NATIONAL GAS FORECASTING REPORT

FOR EASTERN AND SOUTH-EASTERN AUSTRALIA

Published: **December 2016**

AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

AEMO has prepared this document under clause 91D of the National Gas Law, to provide information about gas annual consumption and maximum demand in eastern and south-eastern Australia over a 20-year outlook period.

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

Disclaimer

This report contains data provided by or collected from third parties, and conclusions, opinions, assumptions or forecasts that are based on that data.

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

Anyone proposing to use the information in this report should independently verify and check its accuracy, completeness and suitability for purpose, and obtain independent and specific advice from appropriate experts.

This document or the information in it may be subsequently updated or amended. This document does not constitute legal or business advice, and should not be relied on as a substitute for obtaining detailed legal advice about the National Gas Law, the National Gas Rules, or any other applicable laws, procedures or policies.

Accordingly, to the maximum extent permitted by law, AEMO and its officers, employees and consultants involved in the preparation of this document:

- make no representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of the information in this report; and
- are not liable (whether by reason of negligence or otherwise) for any statements, opinions, information or other matters contained in or derived from this publication, or any omissions from it, or in respect of a person's use of the information in this report.

Version control

Version	Release date	Changes
1	8/12/2016	

EXECUTIVE SUMMARY

The *National Gas Forecasting Report* (NGFR) provides forecasts of annual gas consumption and maximum gas demand across eastern and south-eastern Australia's interconnected gas markets over a 20-year outlook period under Neutral (most likely), Weak, and Strong scenarios.

Key findings

The future of gas is at the crossroads.

- There are uncertainties and challenges complicating gas demand forecasts for eastern and south-eastern Australia's interconnected gas markets over the next 20 years.
- It is anticipated gas will play a role in the transition to a low emission future, however the size of this role is uncertain due to the rapid transformation of Australia's energy industry.
- The domestic gas sector in eastern and south-eastern Australia is now linked to a more volatile world market for gas, and the size of liquefied natural gas (LNG) exports means small supply chain disruptions can have large impacts on domestic gas supply and demand on the east coast.
- The difference between AEMO's Strong and Weak scenarios is almost 1,600 petajoules (PJ), illustrating the need for flexible, innovative planning solutions during this period of energy transformation.

Total annual consumption is forecast to grow due to continued LNG export growth.

- Under AEMO's Neutral scenario, annual consumption is expected to effectively triple to 2,076 PJ compared to before Queensland LNG exports began.
- This growth is projected to transform Australia into the world's second largest LNG exporter and the major supplier for east Asian gas markets.

Gas consumption by gas powered generation is forecast to rise.

- During the 2020s, gas-powered generation (GPG) is expected to support the achievement of Australia's climate commitments by replacing higher-emitting coal, and complementing the increase in renewables along a pathway to a new, lower-emissions power system.
- GPG growth is expected to stretch available domestic gas supply, with the greatest supply challenge between 2018 and 2024.

Residential, commercial and industrial consumption is forecast to decline.

- Domestic gas consumption by households and businesses is forecast to decline across the outlook period.

20-year forecasts for annual gas consumption and maximum demand

Annual consumption

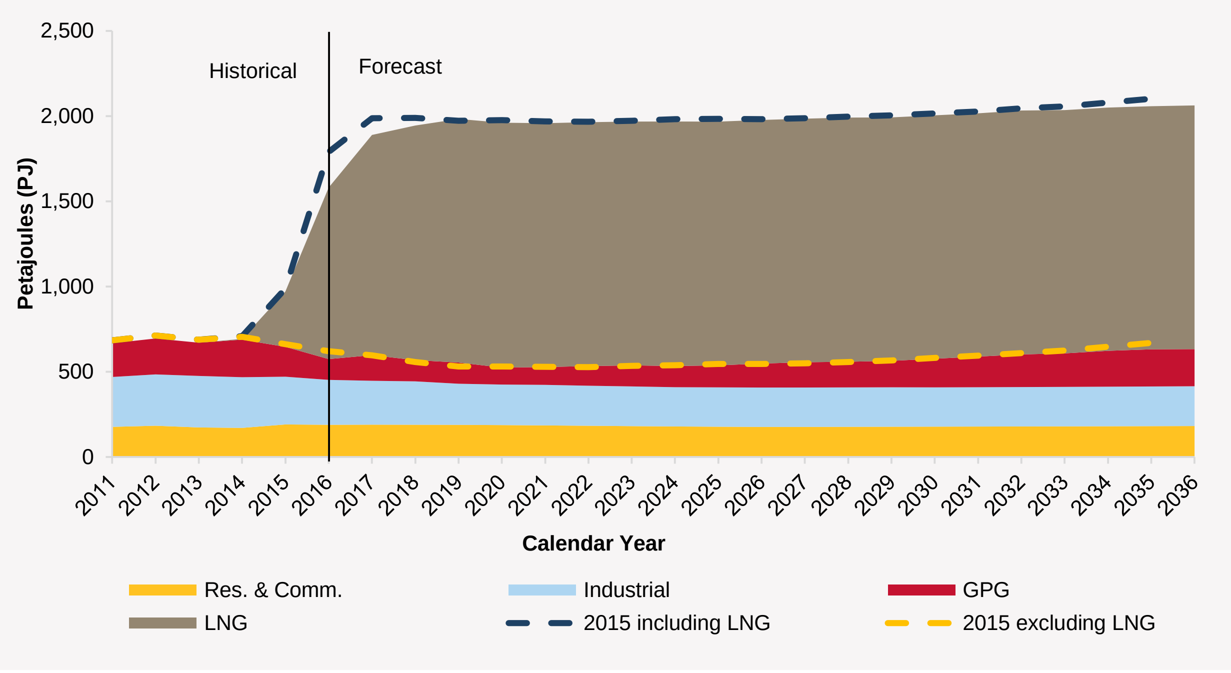
Total gas consumption is forecast to increase, driven by LNG exports and growth in GPG over the outlook period (shown in Table 1). Gas for LNG is forecast to continue ramping up as coal seam gas (CSG) projects continue to be developed for deliveries of LNG exports.

Table 1 Total annual gas consumption by sector, in PJ

Sector	2016	2021	2036
Residential and commercial	190	186	182
Industrial	264	238	233
Gas Power Generation (GPG)	122	104	218
Liquefied Natural Gas (LNG)	1,006	1,430	1,429
Unaccounted for Gas (UAFG)	14	14	13
Total	**1,595**	**1,972**	**2,076**

Figure 1 shows actual consumption since 2011 and forecast consumption to 2036. It highlights the short-term transformation of the market during the ramp-up of the LNG facilities, together with the recovery of GPG from the 2020s. It also illustrates a slight decline in both residential and commercial, and industrial consumption over the 20-year outlook.

Figure 1 Total annual gas consumption by sector, 2016 to 2036



Maximum demand

For most eastern and south-eastern states, maximum daily demand occurs during the winter heating season driven by variations in the domestic gas market. Of note, GPG is driven more by conditions in the electricity market and therefore consumes more gas in summer peak electricity demand periods.

Table 2 shows data for 1-in-2 year and 1-in-20 year peak day forecasts.

Table 2 Total maximum demand[A], all sectors, in terajoules per day (incl. GPG) (TJ/day)

Year	NSW		QLD (incl LNG)		QLD (excl LNG)		SA		TAS		VIC	
	1-in-2[B]	1-in-20[B]	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20
2016	517	555	3,752	3,756	436	440	234	242	56	57	1,218	1,329
2017	515	553	4,317	4,322	457	462	265	273	34	35	1,223	1,334
2018	506	544	4,494	4,498	412	417	242	251	34	35	1,209	1,319
2019	510	548	4,709	4,713	407	411	226	235	33	34	1,200	1,311
2020	516	554	4,717	4,721	415	419	221	230	33	34	1,193	1,303
2021	516	554	4,715	4,719	413	417	224	232	34	36	1,190	1,300
2026	518	556	4,751	4,755	449	453	232	240	35	36	1,193	1,300
2036	571	609	4,815	4,819	513	516	255	263	41	43	1,245	1,353

A All 2016 NGFR maximum demand forecasts assume winter peaking and include unaccounted for gas (UAFG).
B 1-in-2 year is equivalent to a 50% Probability of Exceedance (POE) forecast, and a 1-in-20 year forecast is equivalent to a 5% POE forecast.

The future of gas is at the crossroads

The 2016 NGFR considers a wide breadth of factors contributing to the 20-year forecasts, in particular the increasingly complex interactions between the gas and electricity sectors, energy demand and supply, competition, and price dynamics. It also analyses the relationship between Australia's energy demand and growing linkages to the international gas sector and manufacturing economy.

The 2016 NGFR assumes the COP21 commitment[1], a commitment to reduce greenhouse gas emissions by 26% to 28% below 2005 levels by 2030, is met.

The scenarios used in this NGFR have been designed to represent the most probable pathway for Australia, providing a base case that can be used to test important alternative futures. Table 3 summarises the three greatest uncertainties relevant to gas demand, and summarises how AEMO will test them.

[1] COP21 commitment refers to Australia's commitment at the 21st Conference of Parties to reduce greenhouse gas emissions. COAG has recommended that the NTNDP assume a 26% to 28% of emissions reduction below 2005 levels by 2030.

Table 3 Three determining uncertainties impacting gas forecasts

Uncertainty	Analysis
International supply-surplus of LNG and its impact on the commercial resilience of the QLD LNG export sector.	This uncertainty is addressed in the NGFR. AEMO's Weak scenario models a sustained low oil price outlook that delivers LNG revenues below assumed break-even costs. In this scenario, LNG buyers reduce purchases to minimum "take-or-pay" levels, and, towards the end of the outlook, LNG supply is increasing replaced with gas sourced from other countries.
Adequacy of domestic gas supply to meet gas demand over the next 10 years.	The 2016 NGFR assumes all available reserves will be needed to meet demand projections over the next 10 years, and this gas will increase in production cost and commercial margin. High uncertainty in the pattern of coal generation retirements and the role of GPG could test this supply limit and cost outcome. Possible gas costs may not be affordable to the largest energy-intensive industrial businesses. A detailed supply adequacy assessment will explore this uncertainty in AEMO's 2017 *Gas Statement of Opportunities* (GSOO) for eastern and south-eastern Australia, to be published in March 2017.
Investment incentives for GPG influenced by timing of coal generation retirements and a momentum to renewable energy.	AEMO understands that approximately 9 gigawatts (GW) of coal generation will reach its technical end-of-life[A] in the 2030s. Whether this generation is refurbished or replaced will depend on future climate change policy, technological advances and future gas prices. This introduces a decade when investment decisions could have divergent implications for the energy system. AEMO discussed this with stakeholders at the start of the modelling process, resulting in two projections of timing of coal retirements being examined: • The 2016 *National Transmission Network Development Plan* (NTNDP) examines a pathway of coal generation retirements based on assumed financial viability and announced intentions to close plant at the end of technical life.[B] This results in a greater projection of GPG to support development of new renewable generation. • The 2016 NGFR sought to understand the implications of uncertainty for the energy sector, and therefore examined the outcomes for extension of life of some aging coal plant, resulting in later coal generation retirement and a lower projection for GPG in the horizon to meet capacity needs[2]. The two projections approximately align to 2030, with 2 GW difference in installed GPG capacity and negligible difference in domestic annual gas consumption. By 2036, the forecasts diverge, with 10 GW difference in installed GPG capacity, and almost 50% difference in domestic annual gas consumption.[C] This signals the uncertainty towards the end of the 20-year horizon and the strong influence that timing of coal retirements could have on investment in the gas industry. The 2017 GSOO will further test both of these GPG outlooks, along with implications for gas supply and reserves.

A Technical life is 50 years since first operation.
B NTNDP consultation paper, available at: http://www.aemo.com.au/-/media/Files/PDF/2016-Consultation--NTNDP.ashx.
C Excluding LNG.

Key insights

Robust outlook for LNG exports despite uncertainty

- Since LNG exports began, international oil and gas prices have fallen, caused by excess supply in the international market for LNG. For the next 10 years, LNG spot prices are forecast to remain below the assumed long-run average production cost of Queensland's LNG exports.
- CSG producers face some volume risk if buyers reduce orders to "take-or-pay" levels. AEMO has assumed LNG sales are reduced to take-or-pay levels, with a decline in sales from 2030 due to non-replacement of CSG production capacity, and based on the assumed sustained low oil/LNG price. AEMO has conservatively assumed take-or-pay sales at 85% of the annual contract volumes that inform the outlook.
- The NGFR suggests planned LNG exports could be resilient to variable economic circumstances, due to the following:
  - Current and projected oil prices, if not high enough to cover the long-run average supply costs of LNG from Queensland CSG producers, are above the short-run production costs of these

[2] The NGFR assumes investment cases can be made for this new gas generation.

projects. This enables short-run operating profits that can contribute to capital costs and debt obligations.

- This cost structure also enables profitable participation of Australian LNG in the international spot market, enabling options for trading out of commercial and operational shocks.
- There is the possibility of Queensland CSG supplying the domestic south-eastern market. Production is linked to the domestic gas sector via pipeline connection at Wallumbilla, enabling both supply and demand support. Already some domestic gas supply from the Cooper Basin has supported the delivery of export contracts.

