GAS STATEMENT OF OPPORTUNITIES

FOR EASTERN AND SOUTH-EASTERN AUSTRALIA

Published: **March 2017**

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

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 31 December 2016, although AEMO has endeavoured to incorporate more recent information where practical.

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Version control

Version	Release date	Changes
1	9/3/2017	

EXECUTIVE SUMMARY

The 2017 *Gas Statement of Opportunities* (GSOO) highlights the increasing interdependencies of gas and electricity for reliable supply of energy, and the importance of planning across the entire energy supply chain to deliver energy security and maintain reliable supplies to consumers.

Gas-powered generation (GPG) is vital to continued security of electricity supply as the National Electricity Market (NEM) transitions to lower emission targets. A reliable supply of gas for GPG is critical, at a time when withdrawal of coal-fired generation in the NEM is increasing reliance on GPG to maintain reliable and secure electricity supply and meet emissions target reductions.

Key points in the 2017 GSOO are that:

- **Declining gas production may result in insufficient gas to meet projected demand by GPG for supply of electricity from summer 2018–19.**
  - To meet electricity supply needs, the NEM requires either increases in gas production to fuel GPG, or a rapid implementation of alternative non-gas electricity generation sources. If neither occurs, AEMO projects that declining gas supplies could result in electricity supply shortfalls between 2019 and 2021 of approximately 80 gigawatt hours (GWh) to 363 GWh across South Australia, New South Wales, and Victoria.
- **Maintaining system security is becoming more challenging, increasing the risk of supply shortfalls in both gas and electricity markets.**
  - In Victoria, more gas needs to be transported from Longford to refill Iona Underground Storage (UGS) and avoid projected winter gas shortfalls from 2019, requiring expansion of the South West Pipeline (SWP) by the service provider. In the absence of this expansion, AEMO may need to interrupt gas supply, including to GPG.
  - GPG is required in the NEM to provide operational flexibility, by increasing and decreasing generation relatively quickly to meet changing demand when wind and solar generation is unavailable. The risk of short-term interruptions of electricity demand will increase when there is not enough GPG available to increase generation fast enough to meet demand.
  - South Australia now relies heavily on GPG to provide the minimal level of thermal generation the system needs to manage frequency changes. Otherwise, widespread outages may be experienced, should the region become separated from the rest of the NEM.
- **Market responses could alleviate the risk of forecast gas or electricity shortfalls.**
  - Increases in gas production from existing fields, additional supplies from the Northern Territory gas fields via the Northern Gas Pipeline (NGP), or re-direction of gas earmarked for liquefied natural gas (LNG) export, would help reduce short-term gas supply risks.
  - Alternatives to GPG (such as other forms of generation, and storage) could reduce demand for gas while meeting demand for electricity.
  - Exploration and development of new gas fields would increase supply in the longer term.
- **Continued upward pressure on gas and electricity prices may threaten the financial viability of some commercial and industrial customers.**
  - New gas supplies will help improve the reliability and security of energy markets, but, given rising gas production costs, are unlikely to provide much relief for businesses at risk from high energy prices, potentially leading to closures.

Export and domestic demand and supply

Gas for LNG exports is projected to continue dominating gas demand and supply in eastern and south-eastern Australia to 2036. Over the past year, all six Queensland LNG trains started production, with around 1,290 petajoules a year (PJ/a) of gas now flowing to the plants on Curtis Island for conversion to LNG for export. This is forecast to increase to 1,430 PJ/a by 2020.

This large LNG export demand is changing the dynamics of the east coast gas markets. The smaller domestic gas sector is now linked to a more volatile world market for gas, and the size of LNG exports means small gas supply chain disruptions can have large impacts on domestic gas supply and demand in eastern and south-eastern Australia.

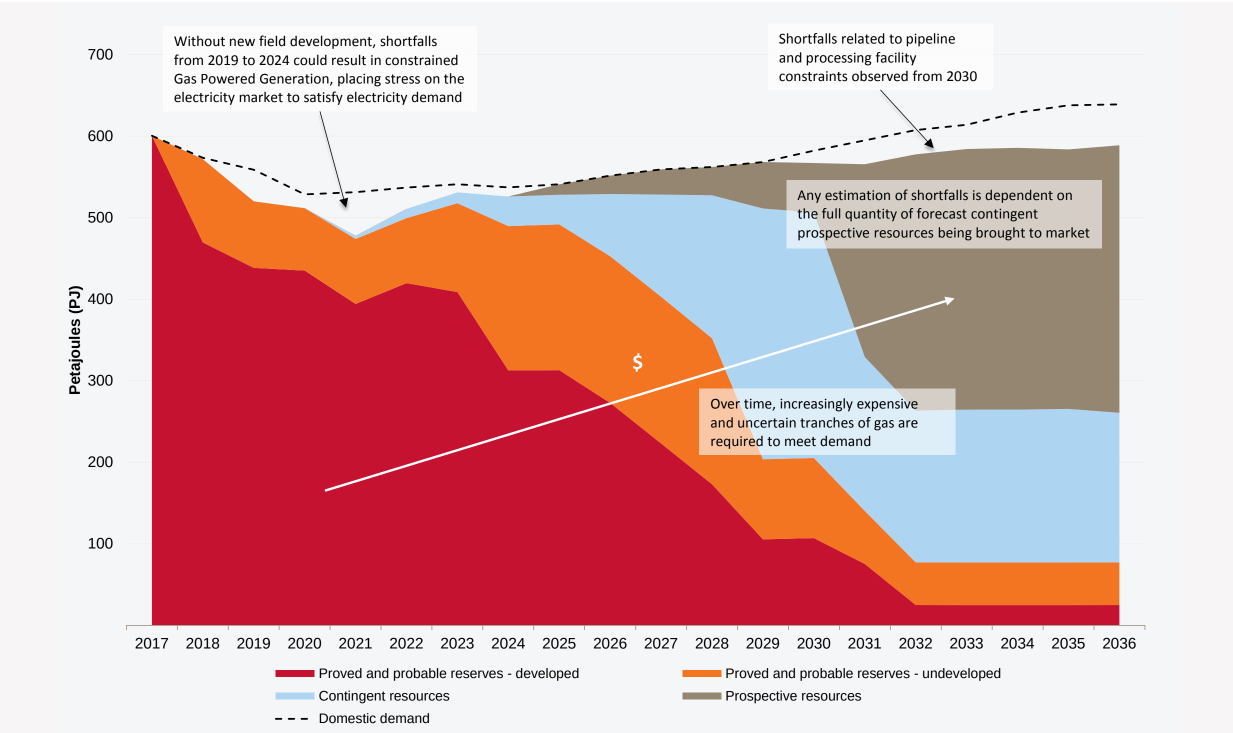
Short-term need for additional domestic gas supply

Based on sales commitments under long-term contracts with international customers, AEMO's modelling assumes that LNG demand will be satisfied and that any gas shortfalls would impact supply to domestic market sectors – industrial, commercial, and residential customers, and GPG.

AEMO's analysis highlights that these domestic gas markets will rely on production from currently uneconomic and undeveloped gas resources (contingent resources) from 2021, and even more uncertain resources (prospective resources) from 2025, to meet forecast demand over the 20-year outlook period.

Figure 1 shows forecast gas demand and production from these developed and less certain reserves and resources. This forecast is for domestic gas markets only, excluding export LNG, under the GSOO Neutral scenario.[1] Forecast demand is from the 2016 *National Gas Forecasting Report* (NGFR).[2]

Figure 1 Eastern and south-eastern Australia domestic gas production (excluding LNG), 2017−36[A]



A For a definition of the terms proved and probable reserves, contingent resources, and prospective resources, see the Glossary.

[1] The Northern Gas Pipeline (NGP) is not included in the GSOO Neutral scenario due to uncertainty of gas supply volumes for this pipeline. The inclusion of the NGP has been studied as a sensitivity to the GSOO Neutral scenario.

[2] The 2016 NGFR and supporting material are available at: http://www.aemo.com.au/Gas/National-planning-and-forecasting/National-Gas-Forecasting-Report.

Based on advice from gas producers, overall gas production for the domestic market is projected to decline from 600 PJ in 2017 to 478 PJ in 2021, as seen in Figure 1. While some fields are forecasting increases in supply, production decline is most apparent in offshore Victoria, where production is forecast to reduce by 155 PJ (or 38%) over this period.

The decrease in gas supply could lead to domestic gas shortfalls of between 10 PJ/a and 54 PJ/a to 2024. Development of new fields will be required to meet forecast demand, although the rate of exploration and development oil and gas wells recently drilled in Australia has nearly halved.[3]

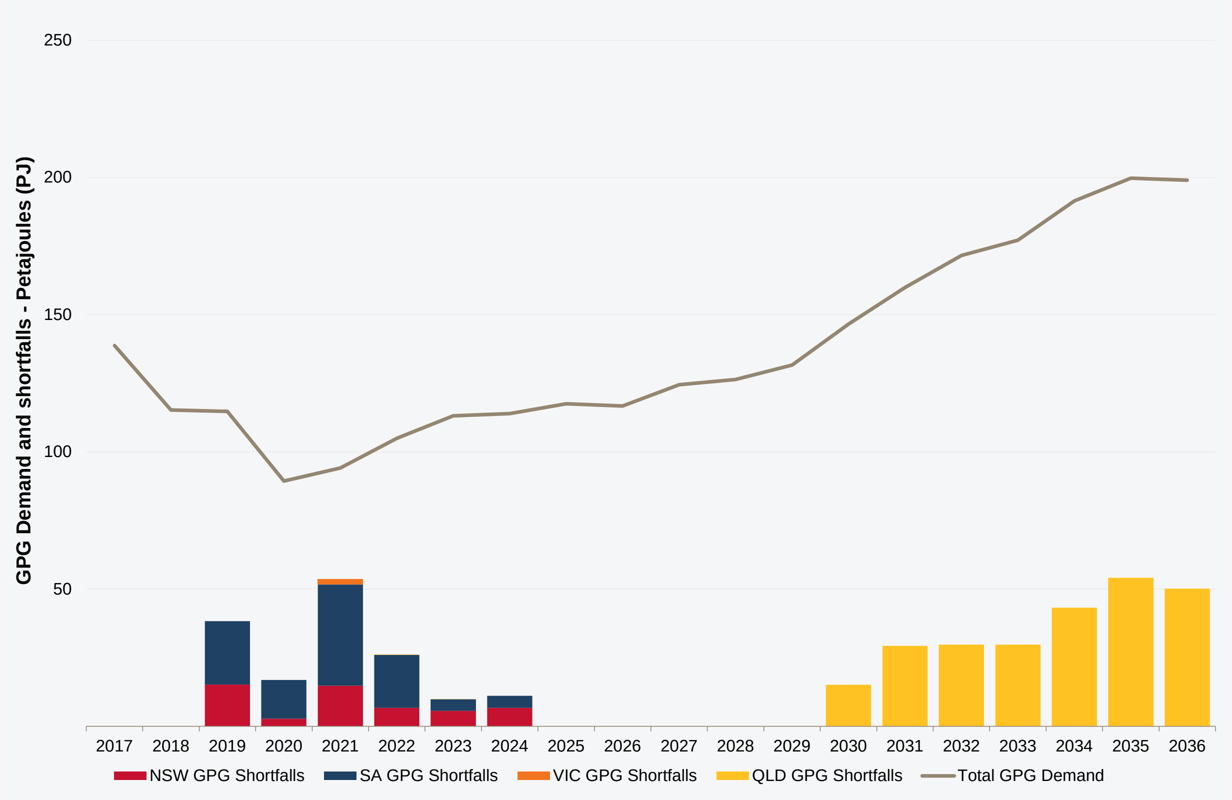
For the purposes of GSOO modelling, AEMO has assumed that all LNG demand will be met and that GPG will be a lower priority for gas supply. In its modelling, AEMO has assumed that, if gas was unavailable for electricity generation, another fuel type (such as coal-fired or hydroelectric generation) could be substituted – an assumption likely to be increasingly challenged as the electricity supply demand balance tightens.

