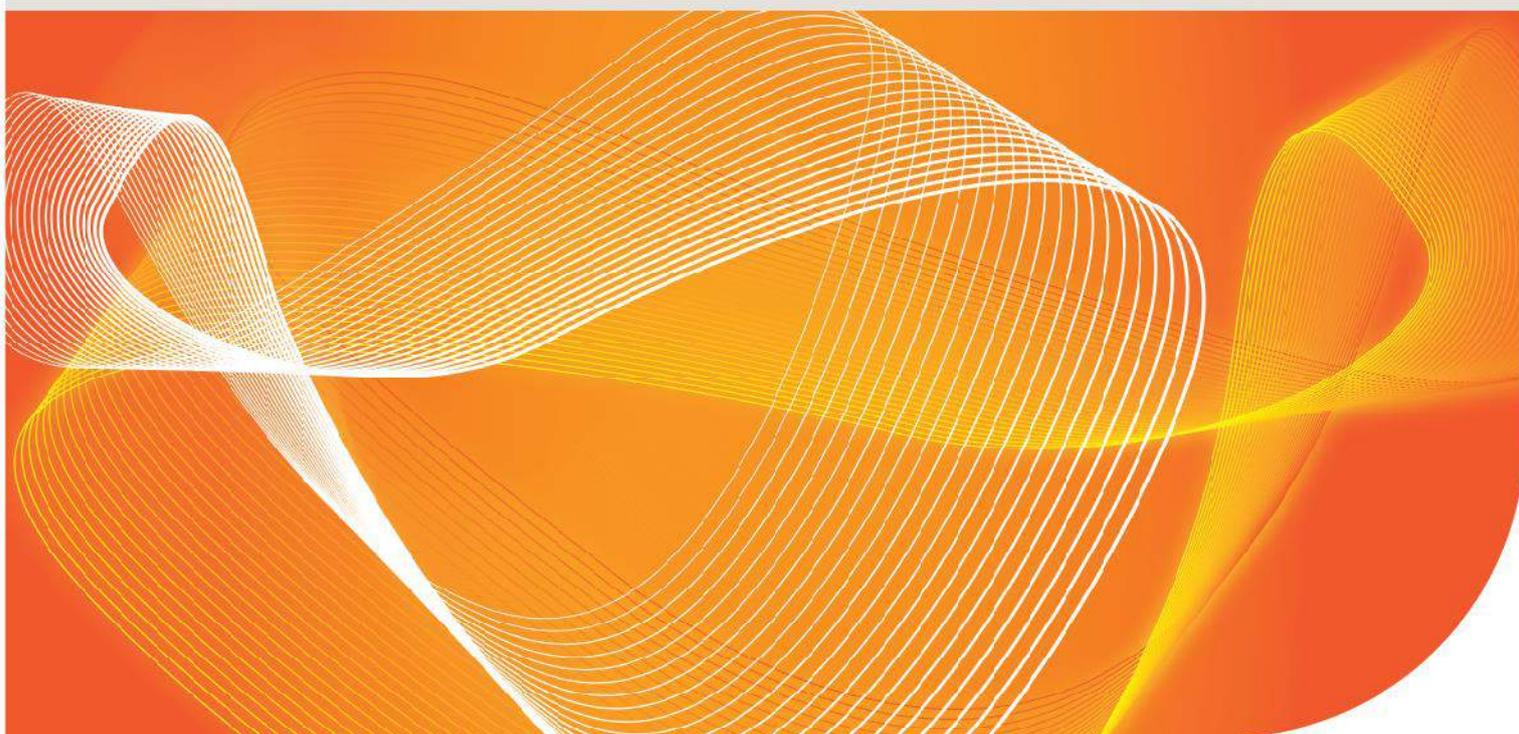


GAS STATEMENT OF OPPORTUNITIES

FOR EASTERN AND SOUTH-EASTERN AUSTRALIA

Published: **March 2016**





IMPORTANT NOTICE

Purpose

AEMO has prepared this document to provide information about the natural gas industry in eastern and south-eastern Australia, in accordance with the National Gas Law and Part 15D of the National Gas Rules. It is based on information available to AEMO as at 10 December 2015, although AEMO has endeavoured to incorporate more recent information where practical.

Disclaimer

The forecasts in this report use information provided by third parties. AEMO has made every effort to ensure the quality of this publication but cannot guarantee that information, forecasts and assumptions are accurate, complete or appropriate for your circumstances. This publication does not include all of the information that an investor, participant or potential participant in natural gas markets might require, and does not amount to a recommendation of any investment.

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Version control

Version	Release date	Changes
1	10/3/2016	



EXECUTIVE SUMMARY

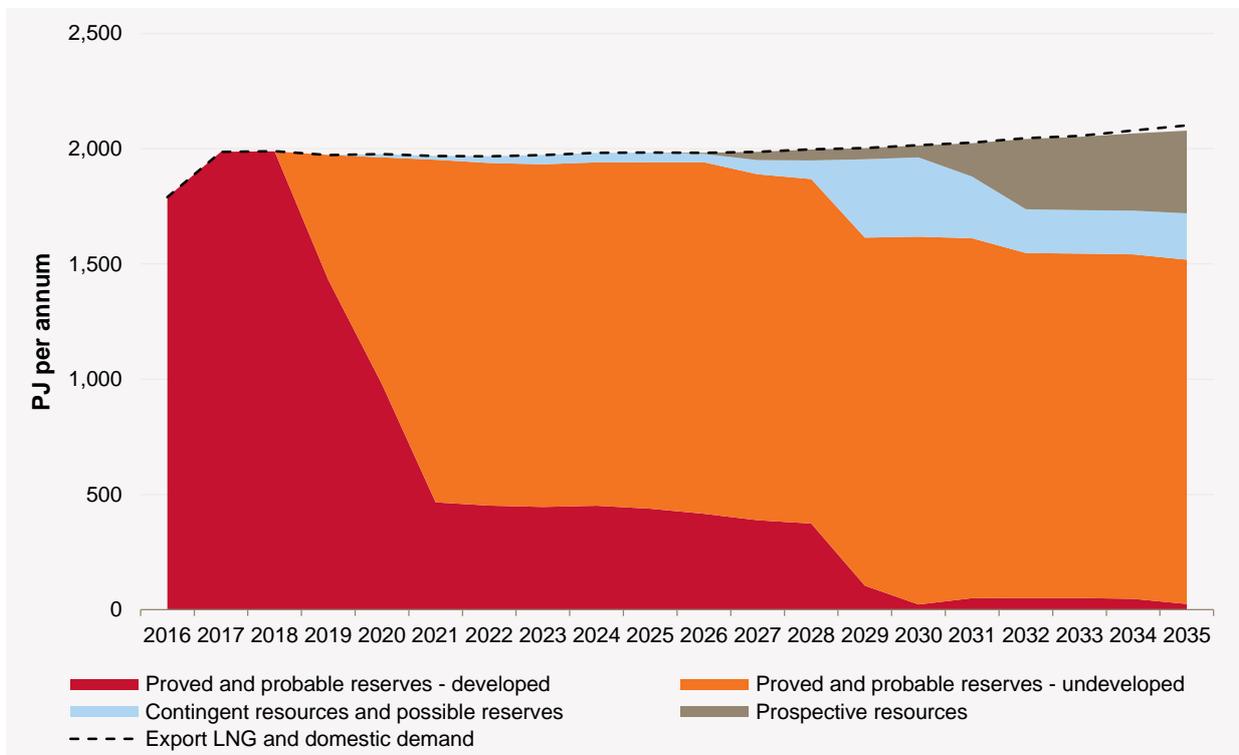
The *Gas Statement of Opportunities* (GSOO) reports on the adequacy of eastern and south-eastern Australian gas markets to supply maximum demand and annual consumption over a 20-year outlook period. It is based on data provided by industry participants up to 10 December 2015.

The 2016 GSOO projects that, under a medium (considered most likely) scenario:

- Proved and probable gas reserves (considered the best estimate of commercially recoverable reserves) start to deplete from 2019.
- To maintain gas supply adequacy between 2019 and 2035, development will be required to ensure contingent and prospective resources and undeveloped reserves become commercially recoverable.
- Gas transmission and processing infrastructure is adequate to meet forecast total domestic gas and export liquefied natural gas (LNG) demand until 2029.
- Shortfalls totalling 50 petajoules (PJ) are forecast in Queensland (Gladstone and Townsville) between 2029 and 2035. This assumes:
 - No additional infrastructure development to address projected pipeline or processing facility constraints.
 - An increase in demand for gas-powered generation (GPG) as forecast in the *2015 National Gas Forecasting Report* (NGFR).¹

Figure 1 shows the volume of supply projected to meet domestic and export LNG demand forecast under the medium scenario.

Figure 1 Eastern and south-eastern Australia gas markets (export LNG and domestic), 2016–35



¹ AEMO. *2015 National Gas Forecasting Report v2.0*. Available at: <http://www.aemo.com.au/Gas/Planning/Forecasting/National-Gas-Forecasting-Report>.



Medium scenario assumptions

The 2016 GSOO medium scenario incorporates:

- Medium demand forecasts from AEMO's 2015 NGFR.
- Production and supply assessments based on information provided by industry.

The following projects are in early stages of development, and have therefore not been included in the medium scenario:

- The proposed Northern Gas Pipeline (NGP).
- Additional New South Wales supply (Narrabri).

Contributions from these projects are considered in the sensitivity analysis. Due to AGL's February 2016 announcement that it is withdrawing from the Gloucester Gas Project, additional supply from this project is not considered in the 2016 GSOO.

