GAS STATEMENT OF OPPORTUNITIES

For eastern and south-eastern Australia

2013

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Purpose

AEMO publishes the Gas Statement of Opportunities in accordance with Section 91DA of the National Gas Law.

This publication is based on information available to AEMO as at 31 July 2013, although AEMO has endeavoured to incorporate more recent information where practical.

Disclaimer

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Revision History

Number	Date	Notes
1	29 November 2013	First issue

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EXECUTIVE SUMMARY

The 2013 Gas Statement of Opportunities (GSOO) identifies opportunities for investment in natural gas infrastructure and reserves development to address potential gas shortfalls in eastern and south-eastern Australia. AEMO's modelling indicates that, under some scenarios, there may be potential shortfalls in Queensland and New South Wales, and some consumption[1] of known reserves basins over the 20-year outlook period.

The GSOO presents potential opportunities to address these supply adequacy shortfalls, including some augmentations that are already being considered by investors. Potential solutions that cross regional boundaries highlight the increasingly national nature of Australia's east coast gas market.

The emerging opportunities arise for a number of reasons.

In the short-term, demand for gas supplying new liquefied natural gas (LNG) export facilities at Gladstone is expected to create opportunities for up to 250 TJ/d[2] of additional processing capacity in Queensland and approximately 50–100 TJ/d in New South Wales by 2019.[3]

In the medium-term, opportunities exist for additional processing to supply projected domestic demand growth in New South Wales from 2018. Significant investment will be required over the longer-term in New South Wales, South Australia or Queensland, with Otway Basin reserves being consumed by around 2027.

Table E 1 summarises key observations by timeframe, and the potential opportunities identified.

Table E 1 — Common adequacy trends and opportunities

Time period	Trends and potential shortfalls	Infrastructure opportunities
Short term (now until 2019)	LNG export demand growth. Qld potential shortfalls. NSW potential shortfalls during peak periods.	Further production development in Qld. Development of new production in NSW. Augmentation of NSW–Vic Interconnect or the Eastern Gas Pipeline.
Medium term (prior to Otway consumption in 2027)	NSW potential shortfalls. Challenges supplying GPG in SA.	Unconventional gas development in the Cooper Basin. New transmission route between Qld and NSW.
Long term (2027 onwards)	Potential shortfalls in all southern states. Flows change after Otway consumption.	Significant new production in the Cooper Basin, Surat Basin, or Gunnedah Basin. Significant new transmission capacity for north to south delivery.

Growth in demand for natural gas

Gas demand for LNG facilities in Queensland is projected to rise from zero to approximately 1,450 PJ/a[4] between 2014 and 2019, posing significant challenges to producers to supply both domestic demand and LNG exports.

In contrast, domestic demand is projected to grow more slowly at approximately 0.9% annually from present consumption of around 620 PJ/a to approximately 750 PJ/a by 2033; this incorporates a projected fall in

[1] Consumption in this context means that all of the available 2P reserves and adjusted 3P and 2C reserves and resources have been converted to produced gas, with no further prospective resources reported as available.
[2] Terajoules per day.
[3] In addition to gas processing facilities already committed or under construction for supply to LNG liquefaction facilities.
[4] Petajoules per annum. One petajoule is equal to 1000 terajoules.

gas-powered generation (GPG) demand in the short term due to rising gas prices and lower carbon pricing projections.

Short-to-medium-term outlook

Potential gas supply shortfalls[5] may occur in Queensland if facilities that are currently dedicated to domestic demand are prioritised to supply rising LNG export demand. Without further production investment, potential shortfalls in Queensland may exceed 250 TJ/d once all six LNG trains reach full output: This is projected to occur in 2019.

If production in Queensland and South Australia is prioritised for export, there will be flow-on effects to New South Wales with potential shortfalls of 50–100 TJ/d over winter peak demand days from 2018.

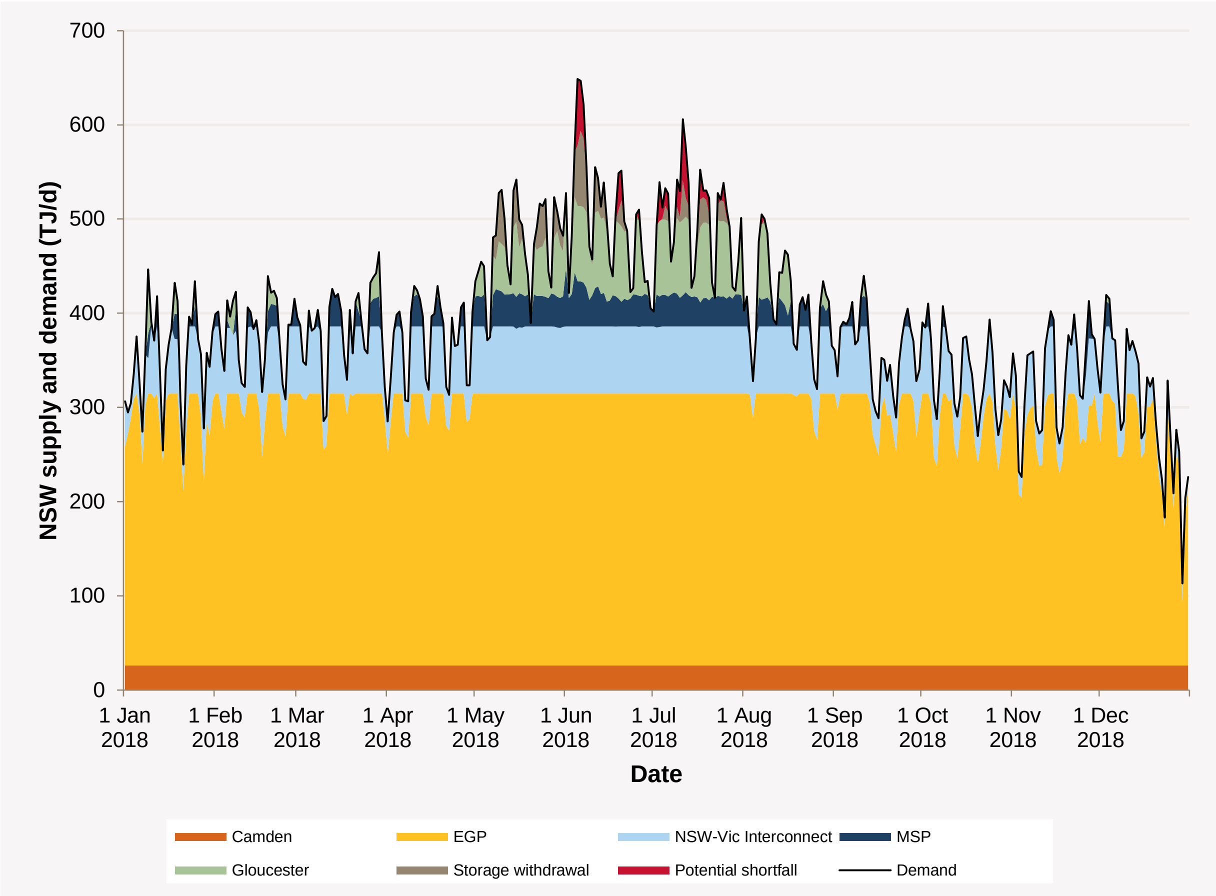
Committed and advanced projects in New South Wales[6] are not sufficient to completely alleviate these shortfalls without further support from the Moomba–Sydney Pipeline (MSP). Opportunities exist to augment transmission capability between Victoria and New South Wales, increase production in the Cooper Basin, undertake moderate development of the Gunnedah Basin, or develop an alternative transmission route between Queensland and New South Wales.

Figure E 1 shows projected daily supply and demand for New South Wales in 2018 under conditions of reduced flow availability on the MSP.

[5] Potential shortfalls highlight opportunities for investment in production, pipeline, processing, or storage facilities. They also indicate locations where competition for gas supply may impact domestic demand or the timing or scope of proposed projects.

[6] An LNG storage facility in Newcastle is due for commissioning in mid-2015. New production in the Gloucester Basin expected to become available in 2016 is well advanced, but is not committed.

Figure E 1 — New South Wales 2018 adequacy



Existing 2P[7] reserves are sufficient to meet projected demand until 2020, until consumption of known reserves in the Denison Trough and Otway Basin begins. This provides opportunities for new field development from that time.

Likewise, consumption of 2P conventional reserves begins in the Cooper Basin from 2025, providing opportunities for further conventional development, or unconventional (shale) reserves development from that time. Consumption of 2P reserves begins in the Bass Basin from 2025 and in the Gippsland Basin from 2026, providing opportunities for further conventional gas development in Bass Strait.

Long-term outlook

Gas is an abundant resource in eastern and south-eastern Australia. Analysis[8] indicates that sufficient reserves are likely to be commercially viable to satisfy projected gas demand for at least the next 20 years.

Despite the availability of gas resources, supply shortfalls may still occur as a result of constraints on existing infrastructure, the timing of new infrastructure, or difficulties and delays in converting resources into 2P reserves.

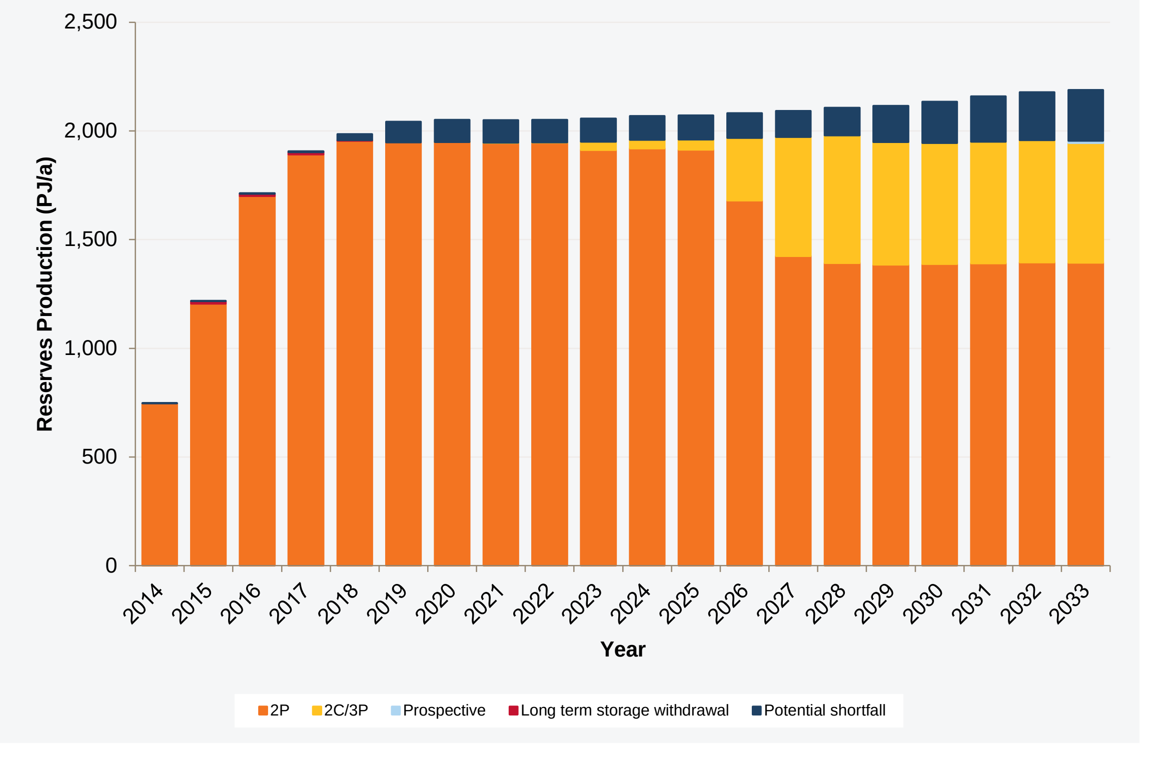
By 2027, consumption of 3P[9] reserves and 2C[10] resources in the Otway Basin are projected to begin.[11] If developed, 3P conventional reserves and 2C resources in the Cooper Basin, Bass Basin, and Gippsland Basin are projected to be sufficient until the end of the outlook period.

[7] 2P (proven plus probable) are reserves that are likely to be commercially recoverable.
[8] AEMO engaged Core to assess availability of 2P and 2C/3P reserves. The report is available at: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/GSOO-2013-Gas-Reserves-Update-and-Projections
[9] 3P (proven plus probable plus possible) are reserves volumes that are less certain than 2P reserves.

Consumption of Otway Basin reserves presents significant challenges for supply of gas to New South Wales, Victoria, and South Australia. Once conventional reserves in Victoria are consumed, current reserves estimates indicate new supply will be required from coal seam gas (CSG) reserves in Queensland and New South Wales, and unconventional reserves in South Australia. Analysis indicates that reserves in any one of these locations are sufficient to supply demand until the end of the outlook period; however, significant infrastructure investment will be required to deliver gas from northern production centres to southern demand centres.

Figure E 2 shows production from 2P and 3P/2C reserves and resources, together with projected supply shortfall where no further infrastructure development occurs.

Figure E 2 — Projected production and supply shortfall profile



[10] 2C (proven plus probable contingent) are reserves that are likely to be retrievable provided additional development costs can be recovered through higher commodity prices.

[11] 2C/3P reserves and resources considered are a fraction of reported 2C and 3P reserves deemed likely to be converted to 2P status.

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TABLES

FIGURES

1. PURPOSE

The Gas Statement of Opportunities (GSOO) provides an adequacy assessment of natural gas infrastructure to meet demand across eastern and south-eastern Australia over a 10-year outlook period, and the adequacy of gas reserves over a 20-year outlook period. The GSOO analyses demand and transmission, production, and reserves adequacy to highlight locations where growing demand presents opportunities to invest in new gas production or transmission infrastructure.

The GSOO provides industry participants, investors, and policy-makers with transparent information to support decision-making to ensure gas—a key resource—is managed in Australia's long-term interests.

1.1 Changes to the 2013 GSOO

The 2013 GSOO continues AEMO's planning publications transition to a more concise format focussing on key results with an accompanying suite of supplementary information. The GSOO supplementary information includes:

- Reserve and liquefied natural gas (LNG) projection reports.
- Data files containing additional modelling results.
- Updated gas pipeline, LNG, field development, and processing facility information.
- The GSOO Methodology document, providing further detail on the 2013 methodology and gas modelling improvements, including how development options were used to study infrastructure and reserves adequacy.

See Section 5 for links to supporting information.

2. MODELLING OVERVIEW

The 2013 GSOO modelling is based on the key economic assumptions provided in Table 2-1.[12]

Table 2-1 — Key economic assumptions in the GSOO modelling

	Economic growth	East coast gas prices	Carbon price assumption	Carbon emission reduction target[a]
Modelling assumption	Medium	4.70\$/GJ[b] – 13.67\$/GJ	Revised NIEIR trajectory based on 2013 NEFR[c]	5% by 2020 80% by 2050

a. Compared to 2000 levels.

b. Gigajoule.

c. The National Institute of Economic and Industry Research (NIEIR) revised the Treasury core scenario carbon prices for the National Electricity Forecasting Report (NEFR). The revised figures increase from 24.15 \$/tCO2-e[13] in 2013-14 to 46.22 \$/tCO2-e in 2033-34 (\$2013-14).

AEMO performs optimised network transport modelling based on daily gas demand projections and infrastructure availability to identify the location, timing, and magnitude of potential gas supply shortfalls.

These potential shortfalls in turn indicate the potential opportunities that exist for pipeline, processing, or reserves development. Modelling is performed on a simplified network topology, shown in Figure 1. In the diagram, existing or committed flow paths are represented by solid lines. Proposed flow paths are represented by dashed lines. The topology is designed to capture material characteristics of the physical network, shown in Figure 2.

[12] See AEMO's *2012 Scenarios Descriptions* for further scenario parameter information. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/2013-Planning-Assumptions. Viewed: 18 September 2013.
[13] Australian dollars per tonne of carbon-dioxide equivalent emissions.

Figure 3 illustrates the 2013 GSOO modelling approach, which explores potential future gas system development options to address potential shortfalls or facility limitations (processing and pipelines).

AEMO pursues two primary aims in option development:

- To explore the indicative investment in infrastructure required to ensure supply adequacy over a 10-year outlook period.
- To explore the production and associated reserve and resource development required to determine adequacy of reserves and indicate a reserve production profile over a 20-year outlook period.

The 2013 modelling approach considers potential solutions to address supply shortfalls observed in the model. The solutions modelled are intended to either:

- Indicate the level and type of investment that may be required to ensure supply adequacy (over a 10-year outlook), or
- Enable creation of a 20-year reserve production profile. (For instance, unless potential shortfalls are addressed in latter half of the 20-year outlook period, reserves development and production requirements to ensure adequacy cannot be accurately assessed.)