Based on these assumptions, forecast gas shortfalls are all related to GPG supply, in:

- South Australia from 2019–24 (up to 37 PJ in 2021).
- New South Wales from 2019–24 (up to 15 PJ in 2019).
- Victoria in 2021 (2 PJ).
- Queensland in 2030–36 (up to 54 PJ in 2035).

Figure 2 highlights the total forecast gas demand for GPG (under a GSOO Neutral scenario, based on the NGFR), along with the timing and location of forecast gas shortfalls, over the 20-year outlook.

Figure 2 Projected shortfalls in GPG supply by region, 2017–36



[3] EnergyQuest. Media release, "Wells drilled in 2015 compared to wells drilled in 2014", March 2016.

Gas or electricity shortfalls?

The 2017 GSOO highlights a projected decline in gas production at a time when withdrawal of coal-fired generation in the NEM is increasing reliance on GPG to maintain reliable and secure electricity supply and meet emissions reduction targets.

AEMO forecasts that sufficient electricity generation alternatives, relying on fuel sources such as black coal, will be available to meet electricity demand until summer 2018–19.

This assumes that Pelican Point GPG in South Australia returns to full service as a market response to the retirement of Victoria's Hazelwood coal-fired generator in 2017, as discussed in AEMO's *2016 Electricity Statement of Opportunities* (ESOO) *Update*.[4] It also assumes that existing coal-fired generation in the NEM would be able to supply more electricity than it has in recent years.

From 2019 to 2024, unless new gas supplies or alternative electricity generation sources become available, AEMO projects that either:

- Shortfalls in supply of gas to GPG highlighted in Figure 2 will occur, resulting in average electricity supply shortfalls of between approximately 80 GWh and 363 GWh between 2019 and 2021[5], or
- Shortfalls in gas supply to residential, commercial, and/or industrial sectors of between 10 PJ/a and 54 PJ/a will occur.

These projections assume the addition of renewable generation currently projected to be developed to meet the Large-scale Renewable Energy Target (LRET).

AEMO projects that renewable generation, driven by the LRET and the Victorian Renewable Energy Target (VRET)[6], will reduce the annual gas requirement by GPG over the longer term, although GPG will still be required when wind or solar generation is not available.

From 2025, renewable generation from the second VRET auction is projected to reduce the risk of gas or electricity shortfalls – assuming contingent and prospective gas resources, currently uneconomic and uncertain, are developed as forecast.

From 2030, investment in the expansion of pipeline and plant capacities is required to support the increased forecast demand for gas:

- Shortfalls in north Queensland will require capacity expansion of the North Queensland Gas Pipeline and Moranbah processing facility.
- The location of the future field development will determine where additional pipeline and processing infrastructure investment is needed.

Challenges to energy security and reliability

To maintain energy security in the NEM as renewable generation is integrated, the system currently needs thermal (coal-fired and gas-fired) generation to provide inertia and manage the speed of frequency changes. Power systems with low inertia experience faster changes in system frequency after a disturbance, and fast frequency changes can lead to supply disruptions.

Currently, South Australia has only GPG and liquid-fuelled thermal generation to supply the needed inertia, which means maintaining the reliability of gas supply to South Australia is essential for energy security in the region. AEMO does not have the power to direct the flow of gas into or within South Australia to maintain and improve the reliability of gas supply, as it does in Victoria.

Outside of South Australia, if sufficient gas is not available across the NEM, the security of the energy system in the short term will largely depend on coal-fired generator performance.

[4] AEMO. 2016 ESOO Update. Available at: http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2016/update/2016-ESOO-Update---Hazelwood-Retirement.pdf.

[5] This equates to between 0.039% and 0.174% of electricity demand.

[6] AEMO acknowledges that other state governments have also announced aspirational renewable energy targets. These other state targets are not included in the GSOO demand forecasts, because the mechanisms applied to reach the targets are not yet defined. AEMO will incorporate other targets into future analysis as the mechanisms to achieve them are confirmed.

The flexibility of coal-fired generation to support intermittent renewable generation is limited compared to gas. Coal-fired generation is slower than GPG to increase and decrease its output when demand fluctuates as the availability of wind and solar generation changes. Less flexibility increases the challenge of managing the power system and maintaining reliability.

Victoria relies on Iona UGS to meet winter maximum gas demand. Failure to refill Iona UGS during summer 2018–19 may result in Victorian gas supply shortfalls during winter 2019 and beyond.

Declining gas production is increasing the requirement to use the SWP to refill Iona UGS, and this pipeline is capacity-constrained. With declining gas production at Port Campbell, there are no other viable options to supply gas to Iona UGS in the short term. GPG at Laverton North Power Station, which draws gas from the SWP, would further reduce the capability of the pipeline to refill Iona UGS.

An inability to refill Iona UGS may also constrain the supply of gas to South Australia via the SEA Gas Pipeline for GPG use in electricity supply in South Australia. GPG at Mortlake Power Station also reduces delivery of gas to South Australia via the SEA Gas Pipeline.

An expansion by the service provider of the SWP capacity towards Port Campbell is required to ensure Iona UGS is refilled prior to winter 2019. AEMO's *2017 Victorian Gas Planning Report* (VGPR)[7] analyses this issue in more detail.

AEMO has identified the inability to refill Iona UGS before winter as a threat to the security of the Victorian gas system. While AEMO can take short-term operational measures to attempt to reduce this threat, including controlled interruption of gas demand, ultimately those measures are limited by the available supply of gas and transportation capacity. AEMO does not have the power to direct the required investment in the SWP to occur and address the longer-term energy security risks.

Potential solutions to projected shortfalls

The GSOO informs market participants, policy-makers, and other stakeholders about projected supply demand challenges, to highlight opportunities for market responses that could deliver solutions.

Various market-led solutions may be available to alleviate forecast gas shortfalls, although some gas volumes would only be realised if moratoria currently in place were to change.

The most efficient solution, to meet price, quality, safety, reliability, and security of supply objectives in the long-term interest of gas consumers, is likely to involve a combination of options.

Possible options being considered by industry include:

- **Redirecting a small portion of LNG supply.** Domestic gas price signals may give Queensland LNG producers incentive to supply gas, previously contracted for export LNG, to the domestic market.
- **Increasing production from existing fields.** Producers have advised that, under market conditions that incentivised increased production, there may be some scope for supply from existing fields to exceed current projections. The size of this potential increase is unknown.
- **Exploring and developing new fields.** Gas price increases may give operators incentives to accelerate the development of gas reserves and resources not yet producing, and to invest in exploration to bring highly uncertain gas resources to market in the longer term.
- **Building the Northern Gas Pipeline (NGP).** The NGP, planned to commence construction in 2017, will link Northern Territory gas supply with the eastern and south-eastern Australia gas market via a connection at Mount Isa. If sufficient gas supply can be sourced to fill pipeline capacity, an extra 30 PJ/a of gas could flow east. Assuming operation from 2018, this would reduce total domestic shortfalls to 10 PJ across 2019 to 2024 (down from a total of 156 PJ currently projected).

[7] AEMO. 2017 VGPR. Available at: http://www.aemo.com.au/Gas/National-planning-and-forecasting/Victorian-Gas-Planning-Report.

- **Developing the proposed Narrabri Gas Project.** This New South Wales gas field development could provide extra supply into the domestic market. Assuming first production in 2020, AEMO's modelling shows this project has the potential to remove all domestic gas shortfalls from 2020 to 2024.
- **Investing in alternative electricity generation and storage technologies.** Alternative generation fuel sources such as biofuels, or technologies such as energy storage, may be viable alternatives to GPG, if cost-effective. These alternatives would help alleviate gas supply shortfalls by reducing gas demand, while still supporting renewable generation integration. Investors in any alternative technologies would be expected to seek some revenue certainty through the electricity contract market.

Rising production costs and gas prices

A combination of factors is likely to mean continued upward pressure on gas prices:

- A market finely balanced between supply and demand is expected to maintain this pressure.
- Geological challenges in accessing and releasing gas are increasing production costs at a time when low cost reserves in eastern Australia are in decline. As the cost of sourcing new gas supply is higher, additional gas in the market may not translate to lower gas prices.

Price increases could threaten the financial viability of some industrial and commercial loads, and reduce demand from forecast levels. For example, AEMO analysis indicates that a $2.00/GJ wholesale price increase (to region averages ranging between $8.80/GJ and $10.25/GJ) may result in the commercial and industrial sectors reducing their annual consumption of gas by 20 PJ (8.6%), on average, over the 20-year forecast period.

Further, as demand for gas for GPG in the electricity market grows, increasing gas prices will drive rises in electricity prices, which could also threaten the viability of vulnerable electricity loads.

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CHAPTER 1. GAS SUPPLY AND INFRASTRUCTURE ADEQUACY

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 new gas processing or transmission infrastructure, or field developments, may be required.

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. AEMO acknowledges the contribution of gas producers in developing a future production profile which has improved the accuracy of modelling outcomes and insights.

This report is based on information available to AEMO as at 31 December 2016, although AEMO has endeavoured to incorporate more recent information where practical.

1.1 Inputs to the GSOO

1.1.1 Demand forecasts

The 2017 GSOO incorporates the annual gas consumption and maximum daily demand forecasts developed for the 2016 *National Gas Forecasting Report* (NGFR) [8], published by AEMO in December 2016.

The gas demand forecasts are similar to the 2015 NGFR forecasts used in the 2016 GSOO:

- To the end of 2018, a slower LNG project ramp-up leads to lower forecast demand than was projected in the 2015 NGFR.
- From 2019 to 2036, the annual differences in demand equate to less than 1% on average.

Further detail on the gas demand forecasts can be found in the 2016 NGFR.

1.1.2 Pipeline, processing, and storage facility infrastructure

AEMO has liaised with industry participants to confirm actual and proposed capacity changes in the pipeline and processing network since the 2016 GSOO.

Whilst there have been no capacity changes to existing pipelines, AEMO has included three new pipelines in the analysis:

- The Reedy Creek to Wallumbilla Pipeline (300 terajoules a day (TJ/d)) from mid-2018 has been included in the Neutral scenario.
- The Northern Gas Pipeline (NGP) (including an extension from Mount Isa to Wallumbilla) and Queensland Hunter Gas Pipeline (QHGP) have been considered as Additional Supply scenarios.
  - The NGP is not included in the GSOO Neutral scenario, due to uncertainty of gas supply volumes and completion date for this pipeline.
  - The QHGP project has not yet progressed sufficiently far to be considered in the GSOO Neutral scenario.