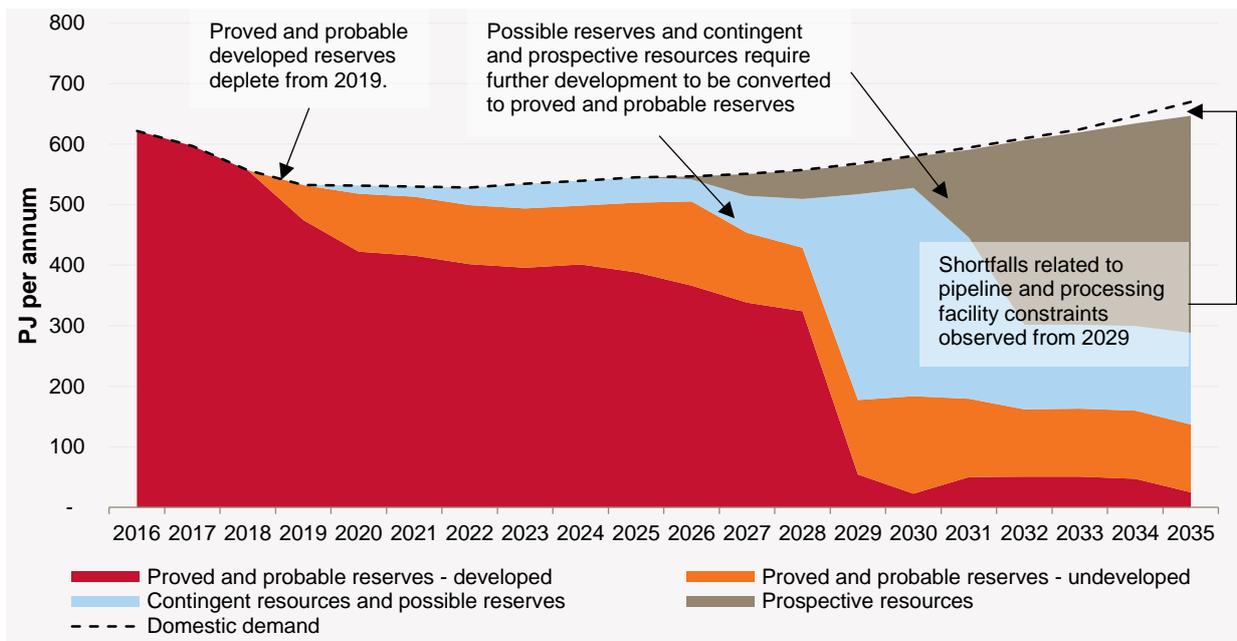
Development opportunities from 2019

As proved and probable reserves are projected to decline from 2019, currently undeveloped gas reserves and contingent and prospective resources will be required to meet forecast demand.

There is technical and commercial uncertainty associated with this resource development. Further, the current economic environment (including low oil prices) is impacting revenue streams and capital budgets, leading to a heightened risk that some resource development may not be commercially viable.

Using wholesale gas contract information, AEMO analysis highlights that the domestic gas markets are reliant on development of these contingent and prospective resources to meet forecast demand over the 20-year outlook period. Figure 2 shows demand and reserves for the domestic gas markets only, excluding export LNG demand. All 50 PJ of projected domestic shortfalls from 2029 to 2035 are due to pipeline constraints along the Queensland Gas Pipeline and the Northern Queensland Gas Pipeline, processing facility constraints at Moranbah, and increased projected GPG demand.

Figure 2 Eastern and south-eastern Australia domestic gas markets (excluding LNG), 2016–35





Changed projections since the 2015 GSOO

The 2016 GSOO projects shortfalls totalling 50 PJ, approximately 164 PJ lower than were reported in the 2015 GSOO. The current demand forecasts assumed are similar to those used in the 2015 GSOO, though slightly higher on average per year (25 PJ or 1%). The reduction in shortfalls is due to net increases in processing capacity, as advised by industry, of up to 585 terajoules (TJ) per day over the 20-year outlook period, spread across eastern and south-eastern Australia.

Sensitivity analysis

Changes in economic conditions, global oil prices, and weather events are increasing gas market volatility. Sensitivity analysis around the medium scenario has been conducted to test the impact of these factors on the supply adequacy assessment, by investigating:

- El Niño drought events, leading to increased GPG demand.
- Consequences of reduced investment in capital projects.

Uncertainties also exist around the timing and impact of future developments including:

- The NGP connecting Northern Territory gas to eastern gas markets.
- Gas field development in Narrabri.

The results of the sensitivity analysis are summarised below.

Table 1 Medium scenario sensitivity studies

Sensitivity	Variations in assumptions from medium scenario	AEMO projection compared to the medium scenario
El Niño drought event	Reduced hydro generation until the end of 2020 leads to increased GPG demand.	No change to the medium gas supply adequacy assessment.
Reductions in investment in capital projects	LNG production reduced by 15% from 2018–23. Two-year delay, to 2023, in bringing non-LNG fields online.	Total forecast domestic shortfalls increase from 50 PJ to 296 PJ, with shortfalls observed from 2018. 13 PJ of shortfalls also forecast for LNG producers between 2018 and 2020.
NGP comes online	NGP available from July 2018. Assumed capacity of 200 TJ per day.	Supply from NGP helps meet export LNG demand, reducing Queensland’s need for gas imports from southern states. Undeveloped reserves and resources are required to be commercialised up to three years later than in the medium scenario. There is no change to the shortfalls, which are driven by infrastructure constraints.
Additional supply from Narrabri	Narrabri available from January 2019, with a capacity of 100 TJ per day.	In the medium scenario, once Camden ceases production in 2023, New South Wales is dependent on gas imports from other states to meet all its demand. With the introduction of Narrabri, New South Wales gas supply can meet up to 15% of local demand by 2035, reducing reliance on gas imports from other states. There is no change to the shortfalls, which are driven by infrastructure constraints.

AEMO will continue to monitor key uncertainties facing the gas industry and will update the GSOO if market conditions change materially.



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CHAPTER 1. INTRODUCTION

The *Gas Statement of Opportunities* (GSOO) reports on the adequacy of eastern and south-eastern Australian gas markets to supply forecast maximum demand and annual consumption over a 20-year outlook period. The GSOO analyses transmission, production, and reserves adequacy, to highlight locations where forecast growing demand may require investment in new gas processing or transmission infrastructure, or field developments. The GSOO provides industry participants and policy-makers with transparent information to support decision-making to ensure the supply of gas – a key energy resource – is managed in Australia's long-term interests.

1.1 What's new in the GSOO

The 2016 GSOO features improvements in methodology and data, and reflects changes in projected gas consumption and supply, since the 2015 GSOO. This section summarises the key differences.

Dynamic changes in the gas markets make data quality and transparency a critical issue. AEMO continues to work with industry to improve data quality and transparency and, therefore, the credibility of modelled outcomes. This report is based on information available to AEMO as at 10 December 2015, although AEMO has endeavoured to incorporate more recent information where practical.

For more detail on 2016 GSOO data, methodology and assumptions, see the *2016 GSOO Methodology Document*.²

1.1.1 Gas consumption forecasts are similar

In December 2015, AEMO published the *2015 National Gas Forecasting Report* (NGFR)³ for eastern and south-eastern Australia. The forecasts in the 2015 NGFR form the basis of the outlooks for annual gas consumption and maximum demand for the 2016 GSOO.

Forecast gas consumption is similar to that reported in the 2014 NGFR, though slightly higher on average per year (25 petajoules (PJ), or 1%). These consumption forecasts are higher due to projected emerging growth sectors in industrial gas consumption that dominate long-term trends.

Key changes to input assumptions since the 2014 NGFR, related to price, weather, new connections, and economic assumptions, are explained in detail in the 2015 NGFR.

1.1.2 System capability – pipeline capacity and processing capacity have increased

Industry provided AEMO with updated information about capacity changes since the 2015 GSOO. The following changes to transmission and processing infrastructure increase capacity for gas to flow to demand areas.

Pipeline capacity from Victoria to New South Wales

The capacity of the Eastern Gas Pipeline (EGP) has been increased by 60 TJ per day (TJ/d). The EGP is now able to deliver 351 TJ/d in summer and 358 TJ/d in winter.

Upgrades to the Victoria – New South Wales Interconnect (VNI) will be completed by winter 2016, providing increased flows to New South Wales by increasing capacity from 118 TJ/d to 148 TJ/d.

These changes allow more gas from Victoria to be either exported to meet New South Wales demand, or sent along the Moomba to Sydney Pipeline (MSP) to Queensland.

² AEMO. *2016 GSOO Methodology Document*. Available at: <http://aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities>.

³ AEMO. *2015 National Gas Forecasting Report v2.0*. Available at: <http://www.aemo.com.au/Gas/Planning/Forecasting/National-Gas-Forecasting-Report>.



Wallumbilla to Gladstone Pipeline

The capacity of the Wallumbilla to Gladstone Pipeline (WGP), previously known as the QCLNG pipeline, has been revised upwards to 1,530 TJ/d, an increase of 120 TJ/d.

Processing facility capacity changes

The processing capacities of many facilities across the eastern and south-eastern Australian gas markets have been revised since the 2015 GSOO.

Changes in processing capacity across Queensland, South Australia and Victoria have resulted in a net increase in processing capacity of 585 TJ/d, increasing the quantity of gas that can be processed to satisfy demand.

The updated processing capacity of each facility used in the GSOO can be found on the AEMO website.⁴

1.1.3 Supply contracts and field production limits

In order to improve the representation of actual gas market dynamics in the gas model for the 2016 GSOO, AEMO has:

- Included publicly-announced Gas Sales Agreements (wholesale gas 'contracts') that provide an assessment of the annual volumes for each contract, and the field earmarked to supply the gas for the contract. Contract profiles reflect forecast production more accurately than processing facility capacities, so AEMO can better identify potential domestic supply impacts.
- Calibrated field production profiles against historical field production obtained from Gas Bulletin Board (GGB) data, to ensure projected annual production levels align with historical observations. Where insufficient historical production information was available, AEMO has assumed that fields are capable of operating continuously at their stated maximum production capacities. If these fields do not deliver to rated capacities, GSOO results will vary accordingly.

