2018 Gas Statement of Opportunities

June 2018

For eastern and south-eastern Australia

Important notice

PURPOSE

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VERSION CONTROL

Version	Release date	Changes
1.0	22/06/2018	

Executive summary

The 2018 Gas Statement of Opportunities (GSOO) contains AEMO's projections for demand, and information from gas producers about reserves and forecast production, to assess the projected supply-demand balance and potential supply gaps under a range of plausible scenarios for the outlook period to 2038, for the eastern and south-eastern Australian gas markets.

This 2018 GSOO, however, comes after an eventful year in the gas industry and in the context of policy and market changes affecting demand and supply in Australia and globally. This GSOO assessment reflects these changes.

The eastern and south-eastern Australian gas markets have been irrevocably changed by liquefied natural gas (LNG) exports and the subsequent coupling of the Australian gas market to international markets. The scale of gas used for export has led to a tightening of domestic supply. One of the major changes for the Australian gas industry in 2017 was the Federal Government's introduction of the Australian Domestic Gas Security Mechanism (ADGSM), under which the Federal Minister for Resources can determine whether export restrictions should be imposed to avoid any potential shortfall in meeting domestic demand for gas. This GSOO includes projections of supply adequacy for 2019, which may, along with a range of other information and contributions from other parties, inform the Minister in relation to the ADGSM.

Domestic supply in eastern and south-eastern Australia will also be enhanced by connection to the Northern Territory gas fields through the Northern Gas Pipeline (NGP) to be completed by the end of the year.

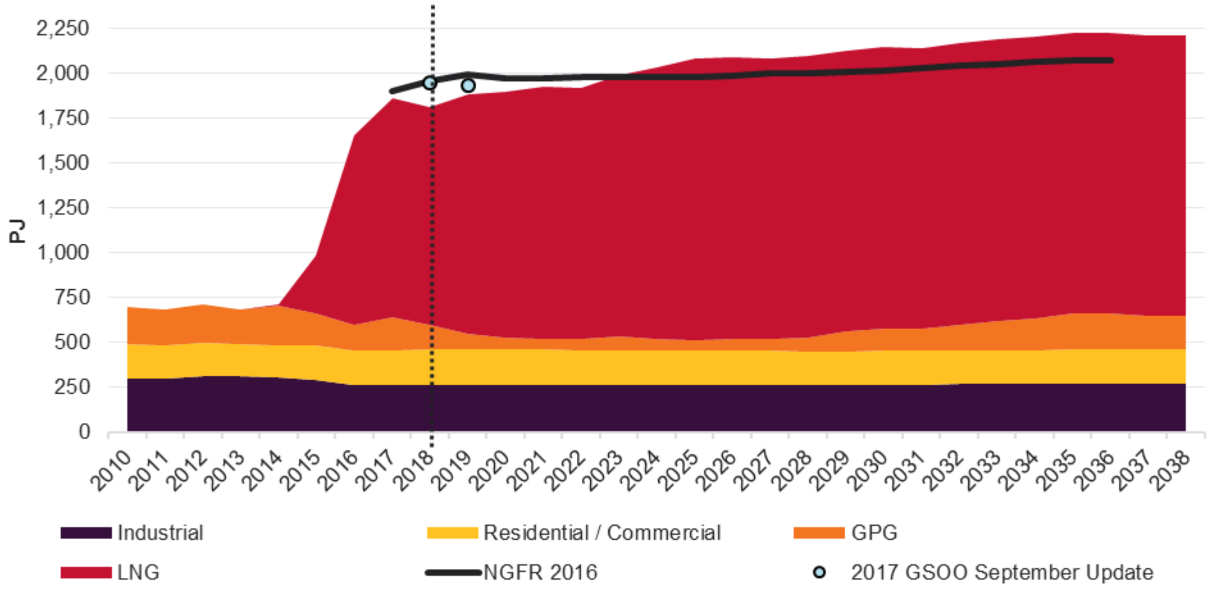
The 2018 GSOO highlights that:

- No supply gaps are forecast before 2030 under expected market conditions. The risk of shortfalls previously projected for 2019 has been reduced due to changes in the energy markets, including:
  - Minor reductions (<1%) in east coast Australian LNG demand estimates provided by the producers, resulting in greater availability of Queensland coal seam gas (CSG) for domestic consumption. This provides the domestic market with access to 8 petajoules (PJ) more gas in 2019 than previously advised.
  - The NGP, expected to be online by December 2018, helping further increase supply available to eastern and south-eastern gas markets by connecting to Mount Isa with up to 90 terajoules (TJ) a day.
  - Increased commitments to develop alternative electricity generation sources reducing the need for high volumes of gas-powered generation (GPG) of electricity in the National Electricity Market (NEM). However, risks remain that natural variances in weather-driven consumption and GPG could increase gas demand and tighten the supply-demand balance.
  - The introduction of the ADGSM, resulting in a Heads of Agreement between the Federal Government and LNG producers for domestic gas supply commitments, and a mechanism to restrict exports if required. This provides an incentive for LNG producers to manage their production and exports to ensure adequate domestic supply.
- Gas production is forecast to continue increasing beyond 2019 to meet forecast demand, requiring new gas reserves and resources to be developed. Producers have advised of intentions to develop new reserves and resources to meet these forecasts.
  - The Victorian Gas Planning Report (VGPR) Update in March 2018 highlighted the need for development of new reserves and resources to avoid shortfalls.
- From 2030, additional gas supply infrastructure will be needed to deliver gas to southern customers, unless early investment in exploration and development programs brings highly uncertain – and as yet undiscovered – southern prospective resources to market.

Forecast demand

Figure 1 shows gas consumption forecasts by demand sector for the 2018 GSOO[1]. In previous years, gas demand forecasts used in the GSOO were published separately in an annual National Gas Forecasting Report (NGFR)[2].

Figure 1 Gas consumption actual and forecast, 2010-38, all sectors, Neutral scenario (PJ)



The gas consumption forecast, compared with previous AEMO forecasts, features:

- Lower gas demand in early years. Projected consumption in 2019 is 55 PJ lower compared to the September 2017 GSOO Update[3], and 61 PJ lower in 2022 compared to the 2016 NGFR, due primarily to:
  - Record levels of new renewable generation in the NEM reducing demand for gas from GPG. Over 4,000 megawatts (MW) of new solar and wind generation has committed to being operational in the next two years, impacting on the market share of both gas- and coal-fired generators. With these new developments, electricity market modelling indicates GPG demand could be less than half of observed 2017 levels by 2020.
  - Projected reductions in the reliance on GPG to provide the minimal level of thermal generation the system needs to manage system security in South Australia. This contributes to lower forecast demand for gas from GPG than projected in September 2017.
  - Changes in international LNG market dynamics, coupled with tight domestic gas supply conditions and the Heads of Agreement, resulting in a slight reduction in LNG export projections.
- Higher gas demand in the longer term. From 2025 to the end of the outlook period, the total forecast demand is between 90 PJ and 150 PJ per annum higher than in the 2016 NGFR, predominantly due to higher projected demand for LNG:
  - LNG exports are expected to increase to maximum production capacity, motivated by increasing international demand for LNG after 2023, as emerging economies increase activities to curb greenhouse gases. Should international demand for LNG accelerate before 2023, Australian LNG exports may increase sooner than forecast.
  - While GPG demand is projected to increase from 2025 to the end of the outlook period, the levels remain below the 2016 NGFR forecast. GPG gas demand is not forecast to recover to recently observed historical levels within the outlook period.

Forecasting uncertainties for gas demand

To address forecast uncertainty relating to factors affecting consumption, including economic conditions and emissions reduction policies (and their impact on GPG demand in the NEM), AEMO has modelled a range of plausible futures.

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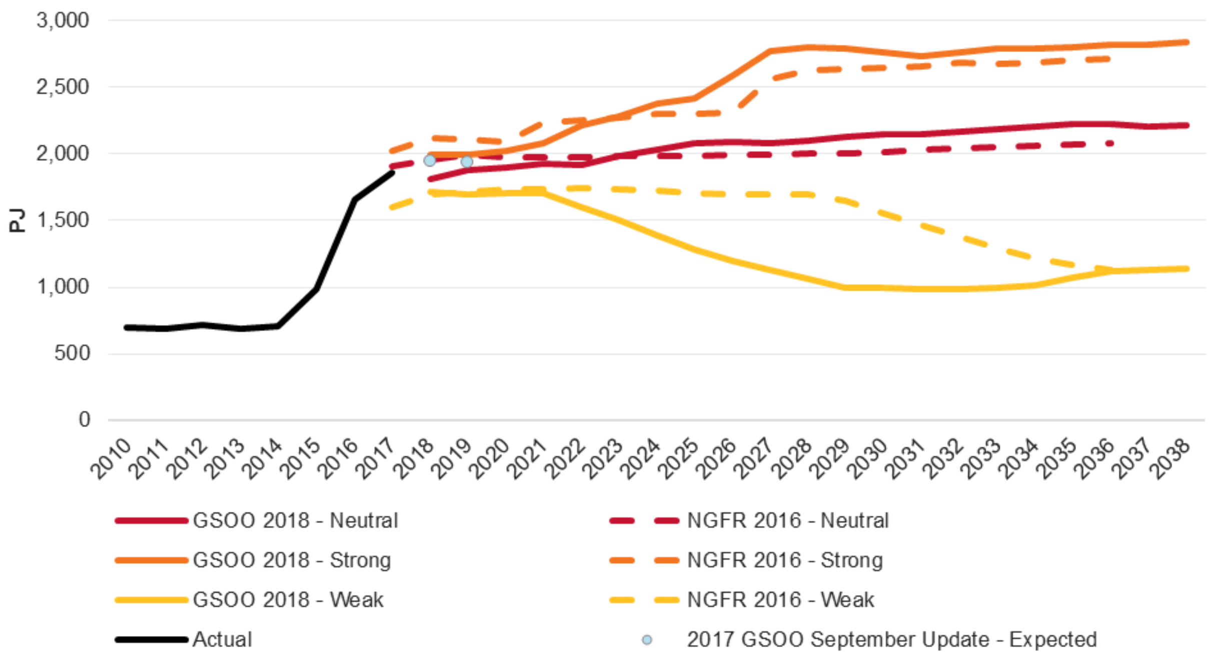
[1] Demand forecasts are available on the Forecasting Data Portal http://forecasting.aemo.com.au/. Select 'GSOO 2018' from the publication drop-down.

[2] NGFRs from 2014 to 2016 are available at http://www.aemo.com.au/Gas/National-planning-and-forecasting/National-Gas-Forecasting-Report.

[3] The September 2017 GSOO Update is available at http://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

Figure 2 shows AEMO's 20-year forecasts under three alternative future scenarios, and compares them to equivalent forecasts from the 2016 NGFR and the 2017 GSOO Update.

Figure 2 Gas consumption forecast in all scenarios, compared to forecasts in 2016 NGFR and 2017 GSOO Update (PJ)



Compared to the Neutral scenario, differences in assumptions in the Strong scenario lead to projected increases in GPG demand to meet stronger emission abatement targets, and a seventh LNG train from 2027 motivated by favourable international economic conditions. Conversely, in the Weak scenario, exploration and development of gas fields for LNG export is assumed to cease, causing LNG exports to reduce correspondingly, and some large industrial loads are forecast to close, reducing demand for gas.

Further to these three scenarios, annual gas consumption naturally varies depending on underlying weather conditions and the availability or strategic operation of competing electricity generation technologies and fuels – coal, hydro, wind, and solar.

Forecast supply

AEMO has been provided with updated production forecasts and gas reserve and resource[4] information from gas producers to inform the 2018 GSOO. This new information reflects the industry's current best view of gas resources and production expectations as at April 2018.

Production forecasts from southern fields (that is, fields south of Queensland) are 16 PJ higher in 2019, compared to production forecasts for the September 2017 GSOO Update. Although a 9 PJ reduction is forecast in production from both CSG and conventional fields in the north, there is still a resulting net increase in production of 7 PJ to the gas system.

In addition, the NGP[5] is expected to have capacity to supply up to 90 TJ/day from Northern Territory gas fields, once connected to the eastern market at Mount Isa by late 2018. In the September 2017 GSOO Update, the NGP was not included in the supply assessment due to gas delivery and timing uncertainties. Supply volume certainty from Northern Territory gas fields has increased following the Northern Territory Government's recent decision to lift a moratorium on hydraulic fracturing, and recent progress[6] in the development of the Mereenie field.

Total production forecasts provided by gas producers show an overall projected increase in annual field output of 144 PJ between 2019 and 2022. These quantities of gas include undeveloped reserves and resources.

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

[5] The NGP development did not feature in 2017 GSOO modelling, although it was noted as an option to ease forecast shortfalls.

[6] For more on recent progress on Mereenie gas field, see http://www.abc.net.au/news/rural/2018-02-26/gas-exploration-to-increase-in-central-australia/9483022.

Table 1 shows the production forecast between 2019 and 2022 provided to AEMO by gas producers as their current best estimate. Gas production in these projections is forecast to increase between 2019 and 2022 in both the south (Victoria/ New South Wales/South Australia) and the north (Queensland/Northern Territory), with the largest increases forecast in northern gas fields to meet forecast growth in LNG exports. This increased forecast of CSG production from the north is highly reliant on large numbers of wells being drilled and constructed annually.

Table 1 Production forecasts to 2022 (PJ) as provided by gas producers

	2019	2020	2021	2022
VIC/NSW/SA[A]	452	483	463	479
QLD/NT [A]	1,486	1,561	1,636	1,603
Total production	1,938	2,044	2,099	2,082

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

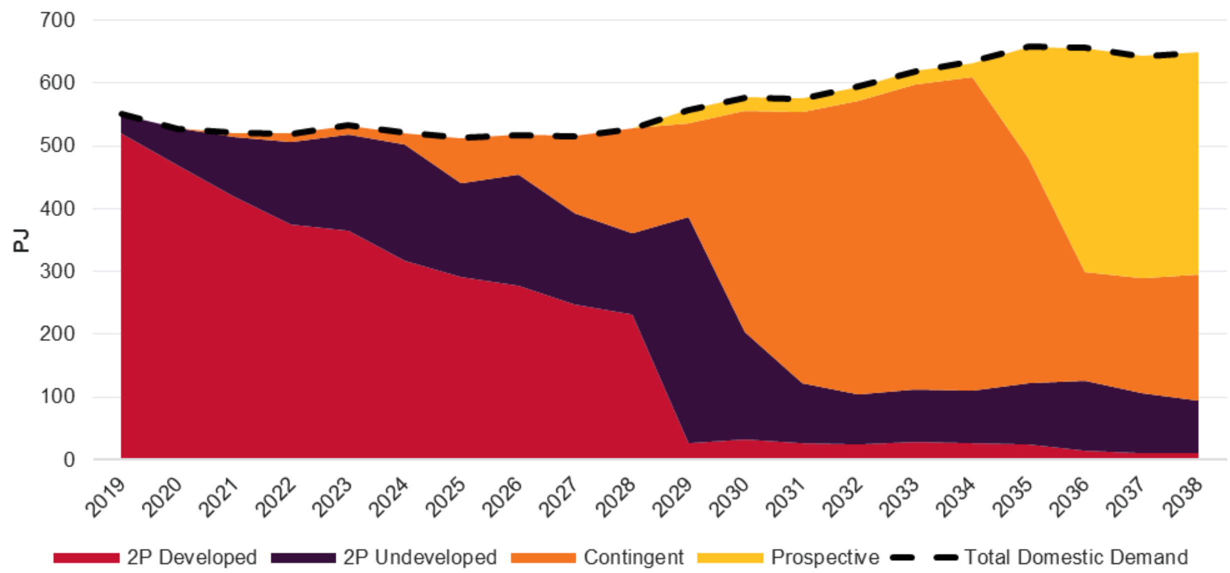
Supply and infrastructure adequacy assessment

There are no gas supply gaps forecast in 2019, or in the short term, under expected conditions, although some field expansions are needed. Producers have indicated to AEMO that up to 42 PJ of undeveloped reserves are expected to come online by 2019 to meet demand, and first gas from contingent resources by 2021.

Provided these as yet undeveloped reserves do come online, comparison of supply adequacy assessments for the Neutral and Strong scenarios indicates a level of resilience to unexpected variations in demand. In 2019, up to 37 PJ more gas supply is projected to be available, if needed, to accommodate weather- or event-driven variations in Neutral scenario consumption forecasts. However, to meet the full 112 PJ of additional LNG demand forecast in the Strong demand scenario, increased Queensland CSG production would be required.

The reserve mix required to meet domestic demand is shown in Figure 3 below, with rapid decline in production from 2P developed and undeveloped reserves clearly visible, mostly from fields located within the southern states.