Price to play a role in domestic gas consumption

AEMO's modelling[3] projects that the delivered wholesale cost of gas[4] in Australia will increase by 48% by 2036.

Increases in domestic gas contract prices are expected to be driven mainly by rising domestic production costs, as new gas is sourced from higher-cost fields, combined with the effect of less domestic supply relative to demand.

Wholesale gas costs make-up a smaller percentage of the retail gas prices paid by energy consumers, so retail price increases are expected to be lower in percentage terms, but otherwise are projected to contribute to a reduction in domestic gas use.

The future of GPG is the greatest variable within domestic gas industry

AEMO's climate policy assumptions for the NGFR are based on the National Electricity Market (NEM) making a proportionate contribution to Australia's emissions target by achieving the expected annual emissions of 132 Mt/CO_2e by 2030.

The forecast growth of gas demand for GPG as a transitional energy supply is subject to increasing uncertainty in long-term projections as the electricity industry moves towards the low carbon emission future.

- GPG is forecast to play a key role in balancing the output from intermittent renewable energy sources as part of the transformation towards a low carbon future, in the absence of alternatives such as large-scale storage and demand management. Unexpected or disorderly coal plant retirements could require GPG investment using higher-cost gas to fill a gap in generation supply.
- If the strong momentum to renewables continues, including beyond the 20-year horizon of this NGFR, newly-constructed gas generators could have short commercial lifespans if alternatives are developed.

Assessments of potential supply gaps are highly influenced by the uncertainty in demand forecasts, particularly relating to the outlook for Australia's largest energy-intensive manufacturing businesses.

The NGFR has analysed investment risk for gas infrastructure based on modelling a strong link between large industrial sector futures and coal plant retirements. Uncertainty-based economic analysis has examined the potential for deferment of coal plant retirement, in a future pathway where:

The potential cost of extending the operation of a coal plant, beyond technical end of life, could be less than the costs of building new replacement gas plants and corresponding production and transmission infrastructure.

The momentum to renewables, with declining costs of renewable energy and potential energy storage, heightens stranding risk of investments in GPG.

[3] *NGFR Gas Price Assessment*, Core Energy Group, 2016. Available at: http://www.aemo.com.au/Gas/National-planning-and-forecasting/National-Gas-Forecasting-Report.

[4] Representing the upstream gas price based on the wellhead price, inclusive of transportation costs to major demand centres, before inflation.

Growth in GPG could challenge supply availability

AEMO's modelling indicates increased demand for new gas supply contracts based on the assumed closure of coal generation and projected increase in GPG. The 2016 NGFR forecasts that this increased demand could stretch domestic gas supply from 2018–24. AEMO will investigate potential new supply developments in the 2017 GSOO.

Industrial gas consumption forecast to decline

AEMO surveyed large gas-using businesses which represented over 200 PJ of load in 2015. It has also surveyed large electricity-consuming businesses, including major smelters, which as a sector consume almost 18% of domestic electricity generation. Research suggests:

- Energy-intensive sectors are generally trade-exposed and face challenging business conditions, caused in part by rising energy prices.
- Some businesses expressed concern about uncertainty in gas pricing and supply from about 2018.

Overall, AEMO forecasts that gas consumption for industry will continue to decline over the forecast period, by nearly 30 PJ by 2036.

Residential and commercial gas consumption to remain flat

AEMO forecasts flat residential and commercial gas consumption to 2036, with a small decline of over 7 PJ over the 20-year period.

A gas to electric appliance-switching trend is projected to offset growth in gas consumption from a rising population. Household appliance options, which are increasingly electric, give consumers the greatest opportunities to achieve energy efficiency savings and therefore offset rising prices.[5]

All scenarios are credible pathways, leading to planning challenges

AEMO's Neutral, Weak, and Strong scenarios all provide credible future paths. While the Neutral case is considered most likely, uncertainties make it important to consider the range of projections in planning.

The difference between Weak and Strong gas consumption projections is almost 1,600 PJ. This highlights the risks facing gas infrastructure planners. More than ever before, this means planning solutions will need to prioritise flexibility, innovation, and options to defer investment until some uncertainty across the energy market is resolved.

[5] Typically, the energy use of a reverse-cycle air-conditioner is only 20% of the energy a gas heater requires for the same measure of heating output.

CONTENTS

TABLES

FIGURES

CHAPTER 1. ABOUT THE 2016 NGFR

1.1 National gas forecasting

The *National Gas Forecasting Report* (NGFR) provides independent gas consumption forecasts over a 20-year outlook period for each state in Australia's eastern and south-eastern interconnected gas markets.

These forecasts are a key input into AEMO's *Gas Statement of Opportunities* (GSOO) for the eastern and south-eastern Australian gas markets, published in March each year. The GSOO uses forecasts for gas consumption and LNG exports in determining the adequacy of gas supplies and infrastructure in eastern and south-eastern Australia over a 10-year outlook period.

AEMO's NGFR forecasts explore a range of scenarios that represent probable pathways for Australia across Weak, Neutral (considered the most likely), and Strong economic and consumer outlooks.[6]

AEMO separately publishes *AEMO Insights* that may explore key forecast uncertainties, or other changes that may be relevant to the forecasts across the 20-year forecast horizon.

1.2 Forecasting and planning scenarios

In 2016, AEMO updated its scenarios framework for forecasting and planning publications. Following this update, all AEMO's major reports[7] are exploring the most probable pathway for Australia, using three scenarios representing weak, neutral, and strong economic and consumer outlooks.

The terms Weak, Neutral, and Strong are used throughout the 2016 NGFR documents to identify the three scenarios. The Neutral scenario is considered the most likely and is the main focus of this report. The Weak and Strong scenarios are based on dynamics affecting the total energy consumption of households and businesses.

Each scenario has the same emission reduction policy assumptions (see Section 1.4.2).

Key assumptions in each scenario are summarised in the table below. Appendix A has more detail on assumptions across all scenarios.

Table 4 2016 NGFR scenarios

Driver	Weak scenario	Neutral scenario	Strong scenario
Population growth[8]	ABS projection C	ABS projection B	ABS projection A
Economic growth	Weak	Neutral	Strong
Consumer	Low confidence, less engaged	Average confidence and engagement	High confidence and more engaged
Gas and electricity network charges	Current AER determinations, fixed after 5 years		
Gas and electricity retail costs and margin	Assume current margins throughout		
Technology uptake	Hesitant consumer in a weak economy	Neutral consumer in a neutral economy	Confident consumer in a strong economy
Energy efficiency uptake	Low	Medium	High
Emissions policies	Assumed to achieve 26% to 28% reduction in 2005 NEM emissions by 2030. Proxy carbon abatement cost starting at \$25/t CO_2e in 2020, rising to \$50/t CO_2e in 2030, affecting both electricity and gas retail prices.		

6 All scenarios assume Australia pursues its commitment at the 21st Conference of the Parties (COP21) for the United Nations Framework Convention on Climate Change (to reduce greenhouse gas emissions by between 26% and 28% below 2005 levels by 2030), and state governments continue to target increasing levels of renewable generation, although instruments to achieve these targets are yet to be determined. See Section 1.4.2 for more information.

7 *National Electricity Forecasting Report*, *National Gas Forecasting Report*, *NEM Electricity Statement of Opportunities*, *Gas Statement of Opportunities*, and *National Transmission Network Development Plan*.

8 Australian Bureau of Statistics, 2013, *Population Projections, Australia 2012 (base)*, cat. no. 3222.0.

Comparison to 2015 NGFR scenarios

While the Neutral scenario of this NGFR is generally comparable with the Medium scenario from the 2015 NGFR, the new Weak and Strong scenarios have alternative climate policy and economic assumptions, so they are not directly comparable with the Low and High scenarios respectively in the 2015 NGFR.

Unlike the 2015 NGFR, when the scenarios had varying assumptions regarding policy and technology uncertainties, in this NGFR the scenarios incorporate a common climate change policy assumption, and represent a range of economic, population, and consumer engagement outcomes around a highly probable baseline for Australia.

1.3 Structure of report and supporting resources

This 2016 NGFR provides:

- Highlights of forecasts for consumption and maximum demand over the next 20 years.
- Insights into key trends and drivers.
- A comparison with forecasts published in 2015, and historical actual consumption and maximum demand.
- A summary of key changes to modelling and reporting approaches in the 2016 NGFR.

This report is supported by a range of resources, summarised in Table 5. All these resources are available on AEMO's website at http://www.aemo.com.au/Gas/National-planning-and-forecasting/National-Gas-Forecasting-Report.

Table 5 2016 NGFR suite of resources

Resource	Description/link
2016 National Gas Forecasting Report	This report.
Online dynamic interface	Users can view graphs and key results, apply their own filters and download 2016 NGFR input and output data. http://forecasting.aemo.com.au/
2016 NGFR Forecasting Methodology Information Paper	Details of methodology, assumptions, and changes in approach for the 2016 NGFR. To be published in January 2017 on AEMO's website.
Supplementary reports	Consultants' reports and additional information. http://www.aemo.com.au/Gas/National-planning-and-forecasting/National-Gas-Forecasting-Report.

1.4 Changes since the 2015 NGFR

1.4.1 Enhancement to forecasting methods

This NGFR continues a major shift in AEMO's forecasting methods that began with the 2015 NGFR.

In 2015, AEMO changed its forecasting methods to use detailed "bottom-up" models that embrace a mix of economic and technical methods to better capture the continuing transformation of the energy supply and demand system. AEMO designed the segmentation of the "bottom-up" approach to separately address each emerging dynamic that explains changes to future gas and electricity use.

Further enhancements have been made to produce this NGFR:

- Long-range climate change trends have been built into the models, based on advice from the Bureau of Meteorology.
- Retail market gas metering data has replaced the need for large industry data requests, providing an automated and timely data-stream for input to the forecasting process. This means the forecasts are based on more current data.

- The forecasting models now integrate supply and demand, gas and electricity, and international and domestic models. This energy system integration enables the identification of dynamic price and competition feedbacks, and provides results that are more indicative of a convergent equilibrium. Notably, it means the gas forecasts used the latest electricity projections (input to GPG fuel usage), which include the following updates and inclusions since the publication of the June 2016 *National Electricity Forecasting Report*:
  - Electric Vehicle projections.
  - Inclusion of the proposed Victorian Renewable Energy Target (VRET).
  - Inclusion of updated projections for electricity use by the Queensland LNG export industry.
  - Inclusion of the announced Hazelwood Power Station retirement
  - Updated gas/GPG fuel costs based on the upstream supply demand balance that is an outcome of these NGFR forecasts.

1.4.2 Policy assumptions

Australia has announced a proposed target to reduce carbon emissions by 26–28% below 2005 levels by 2030, which builds on the 2020 target of reducing emissions by 5% below 2000 levels.

The Energy Council of the Council of Australian Governments (COAG) has agreed that the contribution of the electricity sector should be consistent with national emission reduction targets, and has advised that a 28% reduction from 2005 levels by 2030 is an appropriate assumption for AEMO to use in forecasting and planning. AEMO has assumed the achievement of this target will be supported by energy efficiency trends[9], energy pricing trends, and coal-fired generator retirements.

While it is not yet known if abatement costs will affect prices, AEMO's modelling assumes a partial impact in the 2016 NEFR and NGFR forecasts.

This NGFR also assumes the VRET will be implemented.

1.4.3 Survey and interviews from the largest energy users

AEMO continues to survey and interview the largest industrial energy users to inform its energy and demand forecasts. Surveys and interviews are used to inform near-term and highly probable adjustments to the separately determined business sector forecasts.

In some cases, forecast adjustments are probability-weighted, based on:

- Discussions with the relevant energy users.
- An assessment of economic conditions relevant to the industry sectors, users, and the forecast scenarios (Weak/Neutral/Strong).

1.4.4 LNG

Since 2015, AEMO has revised down both gas and electricity consumption by Queensland's LNG export industry, to align with operational data now available as the facilities have moved into production.

[9] This includes the expected impacts of the National Energy Productivity Plan (NEPP) targeting a 40% improvement in energy productivity between 2016 and 2030.

CHAPTER 2. FORECASTS FOR EASTERN AND SOUTH-EASTERN AUSTRALIA

This chapter reports forecasts of annual gas consumption and maximum demand (see Key definitions and glossary) for Australia's eastern and south-eastern interconnected gas markets. The Neutral (most likely) scenario is presented. The Strong and Weak scenarios are discussed in Chapter 4. Detailed data on forecasts in all scenarios is available on AEMO's online dynamic interface.[10]

2.1 Annual consumption

Key points

- Australia's energy industry is ramping up to become one of the world's largest LNG exporters, with demand for LNG and GPG the two areas of long-term growth in gas consumption.[11]
- Excluding LNG, domestic gas use is projected to remain flat, with growth from GPG and rising population offset by restructuring of the economy away from energy-intensive industry, improvements in energy efficiency of buildings and gas appliances, and changing consumer preferences towards increased use of electric appliances over gas appliances.

Table 6 Total (all regions and sectors) consumption over the short, medium and long term

Timeframe	Forecast (PJ)	Average annual rate of change	Drivers
Short term (2016–21)	1,595 to 1,972	4.3% increase	Forecast growth is driven by LNG export, offset by declining GPG, Tariff D and V consumption.
Medium term (2021–26)	1,972 to 1,990	0.2% increase	In the medium term gas consumption is forecast to plateau, as LNG remains flat and emerging growth in GPG consumption is offset by continued decline of Tariff D and V consumption.
Long term (2026–36)	1,990 to 2,076	0.4% increase	Long term gas consumption is forecast to start to increase driven by continued growth in GPG consumption while the decline in Tariff D and V consumption levels off.