1.1.4 Storage facilities

Gas storage facilities are used to provide additional supply deliverability during periods of peak demand and allow for injections during low demand periods without constraining production. This storage flexibility allows for upstream well capacity to be developed optimally while enabling customer demand and contractual commitments to be met. The storage facilities within the eastern and south-eastern Australian gas markets that provide additional supply deliverability during peak periods are Dandenong and Iona in Victoria, Newcastle in New South Wales, and Newstead and Silver Springs in Queensland.

AEMO has identified several storage facilities that require gas to be processed at nearby gas processing facilities before being transported to customers. These include Moomba Storage, Ballera Storage, and Roma Underground Storage in Queensland. The GSOO model does not include unprocessed gas from these storage facilities because they do not add to the existing processing facility capacity.

⁴ Available at: <http://aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/2016-GSOO-Supporting-Information>.



1.2 Supporting information for 2016 GSOO

Table 2 provides links to additional information provided either as part of the 2016 GSOO suite, or related AEMO planning information.

Table 2 Links to supporting information

Source	Website address
2016 GSOO Methodology document	http://aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities
2016 GSOO inputs and stakeholder information (for updated processing capacity of each facility used in the GSOO)	http://aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/2016-GSOO-Supporting-Information
2016 GSOO Supply-Demand modelling output files	http://aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/2016-GSOO-Supply-Demand-Modelling-Output-Files
2015 National Gas Forecasting Report	http://www.aemo.com.au/Gas/Planning/Forecasting/National-Gas-Forecasting-Report
Archive of previous GSOO reports	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Previous-GSOO-reports

1.3 Reserves and resources categorisation

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.

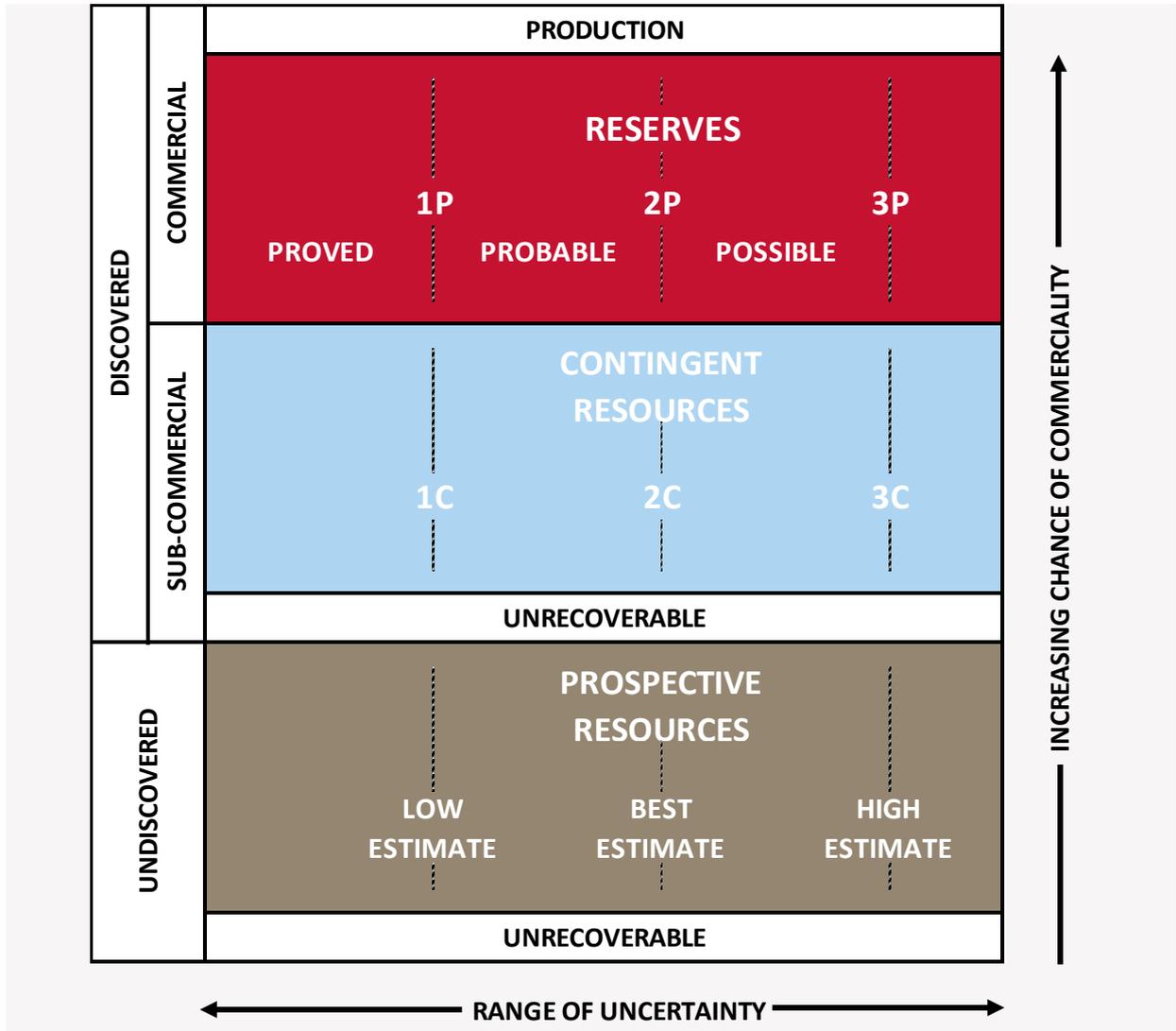
Figure 3 shows how these categories are applied across the industry:

- Proved and probable reserves (2P) are considered the best estimate of commercially recoverable reserves.
- Reserves considered less likely to be extracted due to financial or technical challenges are classified as possible reserves. The category 3P combines proved and probable (2P) plus possible reserves.
- Contingent resources are considered less commercially viable than reserves. The 2C resources are considered the best estimate of those sub-commercial resources.
- AEMO refers to the categorisation of 3P2C in 2016 GSOO documents. This takes into account only the ‘possible’ reserves that are incremental to 2P, plus all 2C resources.
- Prospective resources are estimated volumes associated with undiscovered accumulations.

AEMO’s modelling and projections further categorise 2P reserves as either developed (supply from existing wells) or undeveloped (wells yet to be drilled). All these reserves are included as 2P reserves in the reserves section of Figure 3.



Figure 3 Reserves and resources categorisation (PRMS)



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⁵ Guidelines for Application of the Petroleum Resources Management System. Society of Petroleum Engineers. Available at: http://www.spe.org/industry/docs/PRMS_guide_non_tech.pdf. Viewed 22 February 2016.



CHAPTER 2. SUPPLY AND INFRASTRUCTURE ADEQUACY – MEDIUM SCENARIO

Key insights for the eastern and south-eastern Australian gas markets

The eastern and south-eastern Australian gas industry is experiencing a period of transformation, and annual gas consumption is increasing.

- The start-up of Queensland’s LNG facilities is forecast to more than double total gas consumption (compared to aggregate demand in 2014, before these projects began). The three projects are expected to be operating at full capacity by 2020, at which time gas consumption for LNG export is projected to be over 1,400 petajoules (PJ) per annum.
- In the gas-powered generation (GPG) sector, in the short term the expiry of existing gas supply agreements exposes new contracts to projected rising domestic gas prices and consumption is forecast to decline. In the medium term, from 2020–25, GPG consumption is projected to increase, to support electricity consumption and withdrawal of some coal-fired generation across the National Electricity Market (NEM).

Maximum daily demand is also expected to increase, due to the same drivers.

Additional sources of supply continue to attract investment, including the proposed Northern Gas Pipeline (NGP) linking the Northern Territory to Mount Isa in Queensland, and the continuing development of Narrabri Gas Project in New South Wales. Because these projects are in early stages of development, they were not included in the medium scenario. Instead, they have been studied as sensitivities.

Analysing these supply and demand drivers, the GSOO forecasts that in the medium scenario:

- Developed reserves begin to decline from 2019, requiring development of further reserves and resources to meet gas demand. The current economic environment (including low oil prices) is impacting revenue streams and capital budgets, heightening the risk that some needed resource development may not be commercially viable.
- Gas transmission and processing infrastructure development is required in Queensland to address congestion and processing constraints from 2029. Without this development, shortfalls are expected from 2029.

2.1 The GSOO medium scenario

The GSOO medium scenario, considered the most likely scenario, incorporates the NGFR medium demand scenario, and includes only existing gas transmission and processing infrastructure and announced upgrades.

2.2 Overall adequacy

2.2.1 Field development

The 2016 GSOO projects that 2P (proved and probable) developed gas reserves will satisfy forecast gas demand until 2019. From 2019, as developed 2P reserves decline, the delivery of new gas reserves from existing fields, and/or the development of fields that are not yet producing gas, will be critical to maintaining sufficient gas supply to meet forecast demand to 2035.

A large portion (92%) of 2P undeveloped reserves is forecast to be produced for LNG export.

Figure 4 shows, under the medium scenario:

- The volume of gas supply required to meet total domestic and export LNG demand.
- When newly-developed reserves and resources will be required to start production.



- That production of 3,729 PJ of possible reserves and contingent and prospective resources will be required to meet gas demand to 2035.

Figure 5 shows the field production profile required to meet only the domestic demand for gas (this is a subset of the production shown in Figure 4). It shows that, to meet domestic demand:

- 3P (possible reserves) and 2C (contingent resources) are forecast to be required from 2020.
- From 2026–35, currently highly uncertain prospective resources are forecast to be required.

