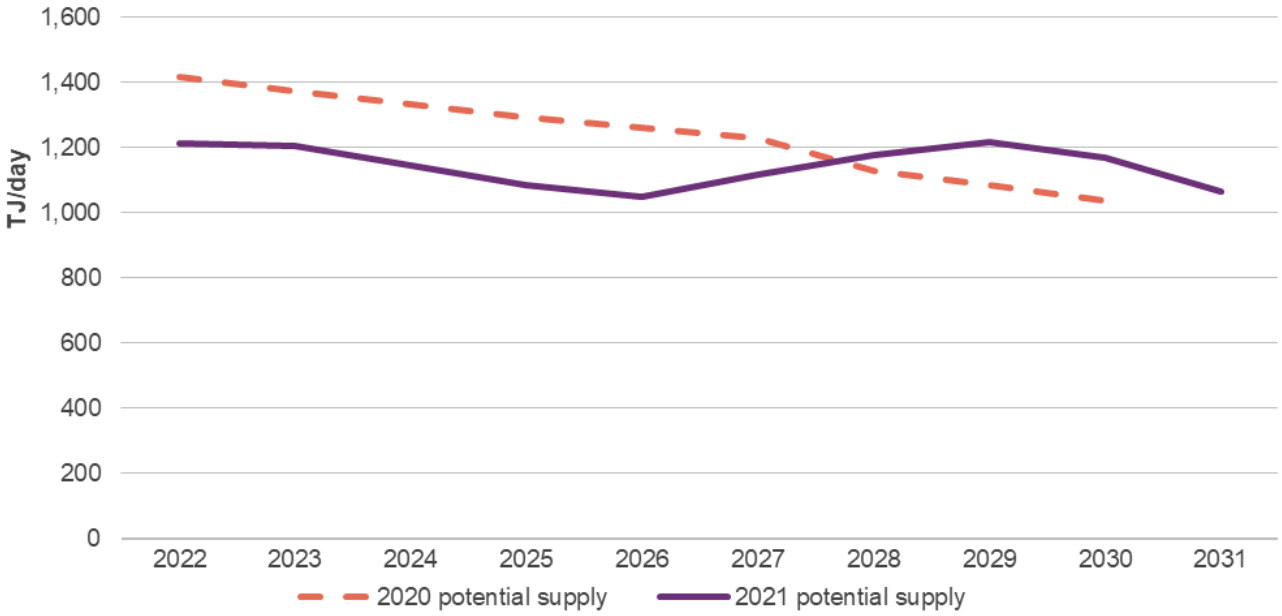
The Base scenario potential gas supply forecasts developed for the 2020[86] and 2021 WA GSOOs are compared in Figure 13. For the 2021 WA GSOO, AEMO updated the:

- Development of Base scenario supply sources, most notably Scarborough from 2027.
- List of prospective supply sources (see Section 3.2.2 for more information about the changes in prospective project assumptions).
- Forecasts for gas reserves and resources, production costs, domestic gas prices and Asian LNG prices.
- Starting level of reserves for domestic gas only production facilities, particularly Macedon and Devil Creek which had reserves downgrades since the 2020 WA GSOO was published.
- Assumptions about reserve depletion rates, based on responses from the 2021 FIR.

These changes (particularly the reserves downgrades at Macedon and Reindeer and the start-up of Scarborough) account for most of the difference between the 2020 and 2021 WA GSOO Base scenario potential gas supply forecasts.

[86] The potential gas supply forecasts in the 2020 WA GSOO covered the period 2021 to 2030.

Figure 13 2020 and 2021 Base scenario potential gas supply forecasts, 2022 to 2031



4 Supply-demand balance

This chapter discusses the supply-demand balance in WA's domestic gas market over the outlook period 2022 to 2031.

While all three modelled scenarios show potential supply-demand gaps at various times over the outlook period, there are multiple options to alleviate those gaps.