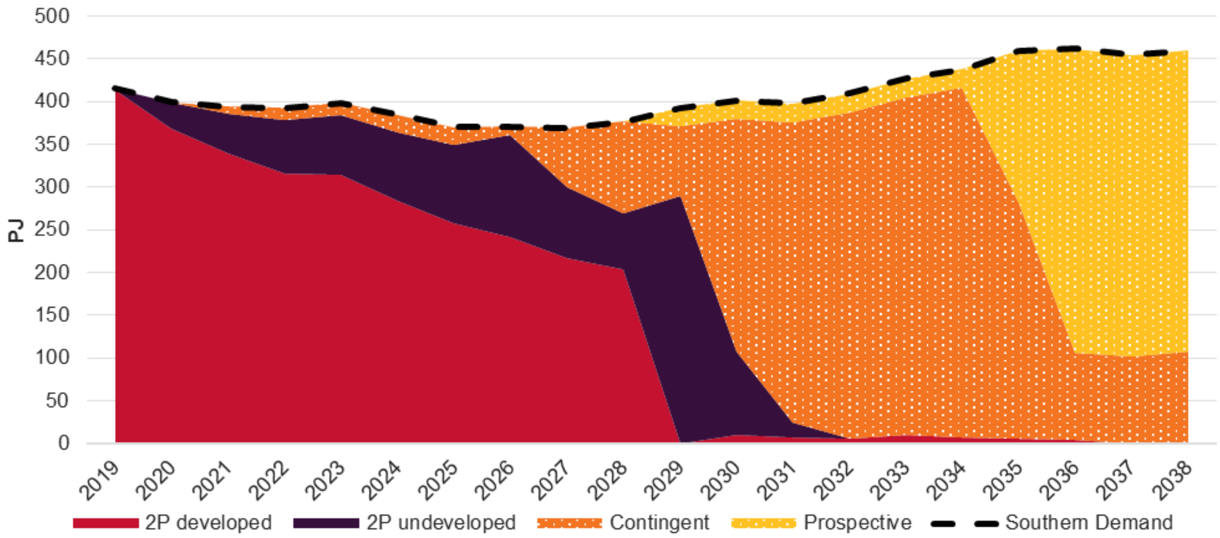
Figure 3 Status of reserves and resources to meet domestic demand, 2019-38



As existing fields decline, exploration and development will be needed to deliver these contingent and prospective resources to market. These new gas supplies will help improve adequacy of supply but, as flagged in the 2017 GSOO, supply from these fields is likely to be more costly than existing production.

Without exploration and development of new southern resources, additional investment in gas supply infrastructure will be required by 2030 to deliver the gas to where it is needed. Figure 4 below demonstrates southern field decline of developed and undeveloped reserves, and the need for contingent and prospective resource development to meet southern demand (New South Wales, Victoria, South Australia, and Tasmania). The location of this exploration and development will influence the needs for pipeline infrastructure.

Figure 4 Status of southern reserves and resources required to meet southern demand, 2019-38



Contents

Executive summary 3

1. Introduction 10

1.1 National gas demand forecasts 10

1.2 The Australian Domestic Gas Security Mechanism 10

1.3 2018 Victorian Gas Planning Report (VGPR) Update 11

1.4 Scenarios 11

2. Gas demand forecast 13

2.1 Eastern and south-eastern demand forecast trends 13

2.2 Consumption forecasts by sector 15

2.3 Maximum daily demand forecasts 22

3. Short-term supply adequacy 23

3.1 Supply outlook 23

3.2 Risks and variability 25

4. Long-term supply adequacy 28

4.1 Supply outlook 28

4.2 Potential new supply options 31

A1. Forecast accuracy 34

Glossary 37

Tables

Table 1 Production forecasts to 2022 (PJ) as provided by gas producers 6

Table 2 Scenario drivers 12

Table 3 Comparison of 2018 GSOO and September 2017 GSOO Update gas consumption forecasts for 2019 (PJ) 15

Table 4 Percentage splits of gas consumption by sector, 2017 15

Table 5 Total 1-in-20 forecast maximum demand, all sectors, including UAFG, excluding GPG (TJ/day) 22

Table 6 Production forecasts to 2022 (PJ), as provided by gas producers 23

Table 7 Impacts of considered risks and uncertainties on GPG demand between 2019 and 2020 26

Table 8 Summary of sensitivities examining new supply options 32

Figures

Figure 1	Gas consumption actual and forecast, 2010-38, all sectors, Neutral scenario (PJ)	4
Figure 2	Gas consumption forecast in all scenarios, compared to forecasts in 2016 NGFR and 2017 GSOO Update (PJ)	5
Figure 3	Status of reserves and resources to meet domestic demand, 2019-38	6
Figure 4	Status of southern reserves and resources required to meet southern demand, 2019-38	7
Figure 5	Recent changes in Gippsland production forecasts, provided by industry	11
Figure 6	Gas consumption actual and forecast, 2010-38, all sectors, Neutral scenario (PJ)	13
Figure 7	Gas consumption forecast in all scenarios, compared to forecasts in 2016 NGFR and 2017 GSOO Update (PJ)	14
Figure 8	Gas consumption actual and forecast, 2010-38, all sectors, Neutral scenario, by north and south regions	15
Figure 9	Residential/commercial annual consumption actual and forecast, 2010-38, all scenarios, and compared to 2016 NGFR	17
Figure 10	Industrial annual consumption, actual and forecast, 2018-38, all scenarios, and compared to 2016 NGFR	17
Figure 11	Annual consumption forecast for Manufacturing sector, 2018-38, by scenario	18
Figure 12	Annual consumption forecast of Other business sector, 2018-38, by scenario	19
Figure 13	GPG annual consumption actual and forecast, 2010-38, all scenarios, and compared to 2016 NGFR	20
Figure 14	LNG annual consumption actual and forecast, 2010-38, all scenarios, and compared to 2016 NGFR	21
Figure 15	Demand and production forecasts compared to the September 2017 GSOO Update	24
Figure 16	Oil and gas exploration expenditure estimate, and Brent Oil Price, 2011-18	25
Figure 17	Status of reserves and resources to meet domestic demand, 2019-38	29
Figure 18	Status of southern reserves and resources required to meet southern demand, 2019-38	29
Figure 19	Production split between north and south, Neutral – Low southern resource case, 2019-38	30
Figure 20	Projected monthly supply and demand balance for the south in 2030	30
Figure 21	Projected flow duration curve for SWQP flows for 2024, 2034, and 2038, Neutral – Low southern resource case	31
Figure 22	Potential new supply options	32
Figure 23	Gas annual consumption forecast comparison, total for eastern and south-eastern Australia	34
Figure 24	Gas annual consumption forecast comparison, LNG	35
Figure 25	Gas annual consumption forecast comparison, residential/commercial	35
Figure 26	Gas annual consumption forecast comparison, industrial	36
Figure 27	Gas annual consumption forecast comparison, GPG	36

1. Introduction

The 2018 Gas Statement of Opportunities (GSOO) assesses 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. The GSOO analyses a range of potential futures that may impact the gas market in the next twenty years. It is focused on providing an adequacy assessment in the short to medium term, and identifying longer term development needs.

This report is based on information available to AEMO at 6 April 2018, although AEMO has endeavoured to incorporate more recent information where practical. It incorporates:

- National gas demand forecasts, previously published separately in the National Gas Forecasting Report (NGFR).
- A brief overview of the Australian Domestic Gas Security Mechanism (ADGSM)[7].
- An update on the gas supply outlook for eastern and south-eastern Australian gas markets, building on information provided in the Victorian Gas Planning Report (VGPR)[8].

1.1 National gas demand forecasts

A key input to the GSOO is 20-year forecasts of annual gas consumption and maximum daily demand.

Since 2014, AEMO has published these forecasts separately to the GSOO, as the NGFR[9]. The 2017 GSOO, for example, used forecasts from the 2016 NGFR. This year, gas demand and supply outlooks have been integrated into this one publication in recognition of their co-dependencies.

Chapter 2 summarises the forecasts and key demand drivers in the 20 years to 2038, and detailed data is available on AEMO's forecasting portal[10]. AEMO's forecasting performance since 2014 is summarised in Appendix A1.

1.2 The Australian Domestic Gas Security Mechanism

The 2018 GSOO comes after an eventful year in the gas industry, and in the context of policy and market changes affecting demand and supply in Australia and globally. One of the major changes for the Australian gas industry in 2017 was the Federal Government's introduction of the ADGSM, under which the Federal Minister for Resources and Northern Australia can determine whether export restrictions should be imposed to avoid any potential shortfall in meeting domestic demand for gas in a calendar year.

The ADGSM was introduced by way of regulations[11] which empower the Federal Minister to impose liquefied natural gas (LNG) export restrictions in a 'domestic shortfall year'. This is a calendar year where the Minister has reasonable grounds to believe that the export of LNG would contribute to a lack of supply of natural gas for consumers and that there will not be a sufficient supply unless exports are controlled. Guidelines[12] made under those Regulations provide that, unless the Minister determines that it is not necessary to consider whether a year is a domestic shortfall year, the Minister commences the process between July and October by issuing a notification of his intention to consider whether the following calendar year will be a domestic shortfall year, and consulting with a range of stakeholders to seek their views.

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[7] Information available at https://industry.gov.au/resource/UpstreamPetroleum/AustralianLiquefiedNaturalGas/Pages/Australian-Domestic-Gas-Security-Mechanism.aspx.

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

[9] NGFRs and supporting material are available at http://aemo.com.au/Gas/National-planning-and-forecasting/National-Gas-Forecasting-Report.

[10] Demand forecasts are available on the Forecasting Data Portal http://forecasting.aemo.com.au/. Select 'GSOO 2018' from the publication drop-down.

[11] Introduced in 2017 by way of the insertion of a new Division 6 in Part 3 of the *Customs (Prohibited Exports) Regulations 1958*.

[12] *Customs (Prohibited Exports) (Operation of the Australian Domestic Gas Security Mechanism) Guidelines 2017*.

The objective of the ADGSM is to ensure there is sufficient supply of natural gas to meet the forecast needs of Australian consumers by requiring, if necessary, LNG projects which are drawing gas from the domestic market to limit exports or find offsetting sources of new gas.

In 2017, the Federal Government decided not to apply export controls for the 2018 year following its considerations under the ADGSM. However, it reached a Heads of Agreement[13] with the east coast LNG consortia under which they made commitments in relation to the domestic supply of gas in 2018 and 2019.

1.3 2018 Victorian Gas Planning Report (VGPR) Update

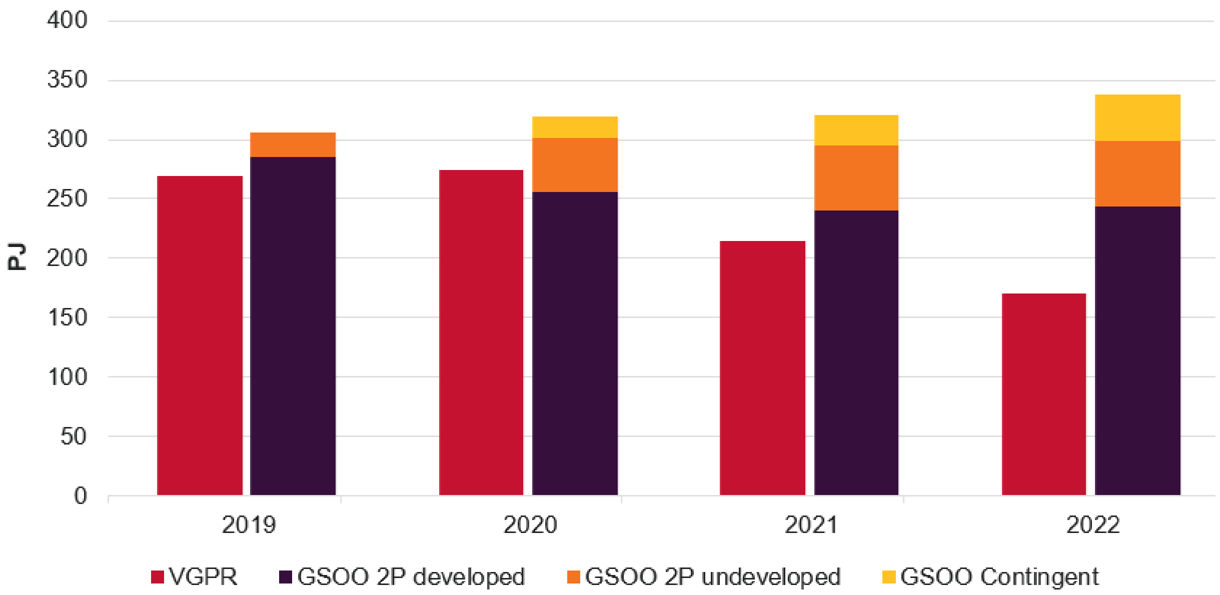
The 2018 GSOO builds on the forecasts AEMO presented in the March 2018 VGPR Update, although its purpose is different. The VGPR specifically examines only those gas production developments that exist or are currently committed in Victoria, while the GSOO uses industry information regarding expected expansions of gas production facilities across eastern and south-eastern Australia.

Both reports support the need for reserves and resources not yet developed to be brought to market in the short term to meet forecast demand, and, in the longer term, for supply to continue to expand beyond producers' current best estimates of long-term industry investments.

The March 2018 VGPR Update considered only developed gas reserves and committed and approved new gas supply projects, and projected that, without additional gas supply, there would be a potential shortfall in meeting annual Victorian gas consumption from 2022.

For the GSOO, gas producers have included additional gas supply from as yet undeveloped reserves and resources as part of their best estimates of production. This new information highlights that Victorian offshore gas producers are expecting to replace declining field production with new reserves and resources in the next few years to 2022, helping to alleviate the risk of gas shortfalls. As an example, production estimates differences for Gippsland producers between the March 2018 VGPR Update and the June 2018 GSOO are highlighted in Figure 5 below.

Figure 5 Recent changes in Gippsland production forecasts, provided by industry



1.4 Scenarios

The demand and supply inputs for the 2018 GSOO are based on a range of scenarios, constructed to be economically consistent. The Neutral scenario considers demand drivers of an economy that takes the most likely pathway. The Strong and Weak demand scenarios provide alternative projections of consumption and peak demand

[13] See https://industry.gov.au/resource/UpstreamPetroleum/AustralianLiquefiedNaturalGas/Documents/Heads-of-Agreement-The-Australian-East-Coast-Domestic-Gas-Supply.pdf.

with reasonable bounds on the core demand drivers, although less likely in aggregate than the Neutral forecasts. Some of the key indicators under the three scenario conditions are described in Table 2[14].

Table 2 Scenario drivers

Driver	Neutral scenario	Strong scenario	Weak scenario
Population growth	ABS Series B (Medium)	ABS Series A (High)	ABS Series C (Low)
Economy	Neutral global and domestic demand	Strong global and domestic demand	Weak global and domestic demand
Energy efficiency	Moderate energy efficiency measures adopted	Aggressive energy efficiency measures adopted	Weak energy efficiency measures adopted
Fuel switching	Average economic case for fuel switching	Strong economic case for fuel switching	Weak economic case for fuel switching
Gas price	Medium gas prices	High gas prices	Low gas prices
Minimum emission abatement achieved by the electricity market	Compared to 2005 levels, 28% reduction by 2030, 70% reduction by 2050	Compared to 2005 levels, 52% reduction by 2030, 90% reduction by 2050	Compared to 2005 levels, 28% reduction by 2030, 70% reduction by 2050

Information on the demand and supply forecasting methodologies, and more detailed explanation of scenarios, is available on the 2018 GSOO webpage[15].

[14] These Neutral, Strong, and Weak scenarios are consistent with the Neutral, Fast change, and Slow change scenarios studied for AEMO's Integrated System Plan (ISP), available at http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

[15] AEMO's 2018 GSOO supporting documents are available at https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

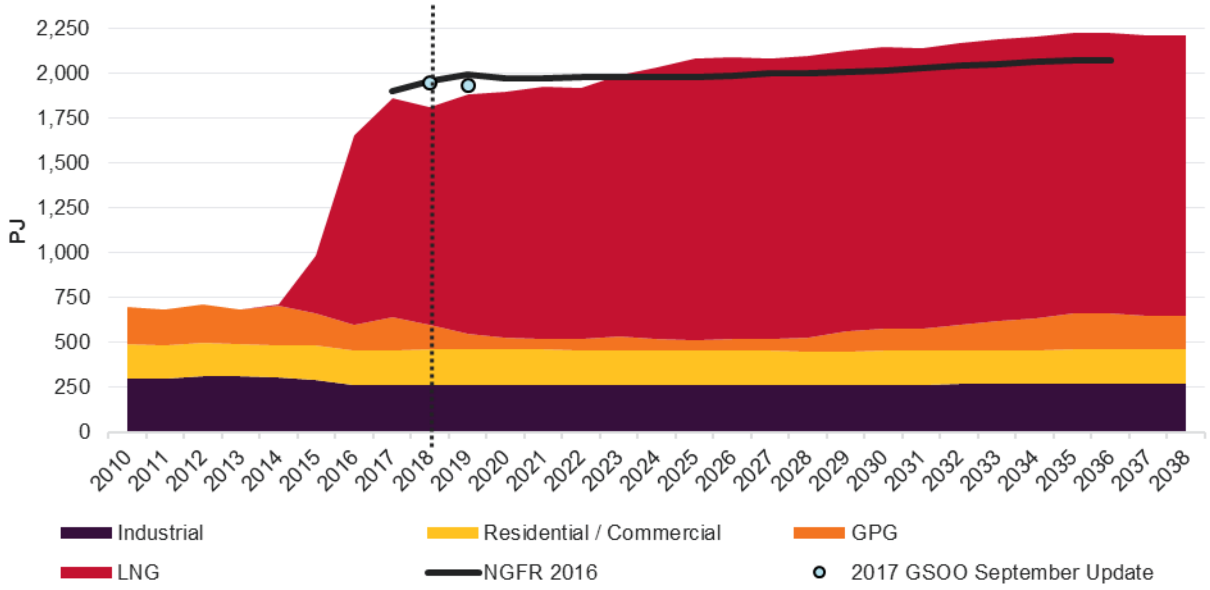
2. Gas demand forecast

The pace of change affecting Australia's energy markets has been rapidly increasing over the last few years. While energy policy has provided a catalyst for this, a more engaged consumer base is also a key contributing factor. This is being evidenced by the volatility in actual consumption in recent years, compared to the steadily increasing trends of the past, suggesting customers are responding to market changes. This is consistent across both the residential and business sectors. More environmentally-conscious, innovative, and responsive consumers are emerging. The demand forecasts for this year's GSOO continue to show diverging trends across consumer sectors and demonstrates the increasing uncertainty in forecasting an evolving consumer and customer base.