Figure 4 Eastern and south-eastern Australia gas markets (export LNG and domestic), 2016–35

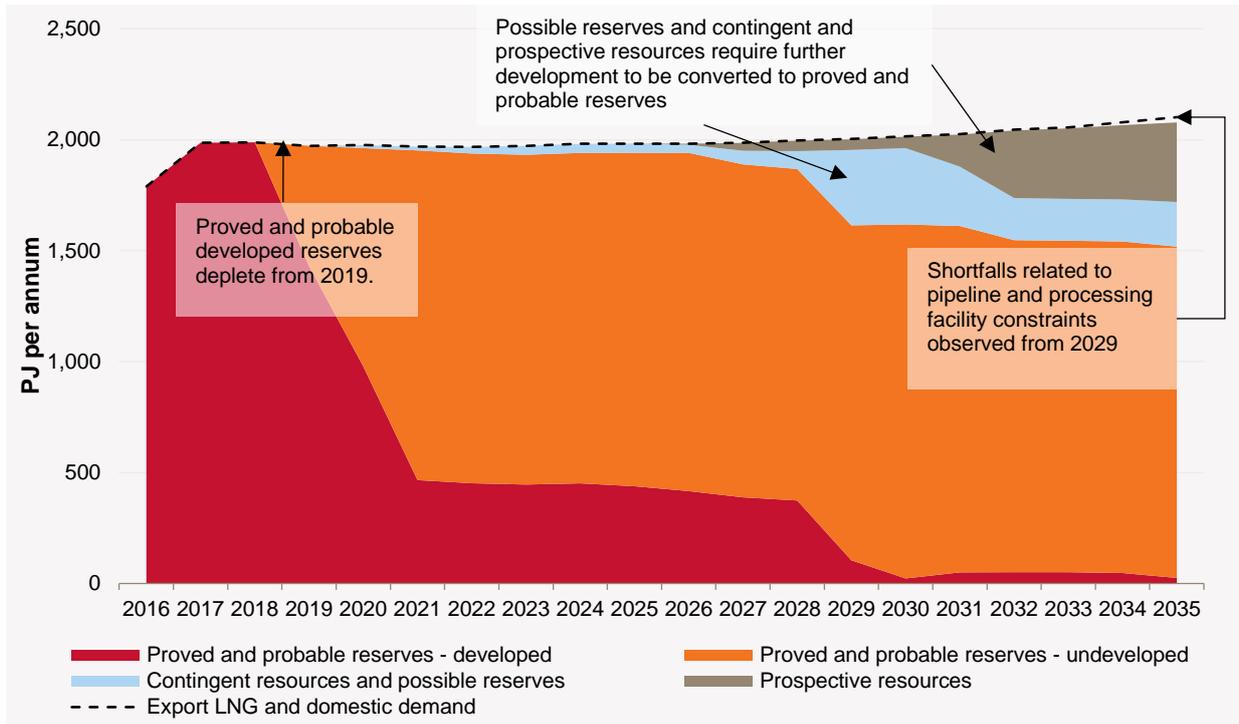
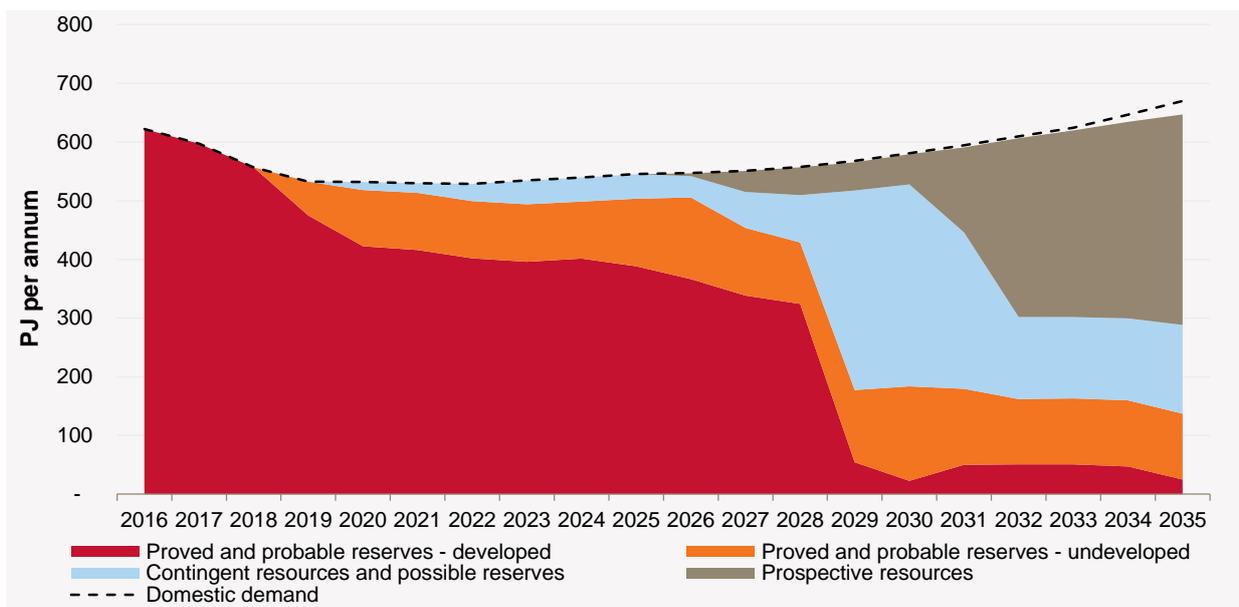


Figure 5 Eastern and south-eastern Australia domestic gas markets (excluding LNG), 2016–35





The notable forecast decline in 2P developed production between 2028 and 2029 is driven predominantly by projected depletion of 2P developed reserves in the Gippsland and Cooper Eromanga basins. The high cost and high risk nature of gas exploration and development can result in contingent resources taking ten or more years to reach production. The decline of the 2P developed reserves in the Gippsland and Eromanga basins is reflective of a typical gas development timeline.

A comparison of Figure 4 and Figure 5 shows that, based on industry advice and contract information, AEMO expects:

- The LNG export market to draw on the majority of 2P reserves.
- The domestic market to rely, far more than the LNG market, on the development of possible (3P) reserves and contingent (2C) and prospective resources. Of the possible reserves and contingent and prospective resources shown in Figure 4, 95% (3,529 PJ) of the total will need to be commercially recovered between 2020 and 2035 to meet forecast domestic demand.

2.2.2 Proved and probable field production

Table 3 summarises the timing of currently developed 2P reserves that are projected to be consumed within the 20-year outlook period. As these 2P developed reserves decline, undeveloped reserves or resources will be required to come online.

Table 3 Final year of production projected for 2P developed reserves

Field	Final year of gas production
QLD CSG – APLNG	2019
QLD CSG – GLNG	2019
Surat–Bowen–Denison	2019
Minerva	2020
QLD CSG – QCLNG	2020
QLD CSG – Other	2020
Bass	2022
Camden	2023
Casino, Henry and Netherby	2024
QLD CSG – Arrow	2025
Halladale/Black Watch/Speculant	2026
Otway Gas Project	2026
Gippsland including Turrum and Kipper	2028
Cooper Eromanga	2029

Depletion of 2P developed reserves within Queensland CSG fields is forecast between 2019 and 2020 (2025 for Arrow reserves). This projection is based on the GSOO model preferencing developed over undeveloped 2P reserves, due to the relative cost of supply. In reality, wells yet to be drilled are expected to commence production before existing wells are depleted. This would extend the final year of production of 2P developed reserves beyond the projected timeline shown in Table 3, but it would also rely on new wells being drilled before 2019.

Production is forecast to cease at the Camden, Casino Henry Netherby, Halladale/Black Watch/Speculant, Minerva and (conventional) Otway fields by the dates in Table 3. There are no further identified reserves or resources to be produced from these fields.

Moranbah 2P developed reserves are projected to be sufficient to meet forecast Townsville and Moranbah demand throughout the entire 20-year outlook. All other 2P developed reserves fully deplete by 2029.



Most of the gas supply is projected to be produced from conventional gas sources and coal seam gas (CSG). Over the 20-year outlook, the 2016 GSOO forecasts that 30,616 PJ of CSG reserves and resources, 9,162 PJ of conventional gas, and 11 PJ of unconventional gas (from 2027) will be required to meet forecast demand.

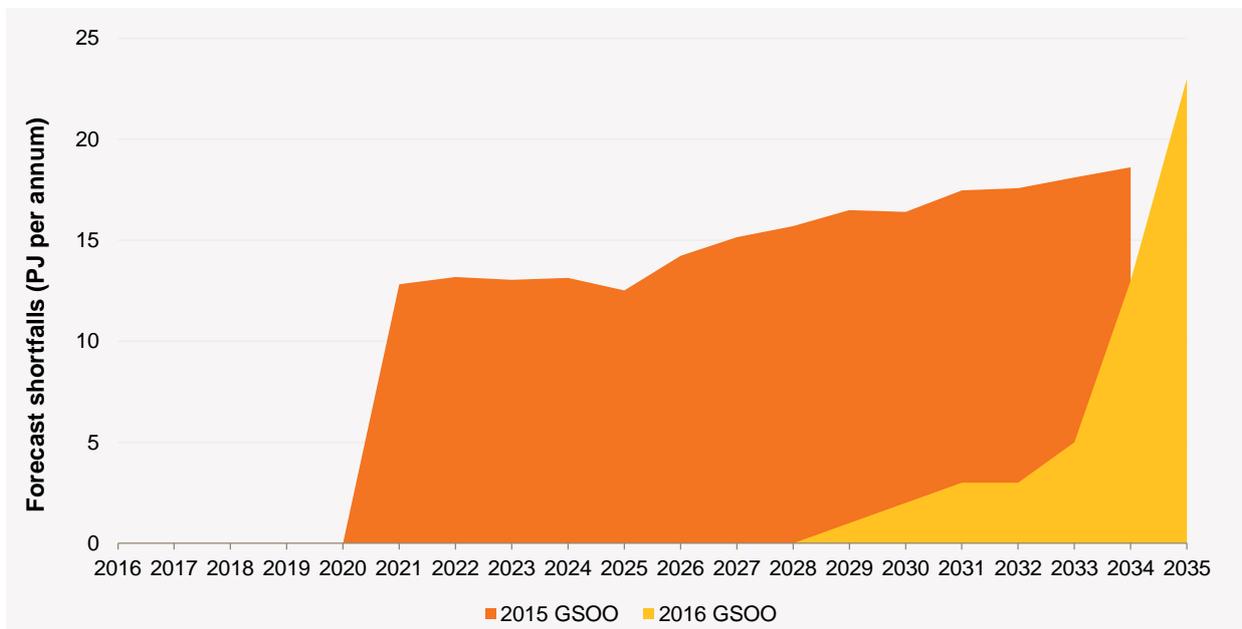
2.2.3 Shortfalls due to infrastructure constraints

Gas supply shortfalls totalling 50 PJ are forecast between 2029 and 2035, compared to the 214 PJ shortfalls forecast between 2021 and 2034 in the 2015 GSOO. All shortfalls forecast in both the 2015 GSOO and 2016 GSOO relate to domestic markets only. Figure 6 compares the magnitude and timing of the shortfalls forecast in the 2015 GSOO and 2016 GSOO.