2.1.1 Tariff V annual consumption

Table 7 Tariff V (residential and commercial) consumption over the short, medium, and long term

Timeframe	Forecast (PJ)	Average annual rate of change	Drivers
Short term (2016–21)	190 to 186	0.4% decrease	Consumers responding to increased cost of gas, investments in energy efficiency, and fuel switching from gas to solar or electricity reduce gas consumption in the short term.
Medium term (2021–26)	186 to 177	1.0% decrease	Continued consumer response to increased cost of gas, investments in energy efficiency, and fuel switching from gas to solar or electricity reduce gas consumption in the medium term.
Long term (2026–36)	177 to 182	0.3% increase	In the long term, the combined impact of energy efficiency measures and fuel switching is not expected to offset growth in gas consumption from growth in population and the economic activity.

[10] See: http://forecasting.aemo.com.au.
[11] After recent declines, GPG is still not expected to recover to the higher levels of 2014 and prior.

2.1.2 Tariff D annual consumption

Table 8 Tariff D (industrial) consumption over the short, medium, and long term

Timeframe	Forecast (PJ)	Average annual rate of change	Drivers
Short term (2016–21)	264 to 238	2.0% decrease	Forecast decline comes from manufacturing sector as: • Some large industrials shut down from rising input costs and depressed economic growth. • Remaining manufacturing industrial users reduce gas consumption in response to sharp increase in gas price in the short term. Other sectors have forecast flat gas consumption due to the competing effects of key modelling drivers of gas price and population growth.
Medium term (2021–26)	238 to 231	0.6% decrease	Industrial production projected to stabilise as economic growth recovers, but manufacturing gas consumption forecast to continue to reduce in response to rising gas prices and some survey-based industrial load adjustments. Other sectors increase in the medium term driven by population change, but manufacturing trend dominates.
Long term (2026–36)	231 to 233	0.1% increase	Forecast growth in other sector consumption drives long-term overall trend. Manufacturing sector consumption forecast to remain flat as gas prices stabilise and economic growth recovers to long-run average.

2.1.3 LNG annual consumption

Table 9 LNG (all regions and sectors) consumption over the short, medium, and long term

Timeframe	Forecast (PJ)	Average annual rate of change	Drivers
Short term (2016–21)	1,006 to 1,430	7.3% increase	Forecast increase as export from all six committed LNG export trains ramp up output to their contracted levels.
Medium term (2021–26)	1,430 to 1,428	Less than 0.05% decrease	Once contracted levels are achieved, output is forecast to remain stable in the medium to long term.
Long term (2026–36)	1,428 to 1,429	Less than 0.05% increase	Once contracted levels are achieved, output is forecast to remain stable in the medium to long term.

2.1.4 GPG annual consumption

Table 10 GPG (all regions and sectors) consumption over the short, medium, and long term

Timeframe	Forecast (PJ)	Average annual rate of change	Drivers
Short term (2016–21)	122 to 104	3.1% decrease	Projected decrease in GPG fuel use as wind generation increases due to LRET. The decrease is partly offset due to the announced closure of Hazelwood, which is projected to increase GPG fuel use in Victoria and South Australia from 2017, before being partially offset by increased output from renewable electricity generators and changes in demand.
Medium term (2021–26)	104 to 141	6.2% increase	Forecast retirements of coal-fired generation and growth in intermittent generation from renewable sources leads to projected growth in GPG for both baseload and peaking operation.

Timeframe	Forecast (PJ)	Average annual rate of change	Drivers
Long term (2026–36)	141 to 218	4.5% increase	Further retirements of coal-fired generation and continued growth in intermittent generation from renewable sources supports ongoing growth in GPG also in the longer term.

2.1.5 Unaccounted for Gas (UAFG)

Table 11 UAFG (all regions and sectors) over the short, medium, and long term

Timeframe	Forecast (PJ)	Average annual rate of change	Drivers*
Short term (2016–21)	13.9 to 13.6	0.5% decrease	The projected change in UAFG is proportional to the residential, commercial and industrial forecasts. However, the magnitude may change subject to the different network operating conditions.
Medium term (2021-26)	13.6 to 13.1	0.7% decrease	
Long term (2026-36	13.1 to 13.5	0.3% increase	

* UAFG forecasts are based on historical patterns and benchmark UAFG rates for residential, commercial, and industrial customers within the designed distribution network. For example, UAFG improvement is continuously monitored and managed by network operators through replacement of aged mains to reduce leakage.

2.1.6 Regional forecasts

Key points

- Queensland is forecast to have the largest change in the short term (2016–21), mainly due to the increase in demand of LNG.
- Tasmania is forecast to have very moderate growth over the whole forecast period, reflecting the smaller market and low regional gas growth forecasts.
- Excluding Tasmania, the main growth driver in the medium to long term (2021–36) is the expected pickup of GPG, with the relative magnitude reflective of each region's forecast generation mix.

Table 12 Regional forecasts over the short, medium, and long term (PJ)

Region	Short term (2016–21)	Medium term (2021–26)	Long term (2026–36)
New South Wales	122 to 117	117 to 121	121 to 142
Queensland	1,180 to 1,579	1,579 to 1,592	1,592 to 1,633
Queensland (excl LNG)	174 to 149	149 to 163	163 to 203
South Australia	74 to 70	70 to 73	73 to 81
Tasmania	6.4 to 6.3	6.3 to 6.4	6.4 to 6.8
Victoria	199 to 187	187 to 185	185 to 200

2.2 Maximum demand

Key points

- Maximum demand has similar dynamics to those of the annual consumption forecasts.
- For most regions, maximum demand is determined by weather driving gas consumption for heating. GPG on a day of maximum demand is otherwise unexceptional and is driven more by conditions in the electricity market than other drivers of gas consumption.
- Trends show decline for maximum demand, exclusive of GPG, caused mostly by the combination of projected industrial load reductions, gas to electric appliance switching, and warming climate.

All 2016 NGFR forecasts assume a winter peak. The following tables shows projections for 1-in-2 year and 1-in-20 year peak day forecasts.[12]

Table 13 Total maximum demand, all sectors (TJ/ day)

Year	NSW		QLD (incl LNG)		QLD (excl LNG)		SA		TAS		VIC	
	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20
2016	517	555	3,752	3,756	436	440	234	242	56	57	1,218	1,329
2017	515	553	4,317	4,322	457	462	265	273	34	35	1,223	1,334
2018	506	544	4,494	4,498	412	417	242	251	34	35	1,209	1,319
2019	510	548	4,709	4,713	407	411	226	235	33	34	1,200	1,311
2020	516	554	4,717	4,721	415	419	221	230	33	34	1,193	1,303
2021	516	554	4,715	4,719	413	417	224	232	34	36	1,190	1,300
2026	518	556	4,751	4,755	449	453	232	240	35	36	1,193	1,300
2036	571	609	4,815	4,819	513	516	255	263	41	43	1,245	1,353

Table 14 Total maximum demand (excl GPG), all sectors (TJ/day)

Year	NSW		QLD (incl LNG)		QLD (excl LNG)		SA		TAS		VIC	
	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20	1-in-2	1-in-20
2016	483	521	3,666	3,671	350	355	159	168	34	35	1,209	1,320
2017	478	516	4,206	4,211	346	351	155	164	34	35	1,208	1,319
2018	484	522	4,420	4,425	339	344	153	161	34	35	1,199	1,310
2019	481	520	4,611	4,615	309	313	150	159	33	34	1,190	1,301
2020	478	516	4,609	4,613	306	311	148	156	33	34	1,179	1,289
2021	477	515	4,607	4,612	305	309	147	155	34	36	1,171	1,280
2026	468	507	4,592	4,596	290	294	140	148	35	36	1,133	1,239
2036	485	524	4,594	4,598	292	296	141	149	37	39	1,146	1,254

[12] 1-in-2 year is equivalent to a 50% Probability of Exceedance (POE) forecast, and a 1-in-20 year forecast is equivalent to a 5% POE forecast.

CHAPTER 3. TRENDS IN GAS CONSUMPTION

This chapter discusses the key trends and drivers that influence the forecasts for annual consumption and maximum demand, focusing on those that have resulted in changes in 2016 NGFR forecasts compared to the 2015 NGFR.

3.1 Queensland LNG

Key points

- The commencement of LNG exports from Queensland is transforming Australia into the world's second largest gas exporter and the major gas supplier for east-Asian markets.
- Compared to 2014 (before LNG exports commenced), the contribution of gas consumption from Queensland's LNG export sector is expected to triple the annual gas consumption of Australia's interconnected east coast gas markets.
- Compared to current levels, the continued ramp-up of the Queensland export projects will have the effect of doubling annual gas consumption over the next five years.
- There is currently a supply surplus in the international LNG market. It is expected to last until the early to mid-2020s, making it difficult for the LNG projects in Queensland to sell above their contracted capacities. The supply surplus is expected to subside as international climate policies are expected to increase the demand for gas in LNG destination countries.
- While LNG contract commitments are maintaining demand for Queensland exports, low international oil prices have lowered expected returns from gas reserves, which may in turn reduce commercial incentives for investment, including the level of exploration. This has also raised risks that export levels may change from forecast assumptions.
- AEMO expects the LNG sector forecasts to be robust despite these commercial risks.

Forecast update

AEMO last published projections for energy use by the Queensland LNG export sector in June 2016.[13] Since this time, further information and more operational data has become available. The 2016 NGFR reflects this new information.[14]

From the commencement of export operations, AEMO has progressively updated key assumptions based on actual gas and electricity meter data coming out of the processing facilities. This data provides a better understanding of gas consumption by the export trains, and enables improved forecasts and a better calibration on previous ramp up projections.

- New project planning information has been received from LNG project operators:
  - The deferral of the second Australia Pacific LNG (APLNG) train from Q2 2016 to Q4 2016.
  - Gladstone LNG (GLNG) experiencing a slower ramp-up to full production.

AEMO has also updated its assessment on commercial risks and opportunities for the sector:

- Strong forecast scenario – gas exports are 5% higher than the 2016 NEFR Strong scenario, reflecting production at 110% of nameplate capacity instead of 105% of nameplate capacity, due to assumed optimisation of the operation at the LNG plants (in industry terms called "debottlenecking").

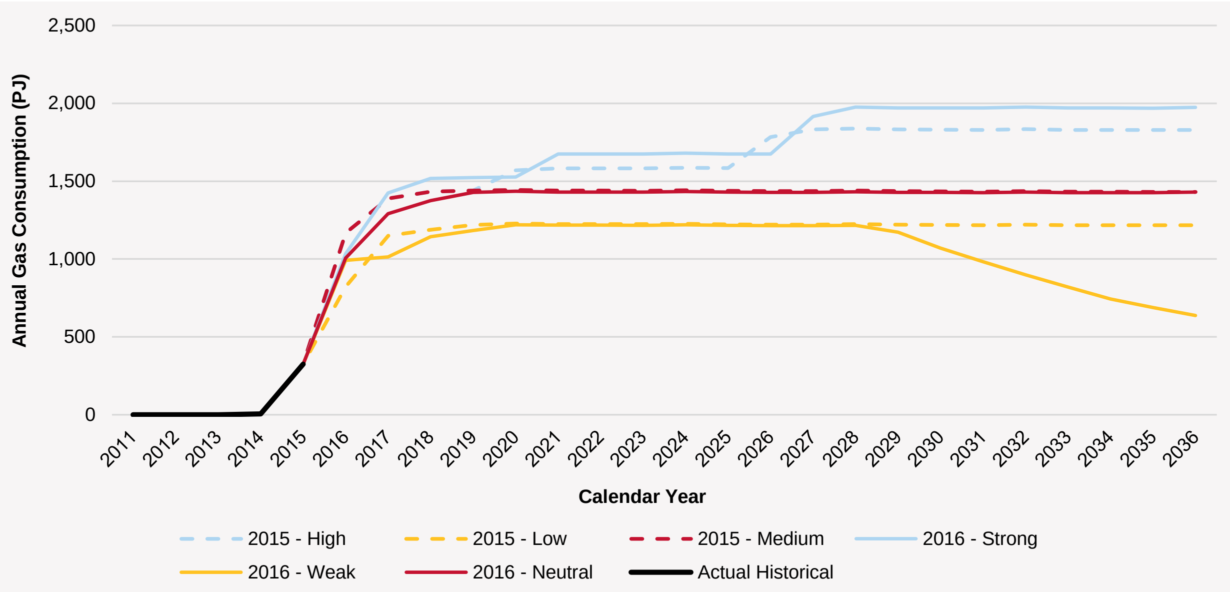
[13] AEMO. *National Electricity Forecasting Report*, June 2016. Available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEFR/2016/2016-National-Electricity-Forecasting-Report-NEFR.pdf.

[14] *Projections of Gas and Electricity Used in LNG*, Lewis Grey Advisory, 2016. Available at: http://www.aemo.com.au/Gas/National-planning-and-forecasting/National-Gas-Forecasting-Report

- Weak forecast scenario – the decline in the Weak scenario from 2028 starts earlier than in the 2016 NEFR projections, due to non-replacement of coal seam gas (CSG) production capacity that is consequential to projections of low oil/LNG prices.