In each case, a range of alternative options are likely to be available for investigation by industry.

Further to the 2012 GSOO modelling investigations into the LNG export market and timeliness of reserve development, the 2013 GSOO assumes that supply to meet LNG export demand is prioritised due to industry incentives to meet contracted LNG volumes.

All scenarios are modelled assuming six committed LNG trains.

Figure 1 — Network transport model

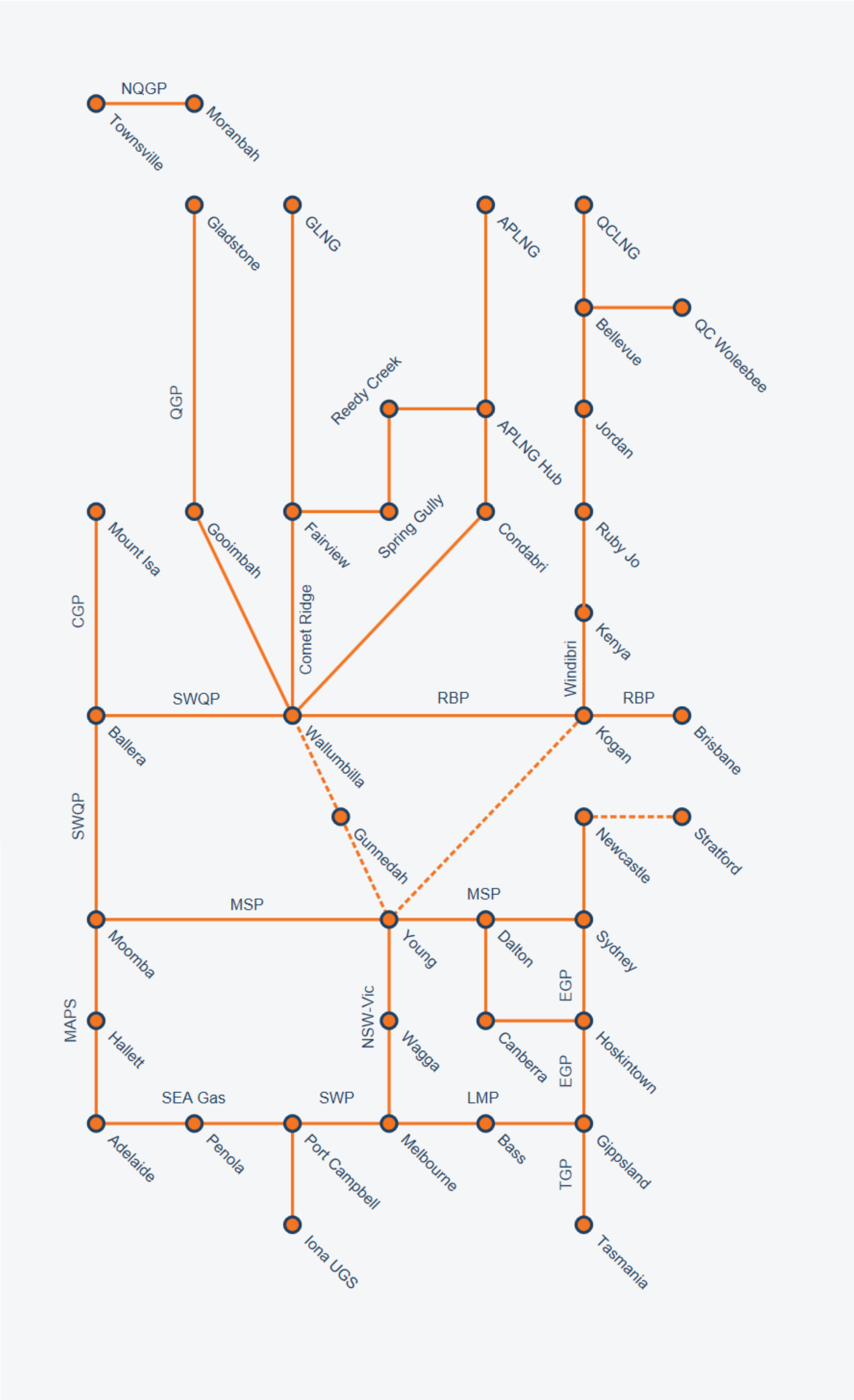


Figure 2 — Eastern and south-eastern Australian gas transmission system

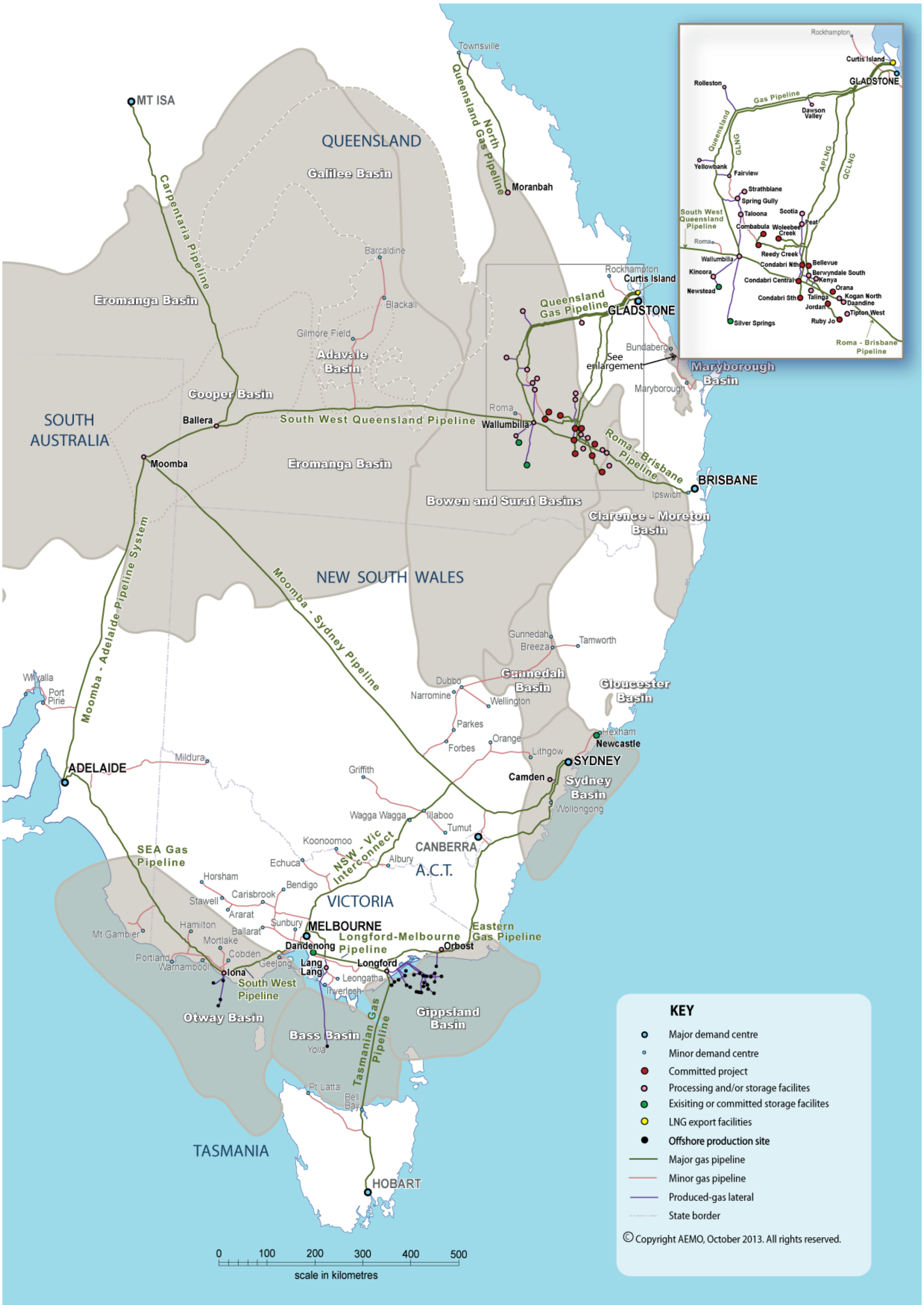
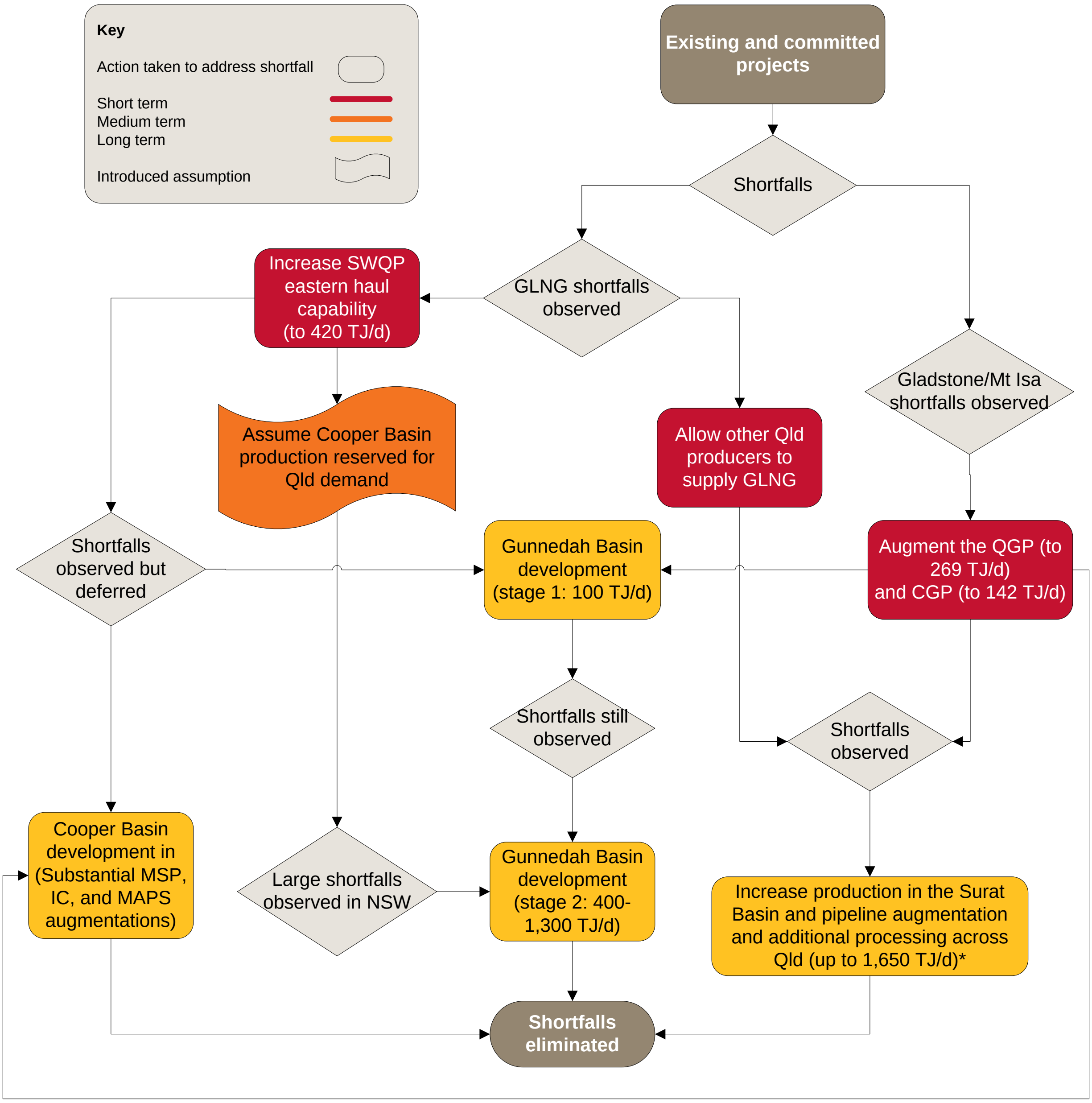


Figure 3 — Overview of the 2013 GSOO modelling approach



* Other pipelines including MAPS, MSP, SWP need augmentation from 2032 to eliminate shortfalls

Detailed modelling results are presented in Section 4. Appendix A provides more detail on the modelling assumptions.

Further detail on the modelling methodology and input assumptions is available in the 2013 GSOO Methodology document.[14]

[14] AEMO. *GSOO 2013 Methodology Document.* Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities.

3. GAS DEMAND PROJECTIONS

AEMO developed gas demand projections for the following gas market segments:

- Mass market (MM), comprising residential and business demand of less than 10 TJ/a.[15]
- Large industrial (LI), comprising consumers with gas demand greater than 10 TJ/a.
- Gas-powered generation (GPG).
- Liquefied natural gas (LNG) export.

In the following, *total gas demand* refers to all four market segments, while *domestic gas demand* refers to the MM, LI, and GPG segments only.

Eastern and south-eastern Australia is further divided into five demand groups along state lines (Queensland, New South Wales and the Australian Capital Territory, Victoria, South Australia, and Tasmania). See the 2013 GSOO Methodology document for further information on demand groups.

Section 3.1 summarises annual gas demand by market segment and demand region, including comparisons to adjusted 2012 forecasts. Adjustments have been made to the forecasts presented in the 2012 GSOO to ensure data is consistent with that presented in 2013.[16] For further information:

- The demand projection methodology is available in the 2013 GSOO Methodology document.[17]
- Annual and peak gas demand and associated drivers is available in the Gas Demand Forecasts for the 2013 GSOO data set.[18]

3.1 Total annual gas demand

Total annual gas demand is expected to increase from 745 PJ in 2014 to 2,182 PJ in 2033.

Gas demand for LNG facilities in Queensland is projected to rise from zero to approximately 1,450 PJ/a between 2014 and 2019, posing challenges to producers to supply both domestic gas demand and LNG exports.

By 2033, LNG export is projected to account for 66% of total annual gas demand. Further detail on gas demand for LNG export is available on AEMO's website.[19]

In contrast, domestic annual gas demand is projected to grow more slowly at approximately 0.9% annually from present consumption of around 620 PJ/a to approximately 740 PJ/a by 2033; this incorporates a projected fall in gas-powered generation (GPG) demand in the short term due to rising gas prices and lower carbon pricing projections.

Figure 4 shows projected demand growth over the 20-year outlook period.

Comparison of 2013 and 2012(adjusted) GSOO annual gas demand forecasts shows that over the outlook period (2014-33):

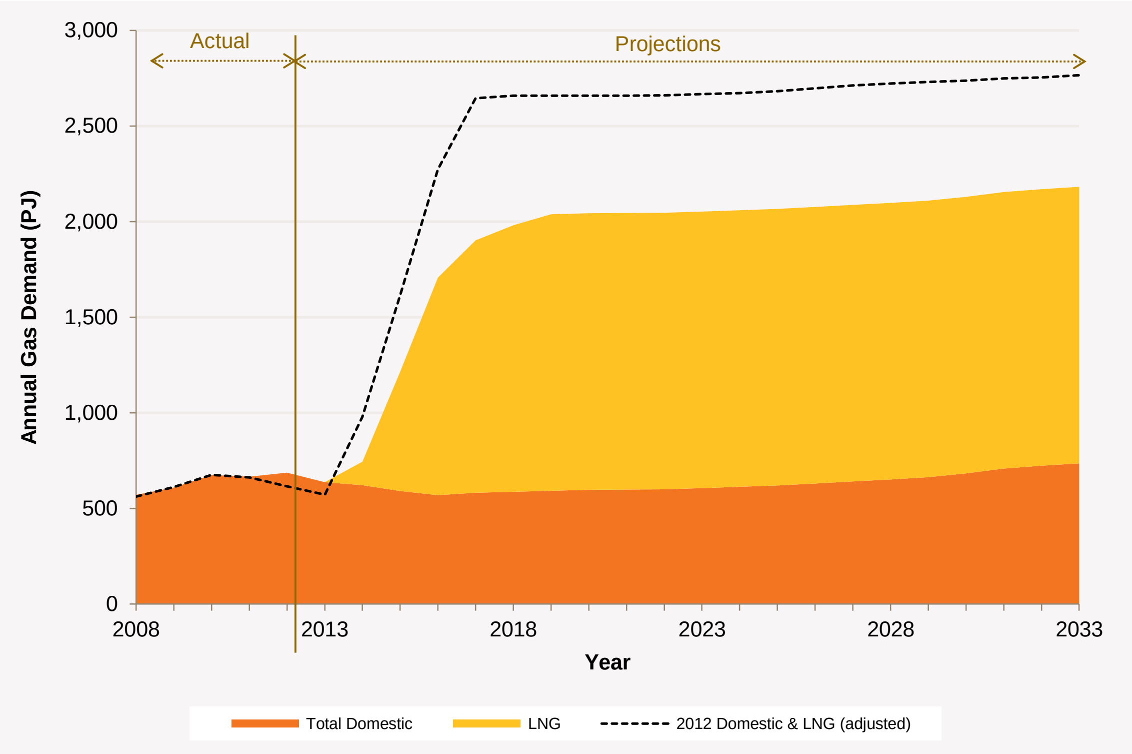
- Gas demand for LNG production is expected to peak at 1,446 PJ/a compared to 2,046 PJ/a in 2012 (adjusted). The primary reason for the difference is that 2013 forecasts consider only the six committed

[15] Terajoules per annum.
[16] 2012 projections of GPG have been adjusted to account for model improvements implemented in 2013; and LNG export demand has been adjusted to remove gas field (processing) losses.
[17] Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities.
[18] Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities.
[19] Available: http://aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/GSOO-2013-LNG-Projections.

liquefaction trains, consistent with the 2013 National Electricity Forecasting Report. The 2012 projections considered both committed and proposed projects, totalling eight trains.