2.1 Eastern and south-eastern demand forecast trends

Figure 6 shows the 20-year total demand forecast for eastern and south-eastern gas markets under the Neutral scenario, and the breakdown of the forecasts by the consumer types.

Figure 6 Gas consumption actual and forecast, 2010-38, all sectors, Neutral scenario (PJ)



Some of the key insights to the demand forecasts[16], expanded in subsequent sections of this report, are:

- Declining forecast consumption in the early years (2018-23), due to:
  - Decline in projected residential/commercial consumption, due to energy efficiency gains and gas to electric fuel switching.
  - Forecast decline in gas consumption from gas-powered generation (GPG) of electricity, due to penetration of renewable generation sources increasing at a rapid rate in the National Electricity Market (NEM)[17].
- Consumption stabilising over the medium term of forecasts (2024-28), due to:

[16] Demand forecasts are available on the Forecasting Data Portal http://forecasting.aemo.com.au/. Select 'GSOO 2018' from the publication drop-down.

[17] AEMO reports information on the capacity of existing, withdrawn, committed, and proposed generation projects in the NEM through the Generation Information page, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

– Projected ramp-up in LNG exports to full LNG train utilisation to meet growing Asian demand, offsetting a forecast continued decline in residential/commercial consumption from energy efficiency gains and gas to electricity fuel switching.

– Forecast GPG gas consumption remaining low while renewable generation continues to play an increased role in the NEM.

– Industrial consumption forecasts remaining flat over the period.

- Forecast growing consumption of residential/commercial sectors and GPG in the long term (2029-38), due to:

  – The projected impact of energy efficiency and gas to electric fuel switching plateauing in the long term, leaving growth in connections as the dominant driver to increase residential/commercial consumption.

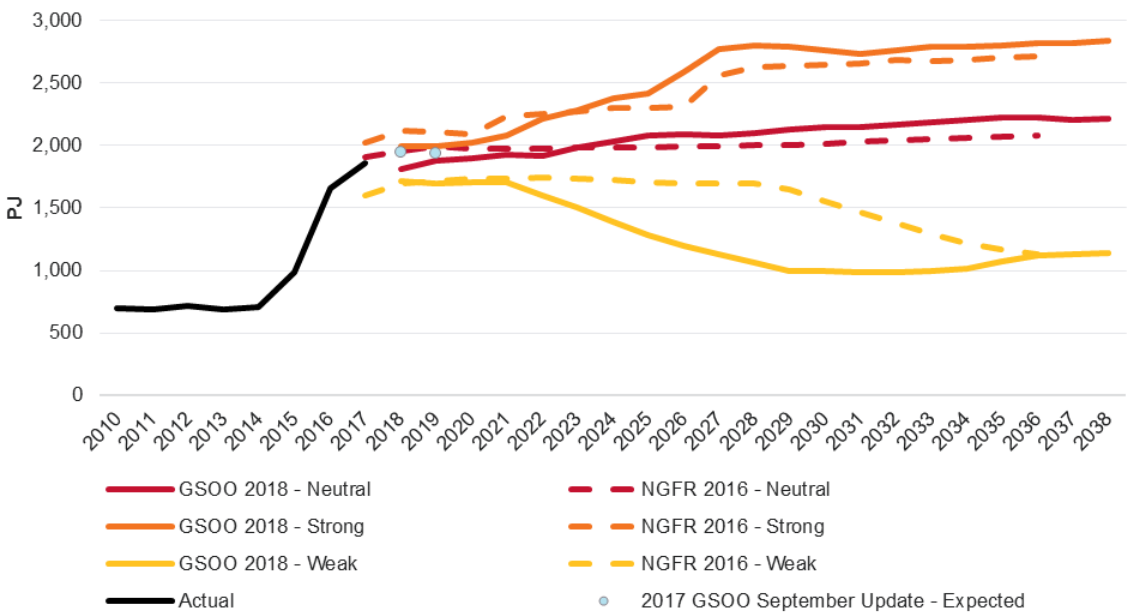
  – Forecast GPG demand for gas growing as it is expected to assist in integrating renewable generation reliably and securely, particularly as aging coal generators are forecast to retire. Despite this forecast growth, demand for gas from GPG is not projected to return to recently observed historical levels within the 20-year outlook period.

Comparison of 2018 GSOO gas demand forecasts to previous forecasts

The difference in demand forecasts across the 2016 NGFR, the 2017 GSOO Update, and the 2018 GSOO are shown in Figure 7. Key differences in trends are:

- All 2018 GSOO scenarios show lower demand than the previous forecasts in the short term. This is primarily due to forecast declines in GPG gas consumption driven by more rapid renewable generator development than was earlier expected, even in the 2017 GSOO Update. Projected ramp-up to full LNG production is also slower than previously projected, due to increased international LNG supply competition in the short term.
- At the end of the forecast period, the 2018 GSOO forecasts are higher than the 2016 NGFR forecasts in the Neutral and Strong scenarios. This is explained by the upward revised forecasts of consumption for both LNG and the industrial sector. Forecast LNG export growth is driven by revised assumptions on efficiency rates of liquefaction and increased debottlenecking[18] to lift total export capacity. Industrial growth is driven by projections of more stable large industrial loads and stronger growth outlook in the Gross Value Added (GVA) of the Services sector[19].
- In the Weak scenario, faster rates of decline of production from CSG wells were assumed than in earlier forecasts, as more data on actual production profiles has become available.

Figure 7 Gas consumption forecast in all scenarios, compared to forecasts in 2016 NGFR and 2017 GSOO Update (PJ)



[18] Debottlenecking is a term specific to the gas industry, in which bottlenecks to the flow of gas through the plant equipment is reduced to allow more efficient processing of gas. For more details, please see https://www.audubоncompanies.com/debottlenecking-what-it-is-and-how-it-can-help-optimize-downstream-processes/.

[19] GVA is defined as an aggregated measure ($'Millions, 2018 real terms) of economic activity in all sectors except agriculture, construction, mining, manufacturing, and utilities. Sector definitions used in the GSOO follow the Australia New Zealand Industry Sector Category, published by the Australian Bureau of Statistics. See http://www.abs.gov.au/ausstats/abs@.nsf/Latestproducts/0C2B177A0259E8FFCA257B9500133E10?opendocument.

The differences in the most recent forecasts for 2019 are shown in Table 3 below.

Table 3 Comparison of 2018 GSOO and September 2017 GSOO Update gas consumption forecasts for 2019 (PJ)

Sector	2018 GSOO	September 2017 GSOO Update	Difference
Residential, commercial. and industrial	464	463	-1
GPG	88	135	-47
LNG	1,328	1,336	-8
Total	1,880	1,934	-54

2.2 Consumption forecasts by sector

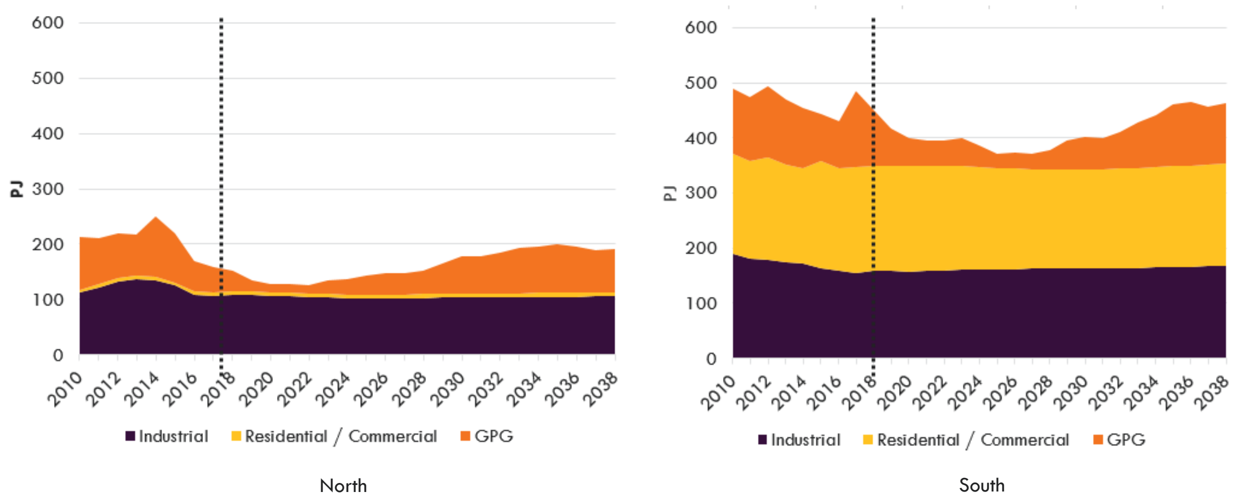
Gas is used in different ways across Australia. For example, in Victoria, gas consumption is dominated by the residential/commercial sector, whereas in Queensland, the residential/commercial sector has a very small proportion of regional gas consumption. Table 4 shows the breakdown of gas consumption for each region by sector.

Table 4 Percentage splits of gas consumption by sector, 2017

Regional	Residential/commercial	Industrial	GPG	LNG	Regional gas consumption
Queensland	< 1%	8%	3%	89%	1,377 PJ
New South Wales	37%	42%	21%	0%	130 PJ
South Australia	11%	23%	66%	0%	101 PJ
Tasmania	5%	33%	62%	0%	15 PJ
Victoria	55%	30%	15%	0%	228 PJ
Total consumption by sector	10%	14%	10%	66%	1,851 PJ

Figure 8 below shows the gas consumption forecast across northern (Queensland/Northern Territory) and southern (Victoria/ New South Wales/South Australia) regions. The figure demonstrates the geographic diversity of each customer sector.

Figure 8 Gas consumption actual and forecast, 2010-38, all sectors, Neutral scenario, by north and south regions



2.2.1 Residential and commercial consumption

AEMO developed residential and commercial forecasts using forward estimates of consumption on a per connection basis. The forecast number of new connections therefore drives the growth trajectory, subject to other influences (such as changing consumer behaviours in response to pricing stimuli, appliance fuel switching and broader energy efficiency impacts). The forecast highlights that:

- Until the late 2020s, new connection growth is projected to be offset by the impacts of energy efficiency improvements and appliance fuel switching, in response to projected increasing retail gas prices[20]. Throughout the 2020s, the combined effect of these impacts is forecast to be larger than the increases in demand from new connections.
  - Energy efficiency improvements occur when older appliances are replaced by newer, more efficient devices, such as instantaneous gas hot water systems that use gas more efficiently than gas-heated systems that store hot water in a tank. Efficiency improvements also come from upgrades to building insulation that reduce the amount of space heating required to maintain a comfortable temperature.
  - Appliance fuel switching is expected to reduce gas consumption for both water heating (where gas-boosted solar hot water systems are gaining in popularity) and space heating (where modern reverse-cycle air-conditioners are becoming a cheaper alternative to gas heating).
  - Retail prices rise in the first three years because of a combination of tight supply and demand balance and retailers transitioning from legacy contracts to higher-priced new Gas Supply Agreements (GSAs) for wholesale gas. Prices stabilise over the long term at higher levels than history, reflective of increased cost of production and the influence of the LNG netback price, which has impacted domestic gas prices since the introduction of the east coast LNG industry.
- After the late 2020s, these connection-offsetting drivers are projected to have a reduced impact, allowing new connections growth to drive the forecast trend. This forecast reduction is partly driven by an average 10-year to 15-year replacement lifetime of gas appliances, as well as the efficiency upgrades of older homes approaching that of newer housing stock.
- Climate change is projected[21] to increase average temperatures by about 0.5°C by the end of the forecast period, thereby reducing gas demand for heating in winter. On average, across eastern and south-eastern Australia, AEMO's modelling projects a reduction of approximately 25 PJ for every 1°C increase in average temperature.

In the Neutral scenario, the above factors produce a residential and commercial gas consumption forecast that declines until the late 2020s, before recovering to close to its 2018 value[22].

Figure 9 shows the overall trend in forecast residential and commercial gas consumption for the three scenarios, and compared to the 2016 NGFR forecast. The 2017 GSOO Update forecasts are not shown because they were aggregated to include residential, commercial, and industrial consumption.

While the overall forecast closely resembles the 2016 NGFR projection, some variation exists at the regional level. A key driver of this variation is the dwellings forecast used to project new gas connections, which has been updated for the 2018 GSOO. These projections now show a higher rate of connections growth in Victoria compared to the 2016 NGFR, whereas growth in other regions is slightly lower. These changes result in a higher gas demand forecast in Victoria and slightly lower forecasts in other regions, however the net impact on the total residential/commercial forecast is negligible at the end of the forecast period.

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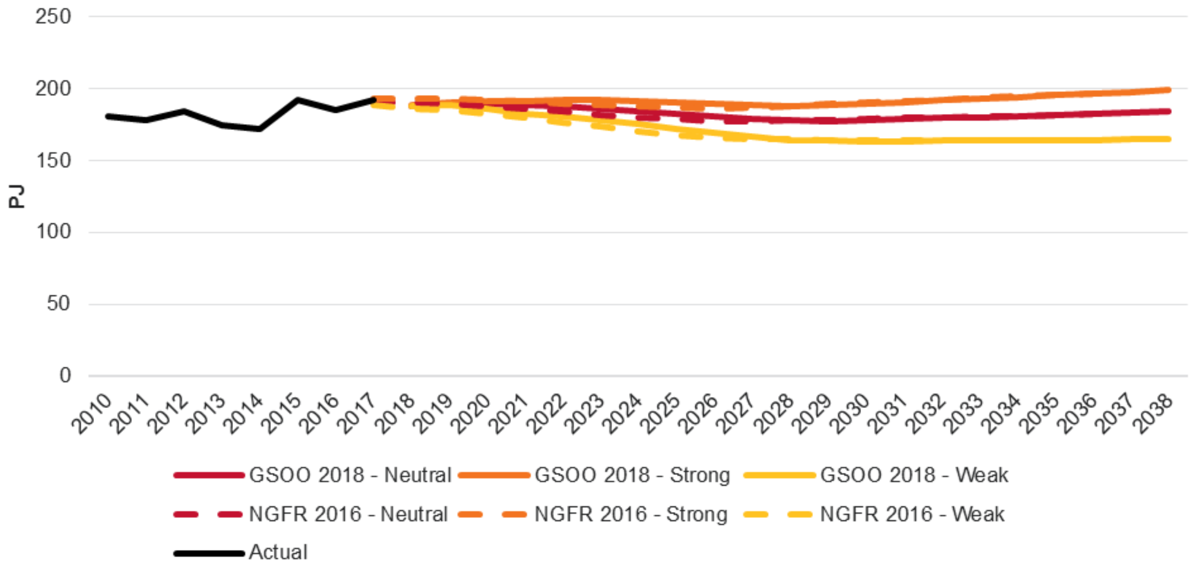
[20] Retail gas prices are derived by AEMO based on wholesale gas price forecasts produced by Core Energy. These wholesale prices reflect the underlying market conditions assumed in each of the forecast scenarios. AEMO has adjusted these external forecasts in the near term to reflect recent observations of wholesale prices. AEMO's index of retail gas price forecasts are available at: http://forecasting.aemo.com.au/.

[21] Further detail on the methodology capturing the influence of a warming climate is in the GSOO Methodology documentation, available at http://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

[22] Climate change projections are based on information available on the Climate Change in Australia website, at https://www.climatechangeinaustralia.gov.au/en/climate-projections/.