The updated forecasts are shown in the figure below.

Figure 2 Total annual gas usage in liquefaction, transmission, and production (calendar year)



Source: LGA - Projections of Gas and Electricity Used in LNG

Australia is on track to be the world's second largest LNG exporter

Queensland's CSG to LNG sector includes exploration and extraction of CSG in the Surat and Bowen Basins of Queensland, and transmission via pipeline to Gladstone (Curtis Island) where it is processed (liquefaction) for export. Queensland CSG transmission is linked to the domestic gas market via pipeline connection at Wallumbilla.

There are currently four trains exporting LNG from Curtis Island – two Queensland Curtis LNG (QCLNG) trains, one GLNG train, and one APLNG train. Both GLNG and APLNG have second trains that are expected to become operational soon. These six LNG trains are each capable of delivering about 3.9 to 4.5 million tonnes of LNG per year when operating at their nameplate capacities.

A fourth major project, that of Arrow Energy, was cancelled earlier this year and Arrow has yet to indicate how it will try to monetise the value of its gas reserves. According to Lewis Grey Advisory, using the gas in a third train at one of the existing projects or another, smaller, project is a widely canvased option. Arrow's 50% owner, Shell, has recently taken over BG Group, the majority owner of QCLNG.

Once the Queensland LNG projects have reached expected levels of delivery capacity in 2018, they will comprise 30% of Australian LNG export capacity, with the other 70% of capacity in Western Australia and the Northern Territory. This will position Australia as the second-largest supplier of LNG in the world, competing with Qatar, and soon the United States of America.

Domestic gas sector is linked to the commercial challenges of LNG exporters

The start of Queensland LNG exports linked international gas prices with domestic prices in eastern and south-eastern Australia.[15] This has been facilitated via interconnection of the LNG supply system with the domestic gas pipeline system at Wallumbilla, providing a physical link that can enable trade

[15] However, increases in domestic gas contract prices are expected to be driven more by rising domestic production costs as new gas is sourced from higher-cost fields, combined with the effect of less domestic supply relative to demand. The forecast result is higher cost gas and less competitive tension, driving increasing domestic prices.

between the two systems. As the size of the LNG export sector relative to the domestic gas sector is expected to more than double by 2018, even small imbalances in the LNG sector could have large impacts for the domestic gas markets.

This linkage means the robustness of the NGFR forecasts are in part dependent on the commercial resilience of LNG export operations to what is projected to continue to be a challenging business environment for international LNG suppliers.

Commercial risks are significant, but the sector is resilient

Across the outlook period, CSG producers are expected to face challenging commercial circumstances with an increased risk that LNG exports will fall below contracted levels. The economics of the LNG projects are determined largely by the global gas and oil market, and the contract management decisions of LNG buyers.

In the Weak scenario, AEMO has modelled LNG sales reducing to “take-or-pay” levels, with a corresponding decline from 2030 CSG production capacity due to the sustained low oil/LNG price assumption of this forecast.

By 2036, the annual difference between projected annual consumption in the Neutral (most likely) scenario and the Weak scenario for LNG exports is almost 800 PJ. By way of context, this is more than total domestic gas use in eastern and south-Eastern Australia before LNG exports began.

Major commercial risks of relevance to the LNG projects are described below. However, AEMO expects the LNG projects will remain resilient against these economic circumstances and will continue to export in line with the Weak, Neutral, and Strong forecast scenarios.

Sustained low LNG prices

Construction of the first LNG trains in the east coast of Australia commenced after the major LNG projects secured long-term contracts to underwrite their capital investments and secure debt funding.[16] These long-term contracts between Curtis Island suppliers and destination countries have been priced against the international oil price in Japan (Japan Customs-cleared Crude price (JCC)).

When the Queensland LNG projects reached Financial Investment Decision (FID), oil prices were approximately 100 US dollars a barrel (USD/bbl). By the time Queensland’s LNG exports commenced in 2015, oil prices had halved to approximately 50 USD/bbl and have since remained near this level, lowering the initial expected returns on investment.

In the Neutral scenario, AEMO has modelled a slow recovery of the oil price to about 60 USD/bbl by 2020, averaging this level over the full 20-year outlook. Although lower than projected when the LNG projects were conceived, this outlook of lower oil prices is expected to be sustainable for the Queensland industry. During its inquiry into the east coast gas market, the Australian Competition and Consumer Commission (ACCC) found that both APLNG and GLNG are “cash flow positive at average oil prices of around US$40–45 per barrel”.[17]

In the Weak scenario, AEMO has modelled the outcomes of a sustained low oil price of USD 30/bbl. Although this level is not expected to recover costs for the LNG projects, the scenario assumes operations are continued until 2030, after which CSG production capacity is no longer replaced. Implicit in this assumption is an expectation of oil price recovery that progressively fades until the 2030 outcome.

A low oil price affects LNG projects’ revenue and reduces the funds available for exploration, as well as the incentives for developing already-explored gas fields if the economics of a gas field is low. This may have long-run implications for the gas market, as it can take up to ten years from initial exploration to the start of production.

[16] *Projections of Gas and Electricity Used in LNG*, Lewis Grey Advisory, 2016, page 8. Available at: http://www.aemo.com.au/Gas/National-planning-and-forecasting/National-Gas-Forecasting-Report.

[17] ACCC. *Inquiry into the east coast gas market*, 2016, page 56. Available at: http://www.accc.gov.au/publications/inquiry-into-the-east-coast-gas-market.

Low spot prices increase chances that exports are reduced to contract take-or-pay levels

CSG producers face contract volume risk if buyers reduce orders to “take-or-pay” levels that AEMO has modelled to be around 85% of the annual contract volumes that inform the outlook.

AEMO has modelled the outcome of a global gas supply surplus into the 2020s, during which there may be a sustained “delinking” of Asian LNG spot prices from oil-linked contract prices. In this case, LNG buyers may have a higher probability of reducing contract purchases to minimum “take-or-pay” levels to benefit from lower cost opportunistic purchases on the spot market. In the Weak scenario, AEMO is assuming exports at this lower “take-or-pay” level.

Supply surplus extends over the 2017–23 period

AEMO expects excess supply to be pushed into price-sensitive countries, with an increased likelihood that demands on liquefaction will be reduced. This has possible consequences for the Queensland LNG projects, as production costs in Queensland are considerably higher than their global competitors’ costs for conventional gas projects.

3.2 Gas-powered generation (GPG)

Key points

- GPG consumption is expected to trend downwards over the next four years, due to projected rises in the gas price, coupled with the forecast influx of large volumes of new wind farm capacity required to satisfy the Large-scale Renewable Energy Target (LRET) and the VRET.
- Retirement of Hazelwood Power Station is expected to cause a spike in GPG consumption for 2017–18.
- Growth in GPG consumption is expected to return after 2020, necessitated by the assumed achievement of the 2030 emissions reduction target, which can only be met by reducing output of coal-fired generation.
  - GPG demand is projected to grow moderately in the 2020s as mothballed plant returns to the market.
  - In the 2030s, an increase in GPG demand is driven by investments in new GPG capacity replacing retiring coal-fired generation.

GPG balances a volatile gap between coal retirements and new renewable generation

The forecast growth of gas demand for GPG as a transitional energy supply is subject to increasing uncertainty in long-term projections as the electricity industry moves towards the low carbon emission future.

GPG is forecast to play a key role in balancing the output from intermittent renewable energy sources as part of the transformation towards a low carbon future, in the absence of alternatives such as large-scale storage and demand management. Unexpected or disorderly coal plant retirements could require GPG investment using higher-cost gas to fill a gap in generation supply.

If the strong momentum to renewables continues, including beyond the 20-year horizon of this NGFR, newly-constructed gas generators could have short commercial lifespans if alternatives such as large-scale storage and demand management are developed.

- Assessments of potential supply gaps are highly influenced by the uncertainty in demand forecasts, particularly relating to the outlook for Australia’s largest energy-intensive manufacturing businesses.

This outlook has made AEMO's long-term projections of generation adequacy extremely challenging, with small changes in assumptions having the potential for large impacts on long term projections of future GPG investment and use. Major investment challenges for GPG include:

- Very tight upstream supply-demand balance over the next 10 years[18], with gas for new contracts increasingly coming from higher-cost gas fields.
- Limited competition in gas supply as an outcome of the above.
- Energy-intensive customer loads which make a large contribution to regional energy demand, and which are very price-sensitive, with weak resilience to adverse business conditions.
- A momentum to renewable energy which, if continuing beyond the 20-year outlook of the NGFR, may mean new gas generation investments could have short commercial life-spans.
- Grid-scale renewable generation technology, such as wind with energy storage, showing possible cost-equivalence with gas generation in the 2030s, and prospects for faster than anticipated reductions in new technology costs.
- Demand and renewable energy trends that show continuing reductions in emissions beyond 2030, without an assumed increase in policy intervention.
- Uncertain coal-fired generation retirements, with the possibility that retirements could be delayed in a context of investment uncertainty, or could even be unexpectedly early if maintenance expenditure is reduced for aging plant.

Updated forecast for electricity consumption

The outlook for GPG has been estimated using projections for electricity use and generation dispatch across the 20-year outlook. The forecasts have used electricity and generation dispatch projections that have been updated since the June 2016 publication of AEMO's NEFR:

- Inclusion of electricity forecasts for Electric Vehicles.[19]
- Updated electricity use by the LNG sector.[20]
- Impacts from announced closure of Hazelwood Power Station in 2017.
- Impacts from the announced VRET.

From these changes, the greatest impacts on projections of GPG have come from:

- VRET – modelling has found the proposed policy may:
  - Cause earlier retirements of brown coal-fired power generation in Victoria.
  - Bring forward investments in renewable energy generation, especially wind generation.
  - Move more of these investments to Victoria from other regions.

  The effect may increase GPG projections.
- Closure of Hazelwood Power Station – modelling suggests the closure may initially lift electricity dispatch prices in Victoria by $19 per megawatt hour (MWh), with replacement generation coming from a 50/50 split between black coal-fired power generation and GPG. Based on AEMO's interviews with large electricity-intensive industrial users, a price lift of this magnitude is expected to reduce electricity use by this sector. This would cause a demand response that later offsets the price impact, and, because GPG is the marginal supplier in the dispatch, also offsets the initial increase in GPG.

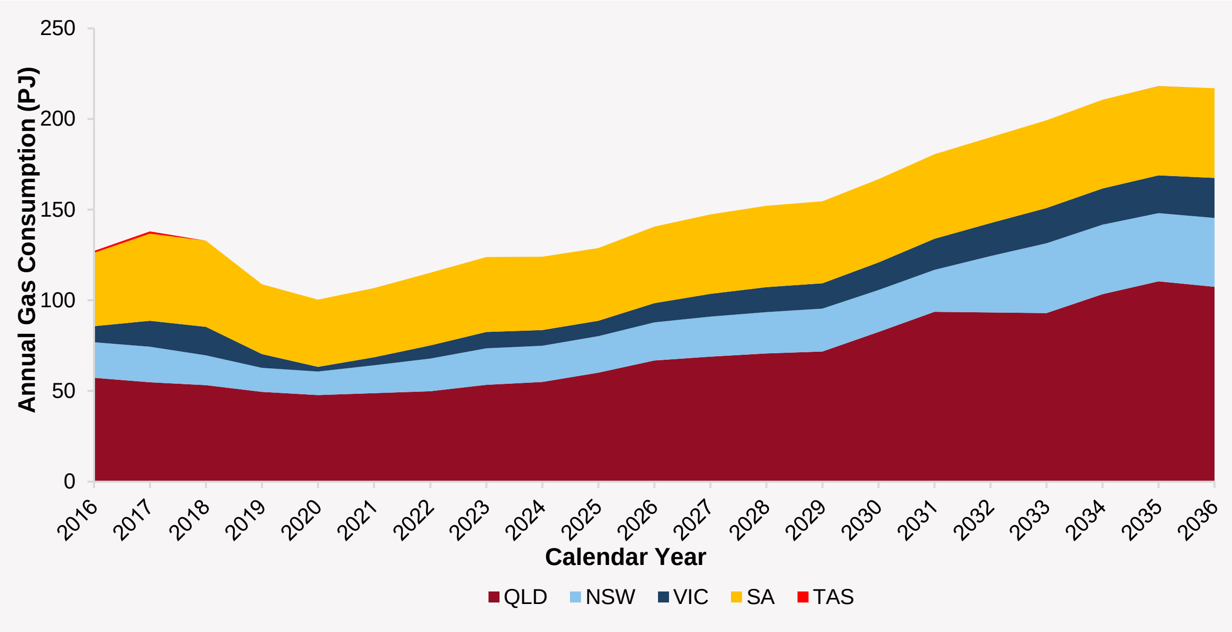
[18] To be explored as part of the 2017 *Gas Statement of Opportunities* for eastern and south-eastern Australia.
[19] *AEMO Insights – Electric Vehicles*, AEMO and Energeia, 2016. Available at http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEFR/2016/AEMO-insights_EV_24-Aug.pdf.
[20] *Projections of Gas and Electricity Used in LNG*, Lewis Grey Advisory, 2016, page 8. Available at: http://www.aemo.com.au/Gas/National-planning-and-forecasting/National-Gas-Forecasting-Report.