- Domestic annual gas demand growth is lower than that projected in 2012 (adjusted), reflecting lower growth in the GPG and LI market segments.

Figure 4 — Total annual gas demand



3.1.1 Domestic annual gas demand

Figure 5 shows domestic annual gas demand projected to increase from 622 PJ in 2014 to 736 PJ in 2033, an average annual growth of 0.9%.

Projected growth in domestic annual gas demand is driven by the MM and LI market segments and is partly offset by falls in GPG. LI is the largest contributor, accounting for approximately 51% of total domestic annual gas demand in 2033.

Figure 6 shows a comparison between domestic annual gas demand projections in 2013 and adjusted 2012 projections.

Projected growth in domestic annual gas demand is lower than that presented in 2012 (adjusted).
In 2013 projections:

- MM demand growth is higher due to lower projected gas price growth and higher projected economic growth.
- GPG demand growth is lower, reflecting lower electricity demand and changes to electricity and carbon price assumptions.
- LI demand growth is lower due to decreased expectations for development of new gas-intensive projects.

Figure 5 — Annual domestic gas demand

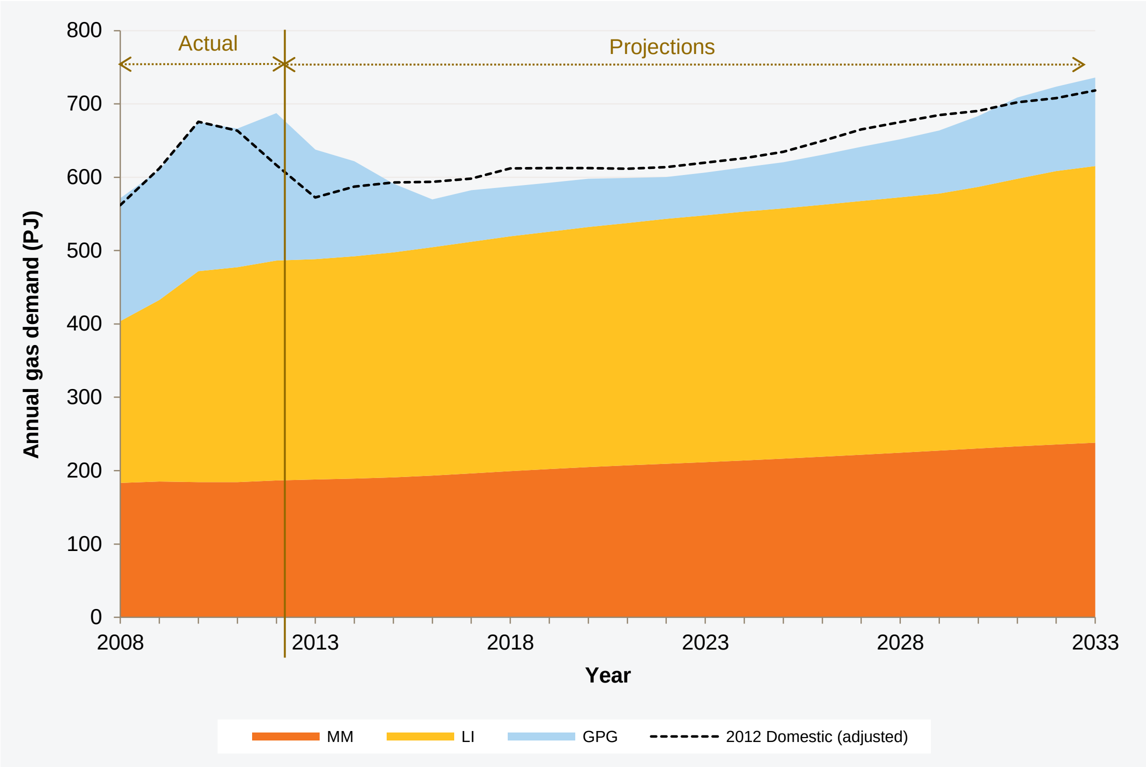
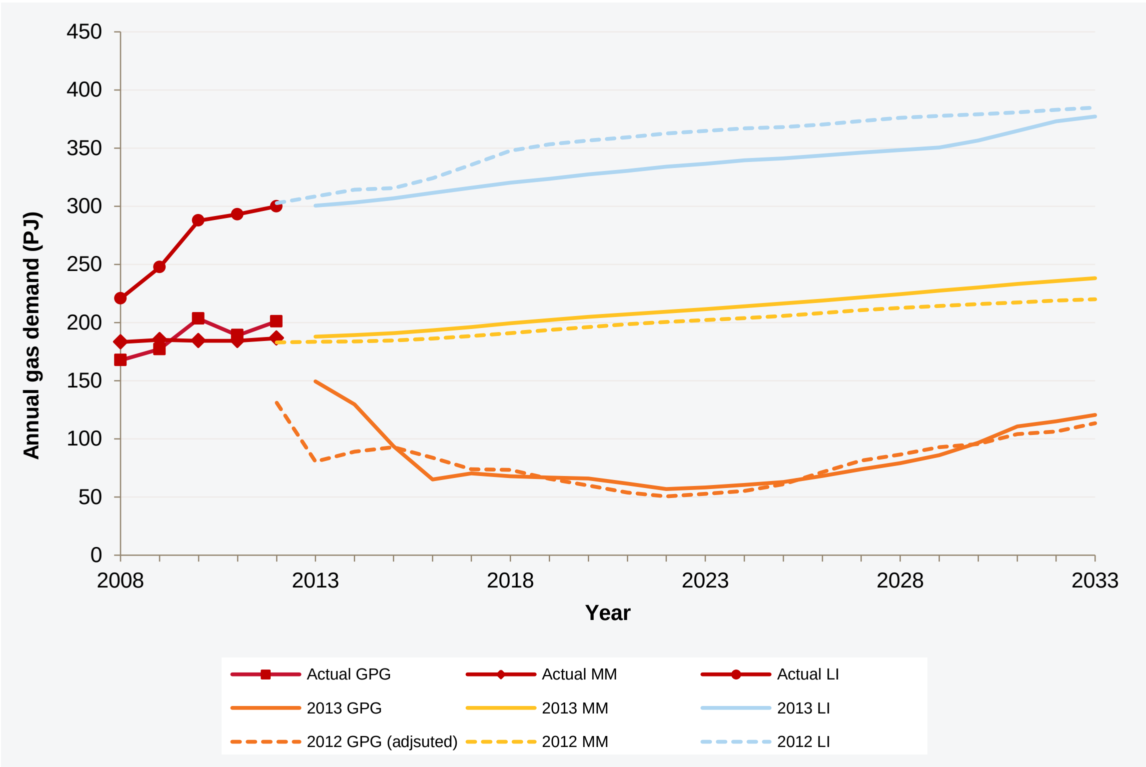


Figure 6 — Comparison of 2012 and 2013 annual domestic gas demand projections



Domestic annual gas demand by market segment

On a market segment basis:

- MM demand is expected to grow at an average annual rate of 1.2% over the 20-year outlook period. This is driven by growth in real household per capita incomes, a moderation in residential and business gas price growth, growth in household dwelling numbers, and positive economic growth over the outlook period. The growth is dominated by the residential sector in New South Wales and Victoria.
- LI demand is expected to grow at an average annual rate of 1.2% over the 20-year outlook period. This is driven by a moderation in energy price growth compared to recent years, and assumed positive economic growth over the outlook period for energy-intensive industry sectors in New South Wales and Queensland.
- GPG demand is expected to fall by an average annual rate of 0.4% over the 20-year outlook period. The trajectory is characterised by an average annual decline of 9.8% from 2014 to 2022, due to decreasing electricity demand and low carbon price assumptions. A gradual recovery from 2022 to 2032 is projected as electricity demand increases.

Domestic gas demand by demand group

Table 3-1 summarises average projected annual growth over the outlook period by demand group.
Key observations are:

- Over the outlook period, demand growth is relatively subdued across eastern and south-eastern Australia, with only Tasmania and Queensland's average annual growth rate above 1%. Growth in Tasmania is primarily driven by projected increases in LI, which is the largest market segment there. In Queensland growth reflects LI activity, including basic and fabricated metal manufacturing.
- In Victoria and South Australia MM growth is higher than LI growth, which is flat or declining. Both MM and LI contribute to domestic gas demand growth in New South Wales.
- With the exception of Tasmania and Victoria, GPG demand declines over the outlook period reflecting slower growth in electricity demand and an assumed reduced price on carbon emissions.
- GPG demand in Tasmania and Victoria comes off a relatively low base (less than 1 PJ) in 2014. While it grows over the outlook period, it is a small contributor to total annual gas demand, at 3% and 16% of 2033 total gas demand in Victoria and Tasmania respectively.

Figure 7 shows annual MMLI gas demand by demand group. Figure 8 shows annual GPG gas demand by demand group.

Table 3-1 — Average annual domestic gas demand growth by demand group and market segment

		SA	VIC	TAS	NSW/ACT	QLD	Total
Average annual growth rate (2014–33)	GPG	-0.4%	12.6%	3.5%	-2.3%	-0.7%	**-0.4%**
	MM	0.7%	1.1%	2.7%	1.6%	2.4%	**1.2%**
	LI	0.4%	0.2%	1.3%	1.3%	1.7%	**1.2%**
	Total	**0.0%**	**1.0%**	**1.9%**	**0.8%**	**1.1%**	**0.9%**

Figure 7 — Annual MMLI gas demand by demand group

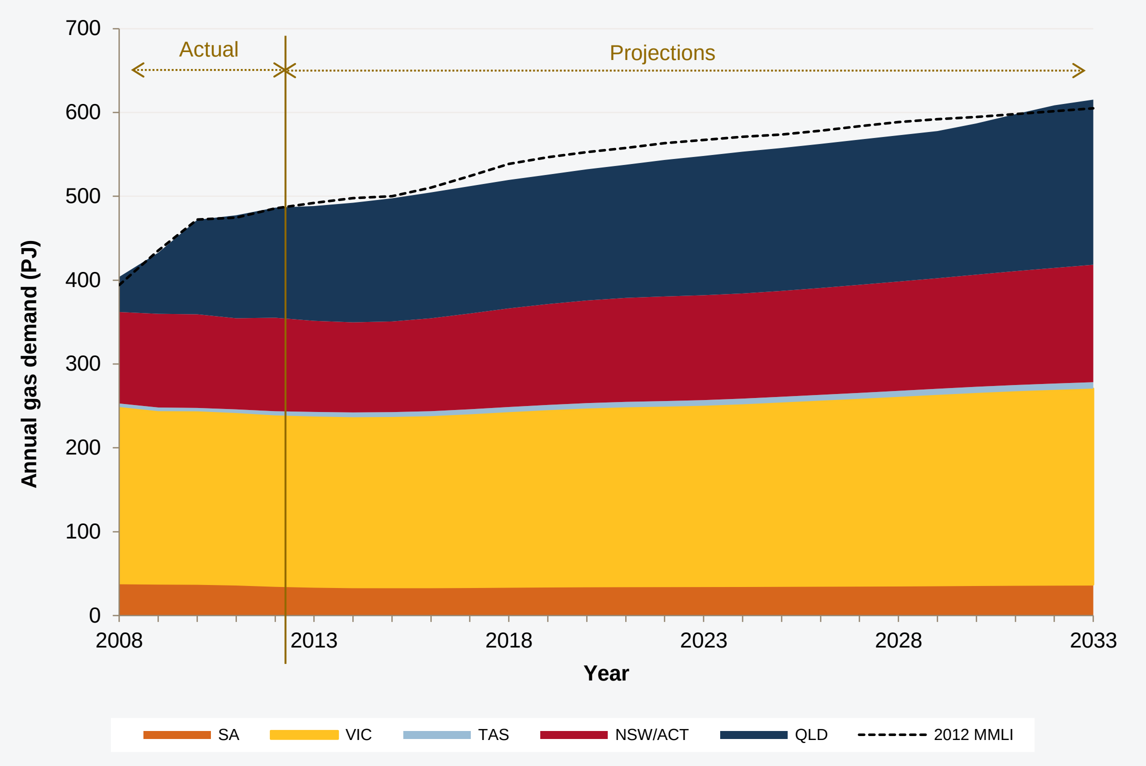
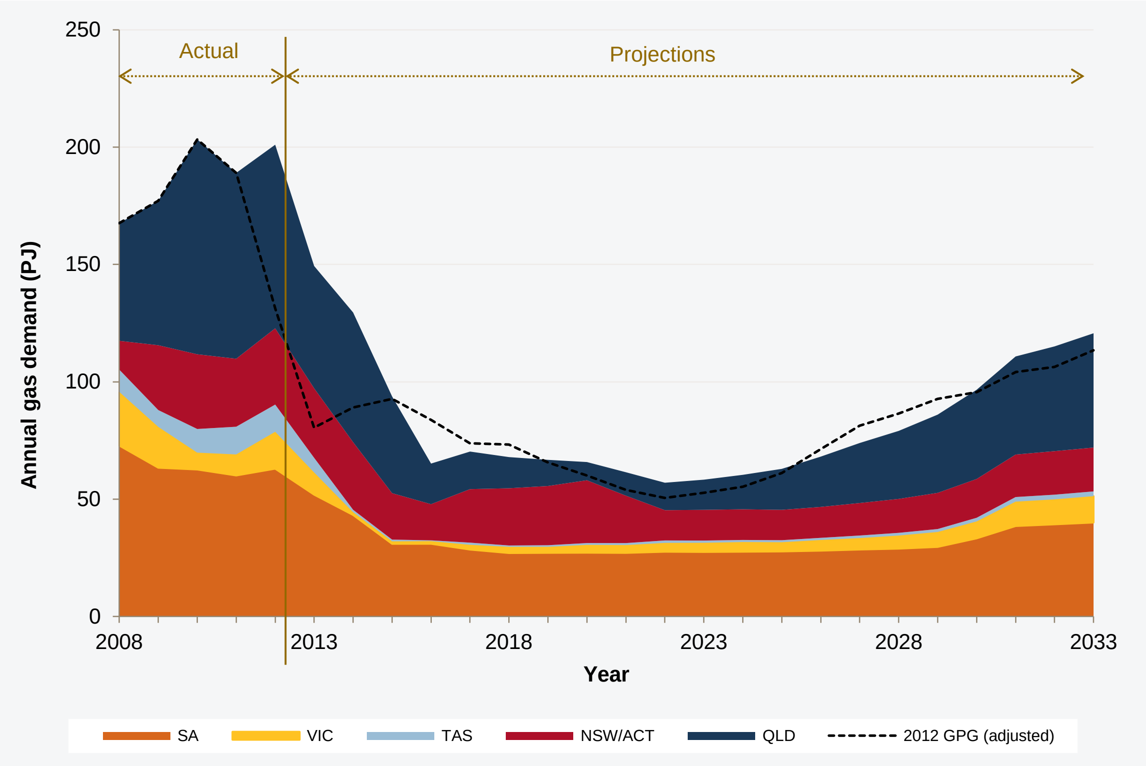


Figure 8 — Annual GPG gas demand by demand group



4. ADEQUACY RESULTS

This section details the adequacy results from the modelled development path depicted in Figure 3. Unless specified otherwise, the results presented are based on the 1-in-20 peak demand condition.[20] The 1-in-2 peak demand condition[21] provides similar results, in some cases with potential shortfalls appearing later, or their magnitude reduced.

Throughout this section, modelling results indicating that supply is insufficient to meet demand are referred to as "potential shortfalls". This is intended to signal potential opportunities for investment in production, pipeline, processing, or storage facilities. Potential shortfalls are not intended to predict future shortfalls unless they occur before there is an opportunity for market correction. In this case, a market response affecting the timing or scope of projects could result, with potential shortfalls avoided due to lower demand.