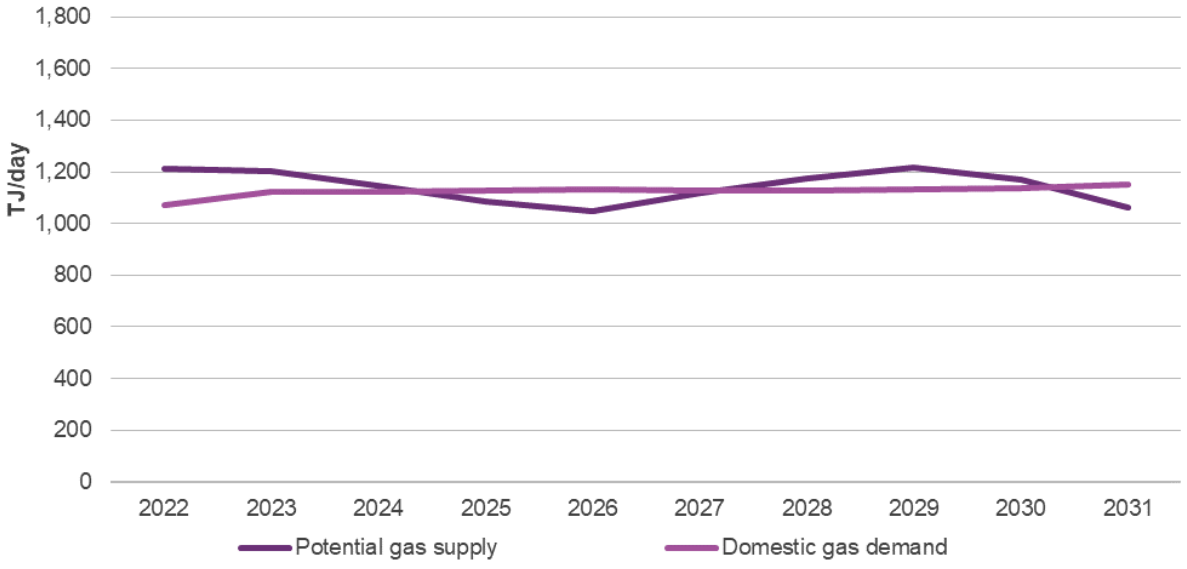
4.1 Base scenario

Under the Base scenario, as shown in Table 6 and Figure 14, potential gas supply is sufficient to meet forecast gas demand until 2024. Between 2025 and 2027, domestic gas demand is expected to exceed potential gas supply by a maximum of 85 TJ/day (7% of demand). From 2027, Scarborough is forecast to supply up to 210 TJ/day to the domestic gas market, resulting in potential gas supply exceeding domestic gas demand until 2030, after which declining production rates see forecast gas demand again exceeding potential gas supply.

Table 6 Potential domestic gas supply and demand forecasts, Base scenario (TJ/day), 2022 to 2031

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Potential gas supply	1,212	1,205	1,145	1,086	1,049	1,116	1,175	1,216	1,168	1,064
Domestic gas demand	1,071	1,125	1,122	1,129	1,133	1,129	1,127	1,134	1,137	1,150
Difference	141	79	23	-42	-85	-13	48	82	32	-86

Figure 14 Potential domestic gas supply compared to forecast gas demand, Base scenario, 2022 to 2031



In comparison, the 2020 WA GSOO forecast that potential gas supply would be sufficient to meet gas demand until 2028. The earlier occurrence of a supply-demand gap forecast in this GSOO is predominantly due to reserves downgrades at the Reindeer gas field and Macedon, which will constrain these facilities' ability to supply the domestic gas market. Further information on the changes in potential gas supply forecasts since the 2020 WA GSOO is in Section 3.4.

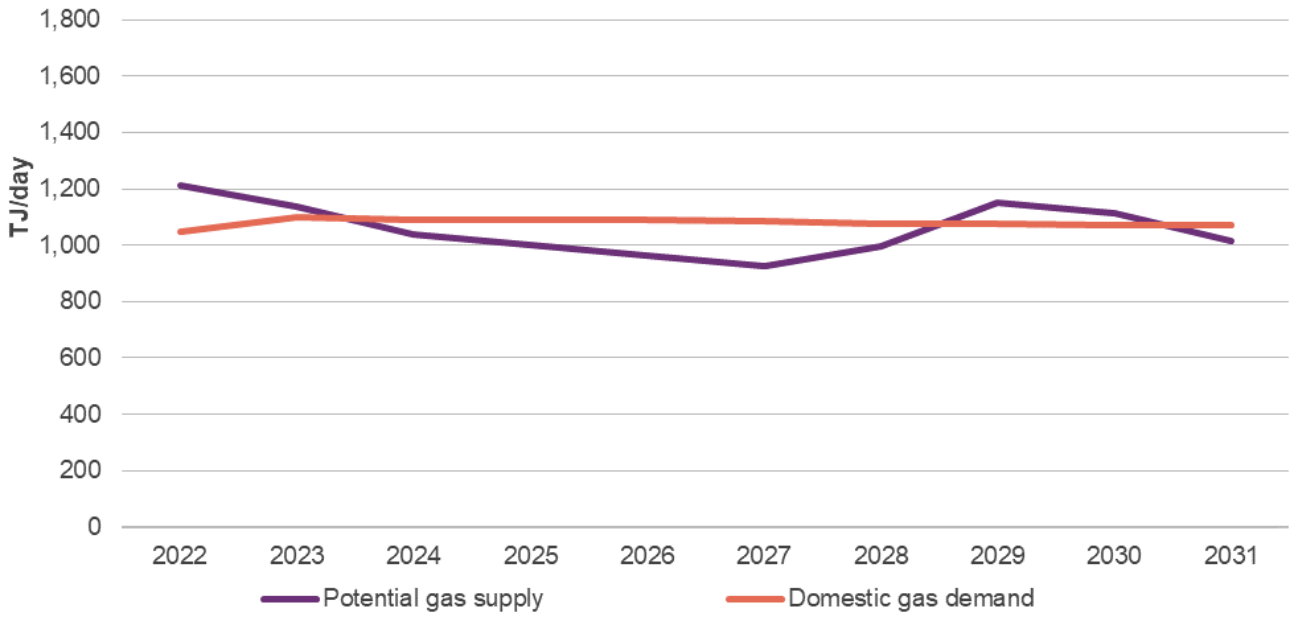
4.2 Low scenario

The Low scenario includes only existing and committed gas supply sources and therefore represents a conservative forecast, albeit it is also matched to a lower demand profile (average annual growth rate of 0.3%) due to factors such as lower economic growth. Potential gas supply is forecast to decline at an average annual rate of 1.9% over the outlook period, in line with reserve depletion at existing production facilities (see Table 7 and Figure 15). This results in a potential supply gap from 2024 to 2028, peaking at 13% of demand (159 TJ/day) in 2027.