See Section 1.3 for more detail on scenarios and sensitivities.

There has been minimal augmentation of existing processing capacities compared to the 2016 GSOO. Capacity changes in various Queensland processing facilities have resulted in an increase of nearly 200 TJ/d (3% of total processing capacity in eastern and south-eastern Australia).

[8] AEMO. 2016 NGFR. Available at: http://www.aemo.com.au/Gas/National-planning-and-forecasting/National-Gas-Forecasting-Report.

Narrabri Gas Project has been included in conjunction with the QHGP as an Additional Supply scenario. Further detail on this scenario can be found in Section 1.3.

The Iona underground storage (UGS) facility operator has advised AEMO of plans to expand the reservoir withdrawal and injection capacity. This includes a reservoir withdrawal capacity increase from 390 TJ/d to 440 TJ/d, and reservoir injection capacity increase from 153 TJ/d to 173 TJ/d, during 2017.

1.1.3 Field development

AEMO relies on Gas Bulletin Board data, producer guidance, and other publicly available information to forecast annual field production over the 20-year outlook period.

The 2017 GSOO uses production projections in offshore Victoria to 2021 that have been submitted by producers to AEMO as part of the 2017 *Victorian Gas Planning Report* (VGPR). [9]

Industry data shows that the rate of exploration and development of oil and gas wells recently drilled in Australia has nearly halved.[10] Gas extraction is becoming increasingly challenging for all producers, due to a variety of factors:

- Increasing geological complexity, which makes it harder to access and release gas deposits to the surface.
- Poor production flow rates, which also compromise the financial viability of field development.
- Negotiating land access agreements.
- Acquiring environmental approval.
- Securing finance and/or joint venture partners.
- Community opposition to gas development in certain areas.
- Government policy of drilling and exploration moratoria.

The challenges of extracting gas and transporting it to market have contributed to a decrease in forecast supply across nearly the whole outlook period.

The confirmed existence of gas reserves and resources may not equate to the entire reserve or resource volume being brought to market. Any shortfalls forecast that rely on these uncertain reserves and resources may actually be higher if the required quantity of gas production is not fully realised.

1.1.4 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.

The following categories are applied across the industry:

- Reserves are quantities of gas which are anticipated to be commercially recovered from known accumulations.
  - Proved and probable reserves (2P) are considered the best estimate of commercially recoverable reserves.
- Contingent resources are considered less commercially viable than reserves.
  - 2C resources are considered the best estimate of those sub-commercial resources.
- Prospective resources are estimated volumes associated with undiscovered accumulations of gas. The resources are estimated to exist in prospect areas, but have not yet been proven by drilling.

AEMO's modelling and projections further categorise reserves as either developed (supply from existing wells) or undeveloped (wells yet to be drilled).

[9] AEMO. 2017 VGPR. Available at: http://www.aemo.com.au/Gas/National-planning-and-forecasting/Victorian-Gas-Planning-Report.
[10] EnergyQuest. Media release, "Wells drilled in 2015 compared to wells drilled in 2014", March 2016.

1.2 Forecast – GSOO Neutral scenario

The GSOO Neutral scenario, incorporating the NGFR Neutral demand scenario, is considered the most likely outcome.

1.2.1 LNG export dominating forecast gas demand and production

Gas for Liquefied Natural Gas (LNG) exports is projected to continue dominating gas demand and supply in eastern and south-eastern Australia to 2036. The final two of six Queensland LNG trains finished their commissioning process in October 2016, resulting in around 3,500 TJ/d, or 1,280 PJ/a, now flowing to Curtis Island for export.

By 2020, this is forecast to increase to approximately 1,430 PJ/a, accounting for 73% of total eastern and south-eastern Australian natural gas demand in that year.

With LNG exports representing such a large proportion of total gas demand in the 20-year outlook period, any changes in conditions in the LNG market are expected to impact the domestic gas market in eastern and south-eastern Australia. Small disruptions in the LNG supply chain could have large effects on domestic gas supply and demand, and the exposure of domestic gas markets to the more volatile world market creates greater uncertainty for domestic supply forecasts.

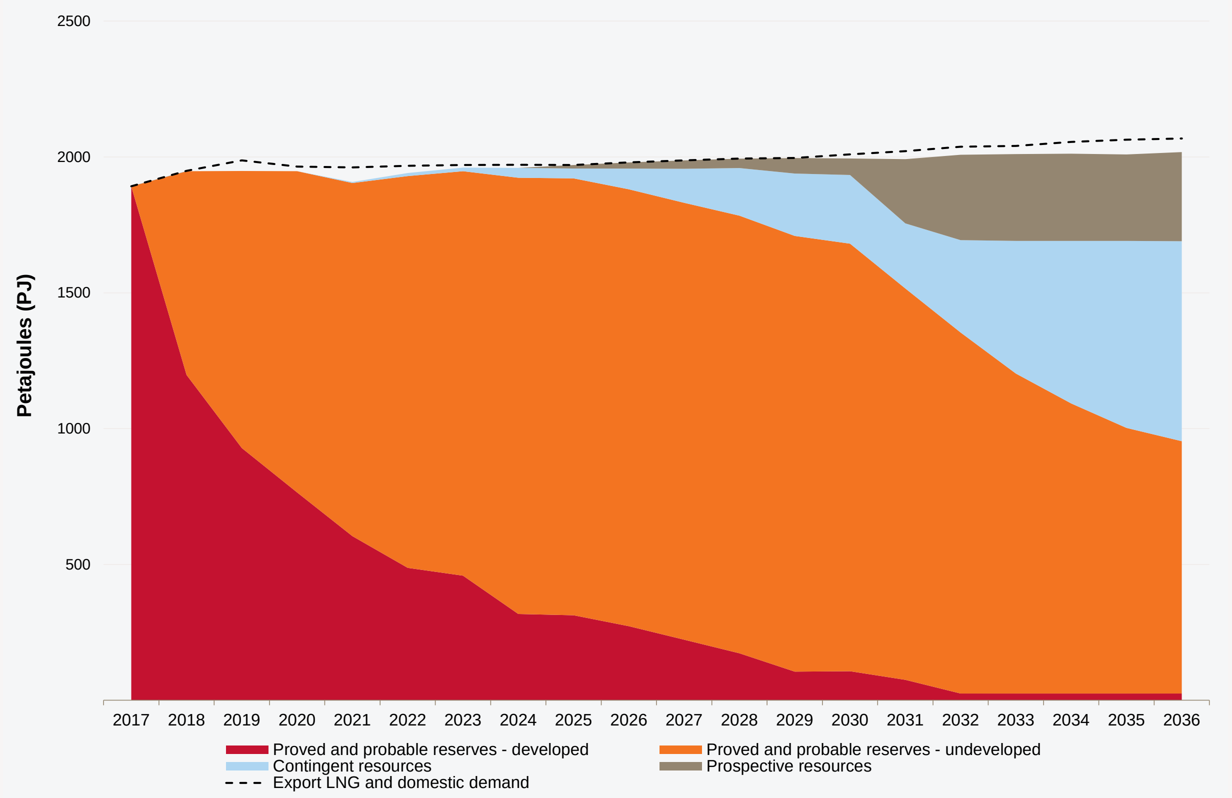
AEMO’s modelling assumes that:

- LNG demand will be satisfied, as LNG export producers prioritise their gas portfolios to fulfil sales commitments under long-term contracts.
- Projected shortfalls will therefore impact supply to domestic market sectors – industrial, commercial, and residential customers, and gas supply for gas-powered generation (GPG).
- Where production from coal seam gas (CSG) fields earmarked for LNG export is in excess of forecast LNG demand, this gas will be available for domestic gas use.

The 2017 GSOO projects that production from 2P gas reserves will satisfy forecast gas demand until January 2019.

From 2019, as shown in Figure 3, the forecast production from developed and undeveloped 2P reserves, and contingent and prospective resources, is projected to be insufficient to meet forecast demand.

Figure 3 Eastern and south-eastern Australia gas production (export LNG and domestic), 2017−36



As existing 2P reserves start to deplete, eastern and south-eastern Australia will become increasingly dependent on production from less certain contingent and prospective resources to meet demand.

The 2017 GSOO assumes that contingent resources and prospective resources will not be available before 2021 and 2025 respectively. This assumption reflects producer guidance on first gas production dates (for new fields), as well as the natural introduction of supply from contingent resources expected following the depletion of reserves from existing fields.

Almost all (92%) of the forecast production from 2P undeveloped reserves is forecast to be produced for LNG export.

Production from contingent resources is forecast to be required:

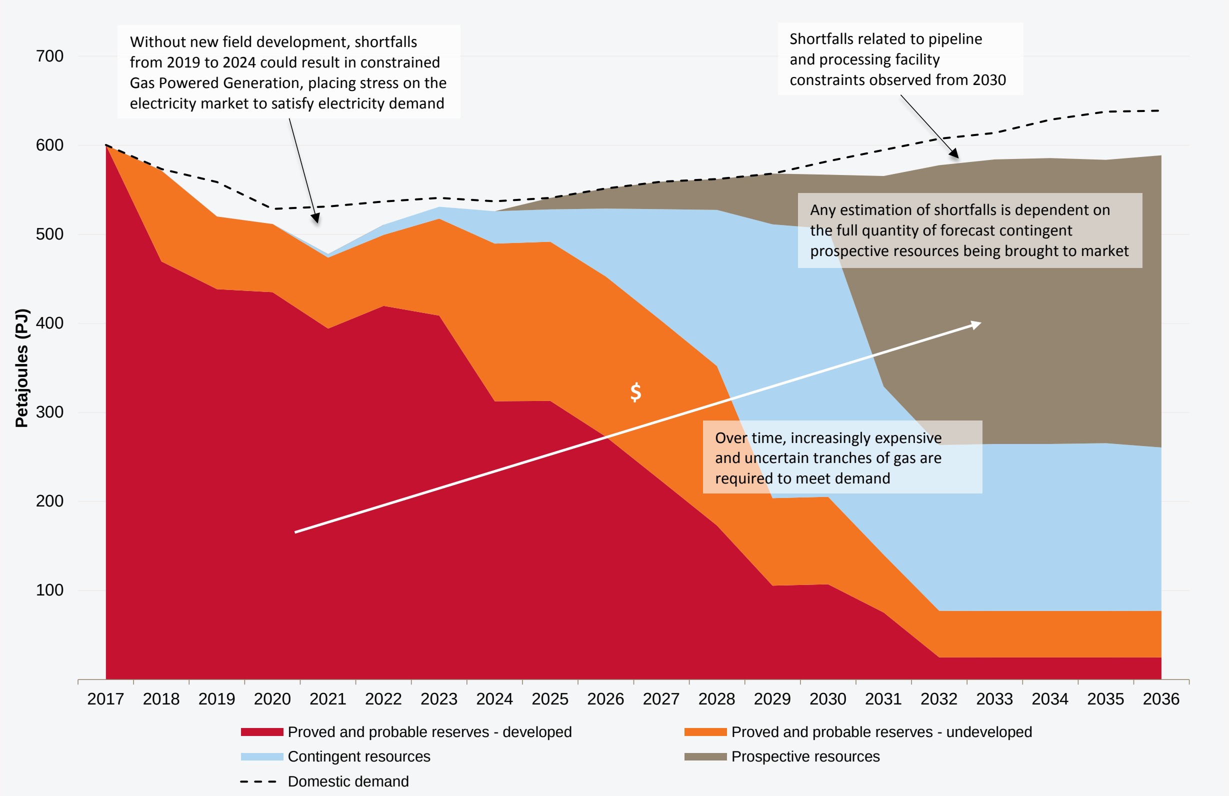
- By 2021 in offshore Victoria.
- By 2029 in Queensland CSG fields.
- By 2031 in the Cooper–Eromanga Basins.