4.1 Infrastructure adequacy

Modelling of existing production and transmission and committed projects[22] indicates that potential shortfalls may occur primarily in Queensland in the short-term. The 2013 modelling assumes that liquefied natural gas (LNG) demand is prioritised above domestic demand. The magnitude and timing of the resulting potential shortfalls is shown in Figure 9, with detail for Queensland shown in Table 4-1.

Table 4-1 — Timing and magnitude of potential shortfalls (existing and committed projects only)

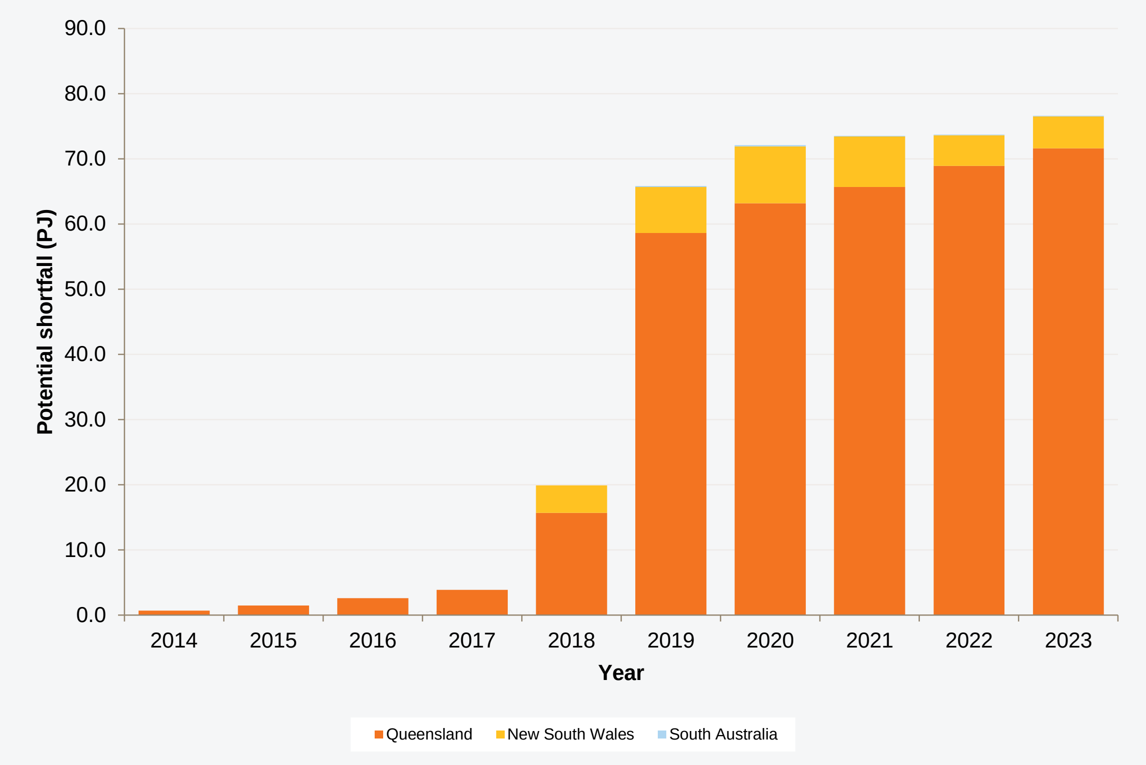
Location	Timing	Magnitude (TJ/d)
Supply to Gladstone LNG	From 2018	83 TJ/d.
Gladstone	From 2014	19–86 TJ/d from 2014 to 2018. At least 150–250 TJ/d between 2015 and 2019. From 300–350 TJ/d between 2019 and 2027.
Mount Isa	From 2018	From 20 TJ/d (with intermittent peaking between 30 and 80 TJ/d until Otway consumption[23] in 2027).

Potential shortfalls (frequently 50 TJ/d, but peaking to above 100 TJ/d) are also present in New South Wales[24], from 2018. Challenges supplying gas-powered generation (GPG) in Adelaide may arise from 2019; however, shortfall magnitudes are small and short-lived, indicating potential to use pipeline linepack to manage supply.

Supply to Queensland demand is constrained by transmission limitations for delivery of gas to Wallumbilla. Surplus production capacity exists both in South Australia and western Queensland, and in the Surat Basin between Wallumbilla and Brisbane. Further augmentation of the South West Queensland Pipeline (SWQP) for eastern haul flow, pipeline augmentation to deliver gas to Wallumbilla from production near Miles, or gas swap agreements may significantly reduce observed potential shortfalls.

[20] 1-in-20 peak demand conditions refer to a peak demand that is expected to be exceeded one year in every twenty years.
[21] The 1-in-2 results are available in the accompanying data files from AEMO's GSOO website: http://aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities.
[22] Where possible, existing and committed projects are modelled as per facility information provided by market participants published on the GSOO webpage at http://aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities. Key assumptions of interest that differ from this are also detailed in Table A-1. Further detail on the basis of facilities data included in the model is available from the GSOO Methodology document.
[23] Consumption in this context means that all of the available 2P reserves and adjusted 3P and 2C reserves and resources have been converted to produced gas, with no further prospective resources reported as available. At other times consumption refers to 2P reserves only; where this is the case the specific classification of reserves or resources under discussion is qualified in the text.
[24] The modelling results frequently refer to "southern states"; this includes New South Wales and the Australian Capital Territory, Victoria, South Australia, and Tasmania.

Figure 9 — Annual potential shortfalls over the 10-year infrastructure outlook, existing and committed projects only



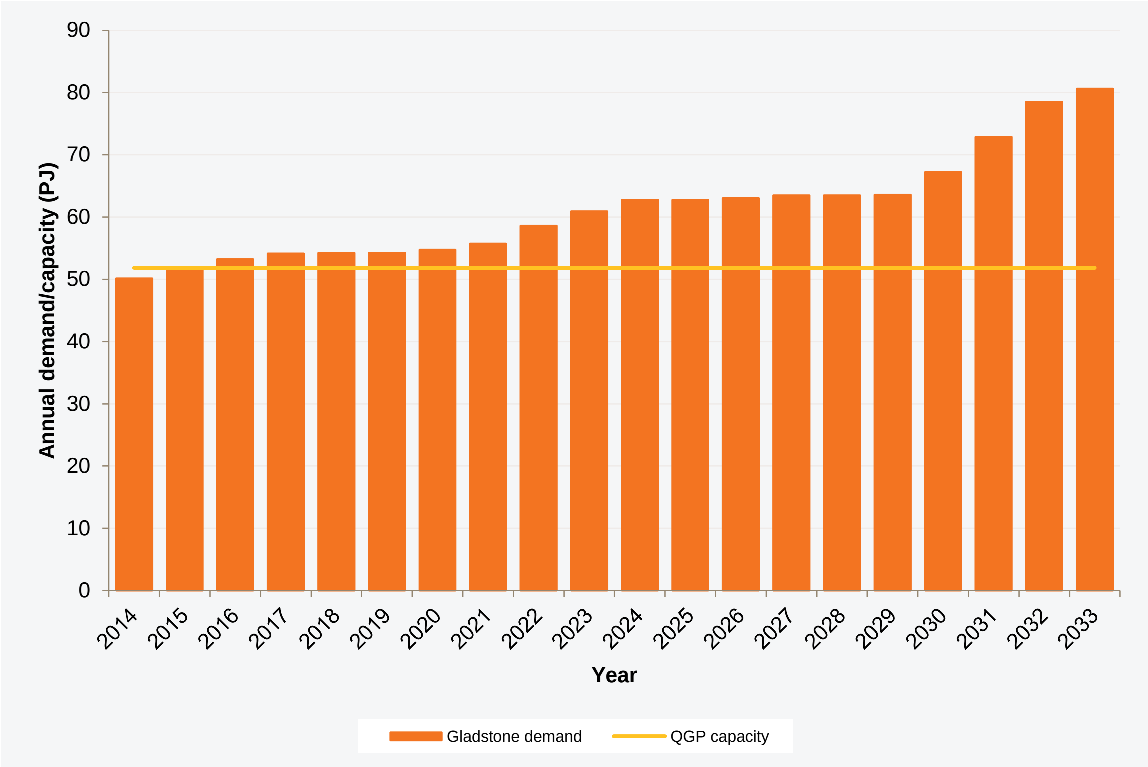
4.1.1 Gladstone and Mount Isa

Potential shortfalls for supply to domestic customers in Gladstone and Mount Isa may occur due to rising demand, assuming that pipeline transmission capacity is not increased and gas destined for LNG facilities is not available to meet domestic requirements.

In Gladstone, rising domestic demand is projected to exceed Queensland Gas Pipeline (QGP) capacity from 2015, as shown in Figure 10. AEMO's modelling approach is to meet demand where possible; this ensures reserves adequacy is assessed. Analysis indicates that QGP capacity may need to be increased from 142 TJ/d to 269 TJ/d by the end of the 20-year outlook period. Jemena advises that a minor augmentation of QGP capacity is planned, due for commissioning in 2015.

As reported in the 2012 GSOO, supply limitations may impact demand growth, or alternative solutions may be presented (for example delivery of gas to domestic customers via LNG export pipelines currently under construction).

Figure 10 — Gladstone annual domestic demand and QGP capability



In Mount Isa, demand consistently but infrequently exceeds Carpentaria Gas Pipeline (CGP) capacity from 2015 onwards. These short-lived potential shortfall events are likely to be managed using the pipeline's linepack. After 2020, increasing frequency of shortfall events indicates that moderate pipeline augmentation from 119 TJ/d to 142 TJ/d may be required by the end of the 20-year outlook period.

4.1.2 Gladstone LNG

Potential shortfalls for supply to the Gladstone LNG (GLNG) liquefaction plant may occur as the facility ramps up to its fully-contracted production capacity. AEMO assumed production of LNG at the GLNG facility reaches its maximum in 2019. At this time, shortfalls of over 80 TJ/d were observed at the facility.

Modelled flow into the facility is limited by both available production and transmission constraints. GLNG sources its supply from production at Fairview, Roma, the Cooper Basin, and third parties under contract. Potential shortfalls may occur when:

- Production facilities at Fairview and Roma are maximised.
- Flow from third parties is maximised.
- Flow in an easterly direction on the SWQP is maximised.

Potential GLNG shortfalls may be addressed by either:

- Additional production at Fairview.
- Additional third party supply contracts (collaboration between LNG exporters).
- Increased eastern flow capability on the SWQP.

AEMO's modelling in the first instance considers existing and committed processing and transmission projects only. The timing of observed shortfalls, four to five years from now, is sufficiently distant to expect that not all projects planned to contribute to supply GLNG will have achieved committed status.

In addition, observed shortfalls, although equivalent to the demand of a typical combined cycle gas turbine (CCGT) power station, are small compared to total GLNG liquefaction facility demand, projected to reach 1,220 TJ/d in 2019.

The projected demand also incorporates assumed system losses of 15%. New facilities at Fairview that are proposed but not committed or a revision of system losses may release suitable amounts of production to relieve the observed shortfalls. In the interests of system adequacy assessment, AEMO did not model these options, instead focusing on transmission augmentation or third party supply options.

To assess the potential for additional third party contracts to supply GLNG, AEMO modelled a case where an augmentation allowing a gas flow reversal along the Roma–Brisbane Pipeline (RBP) provided increased access to Wallumbilla for production located between Wallumbilla and Brisbane. This was sufficient to eliminate shortfalls at GLNG, and formed part of a potential strategy to eliminate shortfalls on the entire system. This case is discussed in detail in Section 4.2.2.

To assess the potential for additional supply to be sourced from production at the Cooper Basin, SWQP easterly flow capability was increased from 340 TJ/d to 420 TJ/d. This was sufficient to eliminate shortfalls at GLNG; however, potential shortfalls for domestic demand in New South Wales were advanced due to a consequential flow reduction on the Moomba–Sydney Pipeline (MSP).

4.1.3 New South Wales

Media reporting of potential gas supply shortfalls in New South Wales has recently increased in frequency. This is in response to increased landholder resistance to coal seam gas (CSG) activities and the introduction of New South Wales government policies to limit the potential effects of CSG exploration and production on water catchments critical to agriculture.

Modelling of existing and committed projects shows that supply shortfalls may occur in New South Wales from winter 2018. AEMO modelled several potential future scenarios specific to New South Wales supply to improve understanding of system conditions underlying the observed shortfalls.

Figure 11 shows potential shortfalls of supply to New South Wales in 2018, in an environment where:

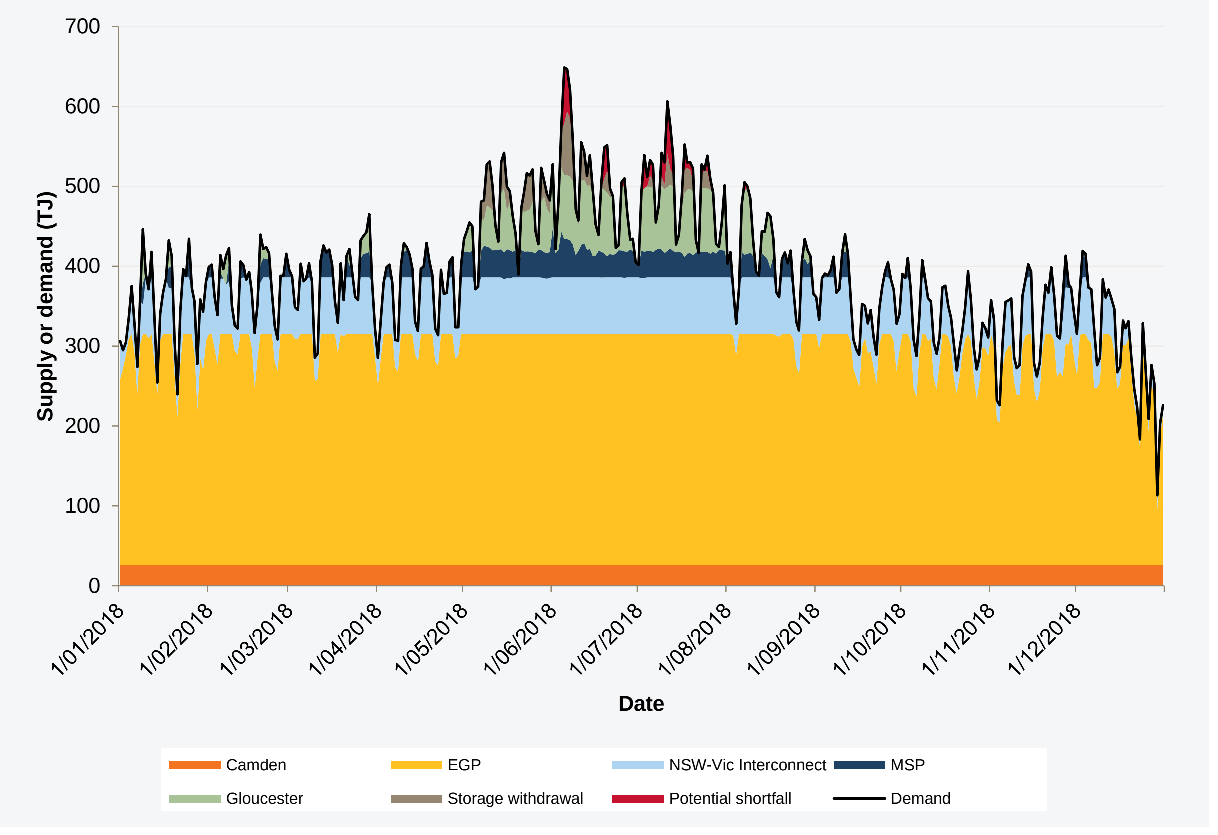
- Supply from the Cooper Basin is limited due to prioritising supply to LNG export facilities.
- An 80 TJ/d production facility proceeds at Gloucester.
- A new LNG storage facility at Newcastle provides peak-shaving services over winter.

In the figure:

- Gas continues to flow on the MSP to support demand in New South Wales, although at significantly lower volumes than today.
- Reduced MSP flow increases reliance on gas supplied to New South Wales from Victoria, with both the Eastern Gas Pipeline (EGP) and the NSW–Vic Interconnect flowing at maximum capability during May, June and July.
- Peak-shaving LNG storage located in Newcastle alleviates the frequency and duration of shortfalls, but does not eliminate them.
- New production at Gloucester alleviates, but does not eliminate, shortfalls.
- Shortfalls are relatively short-lived, with demand falling significantly over the weekend following each peak. MSP linepack may be sufficient to provide additional supply through the shortfall periods; however, shortfalls occur where production is already at maximum capacity, and sufficient capacity to recharge pipeline linepack may not be available.
- Sufficient MSP capacity is available to avoid shortfalls if Cooper Basin production is not prioritised for LNG export.
- The magnitude of shortfalls, when they occur, does not exceed the demand for gas due to GPG. That is, shortfalls may be avoided if alternative sources of electricity generation can be secured.