Outlook for GPG

The figure below shows forecast annual GPG consumption by region in the NEM. The key trends shown are:

- A reduction in GPG over the medium term to 2020, followed by a fairly steady uptrend post 2020.
- GPG consumption is projected to drop in 2017 from current levels, due to projected increases in the price of gas.
- The forecast spike in 2018 consumption (150 PJ) is driven by the retirement of Hazelwood, which results in increased consumption in both Victoria and South Australia as GPG is expected to fill some of the supply gap resulting from Hazelwood's exit.
- However, the projected growth trend in GPG is negative over the short term, caused by increasing penetration of renewable energy across the NEM and especially in Victoria to meet both the LRET and VRET, coupled with a sharp rise in the gas price.

Figure 3 Annual GPG gas consumption forecast, by NEM region



The longer-term trend is one of growth in GPG consumption following the 2020 low point (100 PJ), although current GPG consumption levels are not expected to be achieved again until 2025.

Key drivers for the growth in gas consumption are the assumed carbon price and the retirement of coal-fired generation required to achieve the 2030 emissions target. The carbon price benefits GPG since it tends to raise its position in the merit order relative to coal-fired generation, whereas the retirement policy creates a gap on the supply side by the removal of coal-fired capacity. This gap is filled by a combination of more expensive coal-fired generation and/or GPG.

From the 2020 low point of 100 PJ, annual GPG is projected to reach 218 PJ by 2036, which represents an annual compound growth rate of 4.7%. The growth rate from the 2016 starting point is more subdued, at 2.8% per annum.

3.3 Upstream gas prices

Key points

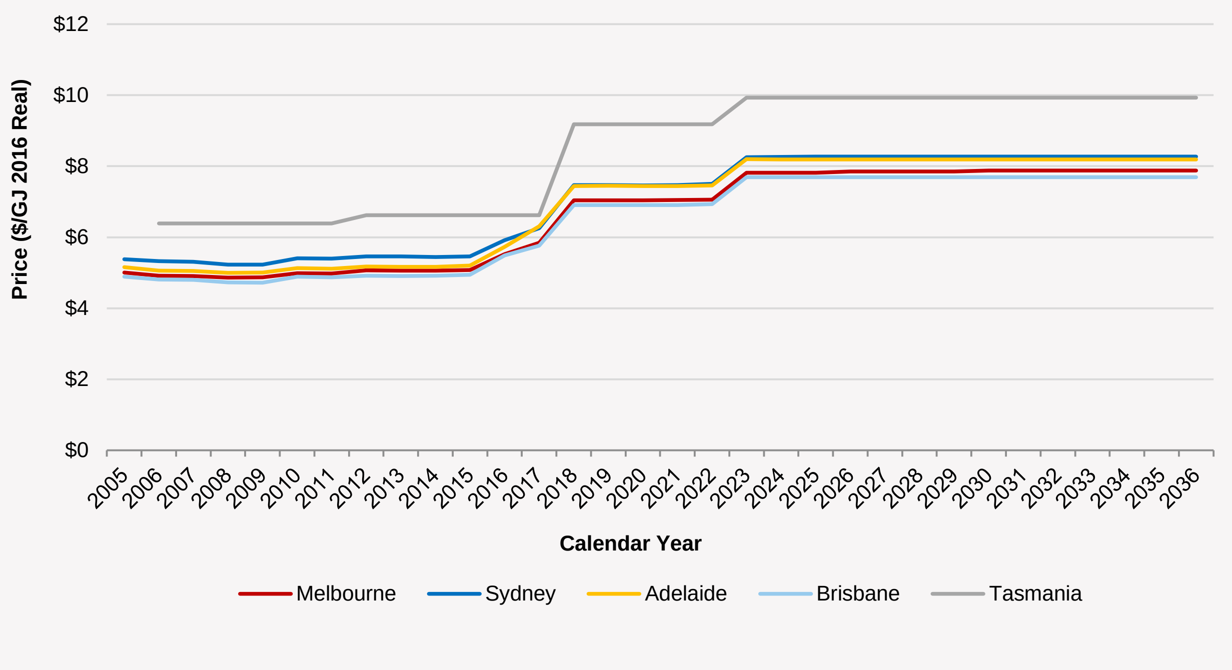
- Compared to 2016, upstream gas prices are expected to increase by 48% across the outlook period.
- Projected price increases are not being driven by international factors, but by a supply-constrained domestic market with new gas contracts increasingly supplied with gas from higher-cost sources.
- Competitive tension is expected to reduce, causing some price increase.

3.3.1 Upstream prices are projected to increase

'Upstream gas prices' refers to the delivered wholesale cost of gas, based on production and supply costs from the gas producers. Upstream prices are a major determinant of fuel costs for GPG, and for wholesale gas costs that make up the retail gas price of large and small gas consumers.

AEMO engaged CORE Energy Group to develop projections of upstream gas prices.[21] The following figure from CORE shows how gas prices, when delivered into each main demand centre, have changed since 2003, and are expected to change over the next twenty years.

Figure 4 Delivered wholesale gas price forecast for each demand centre – Neutral scenario



Source: CORE Energy

Compared to 2016, prices are expected to increase by 48% across the outlook period.

21 *NGFR Gas Price Assessment*, Core Energy Group, 2016. Available at: http://www.aemo.com.au/Gas/National-planning-and-forecasting/National-Gas-Forecasting-Report.

In 2018, and again in 2023, contracts for significant levels of reserve come to an end, causing the need for recontracting and the forecast step changes in contract prices shown above. New uncontracted reserves are expected be negotiated in the current supply-constrained environment, and are expected to be priced higher than legacy contracts. Furthermore, the new contracts are expected to have a component that is linked to the international oil price.

Further increases in upstream gas prices not driven by international factors, but by higher cost gas in a supply-constrained market

While the start of Queensland LNG exports linked international gas prices with domestic prices in eastern and south-eastern Australia, future increases in domestic gas contract prices are expected to be driven more by rising domestic prices.

The 2017 *Gas Statement of Opportunities* (GSOO) will provide a supply-adequacy assessment for eastern and south-eastern Australia. This NGFR has considered a summary assessment of supply adequacy to determine projections of upstream prices. Significant price increases can have the effect of reducing energy use, and are therefore relevant to the gas consumption projections of the NGFR.

This summary assessment has found that gas prices are likely to increase due to two factors:

- Lower cost reserves are depleting, replaced by new supply from higher-cost gas fields.
- Tighter supply-demand balance may limit competitive tension, causing some price increase.

The forecast result is higher cost gas and less competitive tension, driving increasing domestic prices.

Compared to estimated gas production costs for the higher-cost reserves that are supplying new contracts, international gas prices, when converted to domestic prices by accounting for delivery to local markets, are lower. Further, while some existing domestic contracts may have been struck with oil-price linkages, the recent reduction in the international oil price is assumed to have offset a high price uplift.

Impact of Hazelwood Power Station closure in 2017 on gas prices

Electricity dispatch modelling of the announced 2017 closure of the (brown coal-fired) Hazelwood Power Station has projected generation being replaced with an initial 50/50 spilt between black coal-fired power generation and GPG. This could create new demand for gas supply contracts during a period of supply constraint.

While supply adequacy will be thoroughly explored in the 2017 GSOO, this NGFR’s summary analysis suggests there are sufficient available gas reserves to enable this new supply in accordance with current cost-pricing structures.

AEMO has tested this outlook with selected retailers and has been informed that sufficient gas supplies are expected to be available, however the prices of available gas are beyond what some large industrial consumers are willing to pay. This agrees with AEMO’s findings from its surveys and interviews with large energy-intensive industrial businesses.

AEMO expects that new gas supply contracts, if for GPG, will be less sensitive to price increases given that GPG is often the marginal “price-setting” generator in the electricity market.

3.4 Retail price projections

Key points

- AEMO's modelling forecasts retail prices (before inflation) to rise on average at 2.1% per annum for residential and 5.8% per annum for large industrial in the short term, then to stabilise over the long term. The retail price trend is driven by wholesale prices.
- Two main periods of wholesale price rise are expected:
  - **2016–18** – New wholesale gas contracts are priced higher, reflecting increased cost of production.
  - **2020–30** – In this period:
    - Carbon pricing is assumed to affect energy prices from 2020, rising steadily until 2030, to meet Australia's 2030 carbon emissions target;
    - A large number of existing contracts for gas mature in 2022–23, while 2P gas reserves deplete. This leads to a projected supply constraint, reflected in the price of new contracts beyond 2022–23.
- AEMO's modelling projects rising retail margins in the short term, as retailers pass on the marginal price of gas to customers while holding cheaper legacy contracts. Over the medium term, as legacy contracts mature, the retail margin is expected to decline. Long-term price rises are expected to be fully passed onto end users.
- Uncertainty in gas price projections arises from climate change policy, international market linkage, and the spill-over effect from the uncertainty in electricity markets.
  - By the end of the forecast horizon, projected residential retail prices vary on average by 2.4% from the Neutral Scenario to the Weak, and 3.5% from the Neutral to the Strong.
  - This is accentuated in large industrial prices, where the Weak scenario varies by 9.2% on average from the Neutral scenario, and the Strong scenario varies by 12.7% on average from the Neutral scenario.

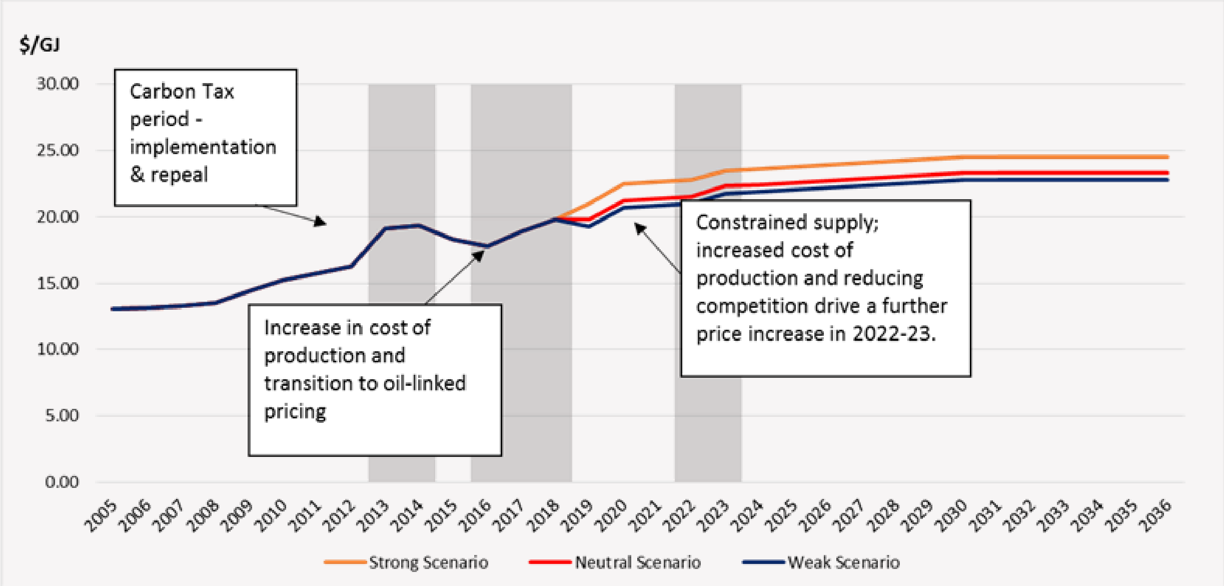
Drivers of retail gas price forecasts

AEMO's retail price projections have been rising steadily since 2005, largely driven by increasing network costs. Since 2011, a combination of policy (such as the introduction and repeal of the carbon tax) and market development (such as linking of domestic gas markets to international markets through the LNG industry[22]) has disrupted the stable trend in retail prices. Wholesale prices have accelerated over the period, for example, driving up retail prices for the average Victorian household by 5.5% annually and for large industrials in Victoria by 10.9% annually (see the figure 5) from 2011 to 2014.[23]

[22] For more information see Section 3.1.

[23] For other states, the average annual residential price increase is 8.4% for New South Wales, 6.0% for Queensland, 9.9% for South Australia, and 0.84% for Tasmania. The average annual price increase for large industrial users is 9.68% for New South Wales, 13.17% for Queensland, 12.0% for South Australia, and 2.3% for Tasmania.

Figure 5 Residential retail gas price forecasts for Victoria – all scenarios



The 20-year retail price projections show prices continuing to escalate on state average by 2.1% per annum for households and 5.8% per annum for large industrials until 2018. This is driven by the increase in wholesale gas price that AEMO has assumed will result from the combined impact of:

- A transition from legacy[24]contracts to oil-linked contracts.
- Sourcing higher-cost gas as cheaper gas sources deplete.

AEMO's retail price analysis also shows that the current transition between legacy contract prices based on lower cost gas production to higher contract prices is being passed on to customers on a marginal instead of average cost basis. This is showing an increase in average retail margins that may soon reduce, once the cheaper legacy contracts expire.