Table 7 Potential domestic gas supply and demand forecasts, Low scenario (TJ/day), 2022 to 2031

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Potential gas supply	1,211	1,136	1,039	1,002	965	927	997	1,153	1,114	1,017
Domestic gas demand	1,049	1,101	1,092	1,092	1,091	1,085	1,074	1,074	1,070	1,073
Difference	162	35	-53	-90	-126	-159	-77	78	44	-56

Figure 15 Potential WA domestic gas supply compared to forecast gas demand, Low scenario, 2022 to 2031



4.3 High scenario

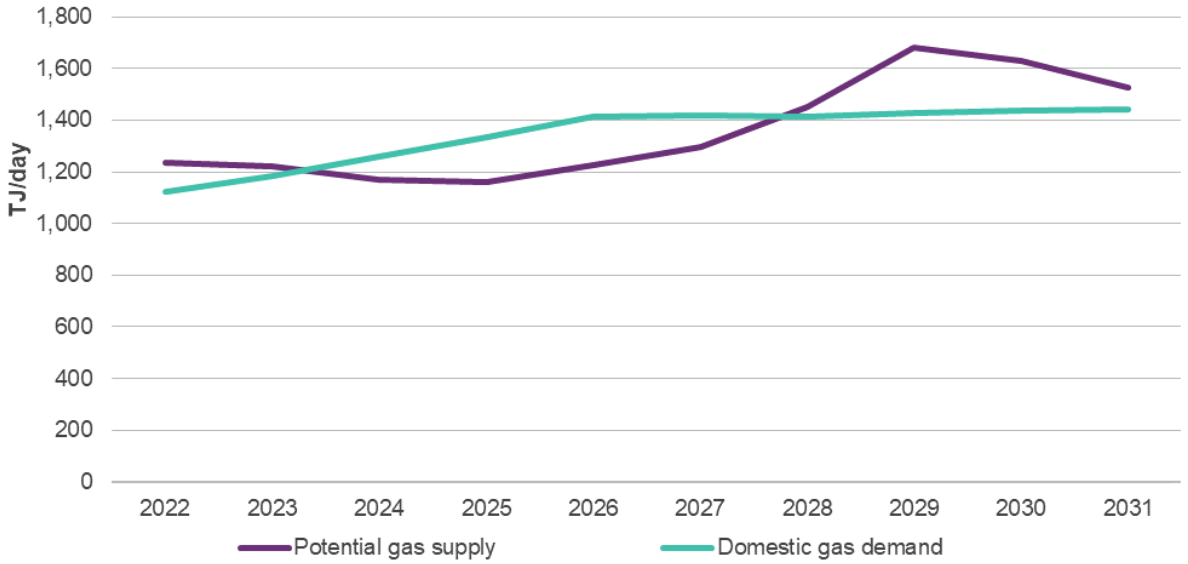
The High scenario potential gas supply forecasts include committed and additional prospective supply and demand sources. It is a more buoyant outlook than the Base scenario. The supply and

demand variance in the High scenario is greatest between 2025 and 2027, as shown in Figure 16 and Table 8. This variance is driven by the scale of the prospective demand projects – forecast demand in 2026 is 25% (282 TJ/day) higher than in the Base scenario. In contrast, supply is only 17% (176 TJ/day) higher.

Table 8 Potential domestic gas supply and demand forecasts, High scenario (TJ/day), 2022 to 2031

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Potential gas supply	1,237	1,223	1,169	1,159	1,225	1,296	1,451	1,683	1,632	1,525
Domestic gas demand	1,123	1,186	1,258	1,333	1,415	1,419	1,416	1,428	1,436	1,442
Difference	114	37	-89	-174	-189	-122	36	256	196	83

Figure 16 Potential WA domestic gas supply compared to forecast gas demand, High scenario, 2022 to 2031



4.4 Options that could reduce or eliminate the potential supply gaps

The forecast supply gaps in this GSOO are:

- 184 PJ between 2024 and 2028 in the Low scenario, at a maximum deficit of 159 TJ/d in 2027.
- 51 PJ between 2025 and 2027 in the Base scenario, at a maximum deficit of 85 TJ/d in 2025.
- 210 PJ between 2024 and 2027 in the High scenario, at a maximum deficit of 189 TJ/d in 2026.