Forecast production from highly uncertain (and as yet undiscovered) prospective resources is also projected to be required by 2025 in offshore Victoria.

1.2.2 Domestic supply adequacy

Figure 4 shows the field production profile required to meet only the domestic demand for gas. This is a subset of the production and demand shown in Figure 3.

Figure 4 Eastern and south-eastern Australia domestic gas production (excluding LNG), 2017−36



Based on advice from gas producers, annual domestic gas production is projected to decline from 600 PJ in 2017 to 478 PJ in 2021, as shown in Figure 4. Most of this production decline is projected to occur in offshore Victoria, where production is forecast to reduce by 38% over this period.

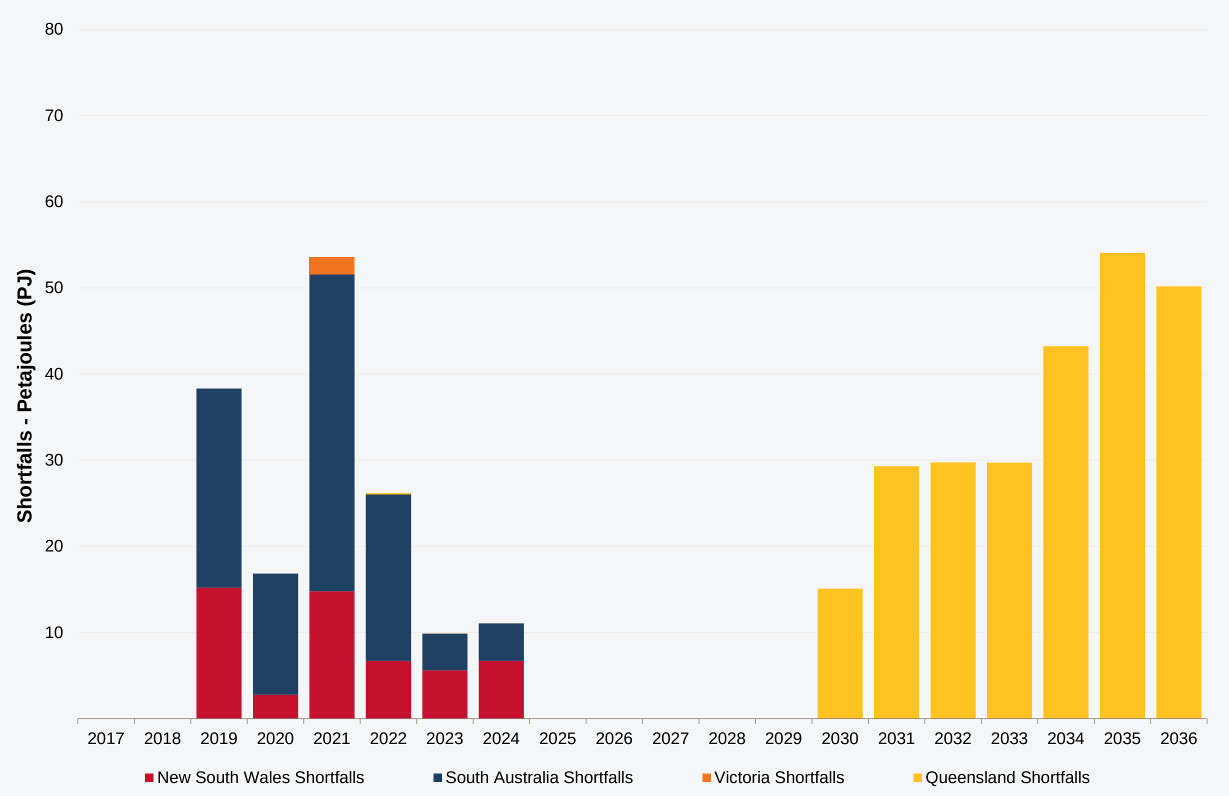
Producers have advised that, under market conditions that incentivised increased production, there may be some scope for supply from existing fields to exceed current projections. The size of this potential increase is unknown.

Unless gas production increases, domestic gas shortfalls between 10 PJ/a and 54 PJ/a are forecast in:

- South Australia from 2019–24 (up to 37 PJ in 2021).
- New South Wales from 2019–24 (up to 15 PJ in 2019).
- Victoria in 2021 (2 PJ).
- Queensland from 2030–36 (up to 54 PJ in 2035).

Figure 5 shows the projected shortfalls by region across the 20-year outlook period.

Figure 5 Projected shortfalls in supply by region, 2017–36



From 2030, gas supply shortfalls in Queensland are forecast, as pipeline and processing capacity are projected to be insufficient to satisfy the forecast increase in GPG demand in that region.

Capacity expansions of the North Queensland Gas Pipeline (up to an additional 132 TJ/d) and the Moranbah Processing Facility (up to an additional 194 TJ/d) are projected to be required to ensure forecast demand can be met.

Alternatively, if the electricity demand at this time were to be met by alternate forms of generation, the reliance on gas for electricity generation would reduce, along with the shortfalls observed.

These shortfalls have been estimated assuming stability of supply, unaffected by any major supply interruption (for example, equipment or infrastructure failure, or industrial action) or field production underperformance. Should any of this occur, shortfalls may be higher than forecast.

Forecast gas shortfalls in GPG demand

All gas shortfalls in the 2017 GSOO are assumed to relate to GPG supply. Therefore, if gas production declines as forecast, there will be insufficient gas between 2019 and 2024 to meet both gas and electricity forecast demand.

If price signals instead incentivised the market to prioritise gas to meet electricity demand for GPG, then LNG, residential, commercial, and/or industrial gas sectors would realise shortfalls between 10 PJ/a and 54 PJ/a, as discussed in the previous section.

Changes to the generation mix

Some of the projected domestic gas shortfalls could be alleviated by reducing demand for GPG, assuming that if gas was unavailable for electricity generation, another fuel type (such as coal-fired, hydroelectric, or diesel-fired generation) could be substituted.

AEMO National Electricity Market (NEM) reliability assessment modelling suggests that, even allowing for this fuel substitution, constraints on the availability of gas for GPG could lead to electricity supply shortfalls of between approximately 80 GWh and 363 GWh during peak periods in 2019 and 2021. These shortfalls would result in a breach of the NEM reliability standard, which sets an expectation that electricity demand will be met 99.998% of the time.

Figure 6 Projected generation mix in the NEM if gas for GPG usage is constrained, 2015–16 to 2025–26

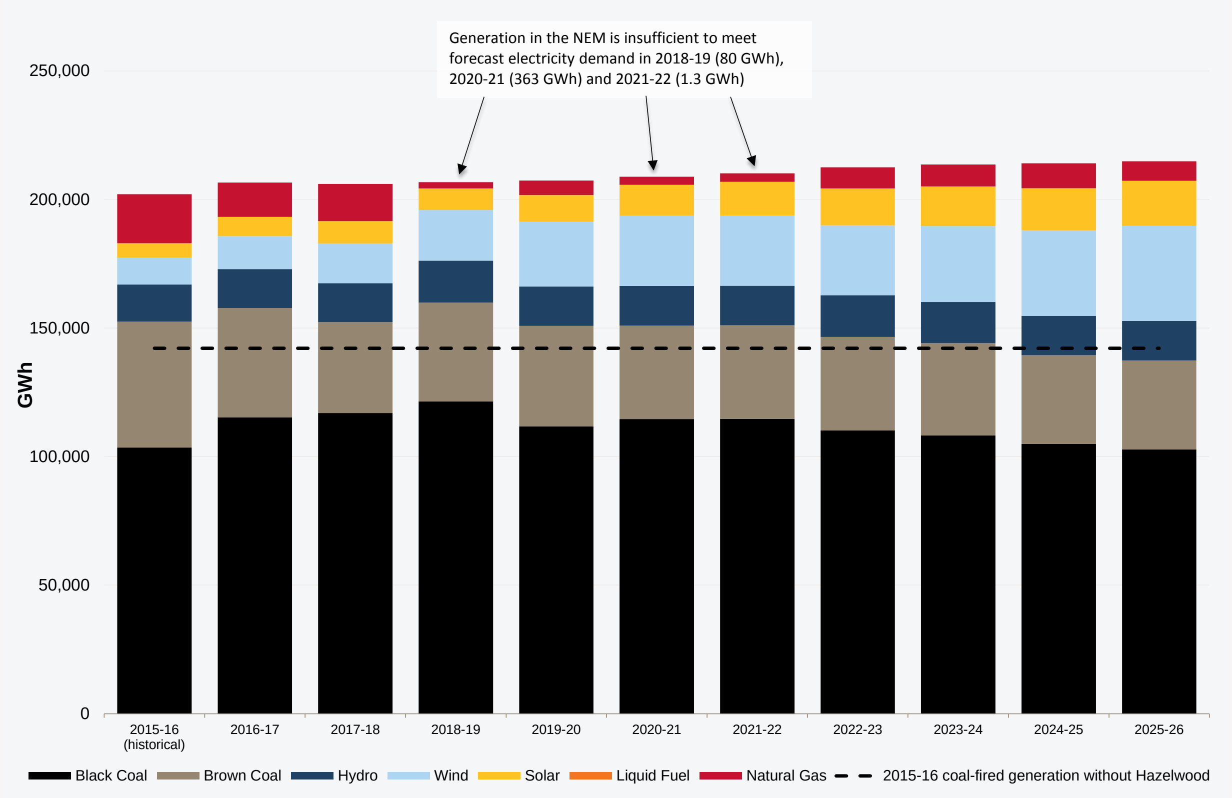


Figure 6 shows the impact of forecast gas constraints on the projected generation mix in the NEM to 2025. It highlights:

- An increase in existing black coal-fired generation, above current and recent levels.
- A decline in GPG from recent levels, which could impact the financial viability of these generators.
- An increase in renewable generation, driven by the combined impacts of the Large-scale Renewable Energy Target (LRET) and the Victorian Renewable Energy Target (VRET).

In the November 2016 *2016 Electricity Statement of Opportunities* (ESOO) *Update*[11], AEMO projected that, following the Hazelwood Power Station closure at the end of March 2017, generation previously supplied by this power station would be supplied by a roughly even mix of GPG and black coal-fired generation. This latest analysis indicates that black coal-fired generation would need to replace a far greater portion of this lost supply.

While existing coal-fired generation has the capacity to deliver this contribution, a range of factors may impact the ability of coal-fired generators to meet the forecast generation levels, including:

- The ability of aging coal-fired generators to reliably increase operation levels to meet forecast generation.