Network costs are assumed to be constant (in real terms) beyond the five-year AER determination period for the respective states.[25]

Impact of carbon pricing on retail gas price

A secondary driver of the projected retail price rise is the climate change policy assumption in the 2016 NEFR and NGFR.[26] AEMO has incorporated an effective price impact into the modelling, making the assumption that it starts around 2020 and increases until 2030. The assumed impact adds 4–8% to the typical household bill. The impact is higher on the typical electricity bill, as gas is seen as an interim fuel in the transition to a low emissions economy.

Retail price forecast – scenario variations

There is uncertainty around future retail gas prices, arising mainly from factors that have disruptive and competing effects on wholesale markets – linkage to international markets and climate change policy. The uncertainty that climate change policy creates for GPG in the NEM, discussed in Section 3.2, also has a spill-over effect for retail pricing. This is reflected in the pricing scenario variations.

The variation in pricing across scenarios is most prominent for industrial prices, where wholesale costs typically make up a larger portion of the total bill.[27] South Australia has the widest retail price range by

[24] CPI Indexed.
[25] Queensland moved to light regulation from 1 July 2016. AEMO assumes network costs remain constant (in 2016 real terms) over the forecast period.
[26] See Section 1.4.2.
[27] On average across states, wholesale cost makes up 84% of the total large industrial retail price, whereas it is only 18% of the residential price.

2036. This pricing uncertainty creates further challenges for long-term investment decision-making for businesses in an already challenging economic climate.

Table 15 Large industrial user retail price variations by scenario to Neutral scenario forecasts by 2036

	NSW	QLD	SA	TAS	VIC
Strong to Neutral	12.7%	12.7%	13.3%	11.0%	10.4%
Weak to Neutral	-8.5%	-8.5%	-8.7%	-7.3%	-4.7%

3.5 Climate change impacts on gas consumption

Key points

- Climate change has resulted in an increase in average temperatures of approximately| +0.8 °C from 1970 to 2016. Climate change is forecast to increase in average temperatures of approximately 0.5 °C over the next 20 years
- AEMO has estimated this impact on historical heating degree days (HDDs)[28] across Australia. For example, the impact in Melbourne today has been an approximate 14 % reduction in HDDs, or approximately 7 HDDs per year, compared to 1995.
- Incorporating a climate change trend in the HDD forecast shows a forecast reduction in the number of HDDs over time compared to current levels. For example, HDD is projected to reduce in Melbourne by approximately 10% (or approximately 5 HDDs per year) by 2036, compared to 2015, with a net reduction of 8.2 PJ by 2036.

Weather is a strong driver of gas consumption, with winter gas demand for space heating driving a very large proportion of total gas usage for residential and commercial users in the south-eastern regions of Australia. Heating demand (excluding GPG and LNG) makes up 40% of total demand in Victoria, 15% of total demand in South Australia, 20% in New South Wales, 7% in Tasmania and 0.4% in Queensland.

Year-to-year, natural variability in different regions results in mild or cool winters. On a longer time scale (a few years), other longer-term weather patterns also drive the variability, such as the El Niño Southern Oscillation (ENSO) that affects wind and temperatures across the Pacific Ocean.

On a decadal time scale, a long-term warming trend can be detected in the temperature record. It has been estimated by a number of meteorological bodies around the world that this long-term warming trend – driven by emissions of greenhouse gases such as CO_2 – has resulted in average global temperatures increasing by approximately 0.85 °C since the beginning of the Industrial Revolution.

For the 2016 NGFR, AEMO has analysed the impact that recent changes in the climate have had on HDDs, and modelled further increases in temperature and reductions in HDDs and the effect on heating demand for gas.

Although climate change represents a long-term trend in the temperature record, there is still local weather variability across the different states in Australia which affects gas demand and is also considered for modelling maximum demand.

[28] The 2016 NGFR uses heating degree days (HDDs), an indicator of outside temperature levels below what is considered a comfortable temperature (usually 18 °C) to help determine heating demand levels. If the average daily temperature falls below comfort levels, heating is required with many heaters set to switch on if the temperature falls below this mark. HDDs are determined by the difference between the average daily temperature and the base comfort level temperature of 18 °C.

3.5.1 Natural weather variability

AEMO gas consumption forecasts use a median (typical) climate assumption of weather. This ensures gas demand forecasts are not modelled on either an extremely cold or mild year of weather, since actual gas consumption can vary significantly due to weather variability year-to-year as well as within a forecast year.

AEMO has estimated that the typical 20-year range of weather variability equates to annual fluctuations in annual consumption of up to 6.0% in Victoria, up to 5.3% in New South Wales, and up to 5.0% in South Australia. Due to the minor use of gas in the residential and commercial sector in Queensland and Tasmania, the impact of weather variability in those states is small.

3.5.2 Climate change – historical trend

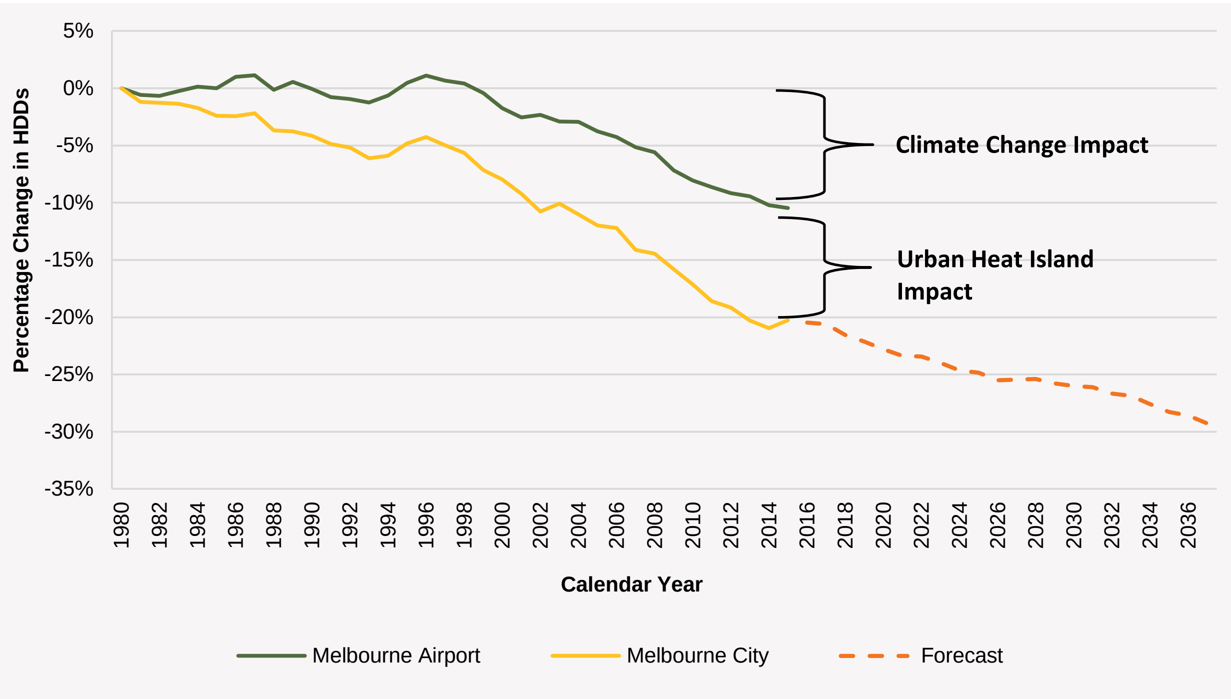
The historical temperature record displays regional differences in warming across the different states.

In addition, temperatures measured from weather stations in cities have increased more than measurements taken in rural areas. The additional heating in most urban regions is commonly attributed to the so-called Urban Heat Island (UHI) effect. UHI reflects that urban areas have more concrete and less vegetation cover, so they absorb and trap more heat compared to surrounding rural environments.

To estimate the historical impact from climate change, AEMO has used some rural weather stations to isolate the effect of UHI on temperatures and HDDs.

The following figure shows the estimated effects of both UHI and climate change on reducing historical HDDs.

Figure 6 Comparison of HDDs (Heating Degree Days) between the metro (Melbourne City) and more rural (Melbourne Airport) weather stations since 1980, with a 20-year forecast



3.5.3 Climate change – forecast temperature change

The dotted orange line in the figure above shows AEMO's 20-year forecast of average HDD changes for Melbourne City. The impact has been derived from the median forecast temperature trace for more than 40 different climate models. This showed an estimated increase in temperature by approximately 0.5 °C over the next 20 years across all regions. For robustness, AEMO still modelled each region separately.

The plotted forecasted decrease in HDDs is reflecting climate change only. There are indications that the impacts of UHI has stabilised somewhat the urban areas, since increased awareness of the impacts have led to local government initiatives towards additional "green zones" and “cool roofs”. This works to offset the UHI effect from the increase in housing developments and growth in high-rise apartments.

The largest impact of incorporating a climate change trend in the forecast is for the projections for Melbourne, where HDDs are projected to reduce by approximately 5.4 HDDs per year compared to current levels, with a net reduction in 2036 of about 8.2 PJ compared to the 2016 consumption level.

Regional differences mean other capital cities are forecast to see different reductions. These are shown in the following table, along with the estimated reduction in gas used for heating. The reductions in gas demand are based on current customer behavioural response, assuming no altered consumption patterns from a different climate.

Table 16 Reductions in HDDs and heating load by 2036 compared to current levels

Region	Average Change in HDDs/year	Reduction in HDDs by 2036	Tariff V: Reduction in Heating Load by 2036 (PJ)	Tariff D: Reduction in Heating Load by 2036 (PJ)
New South Wales	-4	-72	3.6	0.4
Queensland	-3	-52	<0.1	<0.1
South Australia	-5	-96	0.5	0.2
Tasmania	-5	-94	<0.1	NA
Victoria	-5	-107	8.2	0.7

*Gas heating in Tasmania is small in comparison to the state’s total consumption, so a climate change input was not considered for Tariff D.

3.6 Trends and drivers for the residential and commercial sector

Key points

- Australia's population is expected to increase over the 20-year forecast horizon by about 30%, with more people connected to gas than ever before. Total consumption, however, is projected to be flat, as it is forecast to be offset by energy efficiency, gas to electric appliance switching, and lower heating demand from a warmer climate.
- The total number of connections in all regions is forecast to continue to increase over the next 20 years, but at a declining rate.
- New connections are forecast to add 48.2 PJ of additional gas demand over the forecast horizon. The Neutral scenario of the 2016 NGFR forecast for connections is close to the Low scenario in the 2015 NGFR. This is due to:
  - A downward revision of forecasts for new dwelling completions.
  - An increasing proportion of high-density dwellings and buildings with a lower penetration of gas connections.
  - A reduction of the expected future electricity to gas conversions.
- As Australia's housing stock changes, with new buildings and retrofit of insulation, dwellings are becoming more energy-efficient. This is helped by the increasing ratio of high-rise apartments which require less energy to heat than larger detached homes. Also, consumers are purchasing more energy-efficient heaters and hot water systems. Under the Neutral scenario, the savings in energy usage due to energy efficiency are expected to be 25.6 PJ over the forecast horizon.
- Fewer households are forecast to be using gas as their primary source of space and hot water heating. Under the Neutral scenario, the savings in energy usage due to fuel switching (to electricity) is expected to be 10.9 PJ over the forecast horizon
- The forecast increase in gas retail prices leads to a projected reduction in gas consumption of 6.7 PJ by 2036.
- Projected warmer weather is forecast to reduce gas heating consumption by 12.4 PJ over the 20-year horizon, mainly in Victoria, due to the strong penetration of gas heating in this region.

3.6.1 Overall residential and commercial (Tariff V) forecasts

There are 4.2 million residential and commercial gas customers in the states covered by the NGFR. This is expected to increase to 5.6 million customers by 2036. In 2016, the residential and commercial sector represented 11.8% of total consumption. By 2020, this is forecast to reduce to 9.4%, due to expected growth in consumption for LNG production.

The figure below shows 2016 NGFR residential and commercial sector forecasts for the Weak, Neutral, and Strong scenarios. Alongside are comparisons with the Low, Medium, and High scenarios presented in the 2015 NGFR.

The 2016 forecast starts out relatively flat, as did the 2015 NGFR forecast, and the forecasts remain consistent until around 2023. From this point, the 2016 forecasts start to track lower than the 2015 forecasts. The two key reasons for this are a reduction in the forecast number of gas connections, and the adjustment for climate change, which lowers projected heating demand in the longer term (see Section 3.5).