Figure 9 **Residential/commercial annual consumption actual and forecast, 2010-38, all scenarios, and compared to 2016 NGFR**



2.2.2 Industrial consumption

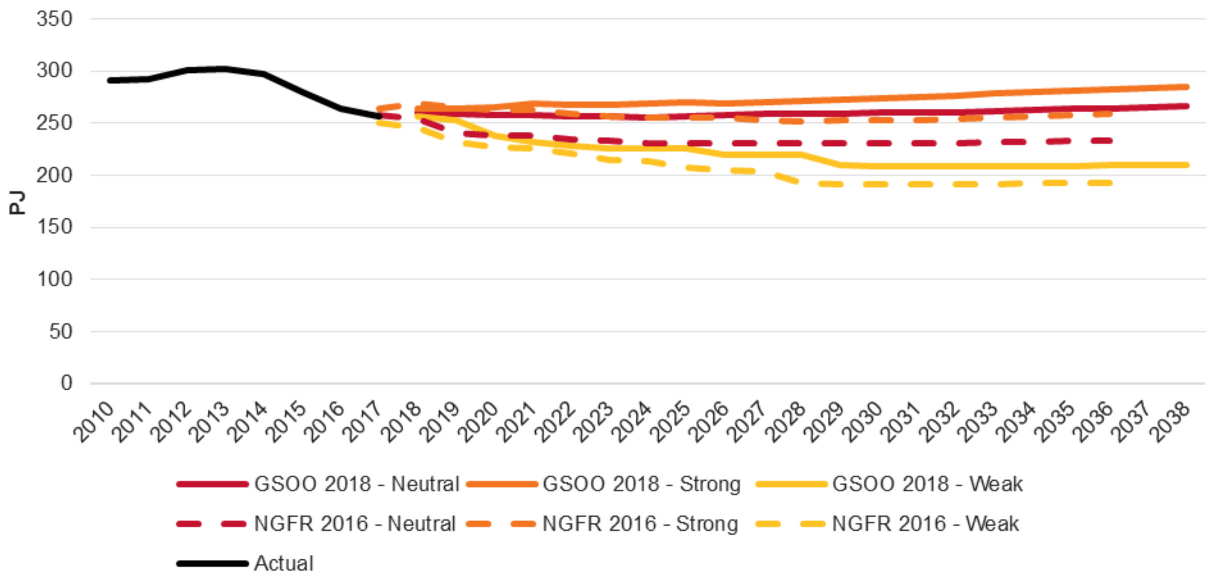
AEMO forecast industrial sector consumption separately for:

1. The Manufacturing sector, which is typically more energy-intensive, and
2. 'Other business' consumers.

Currently, 89% of industrial consumption is from the Manufacturing sector. The underlying drivers affecting the Manufacturing and Other business sectors are discussed separately below. Key trends show a flat neutral projection for the Manufacturing sector, while the Other business sector is forecast to continue to grow, in line with services sector growth.

Figure 10 shows the overall trend in forecast industrial gas consumption for the three scenarios, and compared to the 2016 NGFR forecast.

Figure 10 **Industrial annual consumption, actual and forecast, 2018-38, all scenarios, and compared to 2016 NGFR**

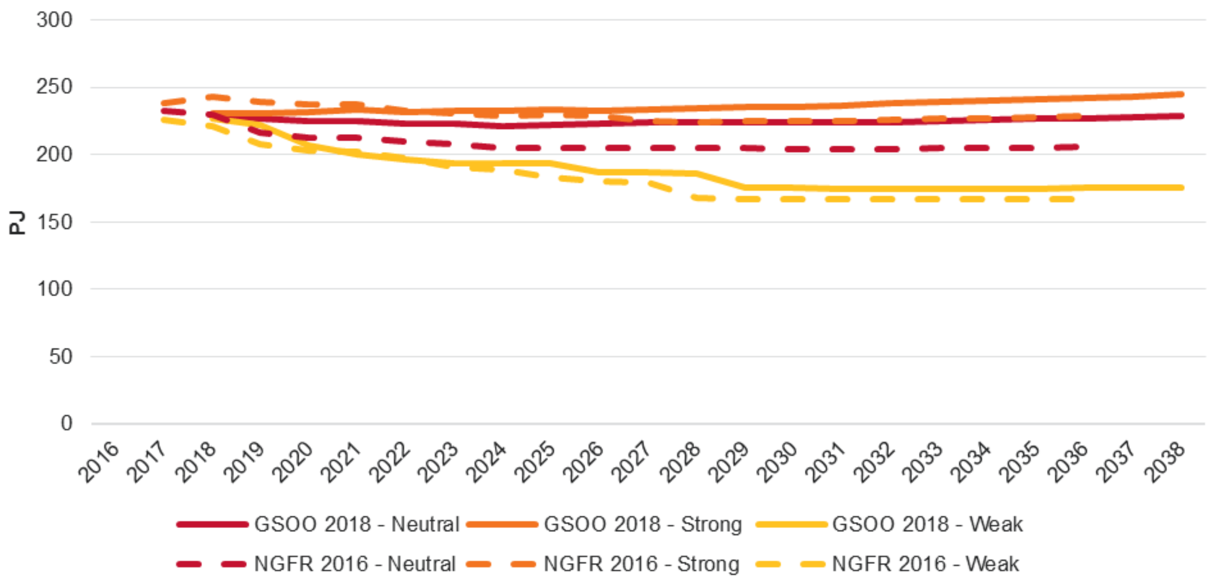


Comparison between scenarios shows more downside risk associated with the potential closure of large industrial loads and stronger price response in the Weak scenario, compared with the Neutral. Scenario variance and risk is asymmetric. While there is some potential in the Strong scenario for new industrial loads to increase consumption, growth is primarily due to increases associated with existing production processes. Industry feedback suggests that there is little incentive currently for such new major investment. Therefore, the upside consumption uncertainty is a lot less than the downside uncertainty where industrial loads may close due to poor economic conditions. These trends are consistent across all regions.

Manufacturing sector trends

The Manufacturing sector forecast (see Figure 11) is largely driven by consumption from large industrial loads[23], which are projected to remain stable in the Neutral scenario over the forecast period.

Figure 11 Annual consumption forecast for Manufacturing sector, 2018-38, by scenario



In contrast to the 2016 NGFR forecasts, AEMO no longer projects a material demand response to rising gas prices:

- Analysis of actual consumption over the last 12 months indicates industrial users have been resilient to recent gas price rises. The Australian Competition and Consumer Commission (ACCC) interim gas market enquiry reports[24] have identified an increase in average contract price of 25% from the last quarter of 2016 to the first quarter of 2017 alone. Despite this, AEMO's consumption data suggests only a 2% decrease in total industrial consumption from 2016 to 2017.
- In addition, detailed interviews with large industrial users, ranging from questions on the broader gas market to industry specific dynamics, reveal that large industrial consumers have increased confidence in gas availability, due, in part, to the ACCC review into the gas markets, and the introduction of the ADGSM and the LNG Heads of Agreement with the potential for diversion of LNG gas from exports to the domestic market.
- Some large industrial users are taking a more active role in their gas procurement by becoming direct market participants in wholesale markets or investigating options for joint ventures with gas producers[25].
- Improved commodity prices and foreign exchange rates have strengthened export conditions for large industrial consumers, further increasing their resilience to recent increases in gas prices.

The ACCC has reported trends on historic prices. The September 2017 interim report[26] highlights that the period of 2015 to 2017 exhibited much higher gas prices than those historically seen. This was a period when the gas industry

[23] Large industrial loads are consumers that use more than 500 TJ of gas annually.

[24] Since September 2017, the ACCC has released a series of interim gas market enquiry reports (https://www.accc.gov.au/publications/serial-publications/gas-inquiry-2017-2020) that review the state of demand and supply in the Australian domestic gas market and also report on contract pricing trends, with a key objective to improve transparency and provide benchmarks for gas consumers.

[25] Small Caps, "Central Petroleum and Incitec Pivot join forces in Queensland", 1 March 2018, available at https://smallcaps.com.au/central-petroleum-incitec-pivot-queensland/.

[26] ACCC, *Gas Inquiry 2017-2020 Interim Report, September 2017*, available at https://www.accc.gov.au/system/files/Gas%20Inquiry%20-%20Interim%20Report%20-%20September%202017.pdf.

was transitioning from legacy contracts to new gas supply agreements (GSAs). New GSAs are typically higher in price, reflecting increases in the cost of gas production and the influence of the LNG netback price, which has impacted domestic gas prices since the commencement of the east coast LNG industry.

Looking forward, price rises of similar magnitude are not evident in future wholesale gas price projections. The rate of increase is expected to slow over the next three years then stabilise.

The forecast changes in market conditions, coupled with this projected softening in gas price rise and greater gas availability expectations, suggest that the largest subset of industrial users have a more stable consumption outlook than previously forecast. This aligns with the survey responses received from these large industrial users, with little change in survey-based consumption projected relative to last year.

Accordingly, AEMO has refined the industrial sector methodology to reflect these changes, with forecasts of large industrial loads being based on survey forecasts and not included in the econometric modelling[27].

The remaining industrial consumption that is driven by econometric modelling also has a lower forecast gas price response, due to updated gas prices that shows earlier wholesale gas price stabilisation than 2016 NGFR.

There are also some large industrial step changes projected, both positive and negative, arising from a combination of industrial closures, fluctuation in industrial user production levels, and adoption of more electricity and heat cogeneration to manage electricity market price exposure.

Other business sector trends

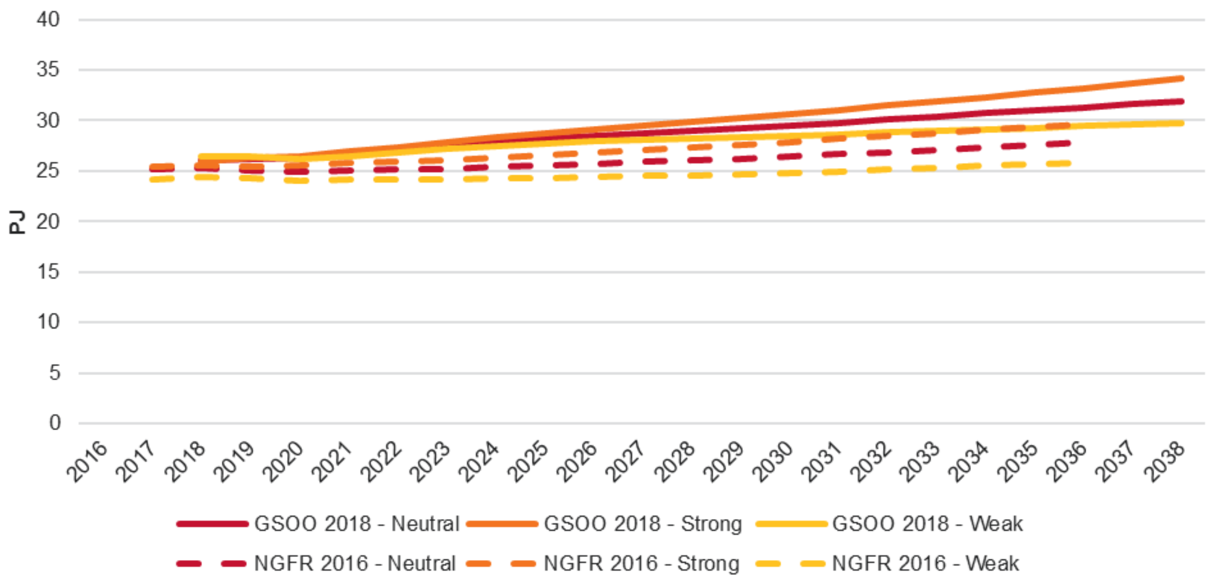
Outside of the Manufacturing sector, gas consumption is projected to grow at approximately 1% each year over the 20 years, as shown in Figure 12. This increasing trend continues to tell the same story as the 2016 NGFR, with some updates to the forecasts of the input drivers resulting in slightly higher projections.

The key drivers for the Other business sector are:

1. Retail gas price – price increases are driven by projected wholesale price rises in the long term. The reduction in consumption in response to price increase is revised down in this year's forecasts, due to an updated wholesale price forecast which has prices stabilising earlier than the projections from last year.
2. Services sector GVA – this is the economic activity of the services sector, which makes up most of the Other sector consumption. Services sector GVA has been revised up because of updated economic modelling done by an economic consultant for AEMO[28].

The trend for Other business sector consumption forecast is dominated by increasing economic activity in the services sector. This is forecast to be moderated in the very short term (first three years of the forecast period) by response to retail price rises. However, as gas price rises are projected to taper off in subsequent years, growth in services GVA drives the long-term trends.

Figure 12 Annual consumption forecast of Other business sector, 2018-38, by scenario



[27] For gas demand forecasting methodology please see http://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

[28] Services sector GVA forecasts are produced for AEMO by economic consultants, in accordance with AEMO scenario definitions. Input forecast data is available at http://forecasting.aemo.com.au/.

2.2.3 GPG

Over the outlook period, AEMO expects the role of GPG to move toward meeting demand when renewable generation is low, and during more extreme weather events. Overall utilisation of existing GPG is projected to decline in the next decade, as renewable generation sources supply more energy during the day and most existing coal-fired generation remains in service. In the period from 2030 to 2040, the capacity factor of the remaining gas-fired generation is forecast to recover as coal-fired generators reach end of technical life and retire.

Forecast gas demand for GPG (in Figure 13) is lower than previously forecast in the Neutral scenario, driven by an increased outlook for renewable generation development. In the short term, the rate at which new renewable generation is being commissioned is faster than previously expected, and greater projected reductions in build costs are accelerating long-term forecast renewable generation penetration. Expanded renewable generation targets set by the governments of Victoria and Queensland further increase expectations for a greater uptake of renewable generation in the next decade than was forecast in 2017.

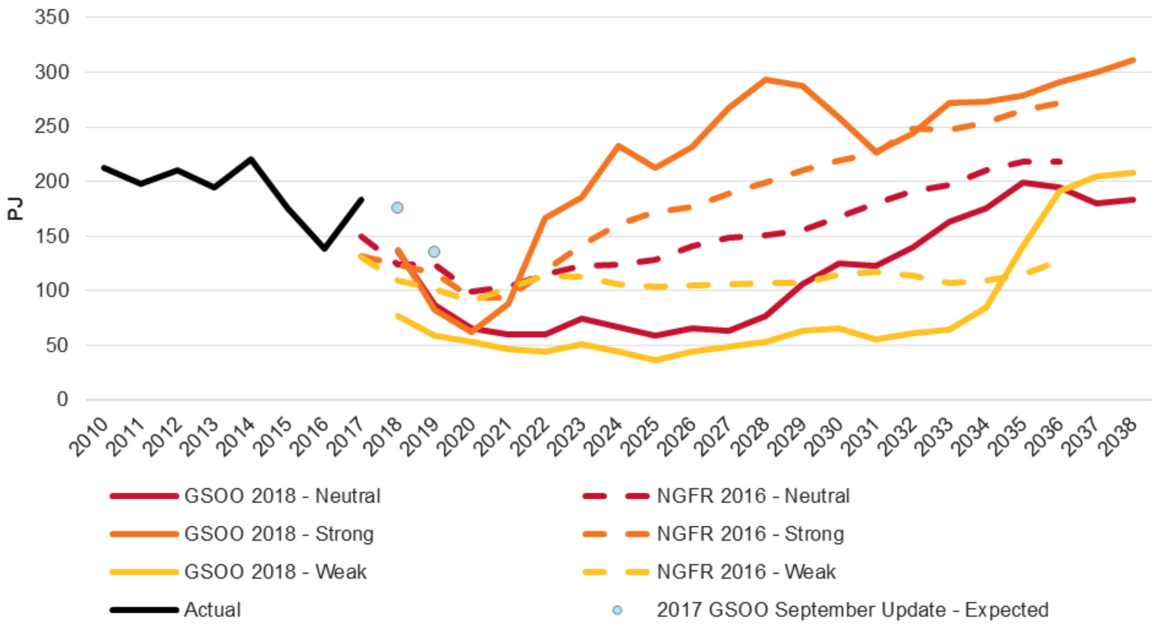
The forecast higher demand for GPG in the Strong scenario is driven by a combination of elements, including:

- Higher electricity demand due to stronger economic growth, stronger electric vehicle uptake, and weaker demand side participation, compared to the Neutral scenario.
- Higher emissions abatement assumed by the electricity sector in the Strong scenario, driving reduced operation of coal-fired generation.

Forecast demand for GPG in the Weak scenario is driven primarily by lower electricity demand leading to a reduced reliance on GPG for electricity generation. With GPG a relatively costly form of electricity generation, particularly compared to renewable energy sources, it is relied upon much less than other generation types under low demand conditions. Relatively high-cost GPG may therefore be called on for generation less frequently, particularly with increasing competition from renewable generation.

While the Weak scenario reflects the lowest forecast general consumption trend for GPG, this scenario is also expected to lead to the least development of renewable energy generation. As such, as coal generators retire, the presence of less renewable energy may lead to greater consumption of GPG. This is evident in the mild crossover between the Neutral and Weak scenarios beyond 2035, and demonstrates increasing uncertainty in the long term.

Figure 13 GPG annual consumption actual and forecast, 2010-38, all scenarios, and compared to 2016 NGFR



2.2.4 LNG

The LNG forecasts used in this 2018 GSOO, shown in Figure 14, have been developed considering stakeholder guidance and long-term forecasts from Lewis Grey Advisory (LGA)[29].