These 2016 GSOO gas supply shortfalls:

- Account for 1.16% of forecast domestic annual consumption between 2029 and 2035.
- Are due to constraints on gas transmission and processing infrastructure (discussed in Section 2.3.1).

Figure 6 Total forecast shortfalls between 2015 and 2035 – 2016 GSOO compared to 2015 GSOO



The lower shortfall in the 2016 GSOO, compared to the 2015 GSOO, is largely driven by the 585 TJ/d net increase in processing capacity across eastern and south-eastern Australia over the 20-year outlook period. This net processing capacity increase is based on industry advice, and has aggregated many different processing capacity changes.



2.3 Regional adequacy

The following summarises the key demand and supply drivers in each state, and the impact on supply adequacy. The demand drivers are explained in more detail in the 2015 NGFR.

2.3.1 Queensland

Queensland forecast annual gas consumption is dominated by the LNG export sector:

- Gas consumption for LNG export is forecast to grow at an average annual rate of 32.5% to 2020, then to plateau and remain flat to the end of the 20-year outlook period.
- Outside of the LNG sector, Queensland domestic demand is forecast to increase after 2020. This is driven by forecast higher GPG consumption to meet electricity consumption growth in the region and cover coal-fired generation retirements in other states. Over the long term, further growth in the industrial sector is also forecast.

The only supply shortfalls forecast by the 2016 GSOO are observed in Queensland. These projected shortfalls are due to forecast daily demand for GPG in Townsville, and industrial demand in Moranbah and Gladstone, increasing above processing and supplying pipeline capacities.

Across 2035, the Queensland Gas Pipeline (QGP) is forecast to flow at full capacity (151 TJ/d) for 231 days. Similarly, the processing facility at Moranbah is forecast to operate at full capacity (68 TJ/d) almost every day.

Shortfalls could be alleviated by augmenting the following infrastructure facilities:

- Expanding the Queensland Gas Pipeline (QGP) by at least 7 TJ/d.
- Expanding the Northern Queensland Gas Pipeline (NQGP) by at least 43 TJ/d.
- Increasing the processing facility at Moranbah by at least 103 TJ/d.

Given the significant increase in shortfalls forecast to occur from 2034 is directly related to new GPG projected to be installed in northern Queensland to support electricity demand at this time, alternative generation technologies to meet this demand in northern Queensland could also help alleviate the projected gas supply shortfalls.

2.3.2 New South Wales

Annual gas consumption in New South Wales is forecast to increase by nearly 17% between 2015 and 2035 (from 137.8 PJ to 160.9 PJ):

- Smithfield, a gas-fired generator, has announced plans to withdraw from the NEM in 2018, leading to a projected reduction in gas demand in the short term.
- Liddell, a coal-fired generator, has announced retirement in 2022, leading to projected increased GPG gas consumption to support the electricity market, with continuing opportunities for new GPG development to meet increasing electricity demand.
- Industrial consumption is forecast to increase over this time.

On the supply side, on 4 February 2016, AGL announced⁶ it would not proceed with its proposed Gloucester Gas Project, and production at the Camden Gas Project would cease in 2023. This information has been incorporated into the 2016 GSOO. Currently, New South Wales is 95% reliant on imports from other regions to satisfy demand for gas within the state. Production from Camden currently contributes around 5 PJ each year. Once production ceases at Camden from 2023, New South Wales will be completely reliant on imported gas to meet demand.

Despite the projected rising demand and limited local production, no supply shortfalls are forecast for New South Wales under the medium scenario.

⁶ AGL. "Review of gas assets and exit of gas exploration and production", 4 February 2016. Available at: <https://www.agl.com.au/about-agl/media-centre/article-list/2016/february/review-of-gas-assets-and-exit-of-gas-exploration-and-production>.



The state's projected reliance on imports is forecast to increase utilisation of the EGP and, to a lesser extent, the VNI. For example, in 2035, to deliver gas to New South Wales, the EGP is forecast to reach full capacity for 212 days of the year, while the VNI would be fully utilised for 32 days of the year. The MSP is not projected to reach full capacity for any day in 2035, as Cooper Basin production would be prioritised for LNG export demand. The remaining supply would be available to meet Sydney demand via the MSP.

2.3.3 Victoria

Annual gas consumption in Victoria is forecast to increase by only 1% between 2015 and 2035:

- An initial decrease in GPG consumption is forecast, due to an expected rise in gas prices.
- A recovery in GPG consumption is projected in the long term, as electricity demand increases and coal generators in neighbouring regions retire.

No supply shortfalls are forecast for Victoria over the 20-year outlook under the medium scenario.

The GSOO is a long term forecast and does not take into account day-to-day operational constraints – this is considered further in the *2016 Victorian Gas Planning Report Update (VGPR Update)*.⁷ While the 2016 VGPR Update identifies two specific constraints that will need to be addressed to manage localised security and reliability issues, it projects that there is sufficient overall system capacity to meet forecast demand. Consult the VGPR Update for more information regarding the two constraints.

2.3.4 South Australia

Annual gas consumption in South Australia is forecast to increase by 2% between 2015 and 2035:

- An initial reduction in consumption is forecast, following an expected increase in gas prices.
- A later recovery in gas consumption across each of the industrial, residential and commercial sectors is projected, in line with population growth.
- The retirement of Northern coal-fired power station in March 2016 drives additional forecast GPG requirements over the long term, even though new wind farms are forecast to be able to meet electricity demand in the short term.

No supply shortfalls are forecast for South Australia over the 20-year outlook period under the medium scenario.

During times of peak demand in South Australia, key transmission pipelines regularly reach 100% daily utilisation. Throughout 2035, the South East Australia Gas (SEA Gas) Pipeline is forecast to reach full capacity (314 TJ/d) on 39 days, while the Moomba to Adelaide Pipeline System (MAPS) is forecast to reach full capacity (241 TJ/d) on 13 days.

⁷ AEMO. *2016 Victorian Gas Planning Report Update*.
Available at: <http://www.aemo.com.au/Gas/Planning/Victorian-Gas-Planning>.



2.3.5 Tasmania

Annual gas consumption is forecast to increase by 5% in Tasmania between 2015 and 2035:

- This is driven by forecast growth in the residential, commercial and industrial sectors.
- GPG consumption is projected to decline to near zero after the announced retirement of Bell Bay Three peaking gas plants and assuming the Tamar Valley combined cycle gas turbine (CCGT) plant is retired. For the 2015 NGFR, installed hydro-electric capacity combined with imports from Victoria were forecast to be sufficient to meet electricity needs.

The 2016 GSOO analysis does not consider the impact of the Basslink interconnector outage⁸ between Victoria and Tasmania, or the return to service of the Tamar Valley CCGT. This gas-fired CCGT is replacing electricity supply previously available over Basslink, and may continue generating once the Basslink interconnector has been repaired, to help replenish hydro storage levels.

AEMO estimates that there is sufficient gas to supply Tasmania during this Basslink outage, as discussed in the *Energy Adequacy Assessment*.⁹ The return to service of the Tamar Valley CCGT is not expected to be material to Tasmania's gas supply adequacy in the long term.

⁸ Basslink. "Basslink Interconnector Outage", 22 December 2015. Available at: <http://www.basslink.com.au/2015/12/22/basslink-interconnector-outage/>.

⁹ AEMO. *Energy Adequacy Assessment – Basslink Outage*, January 2016. Available at: <http://aemo.com.au/AEMO%20Home/Electricity/Resources/Reports%20and%20Documents/EAAP>.



CHAPTER 3. GSOO UNCERTAINTIES

Changes in economic conditions, global oil prices, and weather events are increasing gas market volatility. The medium scenario is AEMO’s best guess at the future based on current information available, but includes supply and demand input assumptions that may be highly uncertain.

This chapter discusses some of these uncertainties. Sensitivity analysis has been conducted around the medium scenario to test the impact of these factors on the supply adequacy assessment. The scenarios and sensitivities are described in Section 3.5. The results of the scenario and sensitivity analysis are discussed in Chapter 4.