Figure 7 Comparison of 2015 and 2016 forecasts for the residential and commercial sector in eastern and south-eastern Australia

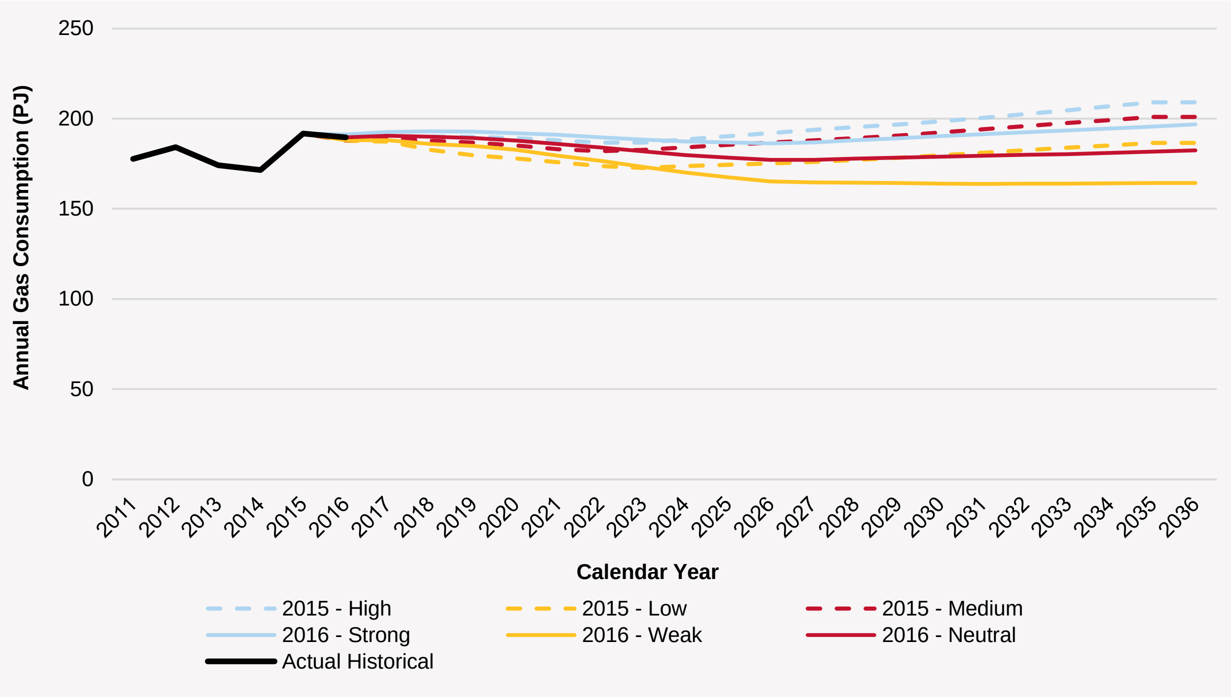
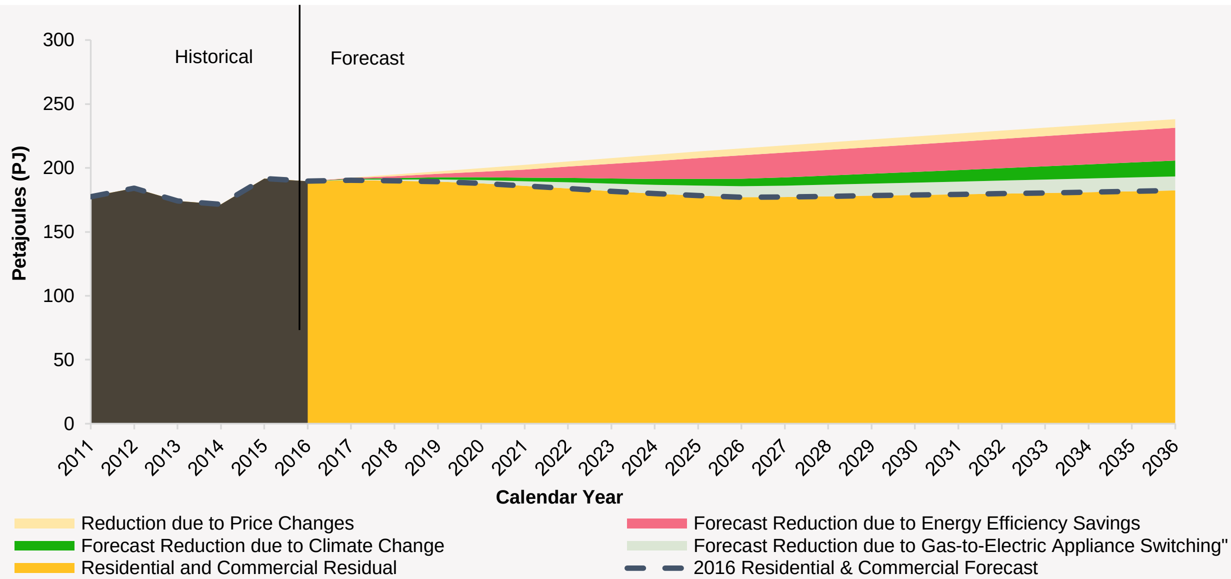


Figure 8 below shows the impact of the individual drivers for the Neutral scenario. The coloured wedges above the dotted line marking total consumption shows what consumption otherwise would have been, if those factors had been excluded from the forecast, and growth in connections was the only thing considered.

Each of these drivers is explained in Sections 3.6.3 to 3.6.5, apart from the climate change impact, which was covered in Section 3.5.

Figure 8 Illustration of impact on residential and commercial sector forecast from different drivers



3.6.2 Growth in meter connections

In recent years, the number of Tariff V connections has increased in line with the demographic cycle. New South Wales and Queensland in particular experienced a surge in the number of connections, linked to the overall steep increase of new dwellings in the Sydney and Brisbane metropolitan areas. Now, the growth rate of new gas connections is slowing down, due to a downturn of the building cycle and an increased proportion of new dwellings in multi-unit developments which tend to be all-electric households.

As reported in the 2015 NGFR, changes in the composition of housing stock are favouring the surge of all-electric dwellings and slowing the uptake of gas connections. Apartments and dwelling units in high-rise developments are characterised by a larger adoption of electric appliances compared to detached houses and brownfield suburbs.

The table below shows the total number of Tariff V connections in the south-east Australian gas markets is projected to increase from the current 4.18 million connections:

- By approximately 340,000 units over the five years to 2021.
- By approximately 1.29 million by 2036.

Table 17 Forecast number of Tariff V connections and growth compared to calendar year 2016

	NSW+ACT		QLD		SA		TAS		VIC	
	Number	% growth	Number	% growth	Number	% growth	Number	% growth	Number	% growth
2016	1,475,049	0%	203,840	0%	456,640	0%	13,484	0%	2,034,536	0%
2021	1,632,443	11%	228,621	12%	485,103	6%	15,494	15%	2,162,515	6%
2036	2,070,840	40%	312,902	54%	545,965	20%	18,222	35%	2,523,045	24%

Despite this increasing trend in the absolute number of connections, gas penetration in almost every state is stable, with the upward trend slowing after a mild increase in recent years. The main drivers behind this trend are an increased percentage of multi-unit high-rise apartments and an ongoing shift to electrify services.

The only exception is New South Wales, which in the past was characterised by a relatively low gas penetration, and now is growing. The proportion of dwellings with a gas connection in New South Wales was estimated to be 45% in 2015, and is projected to be 49% in 2036.

AEMO expects that gas penetration rates may fall in the future, particularly as an outcome of gas-to-electric appliance switching trends, changes in relative pricing between gas and electricity, and due to consumer preferences. However, AEMO's meter data is yet to show this, so it has not been assumed in the forecasts in this NGFR. AEMO is continuing to monitor connection trends for evidence of a shift in preferences.

The connection forecast in 2016 tends to be lower than the corresponding figures in the previous NGFR, with the Neutral scenario tracking close to the Low scenario of the 2015 NGFR.

The number of connections in eastern and south-east Australia in the 2016 NGFR Neutral scenario is forecast to be 4.53 million in 2021 and 5.48 million in 2036. These figures can be compared with the 2015 NGFR Medium scenario forecasts of 4.58 million in 2021 and 5.60 million by 2035. The lower forecasts in the 2016 NGFR are the result of a downward revision of the new dwellings forecasts and different assumptions on the number of new gas connections in brownfield areas.

The most recent forecasts for building completions[29] project the growth rate of building stock to significantly decrease over the next three years, and then to converge to the long-term demographic trend. This reduction in new constructions is attributed to the oversupply currently present in the market, and is expected to be more pronounced in New South Wales.

[29] AEMO uses forecasts for new dwelling completions provided by the Housing Industry Association (HIA).

Compared to the 2015 NGFR, the 2016 connections growth forecast has changed the assumptions on future brownfield conversions[30], lowering this component and effectively reducing the forecast number of new connections. In the 2015 NGFR, the number of brownfield conversions was assumed to be constant over the forecast period. In the 2016 NGFR, this number is assumed to decline linearly to zero within the first 10 years of the forecast horizon. This change causes the total number of connections at the end of the 20-year horizon to be 3% lower than it would been using the 2015 approach.

3.6.3 Impact of gas retail price changes

Increased retail prices incentivise consumers to invest in energy efficiency and potentially switch from gas as a fuel source to using solar or electricity. This is a longer-term impact covered in the following sections.

There is also a shorter-term impact of price increases in reducing consumption due to behaviour change, compared to what consumption would otherwise have been. Examples of behaviour change include a reduction in thermostat settings for space heating, and shorter showers.

The price increase is translated into demand reduction based on price elasticities AEMO estimated from analysing gas meter data as part of the 2015 NGFR. A price elasticity represents the change in demand relative to the change in price. The elasticities applied were varied between new and old houses and between space heating and hot water heating. The values ranged between -0.066 and -0.3. Similar values were applied for commercial gas use.

Table 18 Impact of retail price on residential demand

	NSW+ACT		QLD		SA		TAS		VIC	
	Change PJ	Change %	Change PJ	Change %	Change PJ	Change %	Change PJ	Change %	Change PJ	Change %
2021	0.5	(0.9%)	0.0	(0.3%)	0.3	(2.3%)	NA	NA	3.0	(2.5%)
2036	1.1	(2.2%)	0.1	(0.8%)	0.3	(3.4%)	NA	NA	5.2	(4.4%)

3.6.4 Fuel switching

For the 2016 NGFR, AEMO continued the approach adopted in the 2015 NGFR to account for residential gas-to-electric appliance switching. This includes projected shifts from traditional gas hot water systems to gas or electric-boosted solar hot water systems, and from gas to electric heating, using heat-pumps, or reverse-cycle air-conditioners.

Fuel switching occurs mainly in existing homes, and at times when existing appliances need replacement or during major building renovations.

From this analysis, AEMO has estimated the following on a per gas connection basis:

- Hot water appliance switching − for 2016−21, AEMO has forecast switching rates of 5% in Victorian existing homes and 0.4% for other regions. For 2021−36, switching rates are expected to be a further 7% for Victoria and remain at the same for other regions. Victoria is expected to experience higher switching rates of gas storage hot water heating appliance to solar according to the projections in the Residential Baseline Study. These forecast appliance switching rates are lower than the forecasts in the 2015 NGFR as a result of transferring the previously reported fuel switching impact to energy efficiency savings associated with conversion of gas storage to gas instantaneous hot water units.
- Heating appliance switching − for 2016−21, AEMO has forecast existing home switching rates of 0.5%. For 2021−36, switching rates are expected to be a further 2%

[30] Electricity-to-Gas connections, where an all-electric household connects to the gas network to use gas for heating, hot water, or cooking.

AEMO has added an estimate of the fuel switching impact of commercial Tariff V customers provided by Core Energy.[31]

The table below shows how projected gas to electric appliance switching translates to changes in gas consumption forecasts for each state, compared to what consumption would otherwise have been.

Table 19 Impact of fuel switching on residential and commercial demand

	NSW+ACT		QLD		SA		TAS		VIC	
	Change PJ	Change %	Change PJ	Change %	Change PJ	Change %	Change PJ	Change %	Change PJ	Change %
2021	0.7	(1.4%)	0.1	(1.7%)	0.2	(2.3%)	NA	NA	2.5	(2.1%)
2036	2.4	(4.5%)	0.3	(3.9%)	0.5	(5.3%)	NA	NA	7.7	(6.3%)

3.6.5 Energy efficiency

The forecasts account for projected changes in the energy efficiency of buildings and appliances. Reductions in consumption arise from energy efficiency measures, such as:

- Increase in instantaneous hot water, which is more efficient than storage-based heaters.
- Increased percentage of apartments/units, which use relatively less energy to heat when required.
- More efficient gas heaters.
- Better insulation of buildings.

From its analysis of residential gas meter data, AEMO estimated the difference in gas consumption from older houses in comparison with new houses, showing older homes used relatively more gas.

Ongoing energy efficiency gains are expected to lower gas consumption by new homes by an additional 4% by 2021 and 9% by 2036 respectively.

In addition to this, retrofit of more efficient gas appliances along with improved insulation is expected to reduce the gap in consumption. By 2026, it is assumed that the gap has halved in most regions. In Victoria, it is expected to take longer to reduce the gap in consumption because of the prevalence of gas heating in existing homes and the slow turnover of heating appliances due to their longer lifespan compared to gas hot water heaters.

AEMO has added an estimate of energy efficiency improvements of commercial Tariff V customers provided by Core Energy.[32]

The following table shows how these estimated residential and commercial energy efficiency savings translate to forecast reductions in gas consumption for each state, compared to what consumption would otherwise have been.

Table 20 Impact of energy efficiency on residential and commercial demand

	NSW+ACT		QLD		SA		TAS		VIC	
	Change PJ	Change %	Change PJ	Change %	Change PJ	Change %	Change PJ	Change %	Change PJ	Change %
2021	2.4	(4.7%)	0.3	(4.1%)	0.6	(5.2%)	NA	NA	3.0	(2.5%)
2036	9.4	(15.8%)	1.0	(11.7%)	2.0	(16.7%)	NA	NA	13.2	(10.4%)

[31] *NGFR Gas Price Assessment*, Core Energy Group, 2016. Available at http://www.aemo.com.au/Gas/National-planning-and-forecasting/National-Gas-Forecasting-Report.