[11] AEMO. 2016 ESOO Update. Available at: http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2016/update/2016-ESOO-Update---Hazelwood-Retirement.pdf.

- The flexibility of coal-fired generators to increase and decrease generation in response to rapidly changing demand.
- Whether coal-fired generators have sufficient flexibility in their coal supply contracts to increase their generation levels in the short term.
- The long-term forecast retirement of coal-fired generation to meet emissions target reductions.

Factors influencing energy shortfalls

The magnitude of shortfalls discussed above assumes average conditions in the outlook period, free from unexpected events which may lead to higher shortfalls than forecast.

Unexpected events may include:

- Gas fields underperforming compared to production forecasts.
- Equipment failure leading to pipeline or plant infrastructure outages.
- Coal-fired generation outages occurring at times when gas to supply GPG is constrained.
- Wind or solar generation being limited at times of high demand, in either electricity or gas markets.
- Drought impacting hydroelectric reservoir levels, limiting the availability of hydroelectric generation.

These challenges represent an opportunity for new sources of gas and viable alternatives to GPG to be developed by industry over the outlook period. GPG alternatives may include fuel sources such as biofuels, or technologies to facilitate energy storage and demand side participation.

The role GPG will play in transitioning towards Australia's low emissions future is highly uncertain, and will impact the scale and timing of generation mix changes. Retirement decisions of coal-fired generators, the ongoing direction of energy policy, and emerging new technologies will all influence future demand for GPG.

Pipeline system linepack adequacy is critical in supporting demand. The daily load profile is changing to become increasingly volatile, impacting the capability for linepack reserves to support peaking demand, such as GPG.

See Section 1.3 for more detail on scenarios and sensitivities that investigate a range of GPG demand assumptions.

1.2.3 Security of supply

Ensuring sufficient natural gas supply is essential for energy security in both the gas and electricity markets:

- Refilling Iona UGS will be key to meeting winter demand in Victoria. The refilling of Iona UGS is uncertain for winter 2018, and unlikely for winter 2019 and beyond. AEMO has identified this as a threat to system security.
- Following South Australia's Black System event on 28 September 2016, the region has increased dependence on GPG to provide the minimum levels of thermal generation required to maintain security of electricity supply.

Gas system security in Victoria

The Iona UGS facility plays an important role in supplying gas to Victoria during the winter peak demand period. It also supports GPG demand in South Australia via the SEA Gas Pipeline.

The forecast reduced gas production will increase reliance on gas storage to meet winter demand. Refilling of Iona UGS for winter 2018 is uncertain, due to the forecast decrease in Port Campbell production and limitations on the South West Pipeline (SWP) capacity towards Port Campbell. The SWP capacity limitation is expected to worsen, due to a forecast increase in GPG demand following the Hazelwood closure. Operation of the Laverton North Power Station further exacerbates the transportation limitation, because the SWP capacity reduces by the amount of gas this power station uses.

Iona UGS refilling for winter 2019 is unlikely, without an expansion of the SWP or an increase in Port Campbell production. This may result in winter gas supply shortfalls for Victoria. AEMO has identified this as a threat to system security.

While AEMO can take short-term operational measures to attempt to reduce this threat, including curtailment of large gas users, ultimately those measures are limited by the available supply of gas and transportation capacity. AEMO does not have the power to direct the required investment in the SWP to occur and address the longer-term energy security risks.

The Victorian Declared Transmission System (DTS) service provider has proposed an expansion of the SWP that would be completed during 2018 to address this constraint. This is included in its 2018–2022 Access Arrangement submission to the Australian Energy Regulator (AER). Construction may need to be fast-tracked to support Iona UGS refilling for winter 2018. This expansion will also reduce the impacts of GPG demand, particularly at Laverton North, by allowing other compressors available to support GPG demand if required.

The 2017 VGPR[12] contains more detailed information about this issue.

South Australia security of supply

Maintaining energy security in the NEM as increasing amounts of renewable generation are built requires the Rate of Change of Frequency (RoCoF) to be managed. This is historically managed by inertia, provided by synchronous generation (typically thermal generation such as coal-fired and gas-fired plant). Power systems with low inertia experience faster changes in system frequency after a disturbance, and fast frequency changes can lead to supply disruptions.

While AEMO is exploring the underlying RoCoF limits of the power system and alternative ways to manage RoCoF, inertia from synchronous thermal generation is currently vital to maintain system security and avoid the risk of a black system.

South Australia does not have any local thermal fuel sources other than GPG and diesel to manage RoCoF. This means the reliability of gas supply to South Australia is essential to maintain energy security in the region. AEMO does not have the power to direct the flow of gas into or within South Australia to maintain and improve the reliability of gas supply, as it does in Victoria.

Further, unless the system security problems associated with refilling Iona UGS in Victoria are resolved, the amount of Victorian gas supplied via the SEA Gas pipeline to support GPG in South Australia will be limited.

A map of eastern and south-eastern Australian gas fields and infrastructure can be found in Appendix B.

1.3 Forecasts – other scenarios and sensitivities

The GSOO Neutral scenario assumes:

- The NGFR Neutral demand is used for the residential, commercial, industrial, LNG, and GPG demand sectors.
- Only existing gas transmission and processing infrastructure and announced upgrades.
- Existing fields have maximum supply limitations as advised by industry and calibrated against historical data. Production from contingent or prospective resources located at existing fields is constrained by current rates of supply.

[12] AEMO. 2017 VGPR. Available at: http://www.aemo.com.au/Gas/National-planning-and-forecasting/Victorian-Gas-Planning-Report.

The GSOO Neutral scenario includes some uncertain supply and demand input assumptions. The 2017 GSOO also considered additional scenarios and sensitivities on the Neutral scenario to test these uncertainties, considering:

- GPG demand forecasts, testing assumptions around gas as a key transitional fuel for Australia's low emissions future. See Appendix A.3 for a discussion of these uncertainties and the assumptions behind the GPG forecast from the 2016 *National Transmission Network Development Plan* (NTNDP) Neutral scenario.
- The impact of Weak and Strong demand conditions, based on the NGFR Weak and Strong demand scenarios.
- The impact of additional supply sources, which may require lifting current moratoria on hydraulic fracturing.

Table 1 summarises the variations in assumptions made for these scenarios and sensitivities.

Table 2 provides a summary of scenario and sensitivity results, compared to the 2017 GSOO Neutral scenario.

Table 1 Summary of scenario and sensitivity assumptions different to the 2017 GSOO Neutral scenario

Scenario / sensitivity	Residential, commercial, industrial, and LNG demand assumptions	GPG demand assumptions	Supply assumptions	Infrastructure assumptions
Increased GPG demand	-	NTNDP Neutral	-	-
Weak demand conditions	NGFR Weak	NGFR Weak	-	-
Strong demand conditions	NGFR Strong, including 7th LNG train.	NGFR Strong	Field supply limitations are relaxed.	LNG pipeline capacities sufficient to meet supply for 7th LNG train.
Additional Supply – Northern Gas Pipeline (NGP)	-	-	Reserves available from Mereenie Basin in the NT from January 2018.	NGP is able to supply gas from the NT to Mt Isa in QLD at a rate of 90 TJ/d.
Additional Supply – NGP + Mt Isa to Wallumbilla link	-	-	Reserves available from Mereenie Basin in the NT from January 2018.	In addition to 90 TJ/d along NGP, new 90 TJ/d pipeline constructed connecting Mt Isa to Wallumbilla.
Additional Supply and Infrastructure – Queensland Hunter Gas Pipeline (QHGP), Narrabri field, connection from Narrabri to Newcastle	-	-	Narrabri field in NSW available from 2020, supplying up to 100 TJ/d.	230 TJ/d QHGP connecting Wallumbilla to Narrabri, then further pipeline connecting in to Newcastle or Young.
Reduced demand for LNG export	NGFR Neutral, with LNG demand reduced by 5%.	-	-	-

Table 2 Summary of scenario and sensitivity results different to 2017 GSOO Neutral scenario forecasts

Scenario / sensitivity	Key findings
GSOO Neutral scenario	Shortfalls totalling 156 PJ forecast between 2019 and 2024. Further shortfalls observed in Queensland from 2030 to the end of the outlook period, totalling 251 PJ. Shortfalls from 2030 related to increased GPG demand in northern Queensland. These would be eliminated by increased pipeline and processing facility capacity along the North Queensland Gas Pipeline as noted in Section 1.2.2.
Increased GPG demand	Increased shortages across all regions, especially post-2030 as existing infrastructure is not sufficient to meet the large amounts of new GPG forecast in the NTNDP required in NSW and Victoria to meet electricity demand. • From 2018 to 2024 – 245 PJ additional total shortfalls. • From 2030 to 2036 – 365 PJ additional total shortfalls.
Weak demand conditions	Whilst total forecast demand is met, 1,661 PJ of contingent and prospective resources are still required across the 20 years (compared to 6,108 PJ in GSOO Neutral scenario).
Strong demand conditions	Stronger demand leads to greater shortfalls in all regions with both pipeline and plant capacity constraints limiting demand able to be met. Shortfalls observed in all years between 2018 and 2036, with a total of 7,912 PJ of shortfalls across the 20 years. Single year shortfalls range between 127 PJ and 617 PJ. Full LNG demand unable to be met from 2027 after the 7th LNG train commences. Domestic shortfalls spread between GPG, residential, commercial and industrial, across all regions.
Additional Supply –NGP	Mereenie gas field starts producing to maximum 30 PJ per annum between 2018 and 2030, with the additional gas sent to the eastern gas market eliminating all but 10 PJ of shortfalls between 2019 and 2024.
Additional Supply – NGP + Mt Isa to Wallumbilla link	All shortfalls between 2019 and 2024 are eliminated, as up to 33 PJ per annum is able to be utilised at Wallumbilla.
Additional Supply and Infrastructure – QHGP, Narrabri field, connection from Narrabri to Newcastle	All shortfalls between 2020 and 2024 are eliminated as gas supplied from Narrabri is able to help meet demand in the short term. If the QHGP is upgraded to support bi-directional flow, gas from Narrabri can be sent to either Wallumbilla or Newcastle, and gas from Wallumbilla can be supplied directly south to support southern gas demand.
Reduced demand for LNG export	Reduced reliance on Australian supply to meet LNG demand results in the excess gas being available to meet domestic demand, and is sufficient to eliminate all shortfalls between 2019 and 2024.

AEMO acknowledges the CSG reserves in the Surat and Bowen basins currently operated by Arrow Energy. Information relating to the probable timing, production profile, and target market(s) of this gas is not publicly available, and therefore has not been included as a sensitivity to the Neutral scenario.

See Appendix B for a map of eastern and south-eastern Australian gas fields and infrastructure.

A full set of result data files is available on the AEMO website.[13]

1.4 Potential solutions

The additional supply scenarios provide key insights as to the effectiveness of various potential solutions in addressing supply shortfalls projected under the Neutral scenario. These insights are discussed briefly below.

Northern Gas Pipeline

The NGP is planned to link Northern Territory supply with the eastern Australia domestic gas market, via a connection at Mount Isa. The completion date and capacity of this project is not yet certain, but construction is planned to begin this year.