[29] Further detail is available in the Lewis Grey Advisory (LGA) report on AEMO's website at http://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

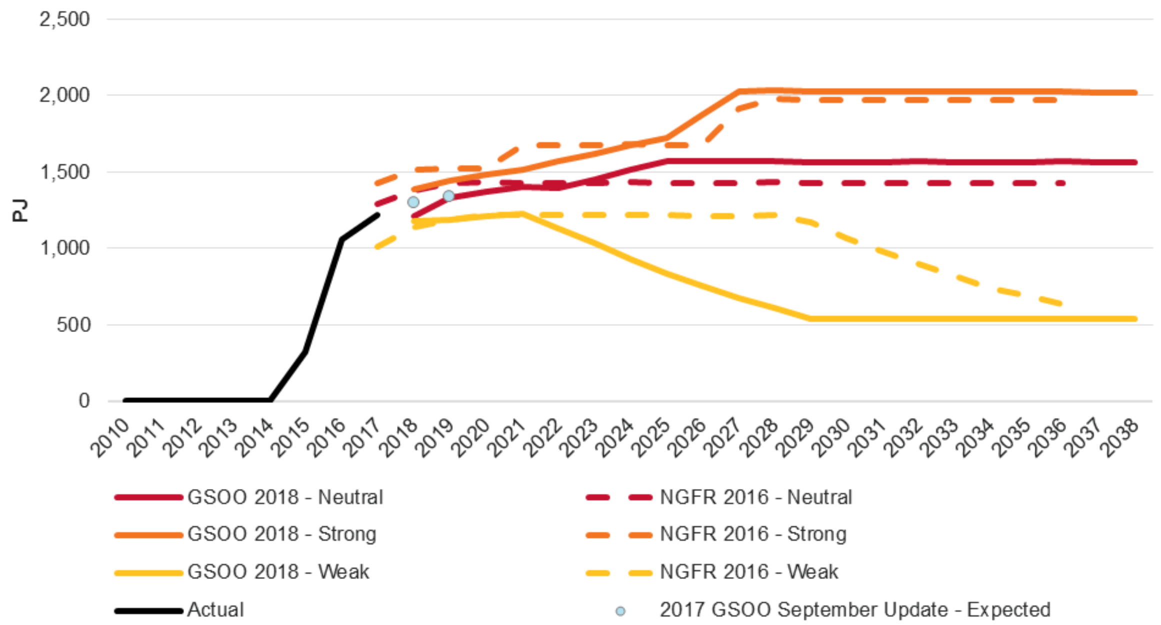
The key trends of the LNG forecasts are:

- In the short term (2019-23), a slow demand increase from current usage to meet global demand is forecast. These projections come from LNG consortia forecasts in aggregate, and are slightly lower than the 2016 NGFR due to changing international LNG market dynamics and the east coast LNG producers increasing their domestic gas commitments.
- Beyond 2023, exports are forecast to ramp to maximum LNG production capacity, largely motivated by stronger demand for LNG in Asia after 2023. This is due to:
  - The continued curbing of greenhouse gases by power generation fuel switching in emerging economies (such as China, South Korea, and India).
  - The further development of international carbon markets.
  - The mandatory reduction of sulphur emissions for marine vessels[30] under the International Maritime Organisation's "International Convention for the Prevention of Pollution from Ships" (MARPOL Convention), which can be met by an increased usage in ships of low sulphur-emitting fuels such as LNG.
  - China's plan to correct the continued mismatch of gas storage and gas demand within China[31].

  Forecast export LNG train capacity has also been revised up from last year, due to a combination of:
  - Servicing the strengthening global demand for LNG.
  - Updated assumptions on efficiency rates of liquefaction (revised down) and nameplate capacity levels (revised up), based on updated consumption data.

  Collectively, these changes result in higher forecast demand in the medium to long term compared with last year.
- The Strong scenario has earlier forecast increases in gas usage compared to Neutral, because it assumed the LNG companies would be more aggressive in debottlenecking the LNG facilities. In the longer term, the Strong scenario considered the possibility of an additional LNG export facility from 2025, ramping up to full capacity export by 2027 and sustained for the remaining forecast period. This is a continued assumption from the 2016 NGFR and, while it is less likely than some drivers, AEMO has included it to provide a book-end to the gas demand scenarios.
- The Weak scenario assumed little incentive for further drilling beyond existing well production. It follows the production profile of existing wells, declining to minimum production levels by 2029, earlier than was assumed in the 2016 NGFR forecast. This revision resulted from more production data being available to assess rates of decline.

Figure 14 LNG annual consumption actual and forecast, 2010-38, all scenarios, and compared to 2016 NGFR



[30] Under the regulations, marine vessels must reduce their sulphur oxides (Sox) emissions from 3.5% to 0.5% by 2020 for non-emission control areas. See http://www.imo.org/en/about/conventions/listofconventions/pages/international-convention-for-the-prevention-of-pollution-from-ships-(marpol).aspx.

[31] See https://oilprice.com/Energy/Natural-Gas/Chinas-Gas-Storage-Capacity-Cant-Keep-Up-With-Demand-Growth.html.

2.3 Maximum daily demand forecasts

Maximum daily demand forecasts have similar dynamics to those of the annual consumption forecasts, noting that:

- For most regions, maximum daily demand is determined by weather driving gas consumption for heating in winter for consumption by households and commercial businesses and, to a smaller degree, industrial use.
- Trends show a forecast decline in maximum daily demand, exclusive of GPG, caused mostly by projected industrial load reductions, gas to electric appliance switching, and (to a lesser extent) a warming climate.

Table 5 shows the 1-in-20-year forecast[32] for all sectors combined. These forecast totals include unaccounted for gas (UAFG) that is lost while being transported through the network[33].

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

Calendar year	NSW		QLD (incl. LNG)		QLD (LNG only)		SA		TAS		VIC	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
2019	329	509	4,224	4,231	3,882	3,882	115	163	22	24	632	1,261
2023	328	508	4,767	4,775	4,438	4,438	116	163	23	25	631	1,242
2028	322	492	4,836	4,844	4,509	4,509	114	158	24	26	616	1,206
2038	332	505	4,848	4,855	4,509	4,509	116	160	25	27	640	1,257

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

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

3. Short-term supply adequacy

This chapter presents the outlook for producers to source sufficient supply to meet the demand projections presented in Chapter 2, given the capabilities of the gas network to deliver gas to the point of consumption. The chapter focuses on the short term, being the next four years from 2019 to 2022 (calendar years), and examines broader risks that may influence the balance of supply and demand for gas.

3.1 Supply outlook

For the 2018 GSOO, AEMO has used producers' forecast production to assess the adequacy of gas supply over the next four years, from 2019 to 2022. Compared to the production forecast for 2019 received for the September 2017 GSOO Update, the outlook has improved, due to:

- A net increase of 7 PJ in projected eastern and south-eastern production. Forecast production from southern fields in 2019 is 16 PJ higher compared to the forecasts for the September GSOO Update, while forecast production from both CSG and conventional gas fields in Queensland is 9 PJ lower.
- The development of the NGP, expected to connect new supplies from the Northern Territory to Mt Isa in Queensland by December 2018. Capacity of this pipeline will provide access to up to 31 PJ of gas per year from Northern Territory gas sources, including the Blacktip and Mereenie gas fields.

Table 6 shows the production forecast between 2019 and 2022 provided to AEMO by gas producers as their current best estimate. Gas production in these projections is forecast to increase annual field output by 144 PJ between 2019 and 2022 across both the south and the north. The largest increases are forecast in northern gas fields, to meet forecast growth in LNG exports. This increased forecast of CSG production from the north is highly reliant on large numbers of wells continuing to be drilled and constructed annually.

These production forecasts contain volumes of undeveloped reserves and contingent resources, as advised by gas producers. Investment in exploration and development will be required to bring these reserves and resources to market.

In 2019, total forecast production in the Neutral scenario is now about 58 PJ above forecast demand, although utilisation will depend on whether supply can be delivered where it is needed. AEMO estimates around 37 PJ of this supply buffer could be available to cover variability in Neutral scenario demand before pipeline constraints become limiting.

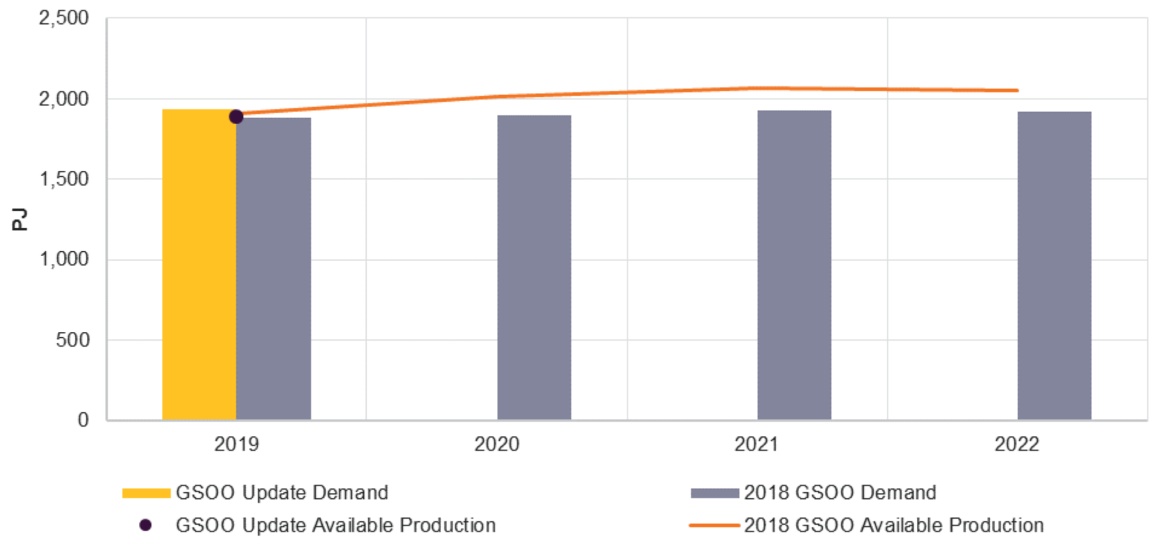
Table 6 Production forecasts to 2022 (PJ), as provided by gas producers

	2019	2020	2021	2022
VIC/NSW/SA[A]	452	483	463	479
QLD/NT[A]	1,486	1,561	1,636	1,603
Total production	1,938	2,044	2,099	2,082

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

These minor changes in total forecast production and demand have resulted in an improved outlook for gas supply adequacy compared to the September 2017 GSOO Update. There is now projected to be sufficient gas supply to meet forecast demand in the next four years in the Neutral scenario, as shown in Figure 15. This figure shows the updated 2019 demand forecast compared to the September 2017 GSOO Update, with the current forecast increasing slightly to 2022. The slight excess supply in the short term may be used to fill storage facilities or be available for consumption should expected developments of reserves or contingent resources not progress as planned.

Figure 15 Demand and production forecasts compared to the September 2017 GSOO Update



In the Neutral demand scenario:

- Production from gas fields located in the southern states is mostly sufficient to meet southern domestic demand, although some net imports from the north is required.
- Northern imports are predominantly observed in winter, with minimal southerly flows at other times.

In the Strong scenario:

- There is sufficient projected supply to meet forecast demand until 2021, so long as Queensland CSG production can ramp up to support the increased LNG demand in the Strong scenario. Otherwise, LNG supply gaps of up to 123 PJ are projected by 2022, indicating that the forecast stronger LNG demand is unlikely to be realised.
- In the short term, forecast strong peak gas demand in the southern states is projected to be met from a combination of southern production, withdrawals from storage, and imports via the South West Queensland Pipeline (SWQP). If volumes from storage were not available to help meet winter peak demand, then even greater imports from the north would be required.
- From 2021, given the forecast increased reliance on northern flows to meet winter demand in the south, modelling indicates that constraints around production and processing capacities in Queensland could start to limit the amount of support the north can provide to the south.

In the Weak scenario:

- A lower demand forecast across all sectors leads to no supply gaps being projected across the full 20-year outlook.
- This lower demand forecast also delays the projected need for undeveloped reserves and contingent resources to come online relative to other scenarios, and would require smaller quantities. Prospective resources are not projected to be required in this scenario.

Reserves and resources

The 2017 GSOO highlighted that the rate of exploration and development of oil and gas wells drilled in Australia has declined rapidly over the last few years.

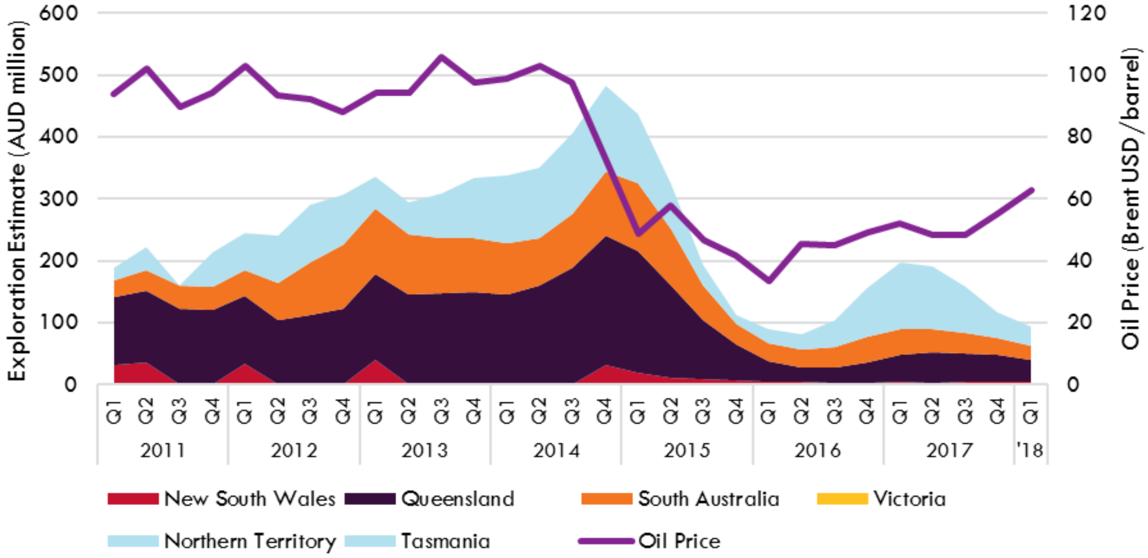
The Australian Bureau of Statistics (ABS) provides estimates of investment in oil and gas exploration[34] which show a marked decline since peaking in June 2015, as can be seen in Figure 16. Although there has been some small improvement from mid-2016, levels of exploration are still below those seen since 2012.

Eastern and south-eastern Australian natural gas 2P developed reserves have increased relative to the 2017 GSOO estimates, but, consistent with the ABS exploration estimates, 2P reserves (developed and undeveloped) overall have reduced by approximately 5,000 PJ, and 2C contingent resources have reduced by 10,000 PJ.

[34] Exploration expenditure data is available at http://www.abs.gov.au/ausstats/abs@.nsf/mf/8412.0, and oil price history is available at https://tradingeconomics.com/commodity/crude-oil.

In total, this represents a 15% reduction in 2P reserves and 2C resources. In particular, the reduction in contingent resources demonstrates gas exploration and development challenges that will need to be addressed in the medium term, to ensure that sufficient gas production extends beyond the next four years in commercial quantities.

Figure 16 Oil and gas exploration expenditure estimate, and Brent Oil Price, 2011-18



It is worth noting that Victorian exploration has been conducted during the timeframe shown in Figure 16, but the amounts spent are too small to be visible. Victorian gas fields are a major supplier of gas for southern domestic demand, however there has not been significant investment in exploration in Victoria since 2010. According to Geoscience Australia data[35], only two offshore exploration wells have been drilled in Victoria in that time, compared to 48 drilled between 2000 and 2010. A scenario presenting the impact of reduced production from southern fields, should further Victorian offshore exploration not eventuate, is discussed further in Chapter 4.

3.2 Risks and variability

The consumption trends for gas in all demand sectors are dependent on a number of independent drivers that may cause variances in the gas consumption requirements in any given scenario. This section focuses on the variability of demand for GPG, residential, commercial, and industrial consumers which creates supply adequacy uncertainty.

As mentioned in Section 3.1, the Strong demand scenario assumes that Queensland CSG production increases to facilitate the increased LNG demand. If this increase in CSG production does not occur, then supply gaps appear from 2019, with only an additional 37 PJ of demand able to be met above the Neutral demand scenario. This 37 PJ provides a reasonable assessment of the quantity of flexibility in gas supply to meet forecast demand in 2019. Additionally, producers may elect to divert LNG cargoes to supply domestic demand if the supply-demand balance is tight. The sections that follow outline primary risks affecting key demand sectors.

3.2.1 GPG demand

The annual consumption of gas for GPG will directly depend on the level of electricity consumption in the NEM, and the operation of GPG relative to coal-fired generation, hydro generation, and renewable sources such as wind and solar.

As the marginal cost generation technology, GPG in the NEM is most at risk of large swings in output, due to a variety of factors including:

- Reduced wind speeds impacting wind farm output.
- Delays in the installation of new renewable generation.
- Reduced rainfall impacting hydro generation.

[35] Geoscience Australia well data is available at http://dbforms.ga.gov.au/www/npm.well.search.

- Extended unavailability of coal-fired generation.
- Return to service of Tamar Valley Power Station in Tasmania[36].

AEMO has conducted a risk assessment to provide insight into how individual drivers may affect forecasts of GPG demand in the short term. Table 7 shows the estimated impact of each listed uncertainty on short-term forecast GPG demand, and the projected impacts of these risks are described in greater detail below the table.

Table 7 Impacts of considered risks and uncertainties on GPG demand between 2019 and 2020

Drivers of additional GPG demand	Lower bound estimate	Upper bound estimate
Reduced wind speeds resulting in lower wind production	+ 11 PJ	+ 15 PJ
Delays in installation of new renewable generation (1 year)	+ 3 PJ	+ 30 PJ
Reduced rainfall resulting in lower hydro production	+ 21 PJ	+ 25 PJ
Extended unavailability of coal for 3 months (single unit)	+ 5 PJ	+ 6 PJ
Return to service of Tamar Valley Power Station	+ 3 PJ	+ 7 PJ

Modelling for the first four uncertainties, related to reductions in electricity production from non-GPG sources, assumed these reductions would be taken up equally between gas- and coal-fired generation types. This assumption reflects observations since the March 2017 closure of Hazelwood Power Station, that a near equal split between coal- and gas-fired generation has replaced its lost output.