These gaps could be alleviated by options including the following:

- Gas could be withdrawn from storage at up to 210 TJ/day, subject to the quantity of gas in storage at the time and the duration of the requirement[87].
- Additional production could be sourced from existing facilities with spare capacity and available reserves (such as the KGP with a nameplate capacity of 630 TJ/day).

[87] Tubridgi and Mondarra have a combined storage capacity of 78 PJ and can deliver an equivalent of 210 TJ/day for four months. This assumes that both storage facilities are full and accounts for Mondarra's higher withdrawal rate and lower capacity compared to Tubridgi.

- Additional supply could be sourced from:
  - Backfill projects at existing facilities, such as Corvus being developed through the Devil Creek infrastructure.
  - Expansion of existing facilities, such as Beharra Springs.
  - Undeveloped gas fields such as Lockyer Deep developed as greenfield projects.
  - Successful exploration leading to backfill opportunities at existing production facilities, like the Dancer prospect near Devil Creek infrastructure.

5 2021 formal information request data analysis

This chapter presents aggregate data submitted by gas market participants (GMPs) and non-GMPs through the 2021 FIR process and provides a comparison with data previously received in FIRs for the 2019 and 2020 WA GSOOs.

In line with the Gas Services Information (GSI) Rules, AEMO has conducted a confidential FIR process annually since 2017 to collect data and information from GMPs[88] for the purposes of the WA GSOO. While some non-GMPs provide information voluntarily, GMPs are required to respond in accordance with the GSI Rules[89].

The data presented in this report includes:

- Gas demand and supply estimates.
- Contracted volumes.
- Gas reserves.
- Domestic gas prices that may cause gas consumers to reduce or increase gas demand.

Data has been aggregated to protect the confidentiality of individual respondents. Some information submitted as part of the FIR process has not been presented[90].

AEMO has used the FIR data as an input into developing the gas demand and potential gas supply forecasts for the 2021 WA GSOO.

AEMO has taken all due care to reconcile the information received but accepts no liability for any errors it may contain. The data reported is from the 2021 FIR process, unless otherwise specified. All data presented is the latest available as of November 2021 and should be considered indicative only. It is important to note the data does not represent AEMO's forecasts.

5.1 Gas market participant profile

Sixty of the 65 surveyed participants responded to the 2021 FIR, increasing the response rate by four percentage points compared to the 2020 FIR (see Table 9).

For the purposes of this analysis, respondents were categorised as either consumers[91], suppliers[92], or infrastructure operators (includes pipelines and storage facilities), with responses distributed as shown in Table 10. Gas consumers were further broken down into sectors (including mining, minerals processing, GPG, and domestic LNG).

[88] Under rule 106 of the GSI Rules, AEMO may require GMPs to provide information for the WA GSOO. This does not cover all participants in the WA domestic gas market.

[89] Under rule 21 of the GSI Rules, GMPs include Registered Facility Operators and Registered Shippers, although some exemptions are available. For example, some facilities that consume gas are not responsible for the shipping of this gas and are thus not required to be registered. The GSI Register for GMPs and facilities is maintained and updated regularly by AEMO. Both are available at https://www.aemo.com.au/energy-systems/gas/wa-gas-bulletin-board-wa-gbb/participate-in-the-wa-gbb/participants-and-facilities-registered-for-the-wa-gbb.

[90] Including gas consuming facility names, their capacities and development status, and consumption by pipeline and storage facilities.

[91] Excludes facilities with gas demand less than 10 TJ/day.

[92] Includes all production facility operators and their joint venture partners (if relevant).

Table 9 2020 and 2021 FIR response rate overview

	2020	2021		
Participants	**Response rate**	**Number of requests issued**	**Number of responses received**	**Response rate**
Gas market participants	92%	53	49	92%
Non-GSI participants (optional)	67%	12	11	92%
Total	**88%**	**65**	**60**	**92%**

Table 10 Distribution of responses

	Consumers	Suppliers	Infrastructure	Total
Gas market participants	39	7	3	49
Non-GSI participants (optional)	1	10		11
Total	**40**	**17**	**3**	**60**

5.2 Gas demand and supply data

For the outlook period, AEMO requested GMPs to provide the following data for each facility:

- For gas consumers – total gas consumption and maximum contracted gas demand estimates.
- For gas suppliers – total nameplate capacity[93] and committed gas supply estimates.

The following sections provide comparisons between these measures to give indicative insights on the WA gas market over the next 10 years.

5.2.1 Gas demand

Expected demand

Expected gas demand[94] is lower than previously reported in the 2020 FIR data, as shown in Figure 17.

In general, GMPs expect gas demand to decline at 0.5% each year over the outlook period, averaging 939 TJ/day. A small increase in expected gas demand is anticipated in 2023 with new mining projects commencing operations. Some facilities are anticipated to reach end-of-life during the outlook period, while others are expected to transition to renewable energy, reducing gas demand. This is expected to be offset by expansions to other facilities that have achieved FID.

[93] The FIR asked for "Total known nameplate capacity (in TJ/day) that is available to the WA domestic gas market".