[13] Data files and other supporting material is available at: http://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

Assuming the NGP could be operational by 2018 at a capacity of 90 TJ/d, AEMO's analysis indicates that:

- The NGP would provide eastern and south-eastern Australian markets with access to about 30 PJ/a of gas supply from the Northern Territory, eliminating almost all projected gas shortfalls in the period to 2024.
- Pipeline constraints within the existing network limit the ability of the NGP to provide further support to eastern and south-eastern Australia.

The NGP pipeline operator has indicated the possibility of expanding daily capacity, as well as extending the pipeline from Mount Isa through to Wallumbilla, a key pipeline connection hub for gas flows in Queensland. If the NGP was extended through to Wallumbilla, all forecast domestic gas demand could be met.

It is important to note that some Northern Territory supply is currently subject to a moratorium on hydraulic fracturing, and that supply volumes quoted in this scenario would only be realised if the moratorium was to be changed.

Narrabri Gas Project and Queensland Hunter Gas Pipeline

If the Narrabri Gas Project was developed in 2020, in conjunction with the QHGP that links Wallumbilla with Newcastle via Narrabri, all domestic gas shortfalls from 2020 to 2024 would be alleviated.

For the purpose of this scenario, the Narrabri Gas Project is assumed to deliver 100 TJ/d.

Redirection of LNG export gas production to meet domestic demand

Appropriate market price signals may incentivise Queensland LNG producers to redirect portions of their gas production to the domestic gas market, including GPG for the NEM.

Only a small portion would be required to help meet domestic gas demand. If up to 5% of supply currently earmarked for LNG export was redirected to the domestic gas market, it would remove all shortfalls from 2019 to 2024.

CHAPTER 2. INTEGRATION OF ENERGY MARKETS

As discussed in Chapter 1, there are strong interdependencies between the gas and electricity markets. Chapter 2 addresses some key drivers impacting the transformation of the energy sector.

2.1 Rising production costs and prices

A gas market finely balanced between supply and demand is likely to continue to place upward pressure on gas prices.

This may give operators incentive to accelerate the development of reserves and resources not yet producing. The removal of onshore drilling bans or hydraulic fracturing moratoria could also allow the market to access supply not currently available.

Geological challenges of gas extraction are reducing gas well productivity and driving production costs higher, while low cost reserves in eastern Australia are in decline. The increased cost of sourcing new gas supply means additional gas in the market may not translate to lower prices.

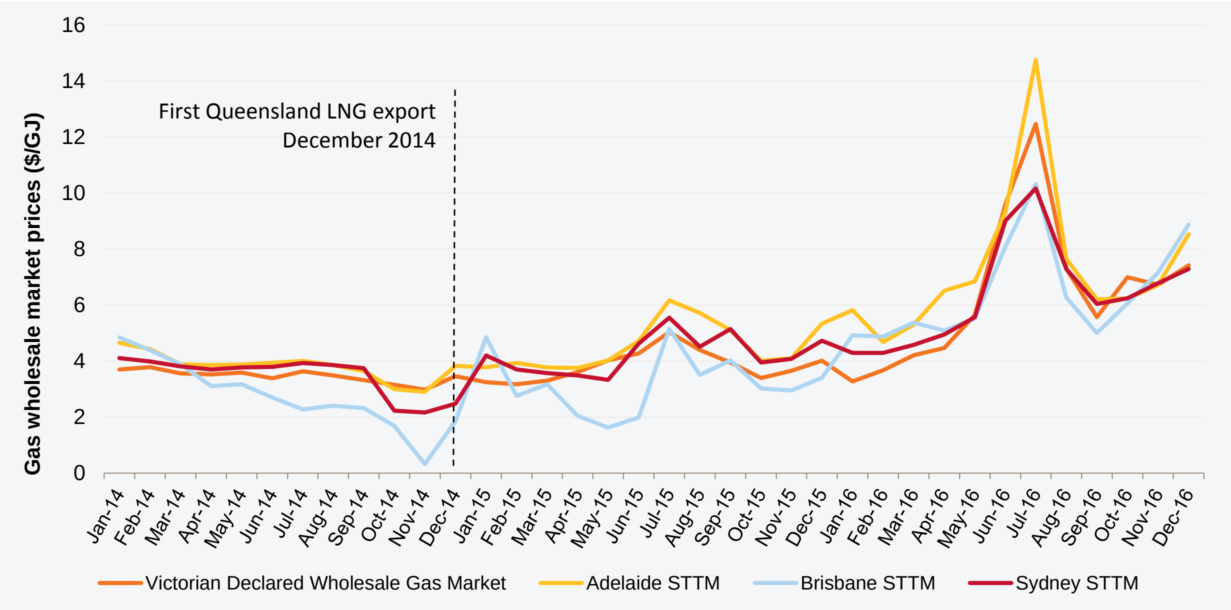
Gas price overview

In 2016, the Queensland export LNG sector continued to ramp up, with the final two of six LNG export trains completing their commissioning process in October 2016, resulting in around 3,500 TJ/d now flowing to Curtis Island for export.

These flows represent approximately 80% of the installed LNG processing capacity. If gas production rises to meet the full installed capacities, potential flows could exceed 4,300 TJ/d.

LNG demand now far exceeds domestic gas demand, even in winter. This has linked the domestic wholesale gas spot market prices to international markets, which has contributed to the increase in gas prices for domestic gas supplies across eastern and south-eastern Australia, as seen in Figure 7.

Figure 7 Average gas market prices since January 2014



With the sharp increase in demand, and limited supply of gas, the market is now more susceptible to outages and shocks.

Coinciding with the first winter of material LNG demand in 2016, spot prices increased from an average of around $5.00 a gigajoule (GJ) across gas markets in April 2016 to an average of $12.00/GJ in July 2016. A combination of increased reliance on GPG, higher LNG demand, rising production costs, and planned and unplanned outages at gas production facilities all contributed to higher and more volatile spot market prices than those observed prior to 2015.

Price sensitivity of gas customers

These increasing and volatile gas market prices will impact price-sensitive gas customers.

Updated demand analysis shows that an increase of $2.00/GJ to the current wholesale price places 5.1% of total forecast gas demand at risk of being no longer financially viable. Price sensitivity is greatest in the commercial and industrial gas sector, where the sector's total load may decrease by an average of 20 PJ/a (around 8.6%) as operations close due to price shock.

Table 3 shows the range of prices considered in this analysis after the $2.00/GJ wholesale gas price increase, and an assessment of demand at risk of closure in each state.

Table 3 Range of retail prices forecast for each region in the commercial and industrial demand sector after the $2.00/GJ wholesale gas price increase

	Retail price ($/GJ)	Forecast decrease in demand (PJ)
Queensland	$13.41 - $19.63	3.4
New South Wales	$8.32 - $14.99	6.8
Victoria	$6.76 - $13.45	1.3
South Australia	$10.05 - $16.20	7.7
Tasmania	$11.07 - $18.45	1.1

For industrial and large commercial customers, sensitivity to gas price rise varies across industry sectors, depending on customers' ability to fuel switch, how much of their operational cost structure is made up by gas costs, and their relative profit margin.

Certain sectors use gas directly as a part of their production process, such as basic chemical manufacturers. These have less ability to fuel switch than other industrial sectors, such as mining or primary metal manufacturers, which use gas predominantly for heating or co-generation. If, over the long term, customers are unable to fuel switch or offset the gas price rise with energy efficiency savings, they may close down part or all of their operations.

Electricity price overview

Where gas supplies for GPG are not fully contracted, generators face exposure to the higher-priced and volatile gas spot market. As coal-fired generation in the NEM withdraws, and reliance on GPG increases, electricity spot prices are becoming increasingly linked to gas spot prices.

Across the NEM, GPG set the electricity spot price more frequently in 2015–16 than in 2014–15. The increasing influence of GPG setting the electricity spot price can be seen in Figure 8. This figure shows the fuel responsible for setting the price across the year, and compares two separate years, 2014–15 and 2015–16. Not only are the prices across 2015–16 higher than those in the previous year, the fuel setting the price most often is natural gas for GPG.

Figure 8 Regional price duration curve by price-setting fuel, 2014–15 compared to 2015–16

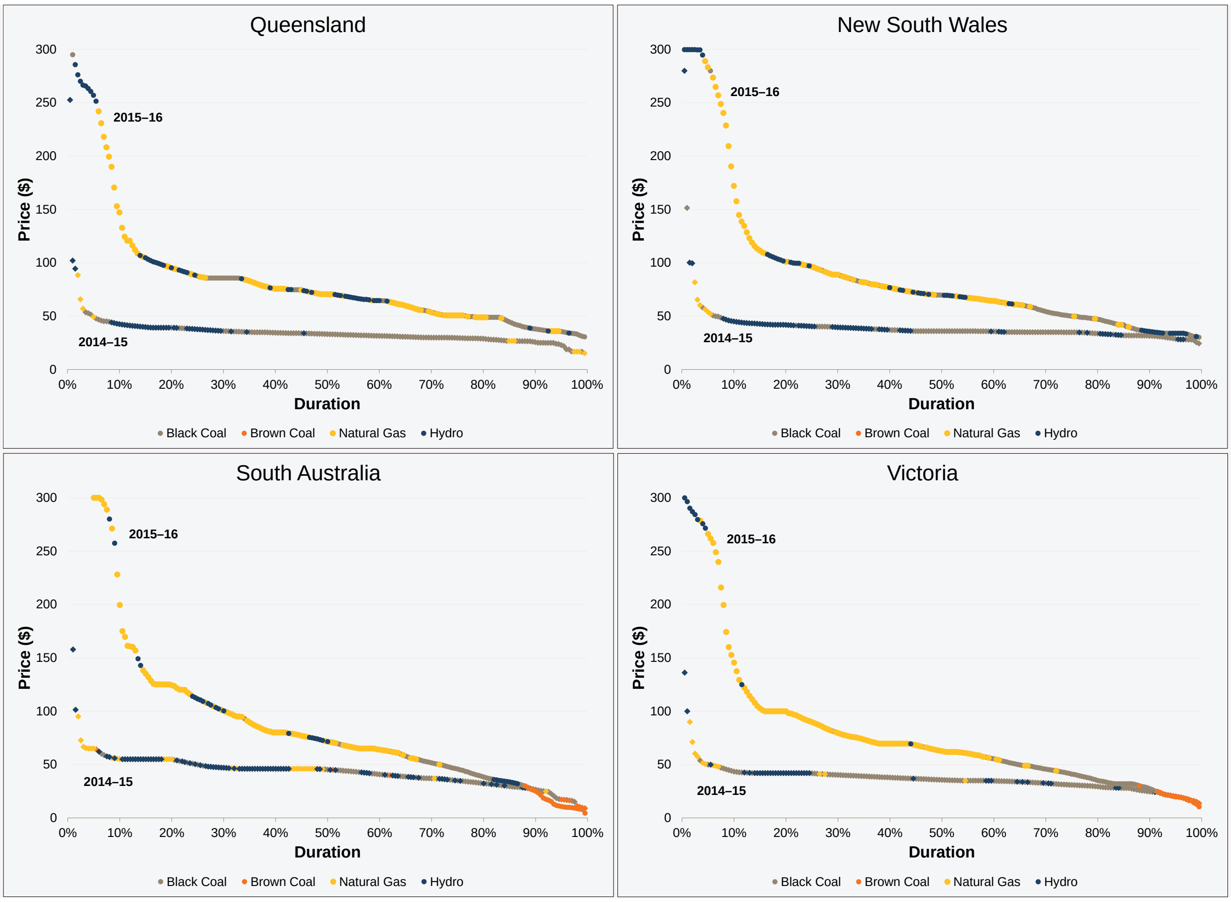
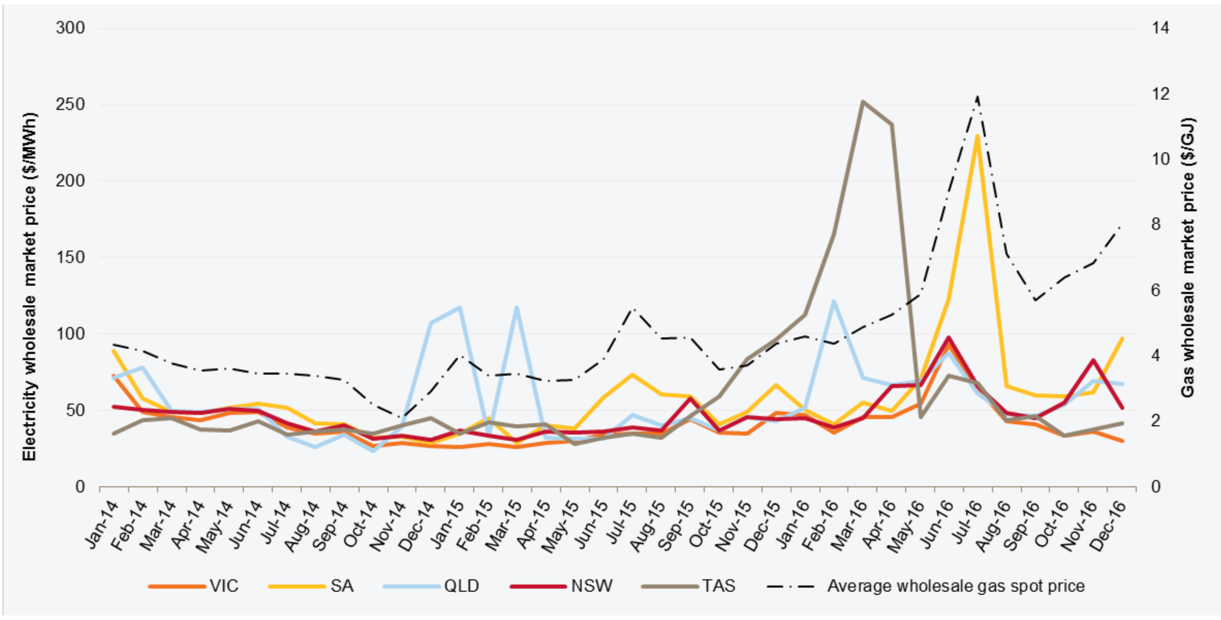