Modelling the potential return to service of the Tamar Valley Power Station considered the historical operation of that power station as the measure to define the relative uncertainty.

Reduced wind speeds resulting in lower wind generation production

Wind generation is inherently dependent on prevailing weather conditions. For each state in the NEM, AEMO analysed historical wind speeds and assessed the impact if wind generation in each state witnessed its lowest annual recorded wind speeds since 2009[37].

This modelling indicated that lower wind speeds, leading to lower production from wind generation, could reasonably lead to additional demand for gas by GPG by between 11 and 15 PJ in a single year, should each state concurrently face its lowest wind speed year. Should the reduction in wind speed be limited to fewer locations, the requirements for additional GPG would be lessened.

Delays in installation of new renewable generation

While the level of investment in renewable generation technologies in the NEM is high, with record levels of committed[38] developments, the timing of renewable generators not currently committed is uncertain. AEMO uses strict criteria to assess whether a proposed development is committed. If development delays were to affect each renewable project currently proposed but not committed, the impact is projected to increase GPG demand by 3 PJ in 2019, but up to 30 PJ in 2020.

Lower rainfall resulting in lower hydro generation production

In an extended drought condition, with lower than expected rainfall, water available for hydro generation may be limited. In this situation, hydro generators can be expected to reduce electricity generation, conserving water resources where possible for peak demand periods. This reduced generation would likely lead to increased GPG operation.

AEMO analysed hydro generation patterns from the Energy Adequacy Assessment Projection (EAAP)[39] to identify differences in electricity generation from hydro-electric sources in the average rainfall case compared to drought

[36] This GPG plant was withdrawn from the NEM from April 2018, after being recalled for summer 2017-18, and Hydro Tasmania has advised that it could be restarted again with less than three months' notice. See AEMO's Generation page, Tasmania spreadsheets, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[37] The lowest wind speed year varied between each state.

[38] To see the generation project commitment criteria, and also which generator projects are currently committed, see AEMO's Generation Information Page at http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information. Commitment criteria are listed on regional spreadsheets under the Background information tab.

[39] Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Energy-Adequacy-Assessment-Projection.

conditions. These lower generation levels are projected to increase demand for GPG by up to 25 PJ, should drought conditions occur across the entire NEM in 2019 or 2020.

Extended unavailability of coal generation

Recent examples of extended coal-fired generation outages in the NEM include the Yallourn mine flood (2012), Hazelwood fire (2014), Eraring outage (2016), and Loy Yang and Yallourn outages (2017).

Based on analysis of both historical and modelled outcomes, should a single coal generation unit face an outage of around three months, the resulting impact to GPG generation could be up to 13 PJ.

The unexpected retirement of a coal-fired power station would have a much greater impact, and would put pressure on gas supply adequacy. The proposed rule change[40] requiring a three-year notice of closure that is currently being considered by the Australian Energy Market Commission (AEMC) aims to help manage a more orderly exit, allowing the market time to adapt.

Return to service of Tamar Valley Power Station

The Tamar Valley combined cycle gas turbine (CCGT) is currently mothballed but has been returned to service in summer recently for energy security purposes. Quantities for this unit were not accounted for in the GPG forecasts. Based on historical generation patterns, this unit could be expected to consume between 3 and 7 PJ if returned to service again next summer.

Gas Supply Guarantee

Gas producers and pipeline operators made a commitment to the Federal Government to make gas supply available to electricity generators during peak NEM periods. The Gas Supply Guarantee mechanism[41] has been developed by industry to facilitate the delivery of these commitments.

While the ADGSM is intended to provide means to manage the risks of annual domestic energy balance, the Gas Supply Guarantee mechanism is directed to short-term deliverability and supply issues for GPG, and as such is most appropriate to address operational risks or major unplanned events. The GSOO projects a sufficient supply buffer under the Neutral scenario to cover any one of these GPG demand risks, although the coincidence of two or more factors may require the Gas Supply Guarantee mechanism to be initiated if alternate fuel sources for electricity generation could not be accessed.

3.2.2 Residential, commercial, and industrial demand

Residential, commercial, and industrial demand forecasts are subject to risk and uncertainty arising from variation in key drivers that may impact the demand, such as:

- Weather variation – weather is highly unpredictable, and while AEMO forecasts on normalised weather conditions[42], actual consumption may be different if the weather deviates from weather normalised projections. Residential and commercial sector gas consumption forecasts and maximum daily demand forecasts are most impacted by this. As an example of weather variation on forecast demand, in Victoria typical system demand is around 200 PJ per year, but a relatively mild winter in 2014 saw system demand drop by 2.5% (5PJ), while in 2015, the coldest recorded winter in the last 26 years, system demand increased by 4% (8 PJ).
- Economy – the industrial sector forecasts do not consider major shocks to the business cycles such as the Global Financial Crisis or the mining boom. Shocks could have a significant impact on the rate of restructuring in the economy and especially on the export-facing Manufacturing sector, thereby impacting industrial sector forecasts.

While these two drivers are the two main uncertainties with potential to substantially impact the forecast demand in the short term, risks to the longer-term forecasts include the above, as well as population variation, gas to electric appliance switching, gas price forecasts, and changes in policy, technology, and consumer preferences.

[40] Available at https://www.aemc.gov.au/rule-changes/generator-three-year-notice-closure.

[41] Information available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Emergency-Management/Gas-Supply-Guarantee.

[42] Weather normalised consumption is consumption that is adjusted for a standard weather year. For details on weather standards, see AEMO's GSOO methodology document, available on http://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

4. Long-term supply adequacy

This section provides the longer-term outlook for supply adequacy in the next 20 years, and highlights projected resource and/or infrastructure development requirements to meet forecast demand. It also demonstrates that future investment requirements are highly dependent on future production from southern gas fields.

4.1 Supply outlook

Gas reserves and resources are categorised according to the level of technical and commercial uncertainty associated with developing them. These uncertainties include securing finance, obtaining government approvals, negotiating contracts or overcoming geological challenges.

Contingent resources are considered less commercially viable than reserves. The exact quantity that can be brought to market is uncertain because:

- The exploration required to build up an accurate and certain resource estimate can be expensive and time-consuming.
- The cost to bring the resources to market may prohibit development until economic conditions make the resources commercially viable, and therefore the resources may not become viable at the same time, or at all.

Additionally, prospective resources are estimated volumes associated with undiscovered accumulations of gas. The resources are estimated to exist in prospect areas, but have yet to be proved by drilling.

As discussed in Section 3.1, AEMO used production forecasts provided by producers for the first four years of the GSOO assessment. Market dynamics and the continuous nature of field development and gas reserves make it more difficult to produce long-term robust production forecasts.

AEMO recognised future production uncertainties, and quantities of contingent and prospective resources that might be available, by considering two potential futures for the Neutral scenario:

1. Constant production case – assumed there would be sufficient development and exploration to maintain gas production at rates provided by industry for 2022, the last year of the supplied five-year forecast (see Section 4.1.1 below).
2. Low southern resource case[43] – assumed there would be insufficient development and exploration to prevent the depletion of existing southern gas basins, and only 15% of southern contingent and prospective resources would be brought to market within the 2018 GSOO's 20-year horizon (see Section 4.1.2 below).

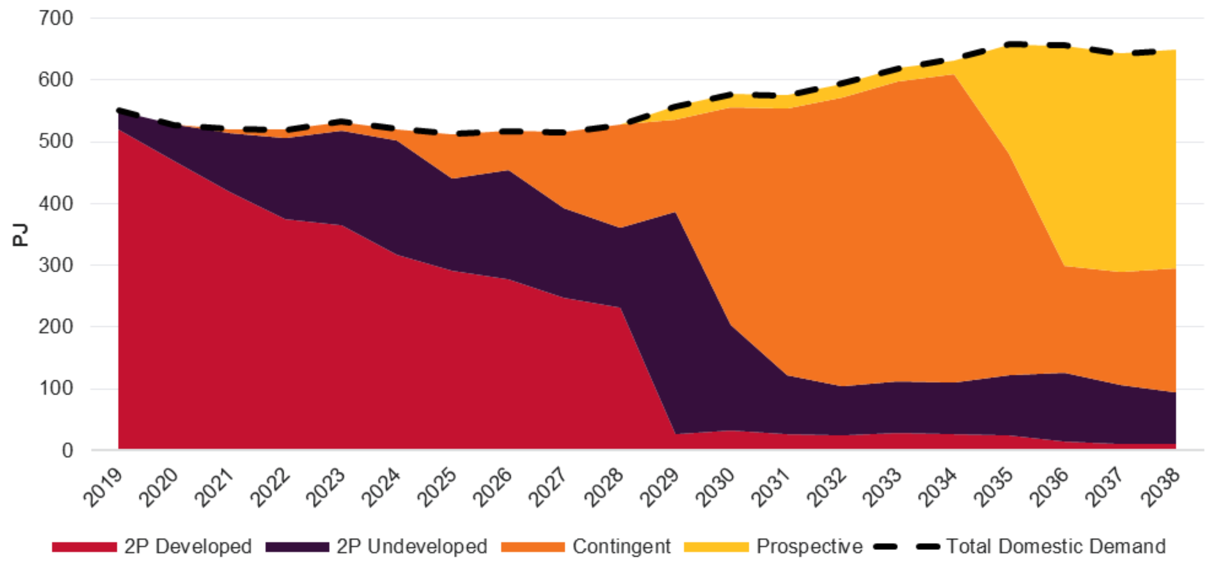
4.1.1 Neutral – Constant production case

Figure 17 shows projected gas production of reserves and resources for the Constant production case to meet the domestic gas market demand. Current 2P reserves (developed and undeveloped) are projected to be inadequate to meet consumption beyond the short term, with projected decline in production from 2P developed and undeveloped reserves clearly visible. Contingent resources are projected to be required in small amounts from 2021, with over 100 PJ of contingent resources forecast to be required from 2027.

In total, about 10,000 PJ of contingent and prospective resources are projected to be required between 2019 and 2038, of which about 50% supports domestic demand. To avoid potential future supply gaps, additional production capacity would be required from 2030 to increase the rate of gas supply.

[43] The Weak scenario, where LNG demand reduces and only limited contingent resources are correspondingly developed in the north, is the northern equivalent of this case.

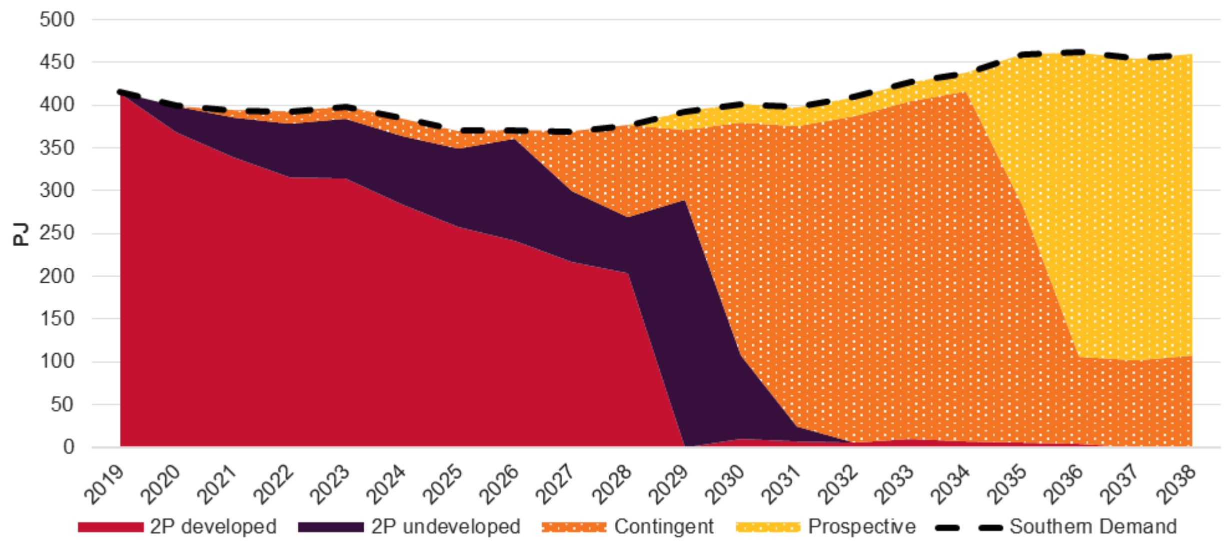
Figure 17 Status of reserves and resources to meet domestic demand, 2019-38



Developing the more uncertain contingent resources and currently undiscovered prospective resources will require early investment in exploration and development. To meet domestic consumption in this Constant production case, about 85% of this resource development would be required in southern regions.

Figure 18 below isolates the production and consumption outlook for the southern states, and shows the magnitude of the exploration and development needed in the south to meet southern demand. Gas from new fields can take multiple years to bring to market and, as highlighted in the 2017 GSOO, the cost of development means that bringing these resources to market will not necessarily reduce gas prices.

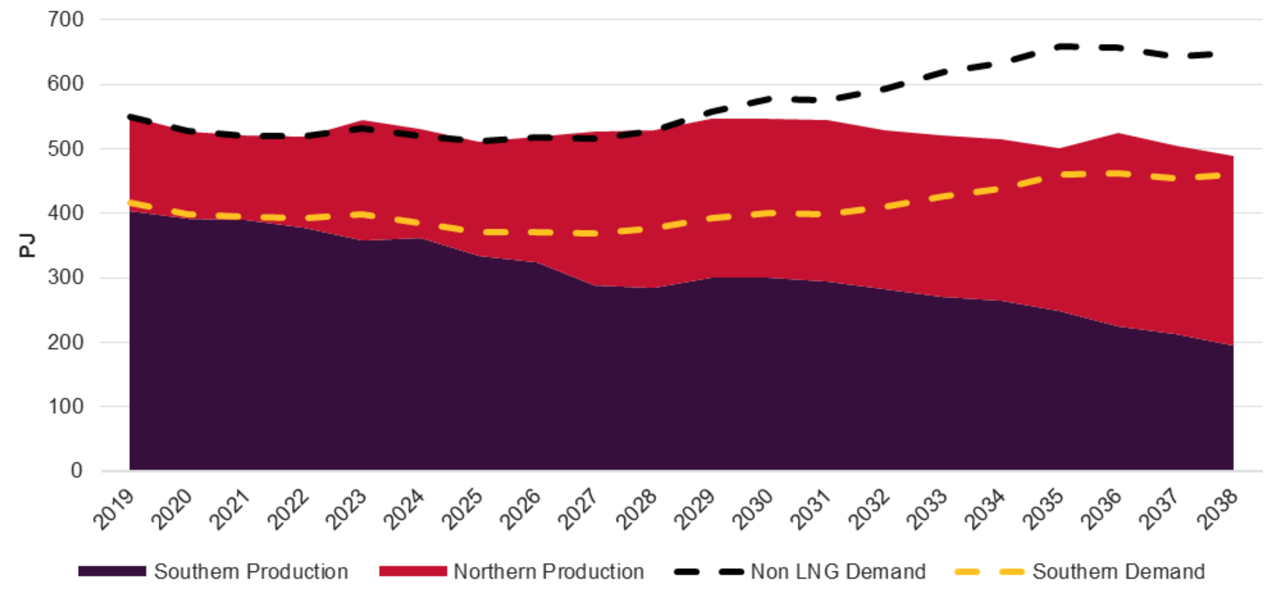
Figure 18 Status of southern reserves and resources required to meet southern demand, 2019-38



4.1.2 Neutral – Low southern resource case

The Low southern resource case explores a future where production from southern fields declines. In this case, northern fields increase production to compensate for the decline in the south – including up to 178 PJ of gas otherwise destined for LNG – although deliverability will become challenging. Expansion of pipeline infrastructure to alleviate constraints on SWQP and Moomba to Sydney Pipeline (MSP) would be required by 2030 to avoid domestic supply gaps. Without this expansion, southern supply gaps of up to 160 PJ per year are projected by 2038, as shown in Figure 19.