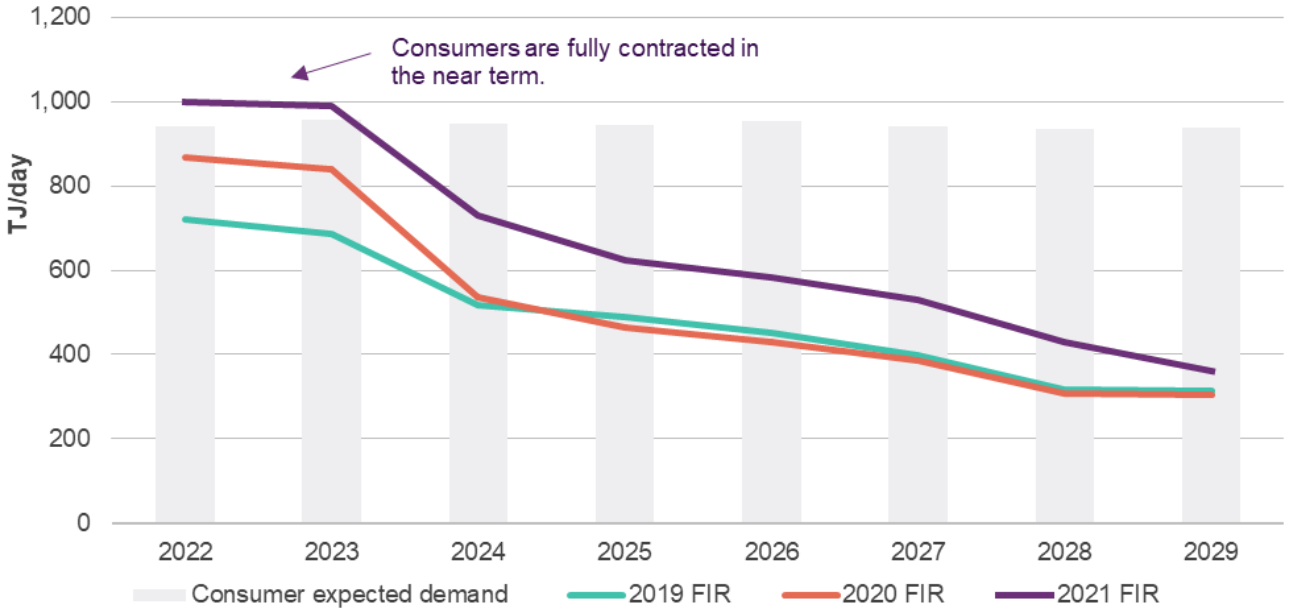
[94] Expected gas demand includes GPGs and committed projects that have attained FID and are expected to commence during the outlook period.

Figure 17 Comparison of consumer expected demand, 2019 to 2021 FIRs

Contracted demand

Consumer maximum contracted quantity (MCQ) is lower than expected demand over most of the outlook period. This suggests that consumers have not fully contracted their gas demand beyond 2023 (Figure 18).

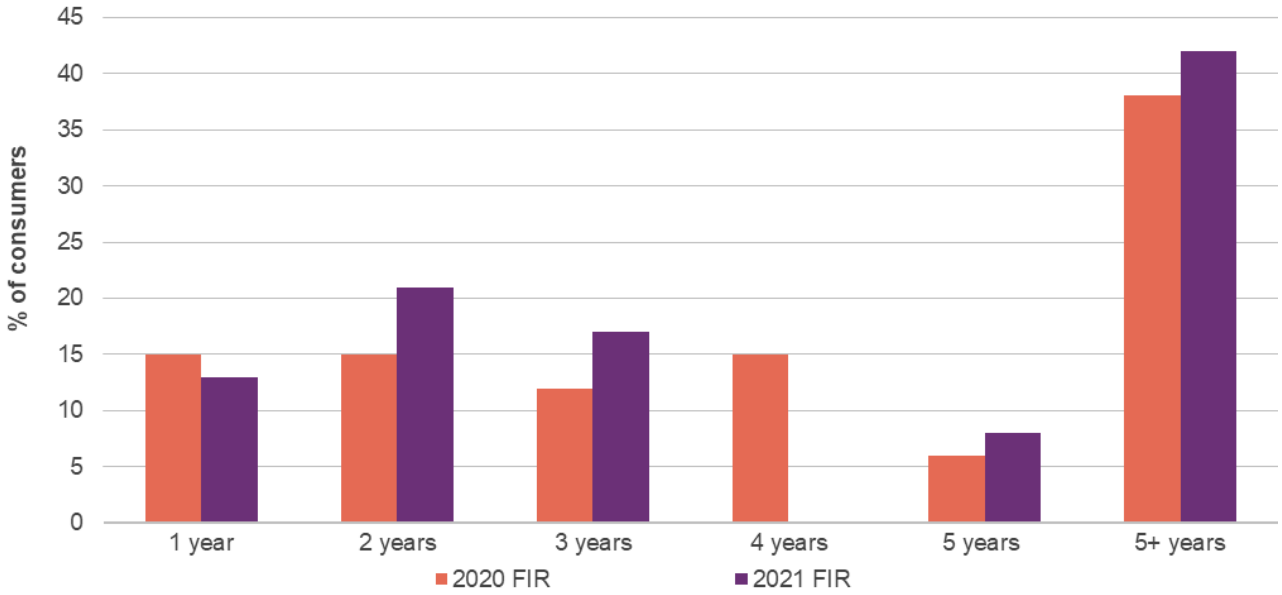
Figure 18 Comparison of consumer contracted levels (MCQ), 2019 to 2021 FIRs