Figure 9 shows the average monthly regional electricity spot market prices since 2014, and compares these prices to the trend in gas prices over the same period.

Figure 9 Average regional electricity prices compared to average gas prices since January 2014



On an annual basis, average electricity wholesale spot market prices observed in each region in 2016 have increased between 30% and 100%, compared to the prices observed in 2015, and this coincides with rising gas prices over the same period. The increased prices in Tasmania coincided directly with the outage of the Basslink interconnector from December 2015 to June 2016.

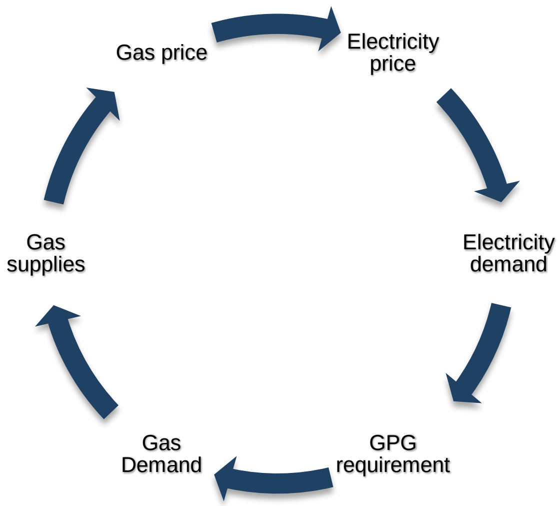
If electricity prices continue to increase in line with rising gas prices, this could ultimately threaten the viability of vulnerable electricity customers.

2.2 Energy market integration

The convergence of energy markets in eastern and south-eastern Australia demands a single energy view – gas and electricity markets can no longer be viewed in isolation, and this 2017 GSOO highlights the increasing interdependencies between gas and electricity, and supply and demand.

Figure 10 conceptually shows the continuous linkage of the key interdependencies.

Figure 10 Representation of linkages between gas and electricity markets



Reliable electricity supply requires a reliable gas supply. Maintaining energy security therefore requires holistic planning across the entire supply chain, to ensure investment decisions are made in the long-term interests of consumers.

APPENDIX A. ISSUES FACING THE ELECTRICITY MARKET

This appendix provides a summary of developments and issues in the electricity market that impact GSOO analysis and insights.

A.1 Emissions reductions target

Australia's increasing focus on sustainability is reflected in its commitment at the 21st Conference of Parties to reduce greenhouse gas emissions (COP21 commitment), with action being taken at both the Federal and state levels.

AEMO's forecasting and planning processes take into account:

- Australia's COP21 commitment – a 28% emissions reduction from 2005 levels by 2030, with AEMO assuming the resultant trajectory continues between 2030 and 2036.
- The Federal LRET – a target for 33,000 GWh of electricity generation in 2020 to be from large-scale renewable sources.
- The VRET – a target for renewable generation to produce 25% of total electricity generation in Victoria by 2020, and 40% by 2025.
- The Australian Capital Territory Renewable Energy Target (ACT RET) – a target for renewable generation to produce 90% of total electricity generation in ACT by 2020, and 100% by 2025. AEMO has incorporated the ACT RET in the Federal LRET for modelling purposes.

AEMO acknowledges that other state governments have also announced aspirational renewable energy targets, of:

- 50% by 2025 in South Australia.
- 50% by 2030 in Queensland.
- Net zero emissions by 2050 in New South Wales.

The VRET is included in GPG demand forecasts, and other state targets are not, because the Victorian government has defined the mechanism it intends to apply to reach the target, being a series of reverse auctions for renewable energy capacity. AEMO will incorporate other targets into future analysis as the mechanisms to achieve them are confirmed.[14]

These assumptions drive the generation mix forecast to meet electricity demand. As renewable generation in the NEM is projected to increase, this has implications for the amount of gas forecast to be required as fuel for GPG.

A.2 Hazelwood retirement

In November 2016, Engie announced that Hazelwood Power Station in Victoria will close at the end of March 2017.[15]

The 1,600 MW Hazelwood Power Station accounts for about:

- 14% of total firm capacity[16] in Victoria.
- 12% of combined firm capacity across Victoria and South Australia.
- 4% of total firm capacity installed in the NEM.

[14] AEMO acknowledges that the Queensland government has released a draft expert report recommending the reverse auction approach is applied to their target for 50% renewable energy by 2030.

[15] Engie. Media release, "Hazelwood Power Station in Australia to close at end of March 2017", 3 November 2016. Available at: http://www.engie.com/en/journalists/press-releases/hazelwood-power-station-australia/.

[16] Firm capacity is the capacity AEMO conservatively assumes will be available during peak demand conditions (with 85% confidence of exceedance). In Victoria, wind generation capacity is currently discounted 93% in this calculation.

In 2015–16, Hazelwood Power Station produced 10,326 GWh (22% of Victoria's operational demand) of electricity.

As Hazelwood Power Station retires from the NEM, the remaining generators will need to increase their generation to meet electricity demand, or new generation will be required to make up the difference.

The demand scenarios studied in the 2017 GSOO all take the retirement of Hazelwood Power Station into account, and assume that other generation types – including GPG – will be operating instead.

A.3 GPG demand – *National Gas Forecasting Report* versus *National Transmission Network Development Plan*

The future for GPG demand is highly uncertain. In 2016, AEMO modelled two possible and credible paths for GPG demand, in the 2016 NGFR and the 2016 NTNDP.

This 2017 GSOO has examined both projections:

- The 2016 NGFR forecast examined how extending the technical life of some ageing coal plant could result in later coal-fired generation retirements and a lower 20-year projection for GPG to meet capacity needs. This is the demand forecast used in the 2017 GSOO Neutral scenario.
- The 2016 NTNDP examined a pathway of coal-fired generation retirements after 2030, based on announced intentions to close plant at the end of technical life. The NTNDP also considered electricity loads to be less sensitive to price increases than the NGFR had assumed, requiring 2% greater annual consumption to be met on average each year to 2026. These assumptions resulted in a greater projection of GPG to support development of new renewable generation, which has been considered in the NTNDP sensitivity to the GSOO Neutral scenario.

See Figure 11 for a comparison between the two sets of GPG forecasts.

The retirement of Hazelwood Power Station has been considered under both GPG projections, but the generation mix assumptions to meet the electricity demand were different:

- The NGFR GPG scenario assumed that coal would play a strong role in the near term.
- The NTNDP GPG scenario assumed that GPG would play a much stronger role to fill the gap left by the Hazelwood retirement.

As Figure 11 shows, both forecasts project an initial decrease in GPG consumption, due to projected rises in the gas price, coupled with the forecast increase of large volumes of new wind farm capacity required to satisfy the LRET and the VRET.

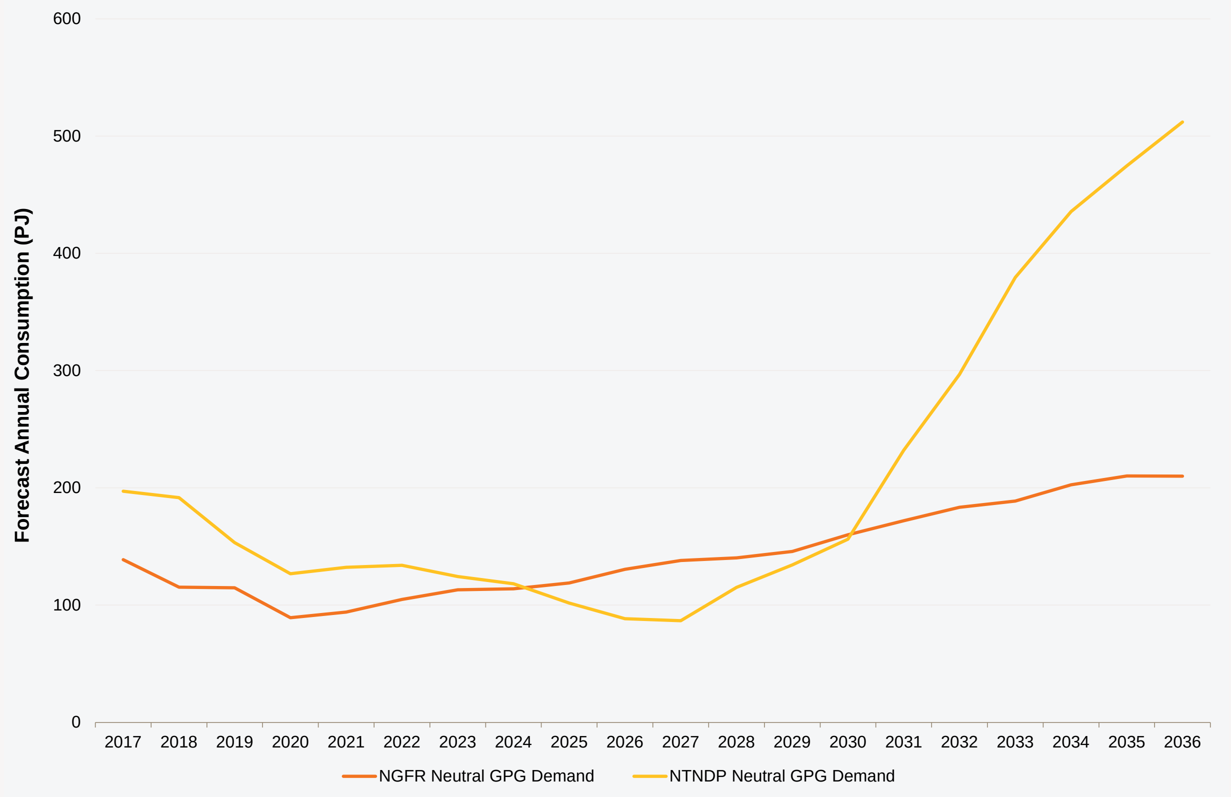
In the longer term, and particularly beyond 2030, both forecasts project GPG to be a key transitional fuel for Australia's low emissions future, as coal-fired generation retires from the NEM in response to meeting the emissions target.