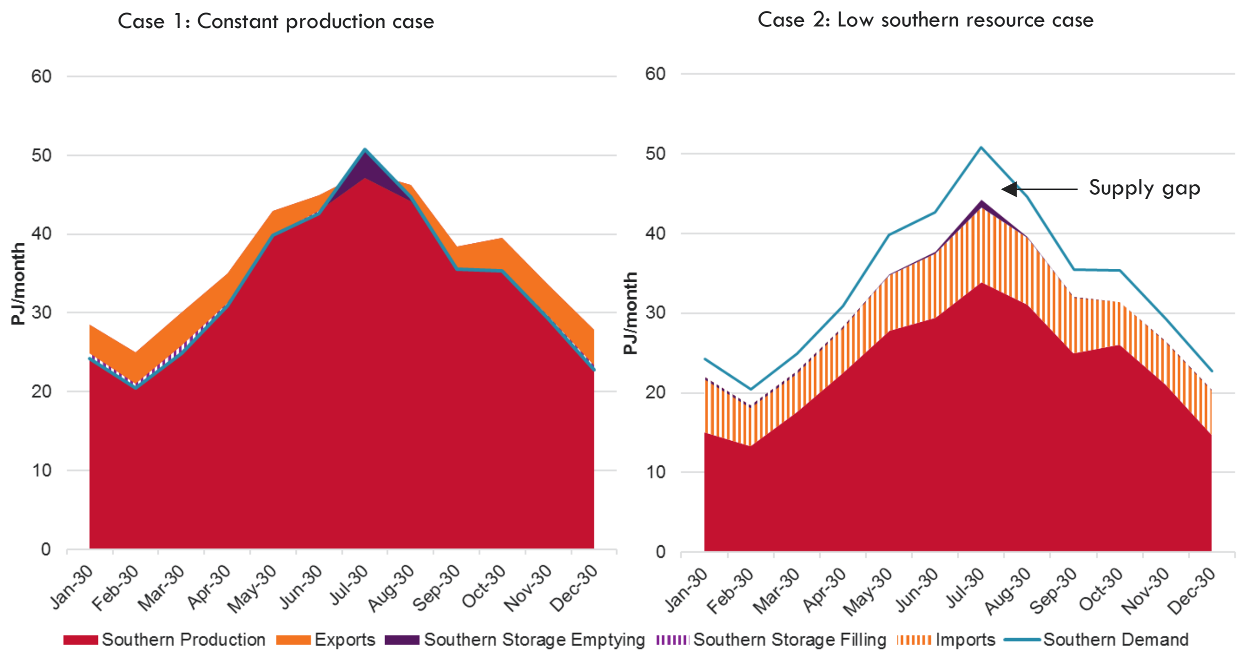
Figure 19 Production split between north and south, Neutral – Low southern resource case, 2019-38



Projected southern supply gaps first appear in 2030, when peak winter capacity can no longer be supported by the combination of southern production, storage, and imports. As the projected supply gap widens, the forecast supply demand balance is so tight that there is forecast to be insufficient gas to fill storages over the summer and shoulder period, and an inability to meet demand year-round.

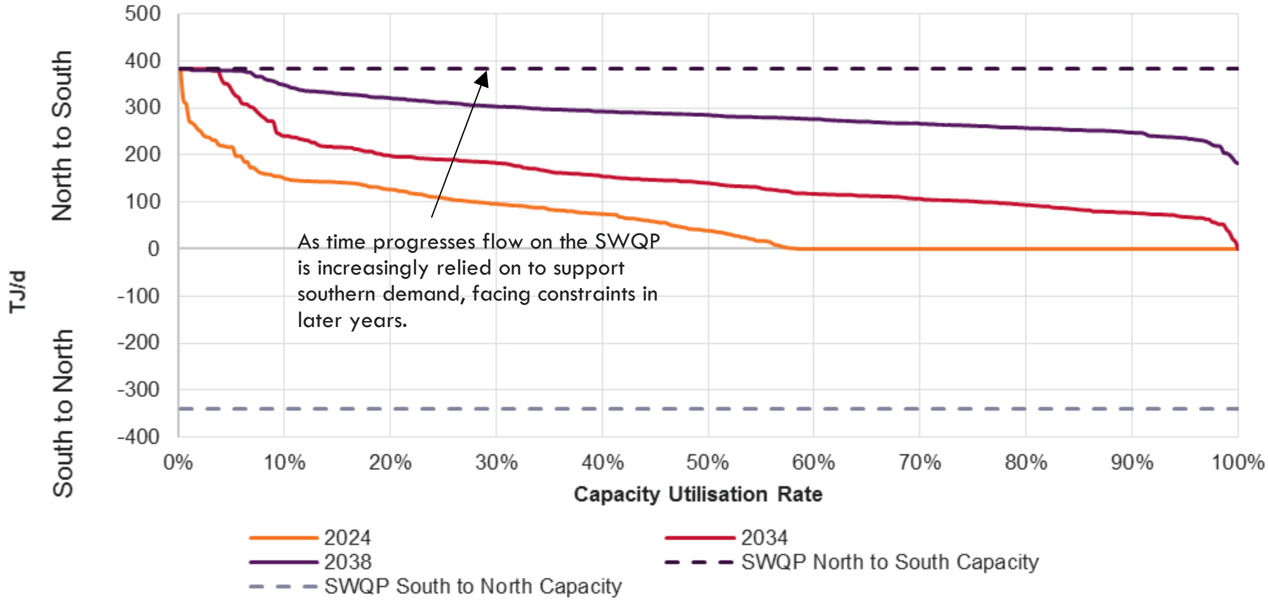
As a comparison, in the Constant production case, no southern supply gaps appear, but the south is dependent on gas withdrawals from storage to meet demand over winter. The comparison between the two cases is shown in Figure 20.

Figure 20 Projected monthly supply and demand balance for the south in 2030



With increasing support projected to be required from northern gas to meet southern demand in the Low southern resource case, the MSP and SWQP are increasingly relied on to meet load in the demand centres of Melbourne, Adelaide, and Sydney. As an example, the flow on the SWQP, displayed as a duration curve in Figure 21, shows how often the SWQP is forecast to flow south at high capacity when southern production is projected to no longer support southern demand. This contrasts strongly with the SWQP's use in the Constant production case, where the pipeline is projected to respond to seasonal demand, flowing south over winter and north in summer.

Figure 21 Projected flow duration curve for SWQP flows for 2024, 2034, and 2038, Neutral – Low southern resource case[A]



A. This chart is a representation of modelled outcomes based on a high level daily transportation model, that does not take intra-day flow, pipeline pressures, or transportation contracts into account. This demonstrates that utilisation of the SWQP is forecast to increase across the outlook period, as requirements to send gas south increase.

While there are no known projects to remove the SWQP or MSP constraints, a number of additional supply sources available in both the north and the south are being explored by the gas industry. No existing alternate solution has formal commitment to proceed. These options to alleviate potential longer-term supply gaps are considered further in Section 4.2.

4.1.3 Strong and Weak scenarios

In the long term, the Strong scenario is forecast to require more accelerated field exploration and development than in the Neutral scenario. Conversely, in the Weak scenario, the need for exploration and development is projected to be reduced, with 2P developed and undeveloped reserves sufficient to meet 93% of forecast demand to 2038.

4.2 Potential new supply options

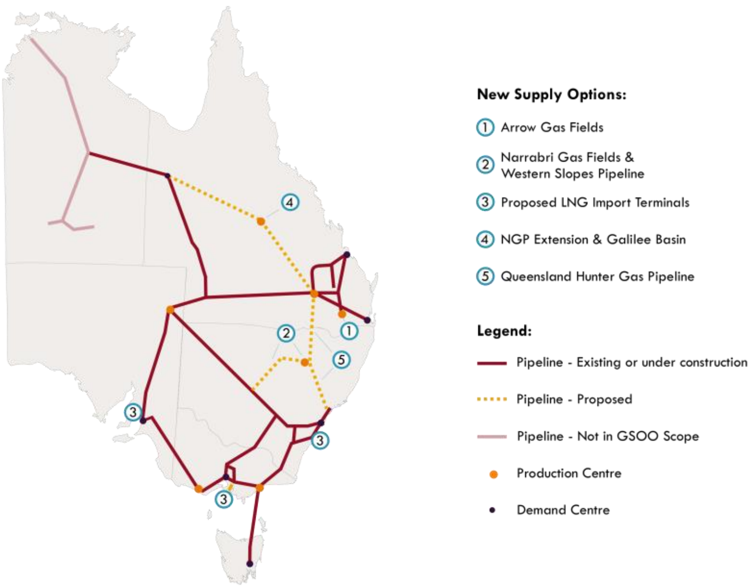
Over the last 12 months, many new supply options have been considered by the gas industry. Each option would improve the gas market's ability to meet forecast demand. These supply options could either replace some of the required contingent and prospective resources highlighted in Section 4.1 (if these resources do not come to market), or provide additional supply if demand is stronger than the Neutral forecast.

Some of the possible long-term solutions currently being explored by industry are listed in Table 8, along with qualitative discussion of possible impact. Figure 22 illustrates these options, which are then discussed in more detail.

Table 8 Summary of sensitivities examining new supply options

Supply option	Details	Estimated impact
Arrow gas field development	Arrow and Shell announced intentions to commercialise Arrow's gas fields in Surat Basin from 2021.	Could provide additional supply of approximately 655 TJ per day, or 240 PJ per annum.[44]
Narrabri gas field development	Narrabri gas fields would support southern production, providing up to 250 TJ per day at peak production. Santos is targeting first gas from 2021-22[45].	Would provide additional supply of 100 TJ per day initially (up to 35 PJ per annum), potentially ramping to 250 TJ per day (up to 90 PJ per annum). [46]
LNG import terminals	Import terminals where LNG volumes are regasified to be injected into the gas network of the importing region. Terminals have been under consideration at Melbourne (Crib Point), Sydney (Port Kembla) and Adelaide (Port Adelaide/Pelican Point).	Melbourne: Maximum of approximately 140 PJ per annum, depending on number of tanker deliveries.[47] Sydney: 100 PJ per annum targeted.[48] Adelaide: Details currently unknown.
NGP extension	The under-construction NGP is capable of extension from Mt Isa to connect to Wallumbilla. Such an extension may give rise to development within the Galilee Basin, increasing available gas supply from both Northern Territory resources and new resources in Queensland.	Up to 700 TJ/day (approximately 250 PJ/y) in additional pipeline capacity, enabling development of appropriate reserves in the Galilee Basin.[49]
Queensland Hunter Gas Pipeline	Additional transmission capacity between Wallumbilla to Newcastle, including access to the Narrabri gas fields.	Up to 450 TJ/day (approximately 160 PJ/y) in additional pipeline capacity, enabling delivery from Narrabri gas fields and greater north-south transfer capacity.[50] Alternatively, the Western Slopes Pipeline has also been proposed to deliver gas from Narrabri to southern demand centres.

Figure 22 Potential new supply options



[44] Numbers based on Arrow press release, available at https://www.arrowenergy.com.au/media-centre/latest-news/pages/2017/arrow-energy-agrees-deal-for-surat-basin-reserves.

[45] Based on Santos response to submissions, available at https://majorprojects.accelo.com/public/f84683501b4fc0d6970771187ddd1fc5/Narrabri%20Gas%20Project%20-%20Response%20to%20Submissions%20-%20Report%20Part%20A.pdf.

[46] See 2018 GSOO Processing Transmission Storage Facilities data, available at https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

[47] Based on the stated maximum of 40 tankers processed at the FRSU per year: https://www.agl.com.au/about-agl/how-we-source-energy/crib-point-project#fsru.

[48] Based on capacity reported in Sydney Morning Herald at https://www.smh.com.au/business/the-economy/forrest-to-build-nsw-s-first-lng-import-terminal-at-port-kembla-20180604-p4zja7.html.

[49] Annual capacity calculated from daily number provided in Jemena press release, available at http://jemena.com.au/about/newsroom/media-release/2018/jemena-welcomes-decision-to-lift-fracking-moratori.

[50] Based on 2017 GSOO Processing Transmission Storage Facilities data.

Arrow (Surat Basin) gas field

According to a recent press release[51], Arrow and Shell will bring Arrow's undeveloped reserves in the Surat Basin to market, using both Arrow and Shell operated infrastructure.

Gas from these fields will bolster Northern supply and can provide additional gas for both the domestic market and export through Shell's QCLNG terminal. In the case where production from southern fields declines over time, the ability for this additional supply to support southern domestic demand would be limited by transmission on the SWQP and MSP.

Narrabri (New South Wales) gas field and Western Slopes Pipeline

Santos is currently progressing the approvals process for their CSG acreage in the Gunnedah Basin in New South Wales. This Narrabri project is proposed in conjunction with APA's Western Slopes Pipeline, which will connect it to the Moomba to Sydney Pipeline near Condobolin.

Narrabri gas is specifically intended for the domestic market, and in the Low southern production case, the development of Narrabri would provide additional production close to the Melbourne and Sydney demand centres. However, if the south is dependent on imports from the north, congestion on the MSP may limit transmission capacity between Narrabri and southern demand centres.

LNG import terminals

Floating regasification and storage units (FRSUs) have been considered by industry as potential sources of additional supply. An FRSU would connect to import terminals to regasify incoming LNG volumes back into gas molecules to be injected directly into the pipeline network of the importing region. Depending on volumes supplied, expansion of the existing pipeline network may be required to deliver gas to where it is needed.

The factors that make it difficult to predict LNG demand also add uncertainty to the use of imported LNG as a supply source in the south. Owners of LNG import facilities will need to manage varied risks including contracting, oil price, currency exchange rates, and other economic drivers in the LNG international market. These factors could limit or enhance the extent to which an import terminal can support southern demand.

Northern Gas Pipeline expansion and Galilee Basin

Jemena's NGP is currently under construction and, once completed, will provide a 90 TJ per day connection between Mt Isa and gas fields in the Northern Territory. Further expansion and extension of the pipeline would extend the pipeline from Mt Isa to Wallumbilla, connecting the Galilee basin in doing so and/or providing access to more Northern Territory gas. According to Jemena, up to 700 TJ of gas per day could be supplied to the east coast market once complete. Front end engineering and design is expected to start in 2019.

This additional supply could play a major role in meeting demand in the future, particularly if southern production declines over time. However, as with the Arrow gas fields in Queensland, transmission capacity between Queensland and southern demand centres may need to be expanded.

Queensland Hunter Gas Pipeline

Southern demand centres may increasingly rely on northern imports if future production from southern basins decline as investigated in the Low southern resources case. This new Queensland Hunter gas pipeline is proposed to connect Wallumbilla to Narrabri, and then Narrabri to Newcastle (this latter half is often referred to as the Hunter Gas Pipeline). The pipeline capacity is proposed to be between 230 TJ and 450 TJ per day.

If exploration and new gas field developments in the north provide sufficient gas production to meet southern demand, this additional transport capacity could relieve constraints on the SWQP and MSP, and allow more flows to be diverted south.

[51] Arrow Energy, "Arrow Energy agrees deal for Surat Basin reserves", 1 December 2017, available at https://www.arrowenergy.com.au/media-centre/latest-news/pages/2017/arrow-energy-agrees-deal-for-surat-basin-reserves.

A1. Forecast accuracy

The following charts compare AEMO's gas consumption forecasts since 2014[52], showing actual recorded consumption back to 2010. These charts can be used to assess the performance of the forecasts by comparing the actual consumption against forecasts in each year. Only the Neutral scenario forecasts are presented.

The actual demand is partly driven by weather conditions in a given year. For example, in a very cold year, gas consumption will be higher, due to the increased use of space heating. AEMO's forecasts are developed on a weather normalised basis that assumes typical weather conditions, so some misalignment between forecast and actual consumption may be expected in years that are particularly hot or cold.

Assessing forecasting performance and understanding any propensity for bias is critical to AEMO's ability to improve its future forecasting accuracy and/or better understand the forecast uncertainties.

Figure 23 shows total gas consumption forecasts for eastern and south-eastern Australia. Key observations include:

- Steep growth is seen from 2014 as LNG facilities ramp up in Queensland.
- There was some overestimation in the forecasts in 2016 and 2017, largely driven by slower than expected ramp-up of LNG exports.
- AEMO's 2018 forecast is lower in the initial years compared to previous forecasts, with slower future LNG ramp-up now assumed. The 2018 forecast exceeds previous forecasts from 2023 onwards, reflecting higher estimates of LNG exports in the longer term than previously projected.

Figure 23 Gas annual consumption forecast comparison, total for eastern and south-eastern Australia

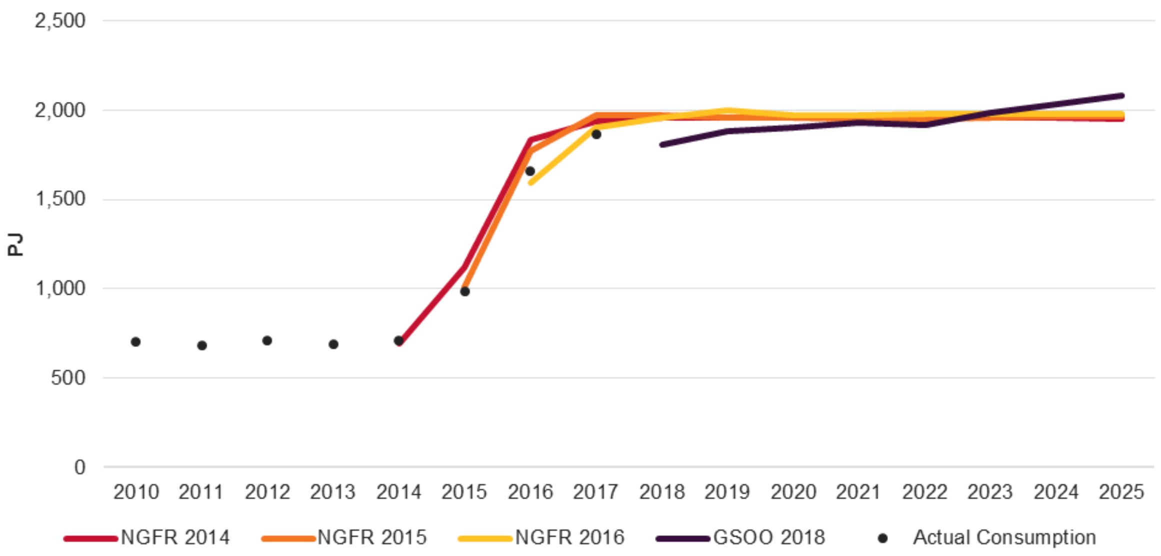


Figure 24 shows AEMO's LNG forecasts only, more clearly showing an overestimation of year on year increases, compared to actual LNG exports. AEMO's 2018 GSOO LNG projections incorporate a more modest rate of increase in the next few years, more consistent with recent trends.