- Production at Gloucester is modelled as a last-resort source; however, historical analysis at Camden indicates that production at Gloucester is likely to follow a constant-output profile. This will reduce New South Wales reliance on MSP, EGP, and interconnect transmission over the spring, summer, and autumn months.
- Outcomes do not consider gas supply contracts for delivery to New South Wales demand centres, only the capability of the physical system to meet demand. Inefficiencies introduced by contractual relationships that reserve pipeline or production capacity, leaving portions of either unutilised, may increase the frequency or magnitude of observed shortfalls, or advance their timing.

Figure 11 — Supply to NSW in 2018 assuming LNG export prioritisation



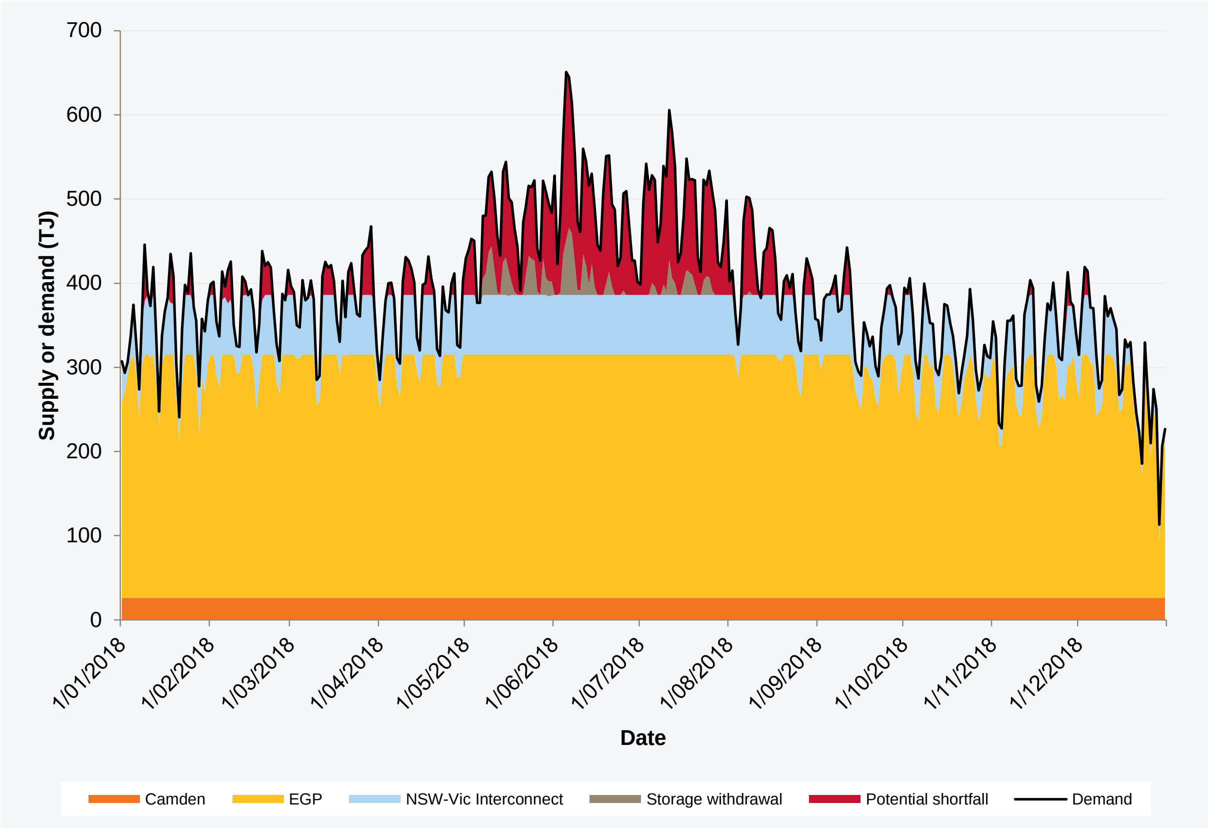
Observed potential shortfalls increase slowly in frequency and magnitude until 2027, when consumption of conventional gas reserves in the south begins to affect supply across the system.

The magnitude and first appearance of potential supply shortfalls in New South Wales is sensitive to actions taken by producers in the Cooper and Gloucester basins. To assess this sensitivity, AEMO modelled a case where:

- SWQP easterly flow capability is increased to 420 TJ/d, to supply shortfalls at GLNG from the Cooper Basin.
- Production in the Cooper Basin is reserved for supply to Queensland demand.
- Production in the Gloucester Basin is delayed or abandoned.

Under these conditions, which are only feasible once existing Cooper Basin supply contracts to customers in the southern states expire, immediate potential shortfalls may occur in New South Wales in the order of 100 TJ/d to 200 TJ/d. Figure 12 shows estimated potential shortfalls of 11 PJ across seven months of 2018 under these conditions.

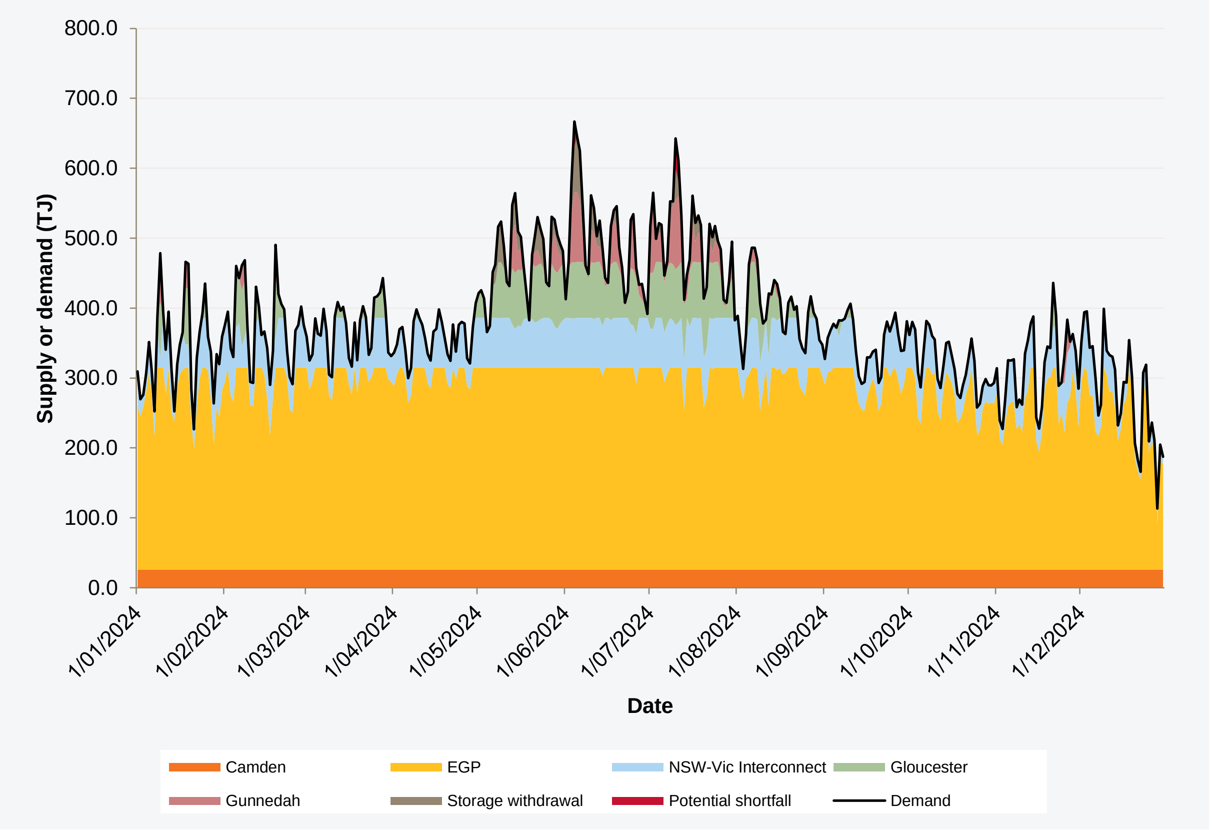
Figure 12 — Supply to NSW in 2018 assuming Cooper Basin production reservation



To assess New South Wales' capability for increased self-supply, AEMO also considered a moderate development in the Gunnedah Basin (100 TJ/d). In this case, shortfalls observed in New South Wales are deferred until 2024. Figure 13 shows supply to New South Wales demand in 2024 in an environment where:

- Cooper Basin production is reserved for demand in Queensland.
- Production in the Gloucester Basin proceeds (80 TJ/d).
- Production in the Gunnedah Basin proceeds (100 TJ/d).

Figure 13 — Supply to NSW in 2024 assuming Cooper Basin production reservation and moderate development of the Gunnedah Basin



4.2 Reserves adequacy

Gas is an abundant resource in eastern and south-eastern Australia. Analysis indicates that sufficient reserves and resources are likely to be commercially viable to satisfy projected gas demand for at least the next 20 years.

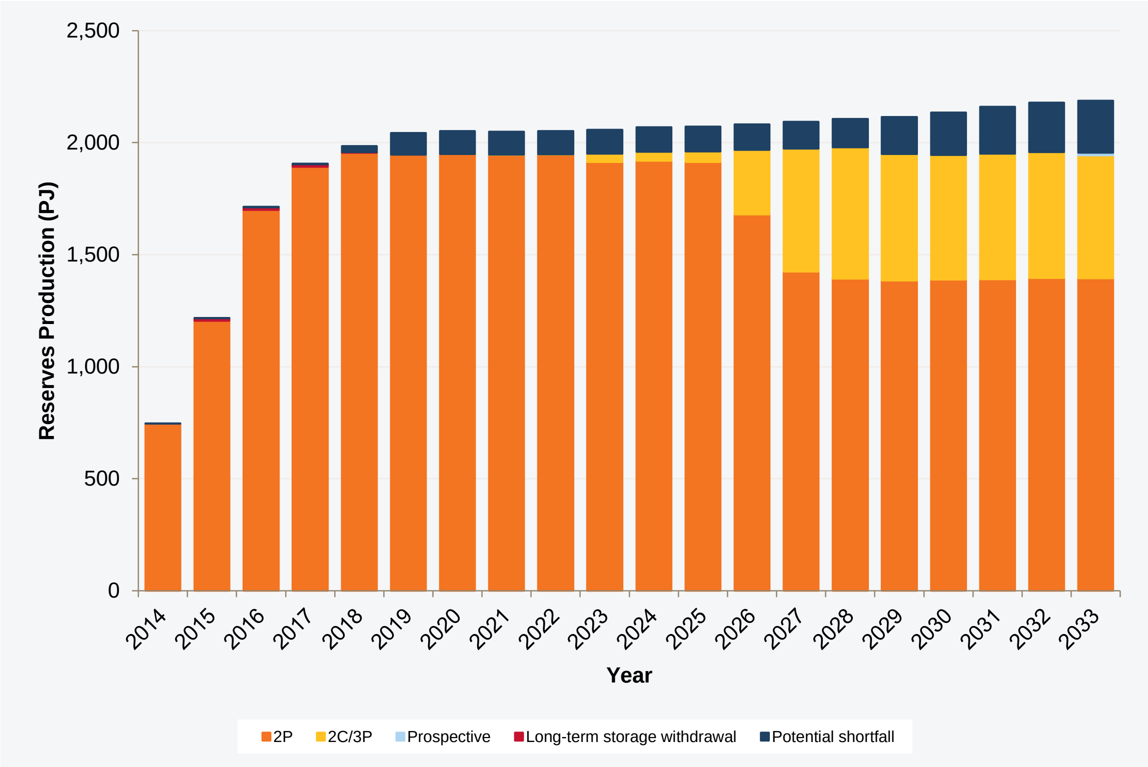
The GSOO considers reserves in four tranches:

- Proven and probable (2P) reserves, indicative of best estimates of commercially viable gas in the ground.
- Best estimate contingent (2C) resources, indicative of best estimates of gas in the ground that is commercially viable under conditions of increased commodity prices.
- Proven, probable and possible (3P) reserves, indicative of potentially commercially viable gas in the ground where volumes are less certain than the 2P classification.
- Prospective resources, indicative of gas that is both uncertain in volume and commercially viable only under increased commodity prices.

AEMO models volumes of 2P reserves, 3P/2C reserves and resources, and prospective resources in three separate tranches with increasing production cost. Within each tranche, reserves are partitioned by cost and volume according to location and type (conventional, unconventional, and CSG), with gas processing facilities frequently having access to multiple partitions. Production cost differences lead to production from increasingly expensive reserves over time.

Figure 14 shows the reserves production profile for modelling with existing and committed projects only, together with potential shortfalls observed due to infrastructure limitations.

Figure 14 — Production profile, existing and committed projects

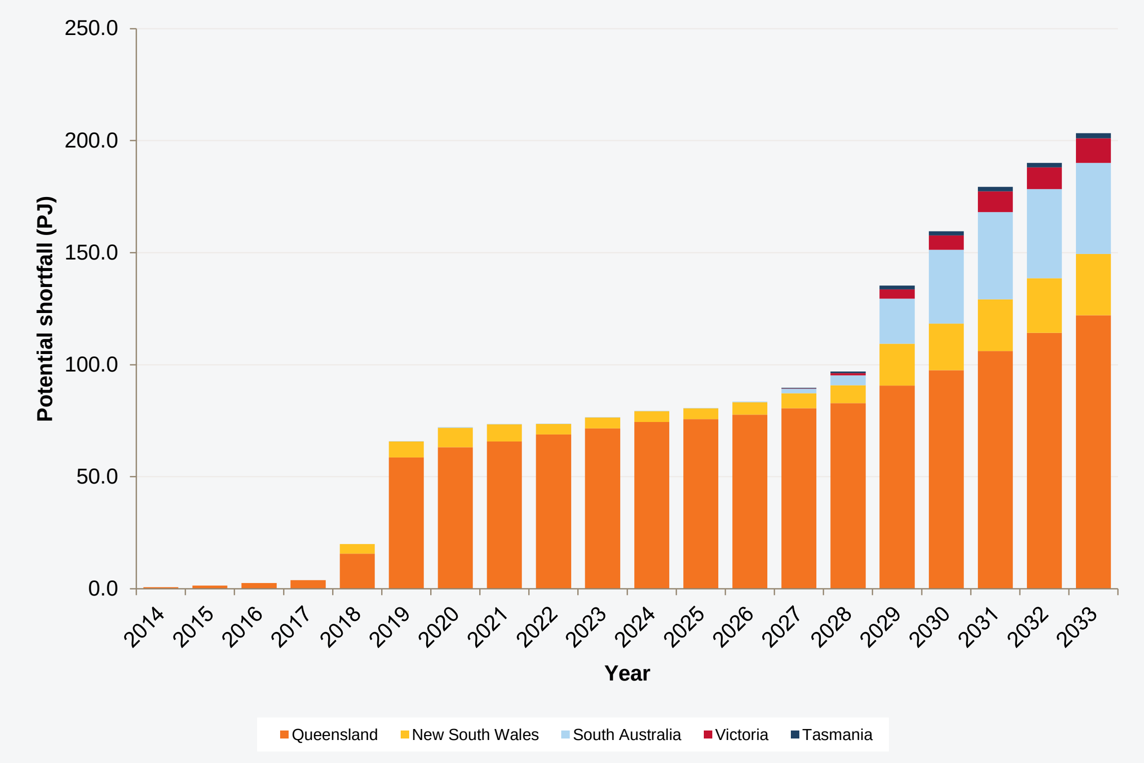


Key features of Figure 14 include:

- The ramp-up of demand for LNG export between 2014 and 2018.
- Small potential shortfalls in Gladstone and Mount Isa due to pipeline limitations from 2015 onwards.
- Increasing potential shortfalls from 2019 onwards, after LNG liquefaction facilities achieve full output.
- Increasing development of 3P/2C reserves and resources in the Otway Basin between 2020 and 2026.
- Development of 3P/2C reserves and resources in the Bass and Cooper basins in 2026.
- Development of 3P/2C reserves and resources in the Gippsland Basin by 2027.
- Persistence of 2P reserves, approximately equal to the requirements of the six committed LNG trains, to the end of the 20-year outlook period.
- Consumption of Gippsland 3P/2C reserves and resources at the very end of the 20-year outlook period and subsequent reliance on prospective resources in that location.

Figure 15 details the potential shortfalls shown in Figure 14. Consumption of conventional 2P reserves in the Denison Trough and growth in domestic demand accounts for shortfall increases observed between 2019 and 2027. This period is characterised by development of conventional 3P/2C reserves and resources in the Otway, Cooper, and Gippsland basins.