Differences in the forecasts reflect uncertainty in the scale and timing of generation mix changes and consequent demand for GPG. Retirement decisions of coal-fired generators, the ongoing direction of energy policy, and emerging new technologies will all influence future demand for GPG.

By 2036, a 10 GW difference in installed GPG capacity is forecast between the two potential outlooks, with approximately 300 PJ – almost 50% – higher domestic annual gas consumption (excluding LNG) projected in the 2016 NTNDP compared to the 2016 NGFR.

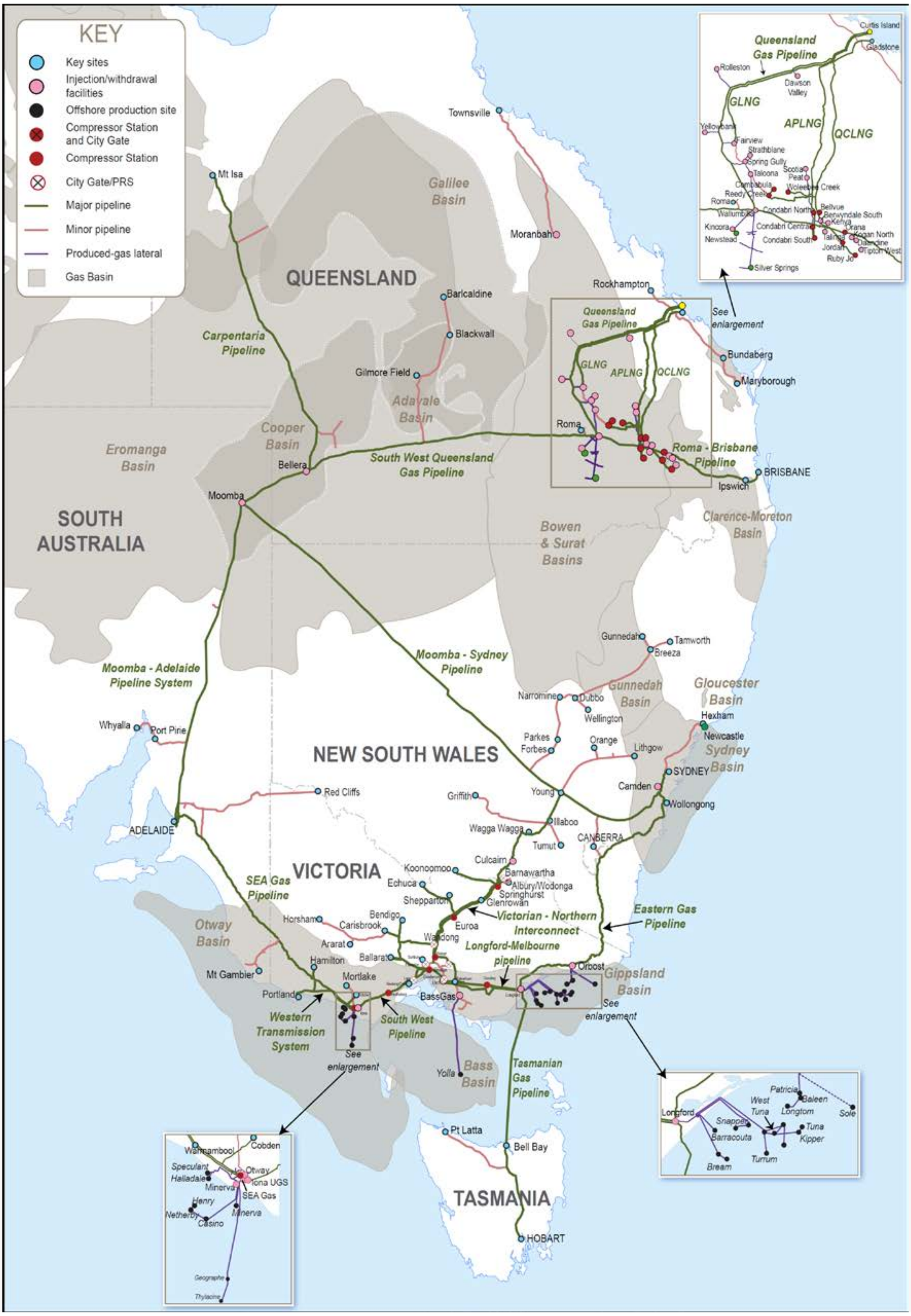
The 2017 GSOO Weak and Strong scenarios are based on the equivalent demand scenarios published in the 2016 NGFR.

Figure 11 GPG demand forecasts, 2017−36



APPENDIX B. MAP

Figure 12 Eastern and south eastern Australian gas producing basins and infrastructure



MEASURES AND ABBREVIATIONS

Units of measure

Abbreviation	Unit of measure
GJ	Gigajoules
GWh	Gigawatt hours
PJ	Petajoules
PJ/a	Petajoules per annum (year)
TJ	Terajoules
TJ/d	Terajoules per day

Abbreviations

Abbreviation	Expanded name
2P	Proved and probable
ACT RET	Australian Capital Territory Renewable Energy Target
AEMO	Australian Energy Market Operator
COP21	21st Conference of Parties, Paris
CSG	Coal seam gas
DTS	Declared Transmission System (Victoria)
ESOO	Electricity Statement of Opportunities
GBB	Gas Bulletin Board
GPG	Gas-powered generation
GSOO	Gas Statement of Opportunities
LNG	Liquefied natural gas
LRET	Large-scale Renewable Energy Target
NEM	National Electricity Market
NGFR	National Gas Forecasting Report
NGP	Northern Gas Pipeline
NSW	New South Wales
NT	Northern Territory
NTNDP	National Transmission Network Development Plan
QHGP	Queensland Hunter Gas Pipeline
QLD	Queensland
RoCoF	Rate of Change of Frequency
SEA Gas	South East Australia Gas Pipeline
SWP	South West Pipeline
UGS	Underground gas storage
VGPR	Victorian Gas Planning Report
VRET	Victorian Renewable Energy Target

GLOSSARY

Term	Definition
2C contingent resources	Best estimate of contingent resources – equivalent to 2P, except for one or more contingencies or uncertainties currently impacting the likelihood of development. Can move to 2P classification once the contingencies are resolved.
2P reserves	The sum of proved and probable estimates of gas reserves. The best estimate of commercially recoverable reserves, often used as the basis for reports to share markets, gas contracts, and project economic justification.
annual consumption	Gas consumption reported for a given year.
black system	Defined in Chapter 10 of the National Electricity Rules as "the absence of voltage on all or a significant part of the transmission system or within a region during a major supply disruption affecting a significant number of customers".
coal seam gas (CSG)	Gas found in coal seams that cannot be economically produced using conventional oil and gas industry techniques. Also referred to in industry sources as coal seam methane (CSM) or coal bed methane (CBM).
contingent resources	Gas resources that are known but currently considered uncommercial based on once or more uncertainties (contingencies) such as commercial viability, quantities of gas, technical issues, or environmental approvals.
curtailment	The interruption of a customer's supply of gas at its delivery point that occurs when AEMO intervenes or issues an emergency direction in Victoria.
demand	Capacity or gas flow on an hourly or daily basis, or the electrical power requirement met by generating units.
developed reserves	Gas supply from existing wells.
Gas Bulletin Board (GBB)	A website **(**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)	The generation of electricity using gas as a fuel for turbines, boilers, or engines.
hydraulic fracturing	Hydraulic fracturing, also called fraccing or fracking, is a method of increasing the extraction of oil and gas from reservoirs, and more recently coal seam gas, by injecting fluid under high pressure to fracture wells or coal seams.
inertia	Produced by synchronous generators, inertia dampens the impact of changes in power system frequency, resulting in a more stable system. Power systems with low inertia experience faster changes in system frequency following a disturbance, such as the trip of a generator.
intermittent generation	Electricity generation, such as wind farms and solar photovoltaic (PV), whose supply varies throughout the day and is not readily predictable.
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.
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 reserves	Estimated quantities of gas that are reasonably certain to be recoverable in future under existing economic and operating conditions. Also known as 1P reserves.

Term	Definition
Rate of Change of Frequency (RoCoF)	When a contingency results in a supply demand imbalance in the electricity power system, system frequency will begin to deviate from the standard 50 Hz. High RoCoF levels make it increasingly difficult to manage frequency disturbances, because responses to correct the imbalance must operate more rapidly to arrest the frequency change, and may not operate quickly enough to prevent a cascading trip of load or generation, and, in extreme cases, widespread supply disruption.
reliability	The ability of the power system to supply adequate power to satisfy customer demand, allowing for credible supply, pipeline, generation, and transmission network contingencies.
reservoir	In geology, a naturally occurring storage area that traps and holds oil and/or gas. Iona UGS is also referred to as a reservoir for gas storage.
reserves	Reserves are quantities of gas which are anticipated to be commercially recovered from known accumulations.
resources	More uncertain and less commercially viable than reserves. See contingent resources and prospective resources.
security	Security of supply is a measure of the power system's capacity to continue operating within defined technical limits, even in the event of the disconnection of a major electricity power system element such as an interconnector or large generator, or disruption of gas supply.
synchronous generation	Synchronous generators (most coal, gas and hydro generators) produce power through directly connected alternating current machines, rotating at a speed synchronised to power system frequency. These generators produce inertia and dynamic voltage to support a more stable power system.
thermal generation	Thermal generation produces electrical power from heat energy, fuelled mainly by coal and natural gas, and to a lesser extent by wood waste and geo-thermal resources. These generators are synchronous.
undeveloped reserves	Gas supply from wells yet to be drilled.