Roughly 40% of consumers who have contracted with suppliers have long-term contracts that exceed five years, as shown in Figure 19. This is two percentage points higher than in the 2020 FIR (38%). The MCQ for these contracts averages around 60 TJ/day. Most of these long-term contracts

were for diminishing volumes over time, with the final year of the contracts having half of the value of their 2022 quantities.

Figure 19 Comparison of consumer contract duration, 2020 to 2021 FIRs



Prospective demand

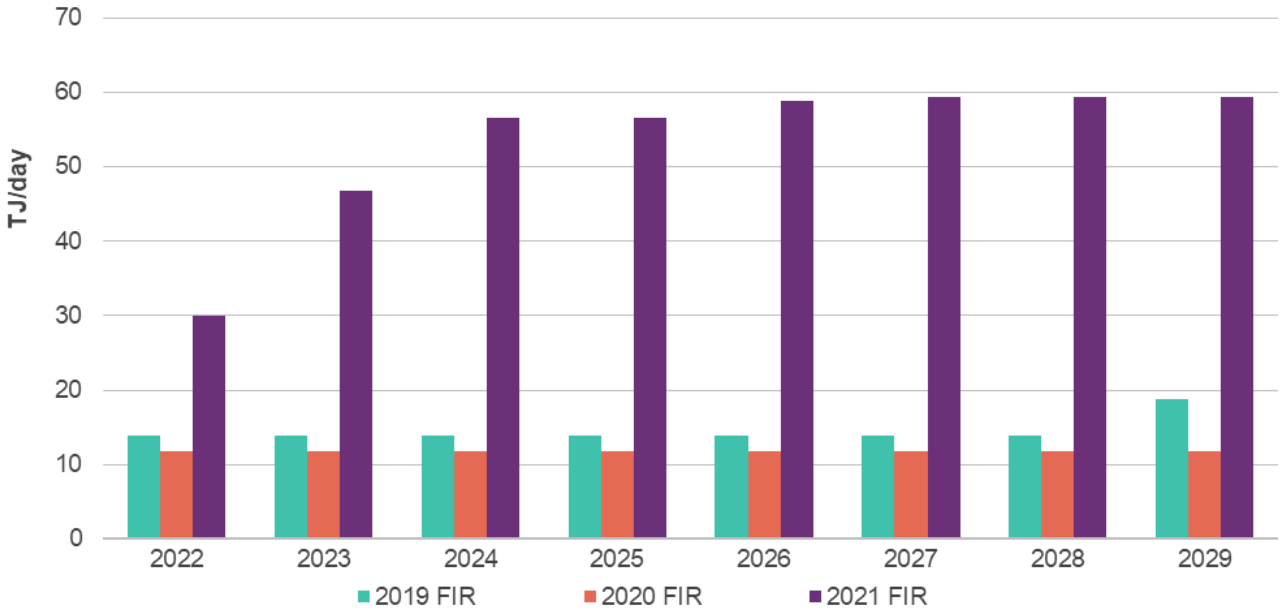
GMPs expect prospective demand[95] to increase from 30 TJ/day in 2022 to 59 TJ/day in 2029, five times greater than the prospective demand reported in the 2020 FIR.

Consumers provided estimates of incremental prospective[96] demand either as a capacity change or as a fuel switch. Fuel-switching is reported by facilities planning to shift from diesel to gas or from gas to renewable energy generation. Some respondents are in the early stages of exploring hydrogen as a substitute for natural gas.

[95] Gas demand from proposed projects that have not yet achieved FID.

[96] Projects were classified according to development stage – FID, environmental approval, internal approval, or speculative.