[52] The 2014 NGFR was the first standalone publication by AEMO for eastern and south-eastern 20-year demand forecasts. This was the first year the forecasts were developed in-house. Before 2014, demand forecasts were produced for AEMO by consultants and published in the GSOO series. For this reason, only forecasts from 2014 onwards are reported in this section.

Figure 24 Gas annual consumption forecast comparison, LNG

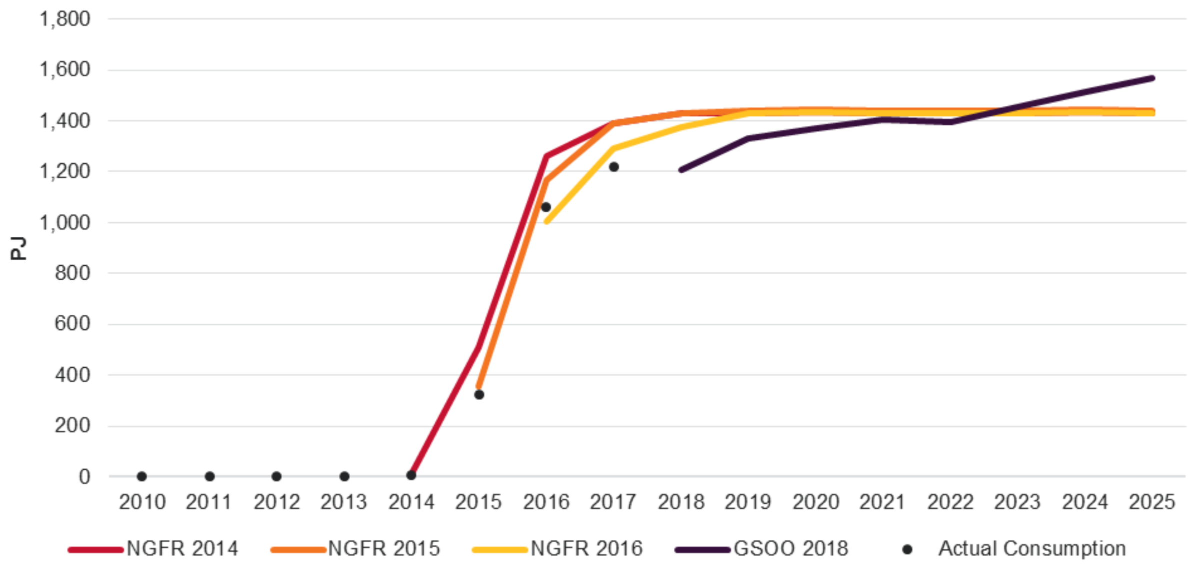


Figure 25 shows AEMO's residential and commercial gas consumption forecasts. The starting point is calibrated to recent consumption data, with the overall trend reflecting AEMO's assumptions relating to the impacts of energy efficiency, gas to electric fuel switching, gas prices, and climate change.

AEMO's residential and commercial demand forecasts projected in the past two NGFRs align reasonably well with historical observations, although some deviations are observed due to external influences such as weather.

Figure 25 Gas annual consumption forecast comparison, residential/commercial

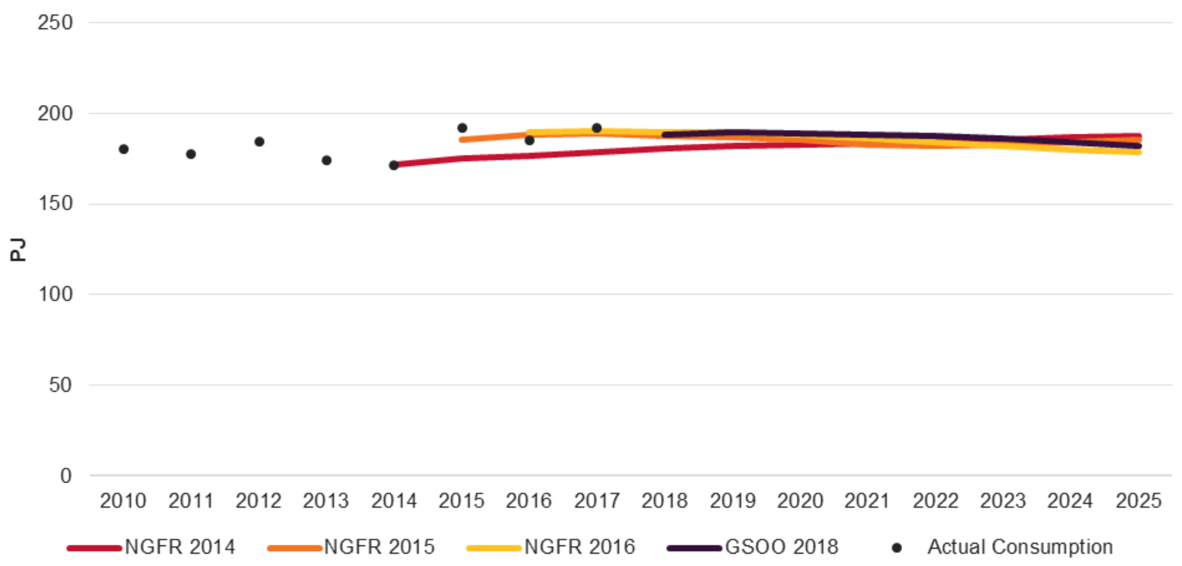


Figure 26 shows AEMO's industrial gas consumption forecasts, incorporating AEMO's assumptions on forecast changes in economic drivers and data obtained by survey from large gas users.

In the 2014 NGFR, AEMO correctly predicted a turning point in historic trends. Key to identifying the turning point in trends was AEMO's increased engagement with large industrial users. This process has helped to develop richer insights into the key trend drivers for this sector and identify structural and behavioural changes.

The 2015 and 2016 NGFR continued to forecast similar declining trajectories, though the 2015 NGFR overestimated the starting point. The 2018 GSOO has a flattening trend in industrials, due to a combination of updated actual consumption data, observed change in industrial behaviour and improved export market conditions for the manufacturing sector.

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

Figure 26 Gas annual consumption forecast comparison, industrial

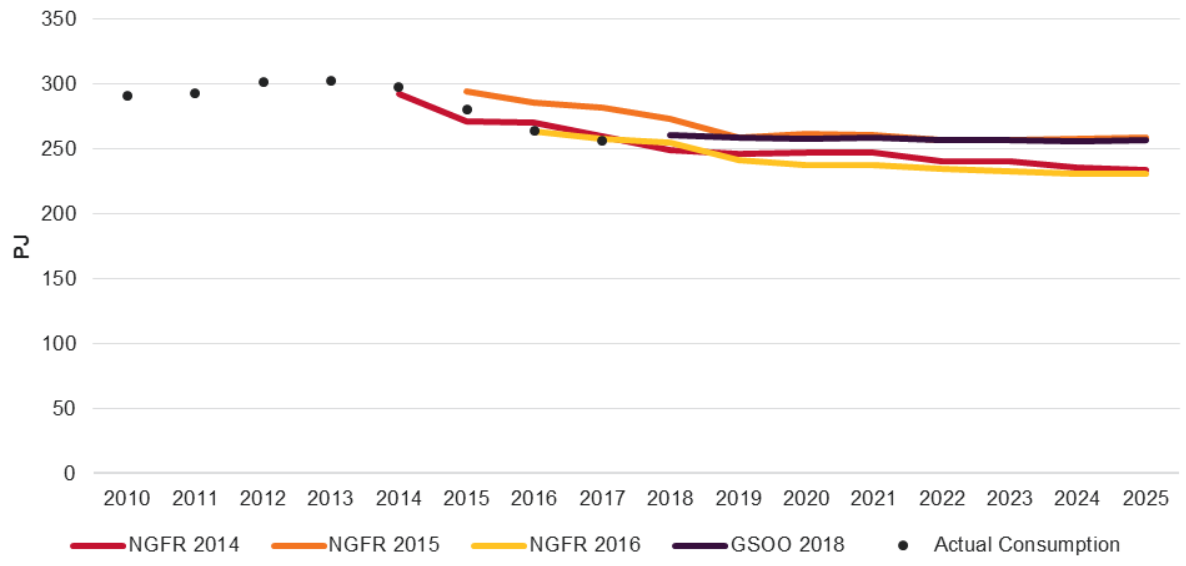
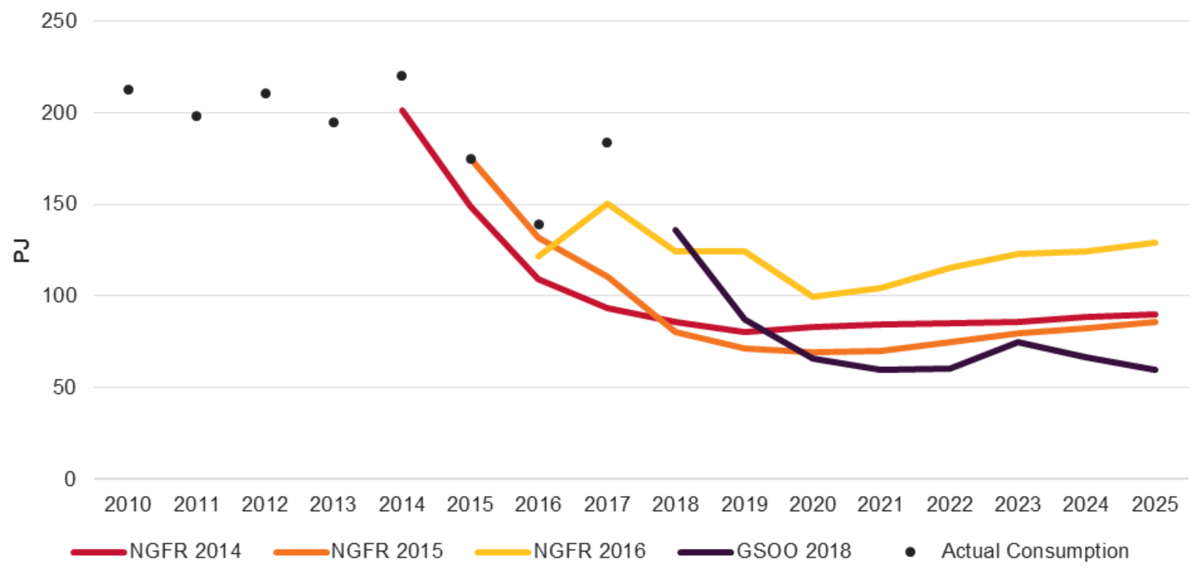


Figure 27 compares AEMO's GPG forecasts since 2014 against actuals, and highlights that trends have been reasonably well anticipated. The consistent declining trend shown in this figure is due to increasing renewable generation developments in the NEM, and this trend is expected to continue, although the absolute level of GPG in any given year is difficult to predict.

Forecasting gas demand for GPG is highly challenging because (as discussed in Section 2.2.3) it is driven by events such as extreme weather or generation outages, that can be unexpected. For example, AEMO's earliest forecasts (NGFR 2014 and NGFR 2015) did not account for the extended outage of the Eraring Power Station in 2016, or the unforeseen closure of the Hazelwood Power Station and extended outages at Yallourn and Loy Yang A power stations in 2017. The 2017 events in particular drove actual GPG demand well above forecast.

Figure 27 Gas annual consumption forecast comparison, GPG



Glossary

Term	Definition
1-in-2	The 1-in-2 maximum demand projection has a 50% probability of exceedance (POE). This projected level of demand is expected, on average, to be exceeded once in two years.
1-in-20	The 1-in-20 maximum demand projection (for severe weather conditions) has a 5% probability of exceedance (POE). This is expected, on average, to be exceeded once in 20 years.
2C contingent resources	Best estimate of contingent resources – equivalent to 2P reserves, except for one or more contingencies or uncertainties currently impacting the likelihood of development. Can move to 2P classification once the contingencies are resolved.
2P reserves	The sum of proved and probable estimates of gas reserves. The best estimate of commercially recoverable reserves, often used as the basis for reports to share markets, gas contracts, and project economic justification.
annual consumption	Gas consumption reported for a given year.
annual demand	Gas demand reported for a given year.
basin	A geological formation that may contain coal, gas and oil.
coal seam gas (CSG)	Gas found in coal seams that cannot be economically produced using conventional oil and gas industry techniques. See unconventional gas. Also referred to in other industry sources as coal seam methane (CSM) or coal bed methane (CBM).
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.
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.
conventional gas	Gas that is produced using conventional or traditional oil and gas industry practices. See also unconventional gas.
demand	Capacity or gas flow on an hourly or daily basis, or the electrical power requirement met by generating units.
developed reserves	Gas supply from existing wells.
domestic gas	Gas that is used within Australia for residences, businesses, power generators, etc. This excludes gas demand for LNG export
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.
initial reserves	On a given assessment date (e.g. 31 December 2010), the total quantity of gas expected to be recovered from a reservoir over its entire productive life (e.g. from 1975 to 2025). See also remaining reserves.
large industrial	A segment of the eastern and south-eastern gas market defined to include businesses that consume more than 10 TJ/yr.
liquefied natural gas (LNG)	Natural gas that has been converted into liquid form for ease of storage or transport.

Term	Definition
LNG netback price	AEMO follows the ACCC definition of LNG Netback price (see "*Gas Enquiry Interim Report 2017-2020*", April 2018, https://www.accc.gov.au/system/files/Gas%20inquiry%20April%202018%20interim%20report.pdf): "*A pricing concept based on an effective price to the producer or seller at a specific location or defined point, calculated by taking the delivered price paid for gas and subtracting or 'netting back' costs incurred between the specific location and the delivery point of the gas. For example, an LNG netback price at Wallumbilla is calculated by taking a delivered LNG price at a destination port and subtracting, as applicable, the cost of transporting gas from Wallumbilla to the liquefaction facility, the cost of liquefaction and the cost of shipping LNG from Gladstone to the destination port.*"
LNG train	A unit of gas purification and liquefaction facilities found in a liquefied natural gas plant.
market segments	For purposes of developing gas demand projections, gas consumers are grouped into domestic market segments (residential/commercial, large industrial, and gas demand for GPG), and gas demand for LNG export.
National Electricity Market	The wholesale market for electricity supply in Queensland, New South Wales, the Australian Capital Territory, Victoria, Tasmania, and South Australia.
possible reserves	Estimated quantities that have a chance of being discovered under favourable circumstances. 'Possible, proved, and probable' reserves added together make up 3P reserves.
probability of exceedance (POE)	Refers to the probability that a forecast electricity maximum demand figure will be exceeded. For example, a forecast 10% probability of exceedance (POE) maximum demand will, on average, be exceeded only 1 year in every 10.
probable reserves	Estimated quantities of gas that have a reasonable probability of being produced under existing economic and operating conditions. Proved-plus-probable reserves added together make up 2P reserves.
production	In the context of defining gas reserves, gas that has already been recovered and produced.
prospective resources	Gas volumes estimated to be recoverable from a prospective reservoir that has not yet been drilled. These estimates are therefore based on less direct evidence than other categories.
proved and probable	See 2P reserves.
proved resources	Estimated quantities of gas that are reasonably certain to be recoverable in future under existing economic and operating conditions. Also known as 1P reserves.
ramp-up gas	Coal seam gas produced during the early stages of an LNG export project.
remaining reserves	On a given assessment date (e.g. 31 December 2010), the total quantity of gas expected to be recovered from a reservoir over its remaining productive life (e.g. 1 January 2011 to 2025). See also initial reserves.
reserves	Reserves are quantities of gas which are anticipated to be commercially recovered from known accumulations.
reservoir	In geology, a naturally occurring storage area that traps and holds oil and/or gas. Iona UGS is also referred to as a reservoir for gas storage.
resources	More uncertain and less commercially viable than reserves. See contingent resources and prospective resources.
scenario analysis	Identifying and projecting internally consistent political, economic, social, and technological trends into the future and exploring the implications.
sensitivity analysis	A technique used to determine how different values of an independent variable will impact a particular dependent variable under a given set of assumptions. For example, in the GSOO, the Higher Gas Price sensitivity tests the impact of higher gas prices in the Fast Rate of Change scenario.
Services Sector Gross Value Added (GVA)	Defined as aggregated measure ($'Millions, 2018 Real terms) of economic activity in all sectors except agriculture, construction, mining, manufacturing and utilities. Sector definitions follow the Australia New Zealand Industry Sector Category, published by the Australian Bureau of Statistics: http://www.abs.gov.au/ausstats/abs@.nsf/Latestproducts/0C2B177A0259E8FFCA257B9500133E10?opendocument.
shale gas	Gas found in shale layers that cannot be economically produced using conventional oil and gas industry techniques. See unconventional gas.
unconventional gas	Gas found in coal seams, shale layers, or tightly compacted sandstone that cannot be economically produced using conventional oil and gas industry techniques. See also conventional gas.
undeveloped reserves	Gas supply from wells yet to be drilled.