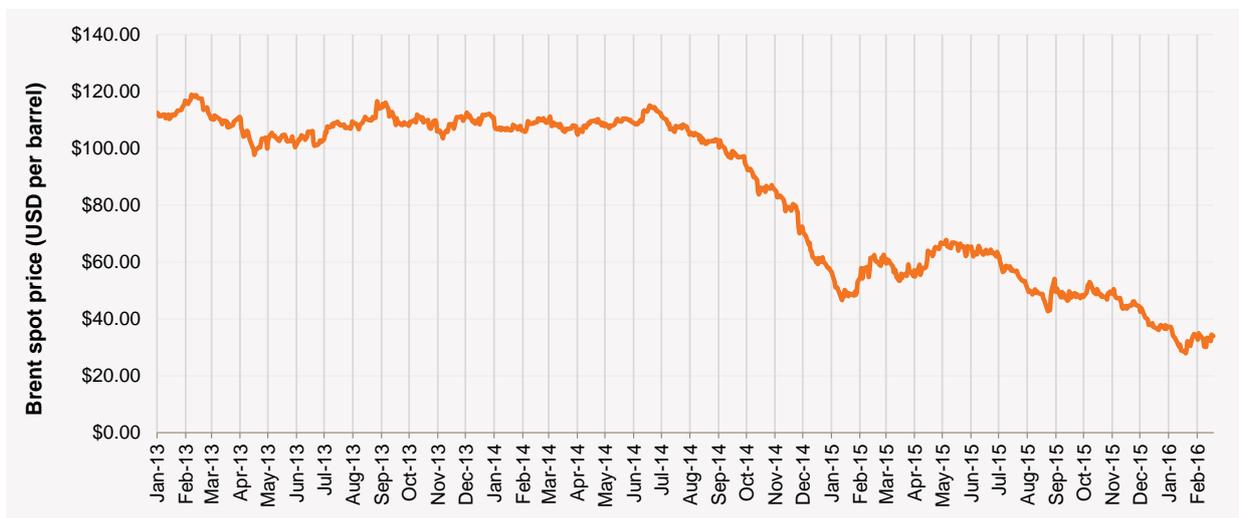
3.1 The effect of oil price dynamics on east coast development

The start of LNG exports from Queensland in January 2015 has continued a transformation of Australia’s gas industry, as international demand for Australia’s gas puts the industry on a pathway to more than double total consumption in eastern and south-eastern Australia by 2020 (compared to aggregate gas consumption in 2014, before the Queensland projects began).

The 2015 NGFR noted that, while LNG sale contracts are negotiated confidentially, contracts are understood to be linked to the price of Japanese customs-cleared crude oil. This price reflects the average price of crude oil imported into Japan, and in turn is highly correlated with the lagged price of Brent oil.¹⁰ Since 2014, Brent oil prices have dropped (see Figure 7) from \$111.87 per barrel in June 2014 to just \$30.89 per barrel in January 2016.

This drop in oil price may impact the revenues and capital budgets of LNG projects and domestic oil and gas producers in eastern and south-eastern Australia. Weakening LNG spot prices may also lead to pressure from Asian LNG customers to re-negotiate contracts with Curtis Island LNG exporters.

Figure 7 Historic oil prices (Brent spot price)



AEMO’s 2015 NGFR demand scenarios capture potential changes in LNG contract volumes:

- The low demand scenario examines the effect if LNG consumption was reduced to take-or-pay contract levels, estimated to be 85% of demand in the medium scenario.

¹⁰ <http://www.rba.gov.au/publications/bulletin/2015/mar/pdf/bu-0315-4.pdf>.



- The high demand scenario includes a seventh LNG train (dependent on the development of Arrow's gas reserves), in addition to assuming current operations deliver at 110% of the medium scenario, in recognition of potential for efficiencies in production and delivery.

3.2 Government policy and market reform

Australia has committed to reducing greenhouse gas emissions by between 26% and 28% below 2005 levels by 2030¹¹, and state governments are targeting increasing levels of renewable generation, although the instruments to achieve these targets are yet to be determined.

The 2015 NGFR and 2016 GSOO make no assumptions about how this abatement target will impact electricity or gas markets in Australia. Only existing climate change policy mechanisms have been modelled, such as the Large-scale Renewable Energy Target. Until the path is clearer, there will be continuing demand uncertainty in the electricity and gas markets, particularly around the impact on levels of GPG gas consumption.

The current gas market reform and jurisdictional policy developments could influence gas prices and may therefore impact on gas demand growth, particularly in the industrial sectors. A significant drop in gas prices would likely drive increased industrial growth and therefore consumption, while continued increasing prices may lead to further industrial closures.

Outside of Queensland, government policy and community sentiment has the potential to create uncertainty around further CSG development.

3.3 Weather conditions

Residential and GPG gas consumption is strongly weather-dependent. Electricity demand often peaks in the summer with more air-conditioner usage, while residential gas demand often peaks in the winter as heating requirements grow. Changes in the weather pattern in both the short and long term may have a dramatic impact on gas consumption behaviour.

In particular, El Niño is part of a natural cycle known as the El Niño–Southern Oscillation (ENSO), and is associated with a sustained period of warming in the central and eastern tropical Pacific. The ENSO cycle operates over timescales from one to eight years.

One potential impact of an El Niño is limited rainfall (nine of the ten driest winter–spring periods on record for eastern Australia occurred during El Niño years, although widespread drought does not occur with every event).¹²

If El Niño drought conditions persisted, hydro storage levels would continue to deplete, resulting in lower levels of hydro-electric generation available to supply the electricity market. Other types of electricity generation, including GPG, would be required to supply the difference.

3.4 Field development

To meet gas consumption forecasts in the medium scenario, field development is required to progress within the forecast timelines. The domestic market is particularly reliant on more uncertain classifications of reserves and resources being available to meet demand.

AEMO has assumed commercial viability of all contingent and prospective resources as they mature and migrate to production, but recognises there is technical and commercial uncertainty associated with development of these resources. Reducing this uncertainty requires timely development of the underlying resource at a time when low oil prices are impacting revenue streams and capital budgets.

Projected unfavourable economic conditions, including low oil prices, are likely to lead to reserve write-downs and a reclassification of reserves and resources. This would accelerate the depletion of 2P

¹¹ From the 21st Conference of the Parties for the United Nations Framework Convention on Climate Change.

¹² Bureau of Meteorology Australia. <http://www.bom.gov.au/climate/updates/articles/a008-el-nino-and-australia.shtml>.



reserves and increase the need for additional contingent resources to be developed to meet forecast demand.

Proposed projects to source additional supply via the Northern Gas Pipeline (NGP) and from Narrabri in New South Wales are of interest to the gas industry and may open new fields to supply the eastern and south-eastern Australian gas markets.

3.5 Scenarios and sensitivities to address uncertainties

Given the uncertainties discussed in this chapter, AEMO has chosen to study additional scenarios and sensitivities. The scenarios and sensitivities studied for the 2016 GSOO are described in Table 4 below. The range of modelling outcomes is summarised in Chapter 4.

Table 4 2016 GSOO scenario and sensitivity descriptions

Scenario/Sensitivity	Demand	Additional details
Medium	NGFR Medium	
High	NGFR High	LNG pipelines expanded to allow for full LNG demand quantities to be delivered to Curtis Island. Field maximum annual production constraints removed.
Low	NGFR Low	
High domestic demand with medium LNG export demand	NGFR High domestic demand with medium LNG export demand	Field maximum annual production constraints removed.
Reduction in capital expenditure	NGFR Medium	A reduced drilling program in LNG acreage assumed to result in production decreases (down 15% from medium scenario) from 2018–23, and a two-year delay in bringing new non-LNG fields online until 2023.
El Niño drought event	NGFR Medium, with adjustments to GPG projections	GPG demand updated to reflect projected electricity market impacts of a five-year drought event.
Additional Supply – Northern Gas Pipeline	NGFR Medium	Inclusion of NGP and supply source of assumed capacity 200 TJ/d from mid-2018.
Additional supply – Narrabri	NGFR Medium	Narrabri production available from January 2019 at 100 TJ/d.

High and low GSOO scenarios

The high and low scenarios provide an assessment of the supply-demand adequacy under the NGFR’s high and low demand conditions.

Under the high scenario, AEMO has assumed that:

- Wholesale gas supply contracts will be in place to meet the higher forecast demand.
- Development will occur to relieve any maximum field production limits that currently constrain annual field production under the medium scenario.

High domestic demand with medium LNG export demand

The high domestic demand with medium LNG export demand sensitivity examined what would arise if:

- Domestic demand was high, including increased GPG consumption (whether driven by further carbon policy or electricity consumption growth) and increased total gas demand as a result of a reduction in gas prices.
- International economic conditions remained unfavourable for high LNG demand.



Reduction in capital expenditure

This sensitivity assumed reduced capital expenditure in the gas industry and tested the robustness of the medium scenario if field development did not meet model assumptions. To study the impact of the economics of field development being less favourable, for any reason, this sensitivity assumed:

- A reduced drilling program for CSG wells for the LNG projects – assumed to be 85% of the production capacities used in the medium scenario – between 2018 and 2023.
- That non-LNG fields, forecast to start producing prior to 2023, would be delayed two years.

El Niño drought event

An El Niño drought event was studied to assess gas supply adequacy should drought conditions continue. This sensitivity replaces the NGFR medium scenario GPG demand and consumption forecasts with the GPG forecast under a five-year El Niño drought event.

AEMO's electricity model was used to test the impact of a prolonged drought on GPG demand, assuming:

- Declining water availability for hydro-electric generators, lasting for five years (from 1 January 2016 to 31 December 2020).
- Negligible impact of drought on thermal generation availability. While water is necessary for the cooling processes when operating a thermal generator, it was assumed that water from desalination plants could be used during drought conditions.

Additional supply – Northern Gas Pipeline

The Northern Territory (NT) Government announced on 17 November 2015¹³ that Jemena Northern Gas Pipeline Pty Ltd had been selected to construct and operate the NGP. The pipeline is planned to run for 622 kilometres between Tennant Creek in the Northern Territory and Mount Isa in Queensland, to connect NT gas to eastern gas markets.

Specifications for the NGP and potential sources of supply are scarce, due to the infancy of the project. As a sensitivity to the medium scenario, AEMO has therefore assumed that:

- NGP becomes operational from July 2018.
- NGP has a pipeline/production capacity of 200 TJ/d plus an interconnection at Mount Isa, with a corresponding upgrade of the Carpentaria Gas Pipeline, leading to a reverse-direction flow of 200 TJ/d capacity.