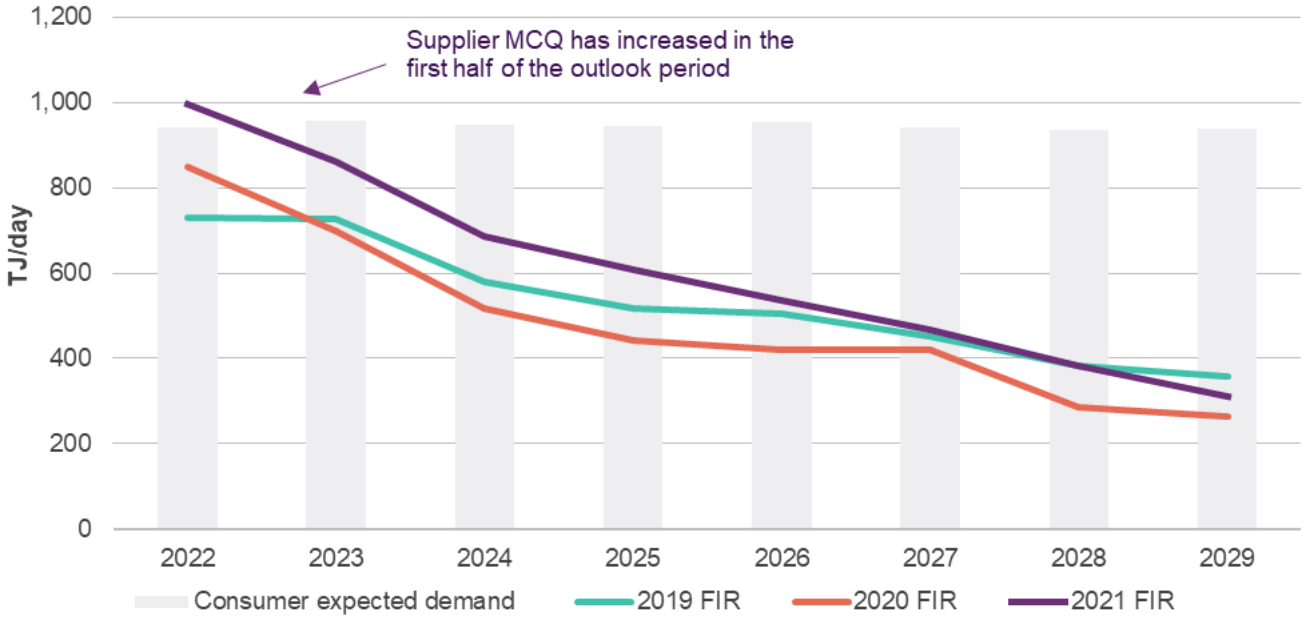
Figure 20 Comparison of prospective demand, 2019 to 2021 FIRs



5.2.2 Gas supply

Suppliers expect nameplate capacity to grow at an average annual rate of 2.1%, from 2,041 TJ/day in 2022 to 2,465 TJ/day in 2031. The supplier MCQ has increased by an average of 109 TJ/day compared with the 2020 FIR, as shown in Figure 21. While the total MCQ is higher, the rate of decline (-13.5%) is similar to the 2020 FIR, suggesting that contracting strategies in 2021 are similar to those in 2020.

Figure 21 Comparison of supplier contracted levels (MCQ), 2019 to 2021 FIRs

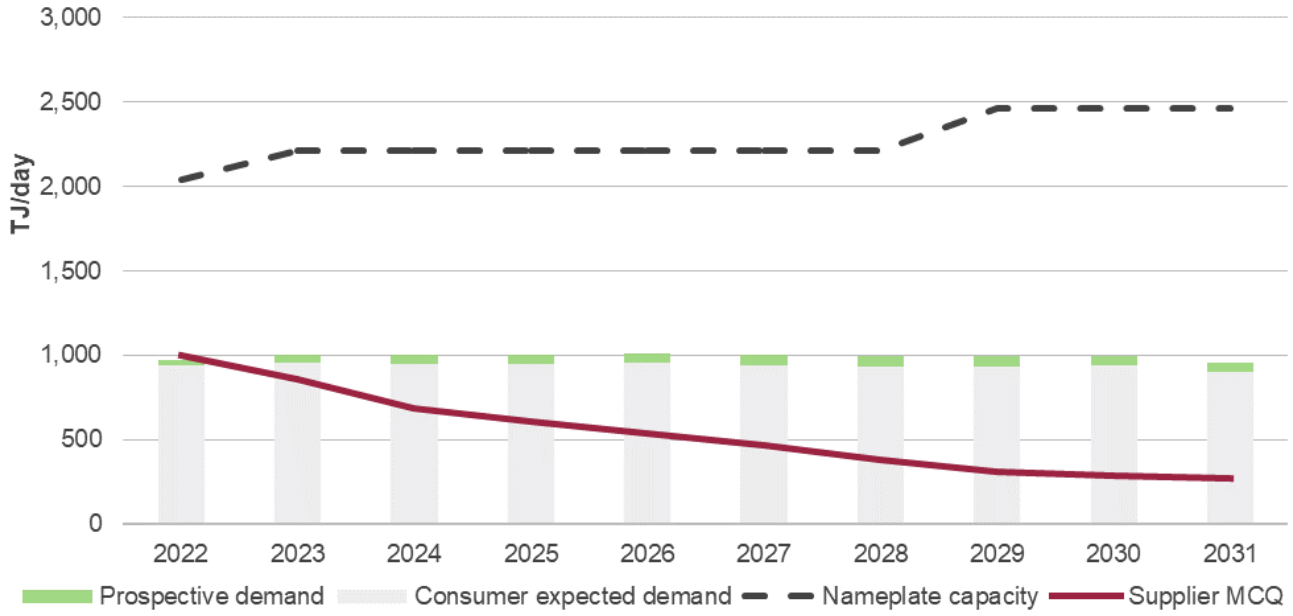


5.2.3 Gas supply-demand balance

Gas supply and demand levels

Supply utilisation is expected to be 43.7% of the nameplate capacity on average over the outlook period, as shown in Figure 22. In 2022, the sum of expected and prospective demand is 971 TJ/day, which would use approximately 47.6% of suppliers' nameplate capacity. The lowest utilisation is expected in 2031, at 38.9%, as new-build gas plants increase installed capacity.