Figure 15 — Annual potential shortfalls, reserves outlook, existing and committed projects



By 2027, reserves in the Otway Basin are not expected to be sufficient to maintain production at the full capacity of processing facilities located at Port Campbell. Potential shortfalls increase in 2029 as the last available 3P/2C reserves and resources in the Otway Basin become consumed.

Loss of production at Port Campbell results in significantly changed flows as the model attempts to source gas from other locations. Transmission limitations begin to constrain flow where capacity would previously have been sufficient. The change in flow implies significant infrastructure development will be required elsewhere to support the development of new reserves.

The projected consumption of Otway Basin reserves occurs at a pivotal time for electricity generation. Modelling undertaken for the 2013 NTNDP, used to forecast GPG demand, indicates an increased uptake of GPG in Victoria and South Australia after 2030.

Low carbon pricing and the absence of the Large-scale Renewable Energy Target (LRET) reduce the attractiveness of renewable generation, and demand growth is primarily addressed by GPG post-2030. At the same time, the NTNDP model retires the Northern Power Station in South Australia, replacing that capacity with GPG. These changes come at a challenging time for gas supply to South Australia: it is likely that alternative sources of gas, potentially from unconventional development in the Cooper Basin, will need to be secured for GPG outcomes projected by the NTNDP to be realised.

4.2.1 Reserves development assessment

To assess the adequacy of reserves system-wide, the potential shortfalls identified above must be eliminated; not supplying gas is not considered an adequate strategy for extending the life of reserves.

To eliminate potential shortfalls, AEMO considered a range of potential solutions based on single-source developments, including:

- Supply from the Gunnedah Basin.
- Supply from the Surat Basin.

- Supply from unconventional reserves in the Cooper Basin.

AEMO's analysis indicates that reserves supplying any one of the considered single-source solutions are adequate to supply demand until the end of the 20-year outlook horizon. While AEMO does not expect that in practice a single development will be used to address all shortfalls, modelling such developments provides a simplified view of reserves adequacy: each potential source indicates the magnitude of infrastructure and gas reserve development required to ensure adequacy.

The results presented in this section assume that transmission augmentations occur to supply demand at the end of radial pipelines. These augmentations include:

- CGP increase from 119 TJ/d to 142 TJ/d.
- QGP increase from 142 TJ/d to 269 TJ/d.
- RBP increase from 233 TJ/d to 378 TJ/d.

4.2.2 Supply from the Surat Basin

The Bowen and Surat basins have the largest amount of 2P reserves available (43,344 PJ[25], most of which are CSG reserves), and have already undergone significant development, with many more processing projects proposed but not yet committed.[26]

Surat Basin development is undertaken in three steps:

1. Release existing processing capacity at locations east of Wallumbilla to supply shortfalls in Queensland.
2. Develop further processing capacity in the Surat Basin, nominally located at the Kogan model location, as shown in Figure 1.
3. Increase transmission capacity between new production at Kogan and the rest of the system.

This solution assumes collaboration between LNG exporters to enable GLNG potential shortfalls to be met.

Collaboration between LNG exporters was enabled by reversing the flow of the RBP at 233 TJ/d to increase access to Wallumbilla for production located between Wallumbilla and Brisbane. This leads to:

- Surat Basin reserves and Queensland Curtis LNG (QCLNG) surplus production to supply GLNG (to eliminate these potential shortfalls).
- The ability to allow gas to flow south via the SWQP and either the MSP or Moomba–Adelaide Pipeline System (MAPS).
- A reduction of the Gladstone potential shortfalls.
- Surplus Moomba production to supply Mount Isa and the southern states.

Subsequent modelling aimed to supply the shortfalls appearing in the southern states using gas sourced from the Surat Basin. Assuming the CGP and QGP augmentations discussed in Section 4.1.1 are in place, augmentations to the RBP and SQWP are required between 2021 and 2025 to eliminate potential shortfalls over the medium term. This is detailed in Table 4-2.

Longer term, significant augmentations to several pipelines and 1,470 TJ/d of additional processing capacity in the Surat Basin were required from 2027 onwards to eliminate shortfalls and assess reserve adequacy. A large proportion of this capacity is only required to address winter peak day demand, so alternatives such as storage or linepack may reduce the magnitude of augmentations required. For example, just over 30% of the final reverse RBP capacity (396 TJ/d) is only used for 34 days in the final six years of the 20-year outlook period.

[25] AEMO. *2013 GSOO Gas Reserve and Resource Data Book*. Available at: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/GSOO-2013-Gas-Reserves-Update-and-Projections.

[26] Approximately two thirds of certified 2P reserves are present in the Surat Basin, with one third in the Bowen Basin. The modelled solution draws on Surat Basin reserves only.

AEMO modelled an alternative solution that introduced a new pipeline between Queensland and New South Wales to transfer gas directly south. Introducing a new pipeline significantly reduced the need to substantially augment existing pipelines.

Table 4-2 compares the pipeline augmentations required to eliminate all potential shortfalls in the system between the two cases investigated.

Table 4-2 — Augmentations required with and without new pipeline between Qld and NSW

Pipeline	Without new pipeline (TJ/d)		With new pipeline (TJ/d)	
SWQP	+483 westerly flow (to 868) in 2029.[a]		+125 westerly flow (to 510) in 2029.	
RBP (forward direction is Roma to Brisbane)	**To Brisbane**	**To Wallumbilla**	**To Brisbane**	**To Wallumbilla**
	+145 (to 378) in 2021.	+ 233 (to 233) in 2014.	+145 (to 378) in 2021.	+ 233 (to 233) in 2014.
		+142 (to 375) in 2021.		+142 (to 375) in 2021.
		+ 921 (to 1,296) in 2027.		+ 563 (to 938) in 2027.
Waloons	+100 to RBP (to 220) in 2029.		+100 to RBP (to 220) in 2029.	
SWP	+300 westerly flow (to 429) in 2025.		+300 westerly flow (to 429) in 2025.	
MAPS	+141 to Adelaide (to 394) in 2027.		+141 to Adelaide (to 394) in 2027.	
MSP	+492 to Sydney (to 912) in 2028.		+134 to Sydney (to 554) in 2028.	
NSW–Vic Interconnect	+290 southerly flow (to 410) in 2029.		+290 southerly flow (to 410) in 2029.	
Kogan–Young Pipeline	N/A		358 in 2029	

a. + indicates an increase to existing capacity.

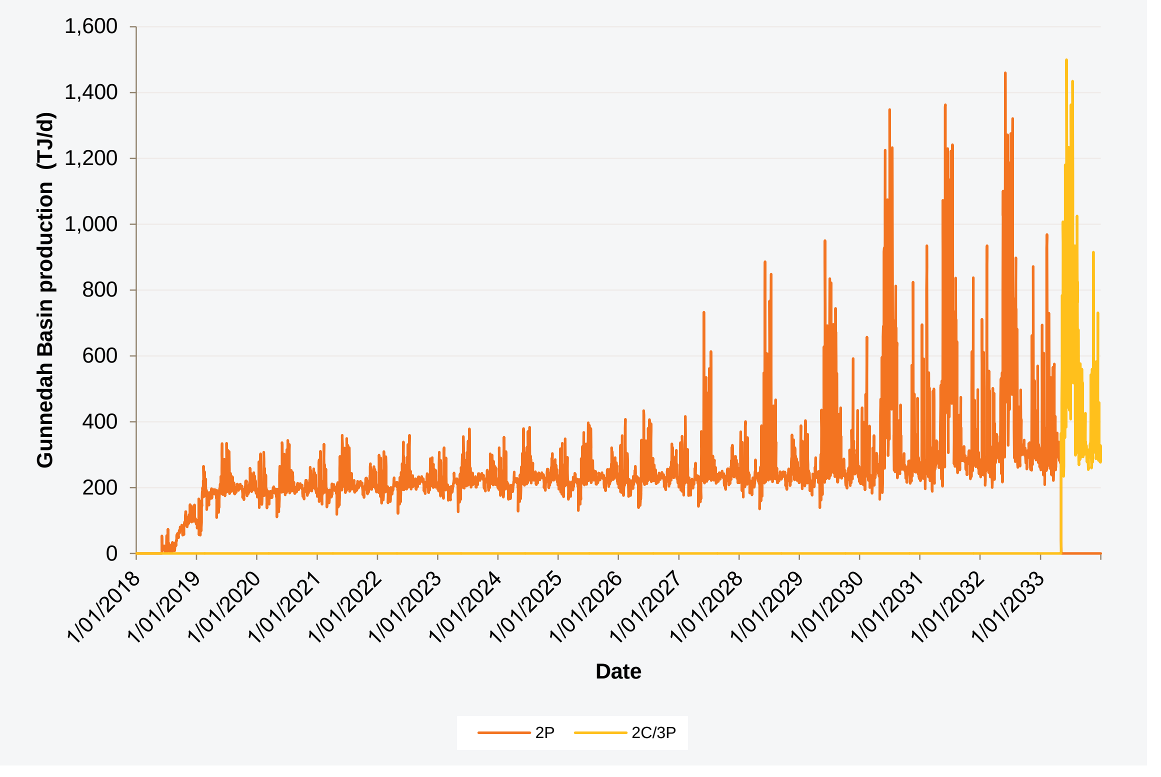
4.2.3 Supply from north-eastern New South Wales

The Gunnedah Basin represents the largest undeveloped gas supply in eastern Australia, with 1,426 PJ of 2P reserves reported at the end of 2012.

As shown in Figure 16, currently certified Gunnedah Basin 2P reserves are not sufficient to exclusively supply potential shortfalls for the entire outlook period, with 2P reserves being consumed in mid-2033.

Production requirements are projected to rise quickly in 2018 but remain below 400 TJ/d until winter 2027, when additional support in the southern states would be required following Otway Basin reserves consumption.

Figure 16 — Production in the Gunnedah Basin to eliminate potential shortfalls



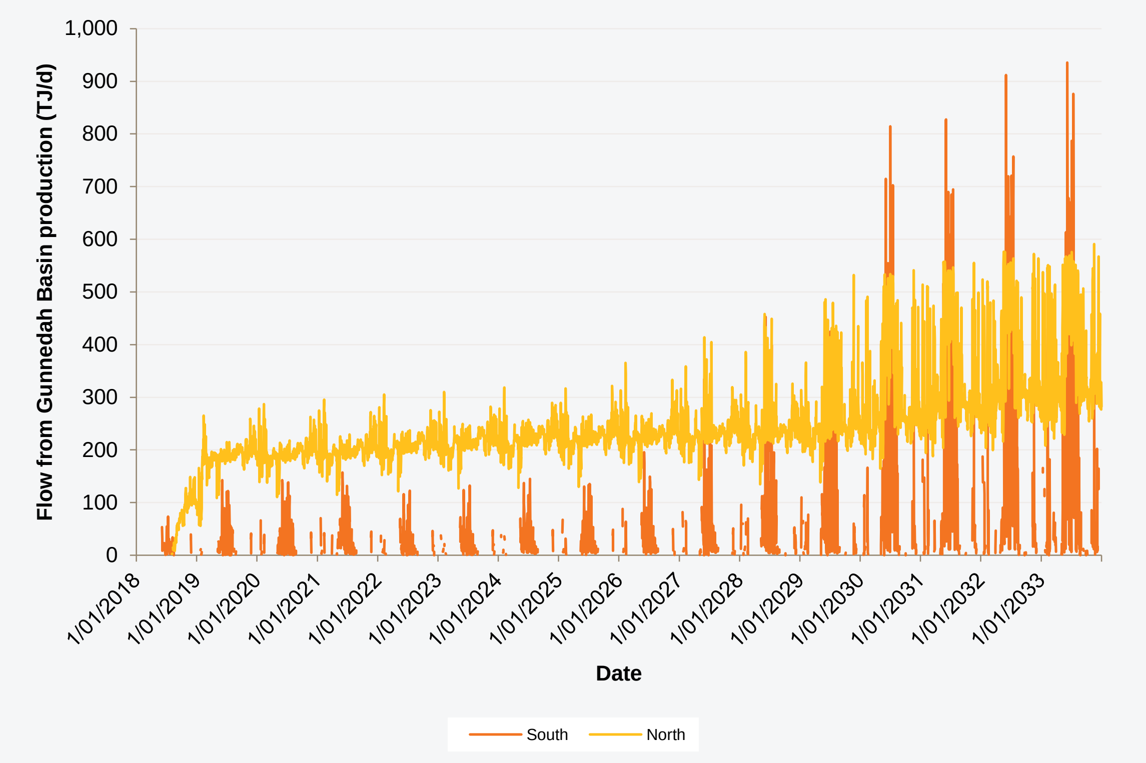
The direction of flow from the Gunnedah Basin (illustrated in Figure 17) shows the relative support given to Queensland (yellow profile) and the southern states (orange profile).

The figure shows rising support required in Queensland as LNG export facilities reach full output and production in Queensland is diverted to meet LNG export demand.

The Gunnedah Basin development is expected to support winter demand in the southern states, with a smaller component providing support to GPG in South Australia on days of high electricity demand over summer.

Production requirements are projected to increase significantly after consumption of Otway Basin reserves. Support to Queensland also increases at this time because Cooper Basin production assumes a larger role in supplying Adelaide.

Figure 17 — Flow to the north (Qld) and south (MSP) from Gunnedah Basin production



4.2.4 Supply from shale or other gas reserves in the Cooper Basin

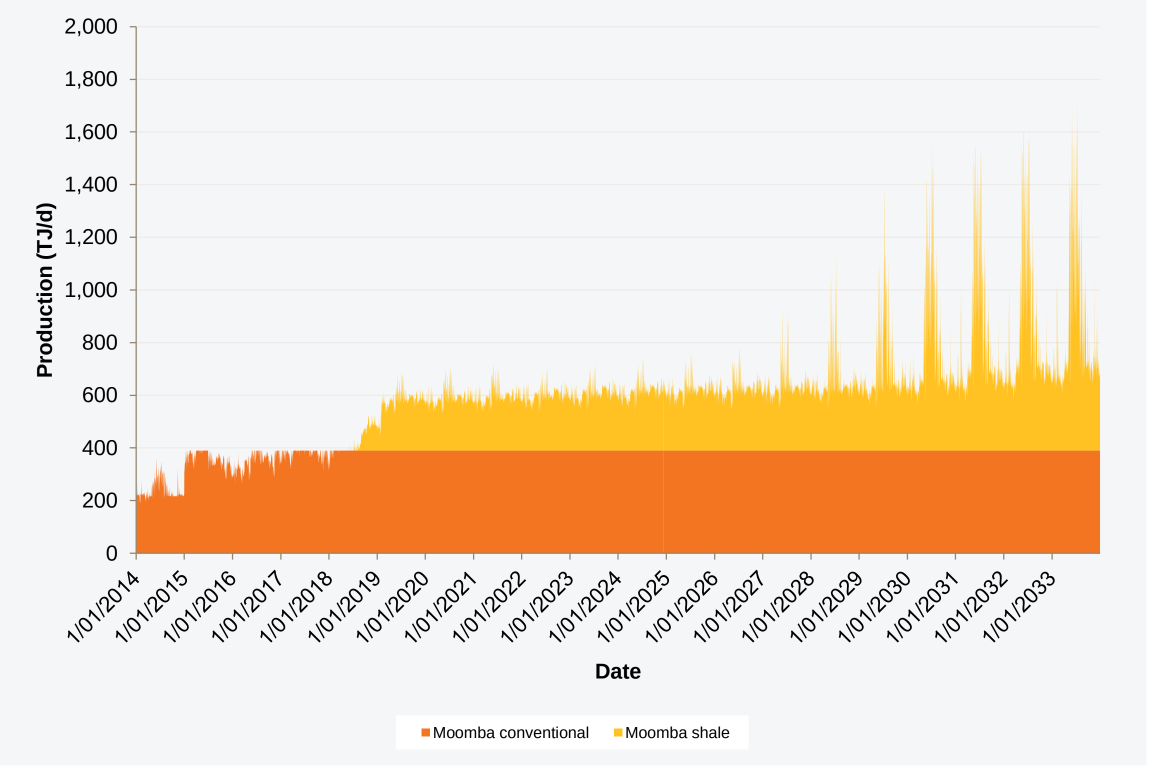
The Cooper Basin is reported to have a moderate potential supply of conventional 3P/2C reserves and resources (about 2,000 PJ), and substantial unconventional 3P/2C reserves and resources (almost 5,000 PJ).

If shale or other gas in the Cooper Basin is developed, the combination of conventional and unconventional reserves is sufficient to supply all of the observed potential shortfalls until the end of the 20-year outlook period.

Figure 18 shows the contribution required from Moomba to eliminate potential shortfalls over the outlook period. Existing conventional production operates at full capacity due to its lower cost. Unconventional production provides the balance, not exceeding 400 TJ/d prior to 2027, and frequently operating in the 200 TJ/d to 250 TJ/d range.