Additional supply – Narrabri

The impact of additional supply in New South Wales from Narrabri has been studied as a sensitivity to the medium scenario. It was assumed that the Narrabri project would be complete by 2019, with a maximum capacity of 100 TJ/d.

¹³ "NT announces Jemena to build gas pipeline to east coast", 17 November 2015. Available at: <http://newsroom.nt.gov.au/mediaRelease/16962>.



CHAPTER 4. SCENARIOS AND SENSITIVITIES

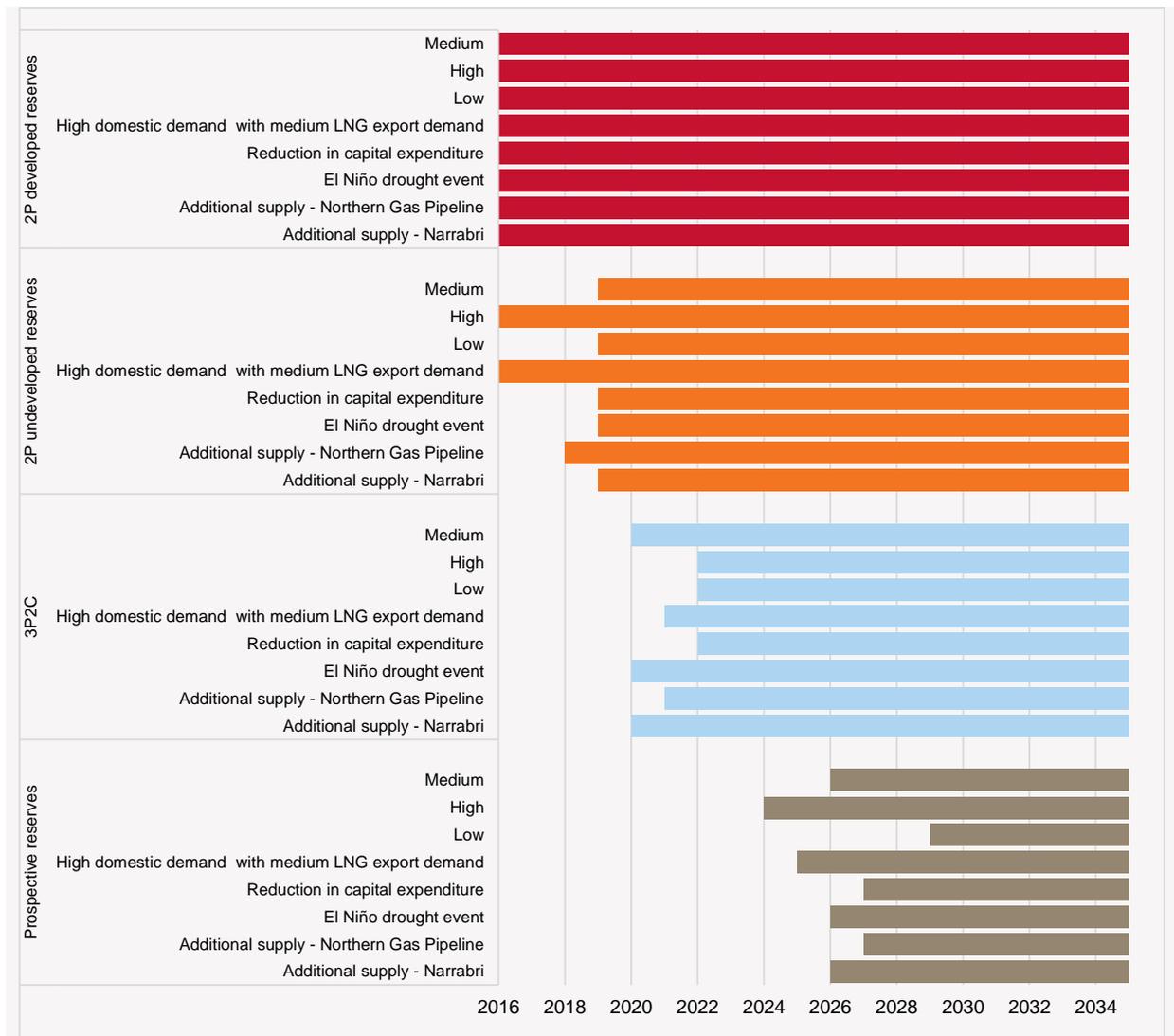
This section provides an overview of how the results of scenario and sensitivity modelling outlined in Section 3.5 differ from the medium scenario forecasts reported in Chapter 2. A full set of result data files can be accessed on the AEMO website.¹⁴

4.1 Field development

Figure 8 highlights when the GSOO forecasts the first gas flow for each category of reserve and resource, for all GSOO scenarios and sensitivities. Within each category of reserve and resource, there may be significant variation in the timing of when individual fields come online or deplete.

In aggregate, the 2P developed reserves are in production throughout the entire 20-year outlook, although by 2035, Moranbah is the only 2P developed reserve still in production.

Figure 8 First gas flow for each reserve and resource category by scenario and sensitivity



¹⁴ Available at: <http://aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/2016-GSOO-Supply-Demand-Modelling-Data-Files>.



The high scenario and high domestic demand with medium LNG export demand sensitivity require 2P undeveloped reserves to start producing before the end of 2016. This accelerated development schedule highlights the large volumes of gas required for the gas markets under high demand conditions. Should these demand forecasts eventuate, major development in reserves and resources will be required to reach forecast levels of supply.

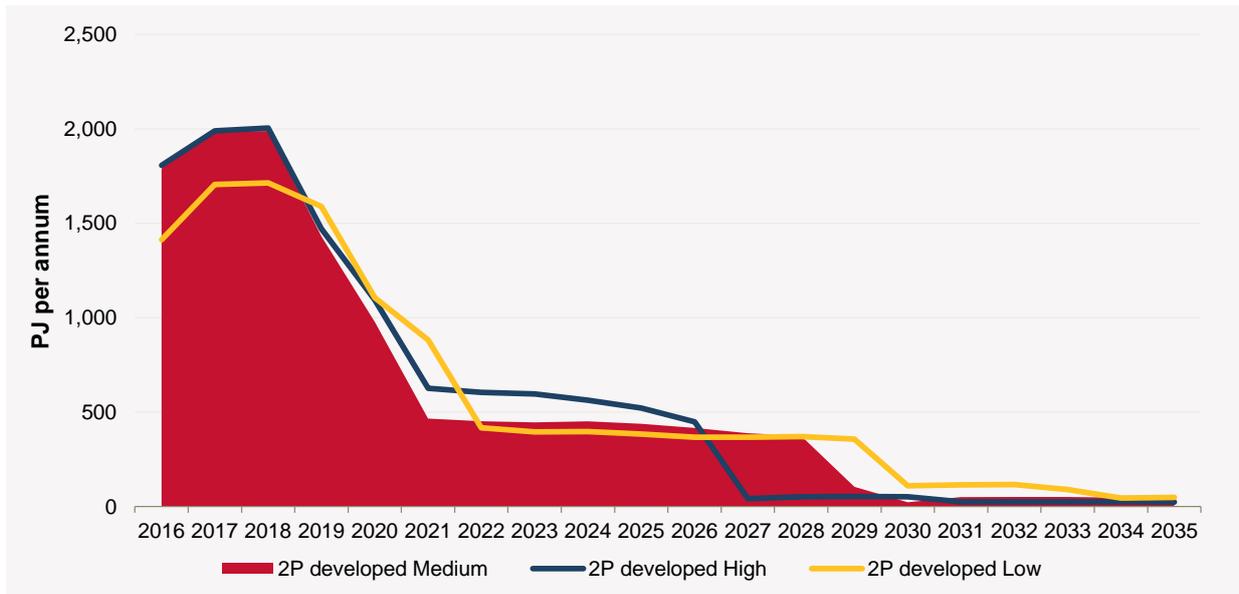
Under the high scenario, the final year of production for 2P developed gas in the Casino, Henry and Netherby, Longtom and Sole fields occurs four years earlier than forecast under the medium scenario, while the Cooper Eromanga, Surat, Bowen and Denison reserves deplete three years earlier.

A low scenario delays development of reserves and resources compared to the medium scenario. Specifically, the final year of production for the 2P developed reserves in most fields are forecast to occur one and two years later than in the medium scenario, with the Casino, Henry and Netherby field forecast to stop producing four years later.

The additional supply – Northern Gas Pipeline sensitivity introduces a new gas supply from the Northern Territory, assumed to be 2P undeveloped reserves, to come online from mid-2018. This sensitivity shows the new Tennant Creek production displacing gas previously supplied from southern basins. In particular, the year of final production of 2P developed gas in the Cooper Eromanga field is forecast to occur three years later than in the medium scenario.

The 2P developed reserve production profile changes between the high, medium and low scenario (see Figure 9). Production of undeveloped reserves is delayed under the low scenario, while it is accelerated under the high scenario.