Figure 22 Consumer expected gas demand compared to supplier contracted levels (MCQ) and nameplate capacity, 2022 to 2031



5.3 Reserves

Domestic gas production facility operators and joint venture partners reported the volumes of 2P gas reserves associated with all their WA petroleum production licences, as well as 2P gas reserves that are physically connected to each existing domestic gas production facility. This data is an input into AEMO's potential gas supply model.

Table 11 compares the 2P gas reserves connected to domestic gas production facilities with the figures collected in previous FIRs[97]. Connected 2P reserves (developed and undeveloped) have decreased relative to the 2020 WA GSOO estimates by 4,730 PJ (-10%), reflecting a reduction in participants' estimated reserves.

[97] Volumes reported at standard conditions (60°C and 1 atmosphere [101.325 kilopascal (kPa)] pressure).

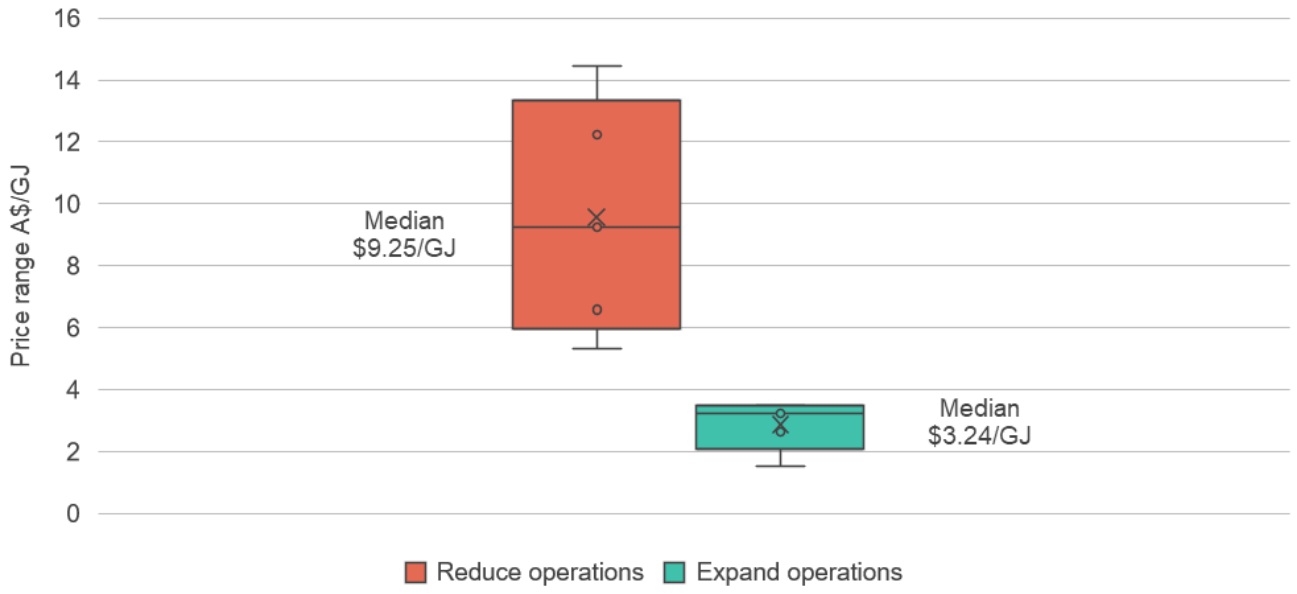
Table 11 Total 2P gas reserves from 2017 through 2021 FIRs (PJ)

Gas reserves and resources	2017	2018	2019	2020	2021
Total 2P reserves connected to domestic gas production facilities	35,159	47,886	43,131	47,337	42,607

5.4 Domestic gas prices that would influence consumption

Consumers representing around one-sixth of WA gas consumption provided WA domestic gas prices they said would affect their gas demand over the outlook period, either by encouraging expansion (new or existing facilities) or prompting reduction of their gas demand (closure or curtailment)[98]. As Figure 23 shows, the gas price at which the median of respondents could reduce operations is $9.25/GJ, while they are likely to expand operations if it falls to $3.24/GJ.

Figure 23 Median gas price estimates that could result in changes in gas consumption



Note: gas prices (A$/GJ) were provided in 2021 dollars.

In addition to gas prices, consumers noted that other factors, including availability of alternative fuel, commodity prices, and approval of project proposals would impact the scale of their operations.

[98] These prices have not been used in the potential gas supply modelling, which requires domestic gas price forecasts.

6 Tables

7 Figures