Requirements would increase significantly over winter after consumption of Otway Basin reserves.

Figure 18 — Contribution to total system supply from Moomba



Substantial pipeline augmentations would be required to support demand in the southern states after the consumption of Otway in 2027. These include 550 TJ/d on the MSP in 2027, and 250 TJ/d on MAPS in 2030 to support summer GPG demand in Adelaide. Augmentation of the NSW–Vic Interconnect, for north to south flow, would also be required during winter peak demand days.

Substantial storage capacity exists at Moomba and Ballera, exceeding 100 PJ in total. Additionally, the model does not efficiently utilise storage capacity at Iona after the consumption of Otway Basin reserves. Utilisation of this storage for balancing services, which were not modelled, may significantly decrease the processing capacity required to eliminate potential shortfalls in the medium term. Efficient use of storage may also benefit supply of GPG in Adelaide, provided withdrawal rates and linepack capacity of MAPS are suitable.

4.3 Summary of potential opportunities

Short term, potential opportunities exist primarily to provide additional supply to demand in Queensland. Diversion of existing processing capacity to supply LNG liquefaction facilities could create opportunities for supply to domestic customers in the order of 250 TJ/d by 2019. Growing industrial demand in Mount Isa and Gladstone indicates there may be opportunities to augment the CGP and the QGP respectively, also in the short term.

To supply projected Queensland domestic demand, new production must be capable of delivery to Wallumbilla. Further eastern haul augmentation of the SWQP, reversal of flows on westerly sections of the RBP, or utilisation of existing minor pipelines connecting Wallumbilla to production around Miles, Tara, and Dalby may provide appropriate delivery routes.

SWQP augmentation to allow increased flow from existing production at Moomba may partially address potential shortfalls in Queensland; however, relocation of supply shortfalls to demand centres in New South Wales is also expected unless further production investment occurs at Moomba.

There may also be opportunities to provide additional supply to New South Wales in the short term. A change in SWQP flow direction implies that New South Wales cannot rely on production in Queensland for supply beyond the ramp up of all six LNG liquefaction facilities at Gladstone. Under conditions of reduced flow on the MSP, existing Victorian production, Sydney Basin production, transmission from Victoria, and demand peak-shaving capabilities of a new storage facility at Newcastle are not adequate to supply all of New South Wales demand from 2018, although supply shortfalls may be absorbed by gas-powered generators if suitable alternative electricity generation is available.

Moderate development of CSG reserves in the Gloucester and Gunnedah basins (80 TJ/d and 100 TJ/d respectively) would be adequate to defer supply shortfall in New South Wales to 2025, even without supply available from the MSP. Storage of gas as linepack in the MSP or at Moomba may also provide adequate supply to manage potential winter peak day shortfalls in the short term.

AEMO's 2013 NTNDP modelling indicates a high rate of GPG growth after 2030. This growth occurs in the context of increasing penetration of intermittent generation and the retirement of ageing coal-fired power stations.

The increasing intermittency of the generation fleet is expected to drive development of open cycle gas turbine generation to provide suitable capacity with fast response. This style of generation development places additional burdens on the gas production and transmission system, which must respond to extreme peaks in demand for very short periods of time. These conditions also indicate potential opportunities for increased storage facility capacity to perform demand smoothing functions.

4.4 Summary of reserves adequacy

The 2013 GSOO gas model[27] included a breakdown of reserves into the following tranches for each basin:

- 2P reserves.
- 3P/2C reserves and resources.
- Prospective resources.

AEMO's gas model uses gas production costs for each reserves tranche to obtain a daily production and flow solution.

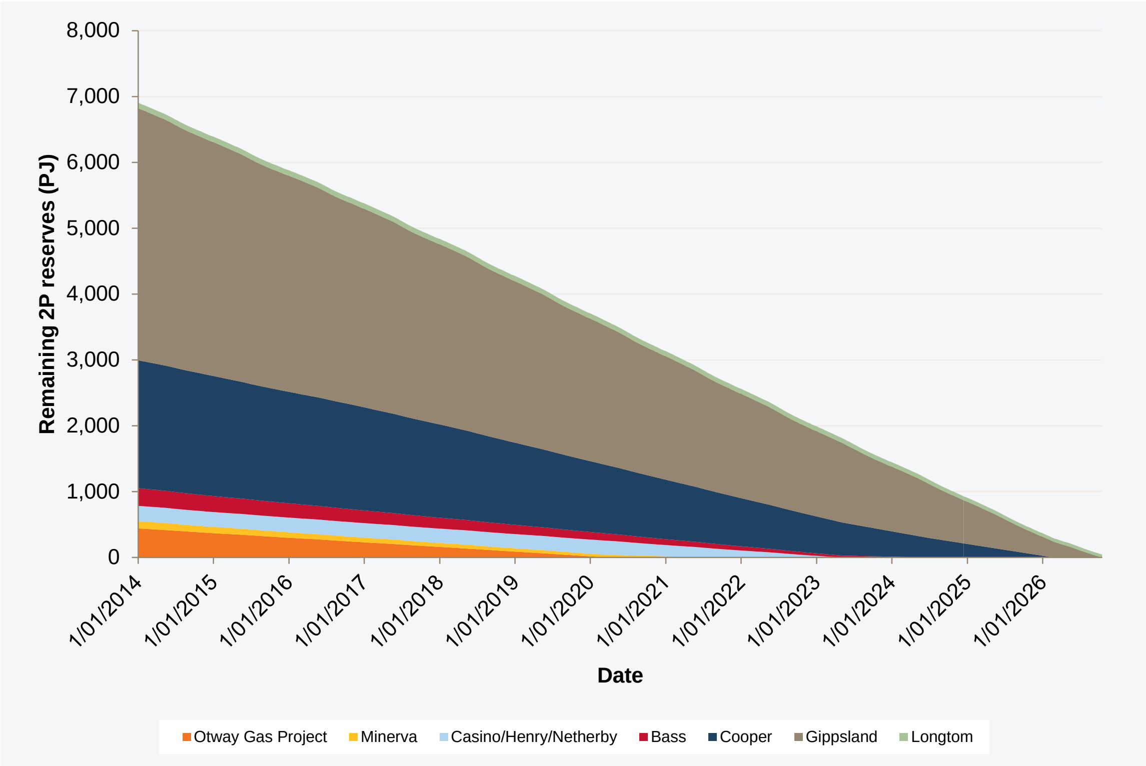
Production costs in the southern offshore conventional basins are the lowest in the system due to the nature of their geology and their accompanying production of liquids. The low production cost means that the model will consume these reserves first, before attempting to access higher-cost supply.

Under the modelled production-cost conditions, consumption of Denison Trough 2P reserves occurs first in 2019. Consumption of Otway Basin 2P reserves begins in 2020, and it is completely consumed by 2023. Bass and Cooper basin conventional 2P reserves are consumed in 2025. Gippsland 2P reserves are consumed in 2026. The 2P CSG reserves in Queensland are sufficient to supply demand until the end of the 20-year outlook period.

Figure 19 shows the consumption profile of conventional 2P reserves, falling to zero by late 2026.

[27] Further information on modelling reserves is available in the *2013 GSOO Methodology Document*. Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities.

Figure 19 — Conventional 2P reserves consumption



Additional 3P reserves and 2C resources are available in the Otway, Bass, Gippsland, and Cooper basins. The 3P/2C reserves in the Bass, Gippsland, and Cooper basins are sufficient to ensure supply until the end of the 20-year outlook period, provided current transmission and production limitations remain unchanged.[28]

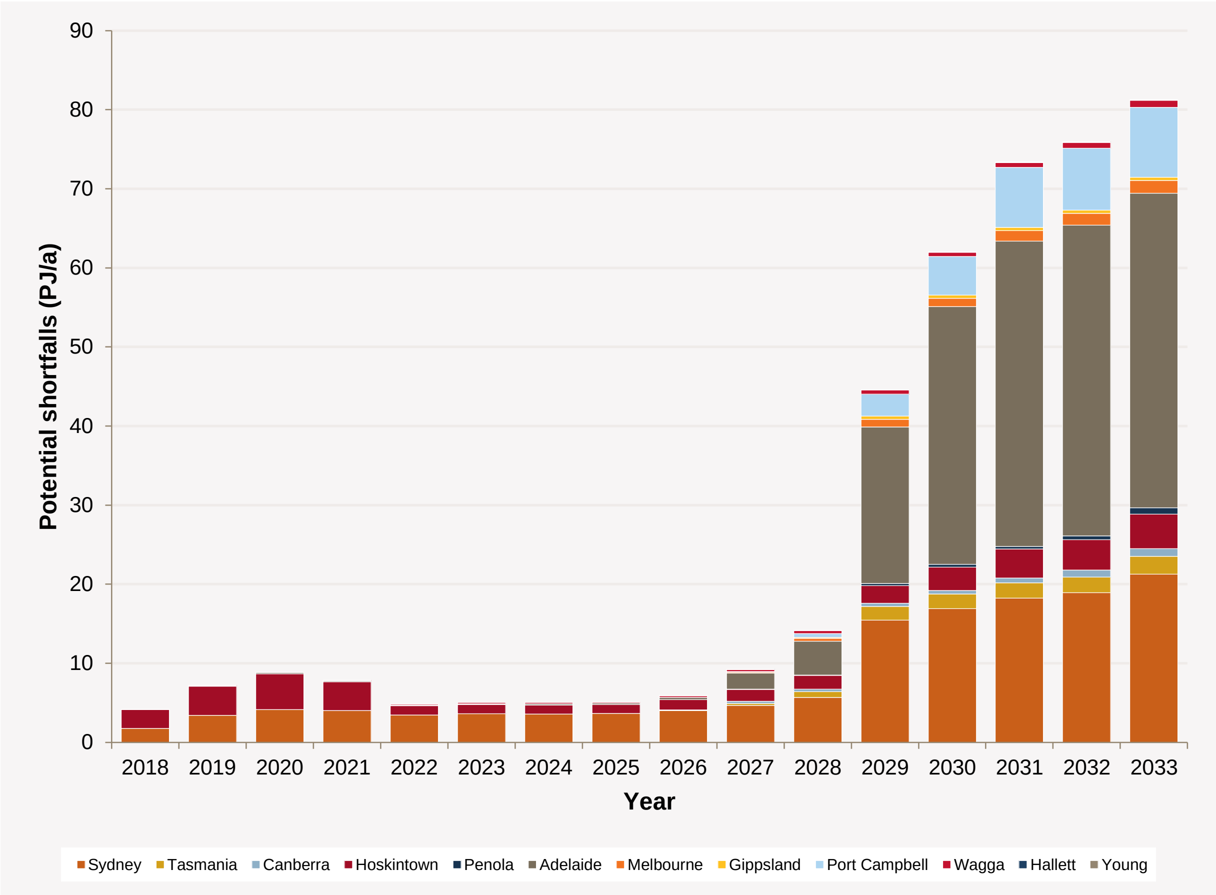
The 3P/2C reserves in the Otway Basin are only sufficient to ensure supply until 2028 or 2029, depending on the level of support the southern states receive from production in the north.

Given its role in supplying demand in Adelaide, Melbourne, and Sydney, the Otway Basin reserves consumption is a significant event, with substantial infrastructure investment required to manage changing system flows.

Figure 20 shows potential shortfalls in Victoria, New South Wales and South Australia only, increasing significantly from 2027.

[28] 3P/2C reserves and resources in the Gippsland Basin may not be sufficient to ensure supply to the end of the 20-year outlook period under conditions of increased flows on the EGP and the NSW–Vic Interconnect.

Figure 20 — Potential shortfalls in NSW, Vic, and SA



5. LINKS TO SUPPORTING INFORMATION

Table 5-1 provides links to additional information provided either as part of the 2013 GSOO accompanying information suite, or other related AEMO planning information.

Table 5-1 — Links to supporting information

Supporting information	Website address
2012 scenario descriptions	http://www.aemo.com.au/~/media/Files/Other/planning/2418-0005%20pdf.ashx
GSOO Methodology	http://aemo.com.au/Gas/Planning/~/media/Files/Other/planning/gsoo/2013/GSOO 2013 Methodology Document.pdf.ashx
Gas Reserves Update and Projections	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/GSOO-2013-Gas-Reserves-Update-and-Projections
LNG export demand projections	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/GSOO-2013-LNG-Projections
Gas production costs	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Previous-GSOO-reports/2012-Gas-Statement-of-Opportunities/Production-Costs
Gas transmission costs	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/Previous-GSOO-reports/2012-Gas-Statement-of-Opportunities/Transmission-Costs
Gas facility information	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/GSOO-2013-Gas-Processing-Transmission-and-Storage-Facilities
Gas forecasts	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities
Maps and diagrams	http://www.aemo.com.au/Electricity/Planning/Related-Information/Maps-and-Diagrams
Supply–demand analysis data files	http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities/GSOO-2013-Supply-Demand-Modelling-files

ATTACHMENT A – MODELLING ASSUMPTION DETAIL

Table A-1 details the modelling assumptions from each of the vignettes modelled in the 2013 GSOO. Further information on the modelling methodology is available in the 2013 GSOO Methodology document.[29]

Table A-1 — Assumptions modelled

Assumption	Description
LNG export prioritised	Demand for LNG export is supplied before domestic demand for mass market and large industrial customers, or for gas powered generation, reflecting willingness of international customers to pay higher prices for gas. Assumed in all sensitivities.
NSW–Vic Interconnect 71 TJ/d northerly flow limit	The flow capability of the NSW-Vic Interconnect is particularly sensitive to the magnitude and correlation of demands in Melbourne and NSW. A conservative figure of 71 TJ/d reflects typical winter conditions where demand is high in Melbourne, after augmentations currently planned and expected to be complete by 2015. Augmentations recently announced by APA to increase firm winter capacity beyond 100 TJ/d, but which are not yet definitively specified, were not included. Assumed in all sensitivities.
Ownership-agnostic production	Aggregated processing facility capacity is not partitioned according to ownership, allowing participants with surplus processing capacity to supply participants with processing capacity shortfall. In practice, such arrangements may be implemented using bilateral swap agreements, or sales on spot markets such as the STTMs in Adelaide, Brisbane, and Sydney. Assumed in all sensitivities.
Spring Gully to APLNG	Flows from processing facilities at Spring Gully to the western end of the APLNG project's Combabula lateral at Reedy Creek may reach up to 120 TJ/d. Assumed in all sensitivities.
Spring Gully to Fairview	Flows from Origin-operated processing facilities at Spring Gully to GLNG at Fairview are limited to 100 TJ/d. Assumed in all sensitivities.
Wallumbilla to Fairview	Flows on the Comet Ridge pipeline from Wallumbilla to GLNG at Fairview are limited to 490 TJ/d. Assumed in all sensitivities.
Silver Springs	Silver Springs underground storage facility is located at Kenya to ensure that it supplies QCLNG. After the storage facility emptiesin 2018 it is no longer used. Assumed in all sensitivities.
Newcastle LNG storage facility	The Newcastle storage facility begins receiving gas from mid-2015, becoming available for withdrawal for winter 2016. Withdrawal occurs at a maximum rate of 80 TJ/d. Assumed in all sensitivities.
Gippsland to Otway transfer	Gippsland reserves of 1.5 PJ are transferred to the Otway Basin each year for withdrawal by the Iona underground storage facility. This is assumed to occur during low-demand times, without being limited by production or transmission capabilities in Gippsland. Assumed in all sensitivities.
Increase SWQP eastern haul capability	The SWQP is expected to be capable of 340 TJ/d flow in an easterly direction from 2015. With 390 TJ/d of processing capacity available at Moomba and 100 TJ/d available at Ballera, there is scope to increase the SWQP capability by up to 150 TJ/d to supply LNG demand when processing capacity closer to the LNG facilities is insufficient. When an increase to SWQP capability was implemented to help supply LNG demand, a value of 80 TJ/d was used.

[29] AEMO. *GSOO 2013 Methodology Document*. Available: http://www.aemo.com.au/Gas/Planning/Gas-Statement-of-Opportunities.