Figure 9 2P developed reserves production – high, medium and low scenarios

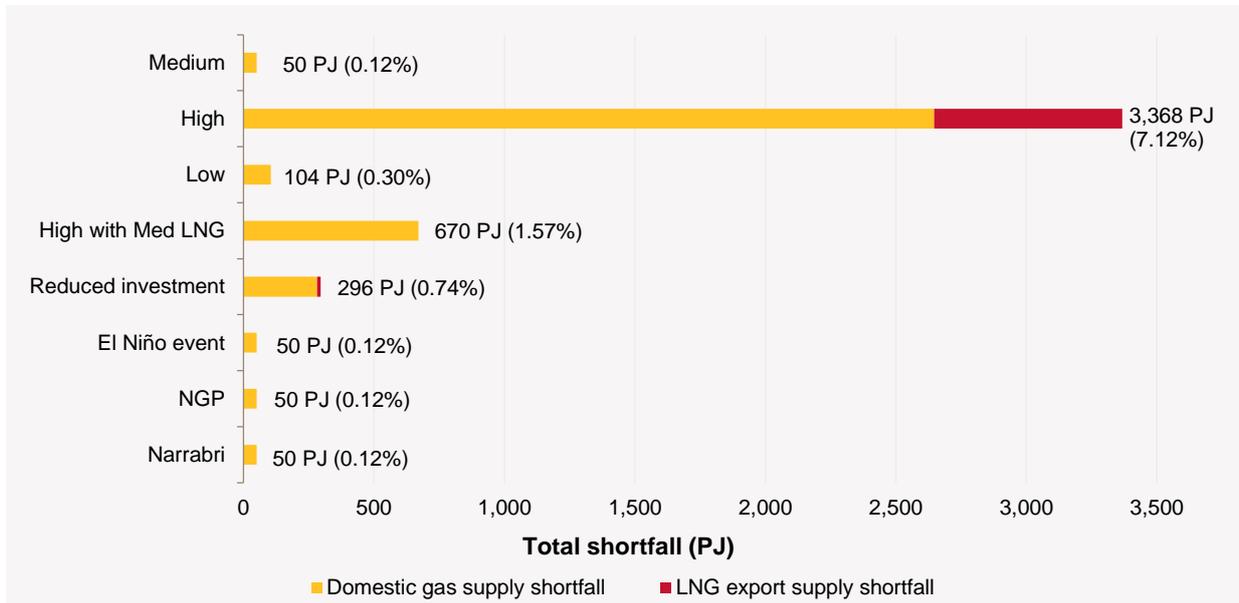




4.2 Comparison of shortfalls

Figure 10 shows the shortfalls observed under all scenarios and sensitivities.

Figure 10 Total shortfalls under all scenarios and sensitivities (PJ)



High scenario

In the high scenario, over 95% of the projected shortfalls occur concurrently with the seventh LNG train coming online from 2026. Forecast gas supply shortfalls totalling 3,368 PJ account for 7% of total forecast demand being unmet in the outlook period, and 12% of total demand in 2026–35. Shortfalls are observed across Queensland (3,057 PJ), New South Wales (250 PJ), and South Australia (61 PJ).

Projected shortfalls in the high scenario are driven by insufficient processing capacity:

- During times of shortfall in Queensland, all processing capacity in the state is operating at 100% capacity, and the South West Queensland Pipeline (SWQP), the only transport route for delivering gas from fields in southern states to Queensland, is also operating at maximum capacity.
- During times of shortfall in Adelaide, the majority of gas processed from Moomba is sent towards Queensland along the SWQP, and there is insufficient remaining gas to meet Adelaide demand via the MAPS. The SEA Gas pipeline is utilised at 100% capacity, delivering gas from Victoria to Adelaide.
- During times of Sydney shortfall, the EGP and VNI flow at 100% capacity, although the MSP utilisation is minimal, due to limited gas availability from Moomba. By the end of the outlook period, Newcastle storage has been depleted, and will not be sufficiently replenished for utilisation during periods of peak demand. Any unutilised gas supply on low demand days is forecast to be sent to Queensland via the reverse direction of the MSP, rather than injected into Newcastle storage.

Potential options to alleviate projected shortfalls could include an increase in processing capacity, both in Queensland and the southern basins, in conjunction with an upgrade of the major transmission pipelines (SWQP, EGP, VNI, and SEA Gas).

Construction of a seventh LNG train is unlikely to proceed without associated new supply capacity.



Low scenario

While the total demand under the low scenario is lower than in the medium scenario, forecast GPG demand is higher in some locations, particularly in Queensland. This leads to double the shortfalls projected under the medium scenario.

All shortfalls observed under this scenario are in Townsville, as gas transmission and processing infrastructure constraints prevent supply delivery for GPG. There is sufficient gas supply in the Moranbah gas field to meet the forecast demand, if the maximum capacity of the Moranbah processing facility is increased by 45 TJ/d.

High domestic demand with medium LNG export sensitivity

In the high domestic demand with medium LNG export demand sensitivity, domestic supply shortfalls are forecast in Adelaide, Sydney and Queensland.

Total shortfalls in Queensland are 616 PJ, observed between 2021 and 2035. Adelaide shortfalls are observed from 2031 to 2035, (a total of 0.5 PJ), and Sydney shortfalls are forecast from 2033 to 2035 (a total of 53 PJ).

These forecast shortfalls are driven by increased domestic demand, including new GPG capacity installed in New South Wales, South Australia and Victoria over this time.

Reduction in capital expenditure sensitivity

The reduction in capital expenditure sensitivity forecasts 296 PJ shortfalls across the 20-year outlook, 246 PJ higher than in the medium scenario, driven by a lack of production availability.

AEMO considers this an extreme sensitivity, but one that highlights the risks if, for any reason, field development or well drilling programs do not meet assumptions.

El Niño drought event sensitivity

There are no changes to shortfalls under the El Niño drought event sensitivity, despite a 5% increase in GPG consumption compared to the medium scenario over the next five years.

The analysis indicates gas supply adequacy is not sensitive to an assumed prolonged five-year drought.

Additional supply sensitivities

Neither the Northern Gas Pipeline (NGP) nor the Narrabri additional supply sensitivities reduced the shortfalls observed under the medium scenario, because the infrastructure constraints driving the shortfalls in the medium scenario continue to constrain under these additional supply sensitivities.

In both cases, the projects would increase supply options for the domestic market and alter pipeline flow patterns.

The new gas flow from Tennant Creek along the NGP would displace production previously supplied from the Cooper Eromanga basin, which in turn would be available as an additional supply source for the southern states. This reduces reliance on Gippsland and Minerva gas projects and delays depletion of these fields by one year.

New South Wales currently relies heavily on imports to satisfy local demand. In the medium scenario, once Camden ceases production in 2023, New South Wales is dependent on gas imports from other states to meet all its demand. The projected introduction of Narrabri as an additional supply source within New South Wales would increase local production from the current 5% of demand up to 15% of forecast demand by 2035.



MEASURES AND ABBREVIATIONS

Units of measure

Abbreviation	Unit of measure
PJ	Petajoule
TJ	Terajoule
TJ/d	Terajoules per day

Abbreviations

Abbreviation	Expanded name
AEMO	Australian Energy Market Operator
APLNG	Australia Pacific LNG
CCGT	Combined cycle gas turbine
CSG	Coal Seam Gas
EGP	Eastern Gas Pipeline
ENSO	El Niño – Southern Oscillation
GBB	Gas Bulletin Board
GLNG	Gladstone LNG
GPG	Gas-powered generation
GSOO	Gas Statement of Opportunities
LNG	Liquefied natural gas
MAPS	Moomba to Adelaide Pipeline System
MSP	Moomba to Sydney Pipeline
NEM	National Electricity Market
NGFR	National Gas Forecasting Report
NGP	Northern Gas Pipeline
NQGP	North Queensland Gas Pipeline
NSW	New South Wales
NT	Northern Territory
PRMS	Petroleum Resources Management System
QCLNG	Queensland Curtis LNG
QGP	Queensland Gas Pipeline
QLD	Queensland
SEA Gas	South East Australia Gas Pipeline
SWP	South West Pipeline
SWQP	South West Queensland Pipeline
VGPR	Victorian Gas Planning Report
VNI	Victoria – New South Wales Interconnect
WGP	Wallumbilla to Gladstone Pipeline



GLOSSARY

Definitions

These terms are used in the 2016 GSOO and/or the *2016 GSOO Methodology Document*.

Term	Definition
1C contingent resources	Low estimate of contingent resources, considered less commercially viable than reserves.
2C contingent resources	Best estimate of contingent resources, considered less commercially viable than reserves.
3C contingent resources	High estimate of contingent resources, considered less commercially viable than reserves.
1P reserves	A low-side estimate of quantities of gas that are reasonably certain to be recoverable in future under existing economic and operating conditions. Also known as proved gas reserves.
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.
3P reserves	The sum of proved, probable, and possible estimates of gas reserves.
3P2C	A combined category, consisting of only the possible reserves – those incremental to the 2P reserves – and the 2C resources.
annual consumption	Gas consumption reported for a given year.
demand	Capacity or gas flow on an hourly or daily basis.
Gas Bulletin Board (GBB)	A website (www.gbb.aemo.com.au) managed by AEMO that provides information on major interconnected gas processing facilities, gas transmission pipelines, gas storage facilities, and demand centres in eastern and south-eastern Australia. Also known as the Natural Gas Services Bulletin Board or the Bulletin Board.
gas powered generation (GPG)	Where electricity is generated from gas turbines (combined cycle gas turbine (CCGT) or open cycle gas turbine (OCGT)).
lateral	A pipeline branch.
linepack	The pressurised volume of gas stored in the pipeline system. Linepack is essential for gas transportation through the pipeline network each day, and as a buffer for within-day balancing.
liquefied natural gas (LNG)	Natural gas that has been converted into liquid form for ease of storage or transport.
LNG train	A unit of gas purification and liquefaction facilities found in a liquefied natural gas plant.
peak day	The day maximum gas demand occurs over the course of a season (winter or summer).
possible reserves	Estimated quantities that have a chance of being discovered under favourable circumstances. 'Possible, proved, and probable' reserves added together make up 3P reserves.
probability of exceedance (POE)	Refers to the probability that a forecast electricity maximum demand figure will be exceeded. For example, a forecast 10% probability of exceedance (POE) maximum demand will, on average, be exceeded only 1 year in every 10.
probable reserves	Estimated quantities of gas that have a reasonable probability of being produced under existing economic and operating conditions. Proved and 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 resources	Estimated quantities of gas that are reasonably certain to be recoverable in future under existing economic and operating conditions. Also known as 1P reserves.
reservoir	In geology, a naturally occurring storage area that traps and holds oil and/or gas.
reserves	Gas resources that are considered to be commercially recoverable and have been approved or justified for commercial development.
resources	See contingent resources and prospective resources.
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.