Assumption	Description
QGP augmentation	Projected growth in mass market and large industrial demand in Gladstone, delivered exclusively on the QGP, exceeds the capability of the QGP in the short term. Assuming sufficient production capacity, meeting demand growth to the end of the outlook period requires the QGP capability to be augmented by 127 TJ/d to a total of 269 TJ/d. Jemena has advised that a minor augmentation of the QGP is due for commissioning in 2015.
CGP augmentation	Projected growth in mass market, large industrial, and non-NEM GPG demand in Mount Isa, delivered exclusively on the CGP, exceeds the capability of the CGP in the short term. Assuming sufficient production capacity, meeting demand growth to the end of the outlook period requires the CGP capability to be augmented by 23 TJ/d to a total of 142 TJ/d.
Moranbah processing augmentation	Projected growth in mass market, large industrial, and GPG demand in Townsville, delivered exclusively by production at Moranbah, exceeds the capacity of the Moranbah processing facility in the medium term. Meeting demand growth to the end of the outlook period requires the Moranbah processing capacity to be increased by 44 TJ/d to a total of 112 TJ/d.
RBP augmentation	Projected growth in mass market, large industrial, and GPG demand in Brisbane, delivered exclusively on the RBP, exceeds the capability of the RBP in the medium to long term. Assuming sufficient production capacity, meeting demand growth to the end of the outlook period requires the RBP capability to be augmented by 128 TJ/d to a total of 361 TJ/d.
Cooper Basin production reserved for Qld	Agreements between customers in Qld and producers in the Cooper Basin lead to Cooper Basin production being fully contracted to supply demand in Qld after existing supply contracts to NSW, Vic, and Adelaide expire. Flows out of the Cooper Basin on both MAPS and the MSP are reduced to zero from 2017.
Gloucester processing	New processing capacity in the Gloucester Basin, with a pipeline to Newcastle, begins production in 2017.
Gunnedah processing	Modest new processing capacity in the Gunnedah Basin, with a pipeline to the Moomba–Sydney Pipeline, or one of its laterals, begins production in 2018.
Significant Gunnedah processing	New processing capacity in the Gunnedah Basin of up to 1,500 TJ/d. Large pipelines between new processing at Gunnedah and Wallumbilla, and Gunnedah and the Moomba–Sydney Pipeline.
Additional Surat processing	New processing capacity in the Surat Basin of up to 1,400 TJ/d. Reversal and augmentation of the RBP between Kogan/Condamine and Wallumbilla, significant pipeline augmentation of the SWQP (for western haul), MAPS, MSP, and the NSW–Vic Interconnect.

Table A-1 details the assumptions applied to each of the New South Wales short-term adequacy sensitivities. The size of the Gloucester and Gunnedah Basin developments considered were practically identical (80 TJ/d and 100 TJ/d respectively), and the “Impact of Gloucester” study may be used as a reasonable proxy for considering the Gunnedah Basin development alone.

Table A-2 details the assumptions applied to each of the reserves adequacy sensitivities. Each additional significant processing addition (Gunnedah Basin CSG, Surat Basin CSG, or Cooper Basin unconventional) is accompanied by transmission augmentations required to deliver gas from new supply locations to demand.

Table A-1 — NSW short-term adequacy assessment sensitivities

Sensitivity	Augment QGP, CGP, Moranbah	Increased SWQP eastern haul	Gloucester processing	Cooper Basin reserved for Queensland	Gunnedah processing
Existing and committed only	✓				
Impact of Gloucester	✓	✓	✓		
Cooper Basin reserved for Qld and no NSW development	✓	✓		✓	
Cooper Basin reserved for Qld with Gloucester	✓	✓	✓	✓	
Cooper Basin reserved for Qld with Gloucester and Gunnedah	✓	✓	✓	✓	✓

Table A-2 — Reserves adequacy assessment sensitivities

Sensitivity	Augment QGP, CGP, Moranbah	Increased SWQP eastern haul	Gloucester processing	RBP reversal	Significant Gunnedah processing	Additional Surat processing	Cooper Basin shale processing
Existing and committed only							
Impact of Gloucester	✓		✓				
Impact of increased SWQP eastern flow	✓	✓	✓				
Surat Basin supply	✓	✓	✓	✓		✓	
Cooper unconventional supply	✓	✓	✓	✓			✓
Gunnedah Basin supply	✓	✓	✓		✓		

ATTACHMENT B – GSOO COMPONENT GUIDE

Table B-1 lists the requirements of the GSOO according to the National Gas Law (NGL) and National Gas Rules (NGR), and which documents contains the required information.

Table B-1 — GSOO NGL and NGR compliance

Clause	Summary of requirements	Relevant GSOO component
NGL, Division 4, Section 91D(2) (a) to (e)	The Gas Statement of Opportunities must:	-
	a) Contain an assessment of medium- to long-term demand (including export demand) for natural gas and for pipeline services.	Demand is assessed in the Gas Demand Forecasts for the 2013 GSOO. Discussion about how demand is forecast is contained in the GSOO 2013 Methodology Document. Demand for LNG export is detailed in LNG export projections. See Table 5 for web links to associated documentation.
	b) Contain an assessment of supply and pipeline capacity to meet existing and foreseeable demand for natural gas and pipeline services.	Section 4 and accompanying data files.
	c) Include forecasts of the outlook for the natural gas industry over a 20-year planning horizon.	Section 4 and accompanying data files.
	d) Point out likely long-term shortfalls in natural gas reserves, and production or transmission constraints.	Section 4 and accompanying data files.
	e) Contain any other information required by the Rules (NGR).	See clauses 135KB(1) to (3) of NGR (below).
NGR, Part 135KB(1) (a) to (h)	The Gas Statement of Opportunities must contain, for each participating jurisdiction, for the period of 10 years commencing on 1 January of the first calendar year to follow its publication, information about:	-
	a) Natural gas reserves (including prospective or contingent resources).	Section 4 and accompanying data files. Gas Reserves Projections. See Table 5 for web link.
	b) Annual and peak day capacity of, and constraints affecting, gas production facilities.	The GSOO models and discusses capacity and constraints on production and transmission at daily resolution. Results are presented in the accompanying data files.
	c) Committed and proposed new or expanded gas production facilities.	Gas facility information. See Table 5 for web link.

IMPORTANT NOTICE

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ACRONYMS, GLOSSARY, AND LIST OF COMPANY NAMES

This section contains a list of measures and abbreviations, a list of acronyms, a glossary of terms, and a list of company names used in the Gas Statement of Opportunities (GSOO) and its associated publications.

LIST OF MEASURES AND ABBREVIATIONS

Units of measure

The following sections list the units of measure and acronyms used throughout the GSOO.

Abbreviation	Unit of measure
GJ	Gigajoule (1 GJ equals 10^9 Joules)
GWh	Gigawatt-hours
MW	Megawatt
PJ	Petajoule
PJ/a	Petajoules per annum
t	Tonnes
TJ	Terajoule
TJ/d	Terajoules per day
$	Australian dollars

Acronyms

Abbreviation	Expanded name
2P	Proved plus probable
ACT	Australian Capital Territory
AEMO	Australian Energy Market Operator
ASX	Australian Securities Exchange
CCGT	Combined cycle gas turbine (a type of GPG)
CGP	Carpentaria Gas Pipeline
CSG	Coal seam gas
DTS	Declared Transmission System (gas)
EGP	Eastern Gas Pipeline
GBB	Gas Bulletin Board
GLNG	Gladstone LNG
GPG	Gas-powered generation

Abbreviation	Expanded name
GSOO	Gas Statement of Opportunities
IC	New South Wales to Victoria Interconnect
LMP	Longford to Melbourne Pipeline
LNG	Liquefied natural gas
LRET	Large-scale Renewable Energy Target
MAPS	Moomba to Adelaide Pipeline System
MEPS	Minimum Energy Performance Standards
MM	Mass market
MMLI	Mass Market and Large Industrial
MSP	Moomba to Sydney Pipeline
NEFR	National Electricity Forecasting Report
NEM	National Electricity Market
NGL	National Gas Law
NIEIR	National Institute of Economic and Industry Research
NQGP	North Queensland Gas Pipeline
NSW/ACT	New South Wales and the Australian Capital Territory
NTNDP	National Transmission Network Development Plan
OCGT	Open cycle gas turbine (a type of GPG)
RBP	Roma to Brisbane Pipeline
POE	Probability of exceedence
QCLNG	Queensland Curtis LNG
QGP	Queensland Gas Pipeline
QLD	Queensland
SA	South Australia
SEA	SEA Gas Pipeline
SWP	South West Pipeline
SWQP	South West Queensland Pipeline
TAS	Tasmania
TGP	Tasmanian Gas Pipeline
VIC	Victoria

GLOSSARY AND LIST OF COMPANY NAMES

Glossary

Term	Meaning
1-in-2 peak day	The 1-in-2-peak day demand projection has a 50% probability of exceedence (POE). This projected level of demand is expected, on average, to be exceeded once in two years. Also known as the 50% peak day.
1-in-20 peak day	The 1-in-20 peak day demand projection has only a 5% probability of exceedence (POE). This projected level of demand is expected, on average, to be exceeded only once in 20 years. Also known as the 95% peak day.
1C contingent resources	Low estimate of contingent resources.
2C contingent resources	Best estimate of contingent resources.
3C contingent resources	High estimate of contingent resources.
1P reserves	Estimated quantity of gas that is reasonably certain to be recoverable in future under existing economic and operating conditions. A low-side estimate also known as proved gas reserves.
2P reserves	The sum of proved-plus-probable estimates of gas resources. 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.
Annual demand	Gas demand reported for a given year.
Average annual growth rate	The average rate over a period of years at which gas demand, for example, increases or decreases. Expressed as a percentage. Negative figures indicate a decline in demand.
Basin	A geological formation that may contain coal, oil, and gas.
Bulletin Board	See Gas Bulletin Board.
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 other industry sources as coal seam methane (CSM) or coal bed methane (CBM).
Combined cycle gas turbine (CCGT)	A device utilising a gas turbine and heat recovery/steam generation to efficiently generate electricity. More capital intensive than open-cycle gas turbines and therefore expected to be highly utilised. See also open cycle gas turbine.
Committed	A project that is considered to be proceeding.
Contingent resources	Resources that are not yet considered commercially recoverable. Technological or business hurdles need to be cleared before these resources can be considered economically justified for development.
Conventional gas	Gas that is produced using traditional oil and gas industry practices. See also coal seam gas (CSG) and unconventional gas.
Declared Transmission System	The Declared Transmission System is a complex network of high-pressure transmission pipelines with a total length of some 2,000 kilometres. It extends from Longford in the eastern Victoria, to Portland in the south-west, across central Victoria, and north to Albury-Wodonga and Culcairn in New South Wales.
Demand area	A geographical sub-grouping within a demand group.
Demand group	A geographical grouping of gas users that is used for reporting gas demand projections and modelling gas supply and demand.

Term	Meaning
Domestic gas	Gas used within Australia for residences, businesses, and electricity generators. This comprises the mass market, large industrial, and GPG market segments, excluding gas demand for LNG export.
Existing	A project that is commissioned and operating.
Export facility	A liquefaction facility that cools gas to -160 °C (its liquefaction point), reducing its volume by 600 times for export via ship.
Gas Bulletin Board (GBB)	A website (www.gasbb.com.au) managed by AEMO that provides information about major interconnected gas processing facilities, gas transmission pipelines, gas storage facilities, and demand centres in eastern and south-eastern Australia. Also known as the National Gas Market Bulletin Board or simply the Bulletin Board.
Gas source	The type of reservoir that is being targeted or from which gas is being produced (conventional, coal seam gas, or unconventional).
Gas-powered generation (GPG)	The generation of electricity using gas as a fuel for turbines, boilers, or engines. A market segment of the domestic eastern and south-eastern Australian gas market.
Initial reserves	On a given assessment date, the total quantity of gas expected to be recovered from a reservoir over its entire productive life (for example, from 1975 to 2025). Also known as total reserves, or reserves plus historic production. See also remaining reserves.
Lateral	A pipeline branch.
Linepack	The pressurised volume of gas stored in a pipeline system.
Large industrial (market segment)	A segment of the eastern and south-eastern Australian gas market involving businesses that consume more than 10 TJ/a. See also mass market.
Large-scale Renewable Energy Target (LRET)	See ‘national Renewable Energy Target scheme.
Liquefied natural gas (LNG)	Natural gas that has been converted into liquid form for ease of storage or transport.
LNG train	An LNG plant’s combined purification and liquefaction facilities. Also referred to as a unit of gas purification and liquefaction (for example, an LNG plant may have several LNG trains).
Mass market (market segment)	A segment of the eastern and south-eastern Australian gas market involving residential users and businesses that consume less than 10 TJ/a. See also large industrial.
Market segments	To develop gas demand projections, gas consumers are grouped into domestic market segments (mass market, large industrial, and GPG) and gas demand for LNG export.
National Electricity Market (NEM)	The wholesale market for electricity supply in Queensland, New South Wales (including the Australian Capital Territory), Victoria, South Australia, and Tasmania.
National Renewable Energy Target scheme	The national Renewable Energy Target (RET) scheme, commenced in January 2010, aims to meet a renewable energy target of 20% by 2020. Like its predecessor—the Mandatory Renewable Energy Target (MRET)—the national RET scheme requires electricity retailers to source a proportion of their electricity from renewable sources developed after 1997. The national RET scheme is currently structured in two parts: • The Small-scale Renewable Energy Scheme (SRES) is a fixed price, unlimited-quantity scheme available only to small-scale technologies (such as solar water heating) and is being implemented via Small-scale Technology Certificates (STC). • The Large-scale Renewable Energy Target (LRET) is being implemented via Large-scale Generation Certificates (LGC), and targets 41,000 GWh of renewable energy by 2020.
Open cycle gas turbine (OCGT)	A generating system that uses a gas-powered turbine to generate electricity. Less efficient and less capital intensive than a combined cycle gas turbine (CCGT), an OCGT is often used to supply peak electricity demand.
Peak day	Over the course of a season (winter or summer), the day on which maximum gas demand occurs.

Term	Meaning
Peak demand condition	A point in time (usually a day) where the projected level of demand is expected to reach a specified level (see also 1-in-2 peak day and probability of exceedence).
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 exceedence (POE)	Refers to the probability that a forecast maximum demand figure will be exceeded. For example, a forecast 10% POE maximum demand figure 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	When used in the context of defining gas reserves, gas that has already been recovered and produced.
Production facilities	Facilities in which raw gas (produced from the field) is processed to separate liquids and remove impurities.
Proposed	Either advanced proposals, representing projects at an intermediate stage of development; or publically announced proposals, representing projects at an early stage of development.
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.
Proved reserves	An estimated quantity of gas that is reasonably certain to be recoverable in the future under existing economic and operating conditions. Also known as 1P reserves.
Proved plus probable	See 2P reserves.
R/P ratio (years)	See reserve-to-production ratio.
Ramp gas	Coal seam gas (CSG) produced during the early stages of an LNG export project. The need to drill CSG wells several years before LNG start-up and the wells' limited ability to be turned off result in this gas production.
Remaining reserves	On a given assessment date, the total quantity of gas expected to be recovered from a reservoir over its remaining productive life (for example, from 1 January 2012 to 2025). See also initial reserves.
Reservoir	In geology, a naturally occurring storage area that traps and holds oil or gas (or both).
Reserves	Gas resources that are considered to be commercially recoverable and have been approved or justified for commercial development.
Reserve-to-production (R/P) ratio	A quantity, expressed in years, that is the ratio of remaining reserves divided by the current rate of production. A nearly consumed gas basin may have a low R/P ratio (for example, five years) whereas a newly discovered or very large basin in the early years of its production life may have a high R/P ratio (for example, 20 years). Increasing the estimated reserves increases the R/P ratio, whereas increasing the production rate decreases the R/P ratio.
Resources	See contingent resources and prospective resources.
Shale gas	Gas found in shale layers that cannot be economically produced using conventional oil and gas industry techniques. See unconventional gas.
Storage facility	Facilities that store gas for use at times of high demand.
Train	See LNG train
Transmission facilities	Facilities for transporting gas to the market (for example, pipelines and compressor infrastructure).
Unconventional gas	Gas found in shale layers, or tightly compacted sandstone that cannot be economically produced using conventional oil and gas industry techniques. See also coal seam gas (CSG) and conventional gas.

List of company names

The following table lists the full name and Australian Business Number (ABN) or Australian Company Number (ACN) of registered companies that may be referred to in the GSOO and accompanying documents.

Company	Full company name	ABN/ACN
ACIL Tasman	ACIL Tasman Pty Ltd	ABN 68 102 652 148
AGL Energy	AGL Energy Limited	ABN 74 115 061 375
APA Group	APA Group Limited (a stapled trust comprising the Australian Pipeline Trust and the APT Investment Trust)	ACN 091 344 704
APLNG	Australia Pacific LNG Pty Limited	ABN 68 001 646 331
ASX	ASX LIMITED	ACN 008 624 691
Core Energy Group	Core Energy Group Pty Ltd	ACN 110 347 085
GLNG (Gladstone LNG)	Santos GLNG Pty Ltd	ABN 12 131 271 648
NIEIR	National Institute of Economic and Industry Research (also known as National Economics)	ABN 72 006 234 626
Origin	Origin Energy Limited	ACN 000 051 696
QGC	Queensland Gas Company Pty Limited	ACN 089 642 553
Santos	Santos Limited	ACN 007 550 923