[32] *NGFR Gas Price Assessment*, Core Energy Group, 2016. Available at http://www.aemo.com.au/Gas/National-planning-and-forecasting/National-Gas-Forecasting-Report.

3.7 Trends and drivers for the industrial sector

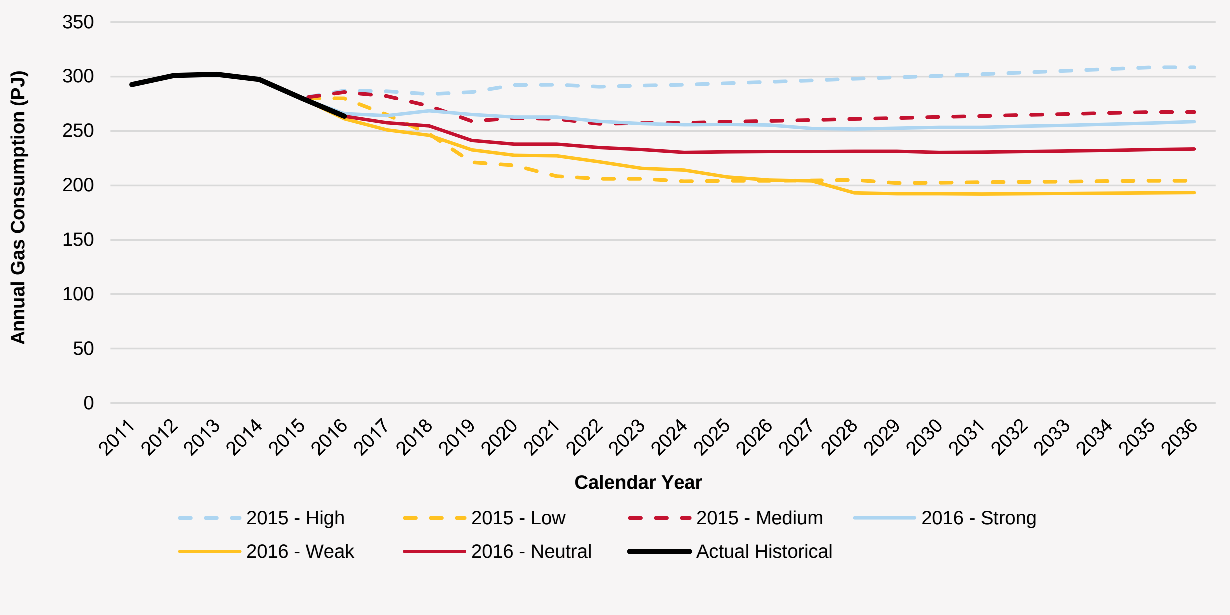
Key points

- The Australian economy continues to restructure away from energy-intensive industries, with closures of energy-intensive manufacturing businesses observed in recent years. This is a result of depressed international commodity prices, increasing input costs, and reducing competitiveness in international markets negatively impacting trade-exposed industries.
- While commodity prices are expected to recover in the Neutral scenario, AEMO expects the decline in gas consumption to continue, with no apparent growth driver on the horizon, increased cost pressures from rising gas prices, and considerable risk of permanent closures.
- Significant increases in the domestic gas price, along with the uncertainty of future gas supply (and prices) in the short term, continue to exert pressure on industry to reduce and review gas usage in their business processes.
- Other sector industrial users exhibit projected growth in the long term, particularly in food and beverage manufacturing as well as commercial services, driven by population growth. This growth is forecast to be tempered in the earlier years by response in consumption to gas price increases.
- Over the 20-year forecast period, sharp reductions in usage are expected in the short term, followed by a flattening of demand as market forces stabilise and other growth areas for demand mature.

This section addresses trends that have influenced forecasts for the industrial sector. The forecasts have been generated from applying a combination of survey results and econometrics separately for the manufacturing sector (except for Queensland which is mostly survey based) and another econometric model for the ‘other’ category for industrial users of gas (which largely consists of commercial users).

The following figure presents the 2016 NGFR industrial forecasts for the Weak, Neutral, and Strong scenarios, alongside the Low, Medium, and High scenarios from the 2015 NGFR. Of note, the Strong and Neutral scenarios in 2016 NGFR are significantly lower compared to the respective High and Medium scenarios from the 2015 NGFR, reflecting updated inputs (including survey results) and the impacts of further model and data improvements this year.

Figure 9 Comparison of 2015 and 2016 forecasts for the industrial sector in eastern and south-eastern Australia



3.7.1 Impact of gas industrial price and supply changes felt sharply in the short term

AEMO considers the current high prices and future price uncertainty as a strong economic variable that interacts with decision-making about current and future gas usage.

Over the next five years (2016–21), AEMO forecasts a large reduction in industrial gas consumption (9.7 % decrease over five years), as the manufacturing sector continues to experience further pressure from existing lower cost gas supply contracts maturing and being renewed at historically high gas prices. The reduction in gas usage is likely to consist of closures, energy efficiency, fuel switching, and import substitution where possible. As there is likely to be strong interplay of these drivers, they are only considered in aggregate.

The average change expected over this short-term period for industrial gas consumption for eastern and south-eastern Australia is a reduction from 264 PJ to 238 PJ (an average of 2.0% decline per year). This is the period of largest change across the 20-year forecast horizon. The price impact on gas usage has been considered separately across Australia's regions, reflecting the cost-to-serve differences, diverse industry mix, and distinct characteristics across the states, as shown in the following table.

Table 21 Reduction in industrial consumption in response to retail price from 2016 consumption

	NSW+ACT		QLD		SA		TAS		VIC	
	Change PJ	Change %	Change PJ	Change %	Change PJ	Change %	Change PJ	Change %	Change PJ	Change %
2021	4.2	(7.7%)	0.7	(0.6%)	1.7	(7.0%)	0.2	(3.0%)	7.8	(11.2%)
2036	6.0	(11.0%)	1.0	(0.9%)	2.7	(11.1%)	0.3	(5.1%)	11.4	(16.4%)

*Although Queensland shows a low price impact (1.1% reduction in 2036) when considered separately in the forecast, price was a strong factor in the large industrial load adjustment made on the forecast (42% reduction in 2036).

3.7.2 Large industrial users of gas continue to face challenges domestically and abroad

AEMO surveyed large gas-using businesses representing over 200 PJ of load in 2015, with almost 60% of this gas usage within two manufacturing subsectors:

- Basic chemicals and chemical products (such as fertilisers, explosives, and methanol).

- Primary metal and metal products (such as alumina refineries, iron and steel mills, and smelters).

These subsectors are generally trade-exposed, and the survey results indicated a concern at the challenges they face from low commodity prices and a strengthening Australian dollar exchange rate, as well as challenges related to gas supply and prices outlined below.

Closures of some gas-intensive businesses are expected to continue. Businesses are also responding to challenging conditions by reducing gas usage where possible.

For large gas-intensive industries, the price paid for gas is highly important, especially when compared against the prices paid for gas in countries against which these industries compete. Some of the industries AEMO has surveyed are seeing a marked deterioration in the competitiveness of the products they produce following recent increases in the eastern Australian gas price.

Of additional concern to many of the businesses surveyed is uncertainty about gas pricing and availability, and lack of competition to supply from about 2018. Several businesses have replied to AEMO that they cannot get offers for supply in 2018, or can only get offers from one source.

Businesses exposed to a domestic market, especially on construction and infrastructure, are currently operating in a stronger business environment. Survey results indicate an expected expansion of production and gas usage in these businesses in future years.

Overall, however, AEMO expects gas usage for large industry to continue to decline over the forecast period, and have considered these large industrial load closures/expansions in the forecast. The largest impact in 2036 is 37 PJ in Queensland, due to this region containing a significant proportion of large industrial gas users of the total industrial gas market.

Table 22 Reduction in industrial consumption due to large industrial load adjustments from 2016 consumption

	NSW+ACT		QLD		SA		TAS		VIC	
	Change PJ	Change %	Change PJ	Change %	Change PJ	Change %	Change PJ	Change %	Change PJ	Change %
2021	1.3	(2.4%)	27.3	(24.9%)	0.4	(1.5%)	0	(0%)	0.8	(1.2%)
2036	1.3	(2.4%)	37.0	(33.8%)	0.4	(1.5%)	0	(0%)	1.8	(2.9%)

3.7.3 Manufacturing sector drives decline, with some growth and offset from other sectors

In the medium term (2021–26), the forecast decline in manufacturing sector consumption is softened by improving commodity prices and restored industrial production levels in the Neutral scenario. In the long term, manufacturing is projected remains flat and growth from the food and beverage manufacturing and commercial services sectors drives the overall industrial trend. Key to this are domestic population increases, improved business conditions, stability in gas prices, and anticipated North Asian and ASEAN free trade agreements driving demand for Australian goods.[33]

Growth sectors in the industrial users of gas are more apparent in the medium term, with a projected increasing share from food, beverage, and dairy manufacturers. Consumption in this period is expected to decline from 238 PJ to 231 PJ, but at a much lower rate (an average of 0.6% decline per year). AEMO forecasts that this growth in manufacturing activity in Australia will not correspond to a large pickup in gas consumption, due to lower gas usage for these manufacturers compared to the current snapshot of Australia's manufacturing industry.

Due to the different economic drivers and gas usage requirements across the commercial services sectors (such as education, health care, telecommunications, finance services, transport, and

[33] General: https://www.austrade.gov.au/Australian/Export/Free-Trade-Agreements/MAFTA;
The Centre for International Economics, "Economic Benefits of Australia's FTAs"; 2015; Prepared for Department of Foreign Affairs and Trade, available at https://dfat.gov.au/about-us/publications/Documents/economic-modelling-of-australias-north-asia-ftas.pdf; Dairy Australia, "Trade Liberalisation", available at http://www.dairyaustralia.com.au/Markets-and-statistics/Exports-and-trade/Trade-liberalisation.aspx; PricewaterhouseCoopers, "The Australian Dairy Industry – the basics", 2011; prepared for The Australian Dairy Industry, available at http://www.pwc.com.au/industry/agribusiness/assets/australian-dairy-industry-nov11.pdf

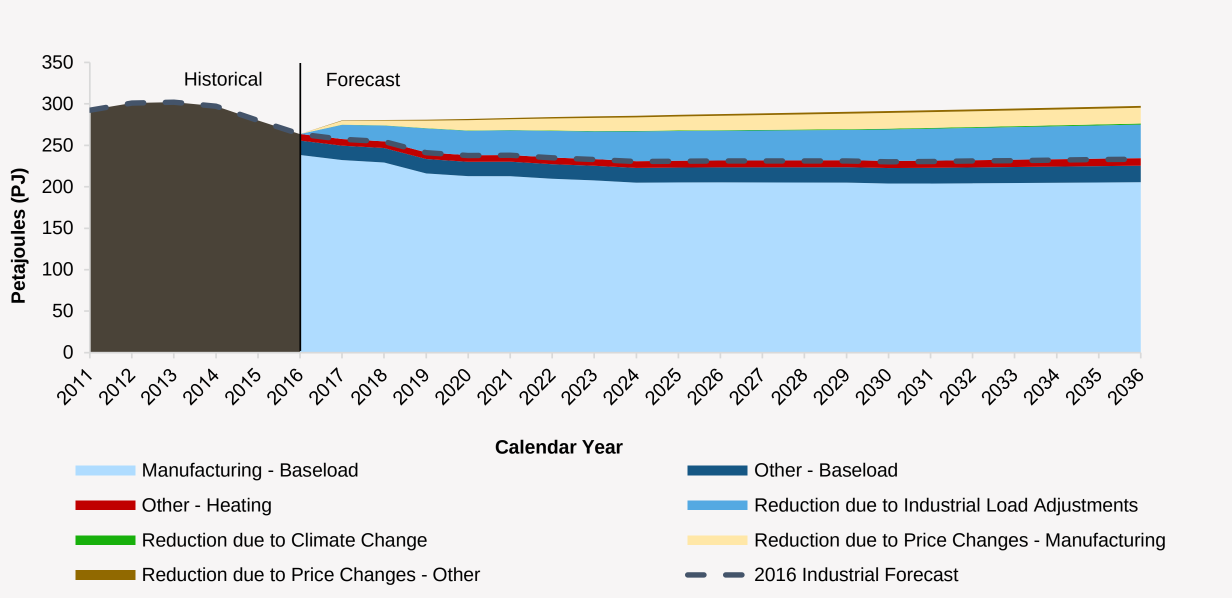
construction services), AEMO considers this ‘other’ group separately from manufacturing when modelling these sectors’ gas consumption.

The overall forecast for the long term (2022–36) is strong growth after the economy picks up, with population increases driving the majority of the growth in gas usage. However, as these sectors consume far less gas than manufacturing, their impact on overall gas usage is minimal.

After considering population growth and stabilisation in the manufacturing sector, AEMO does not see any other strong growth driver for industrial gas usage over the long term, with an almost flat forecast from 231 PJ to 233 PJ (0.1% average growth per year) in the period 2026–36.

The figure below shows the various drivers impacting the industrial forecast, highlighting the relative market shares of the different sectors that were considered in the NGFR 2016.

Figure 10 Illustration of impact on industrial sector forecast from different drivers



CHAPTER 4. RISKS AND UNCERTAINTIES

4.1 Scenarios

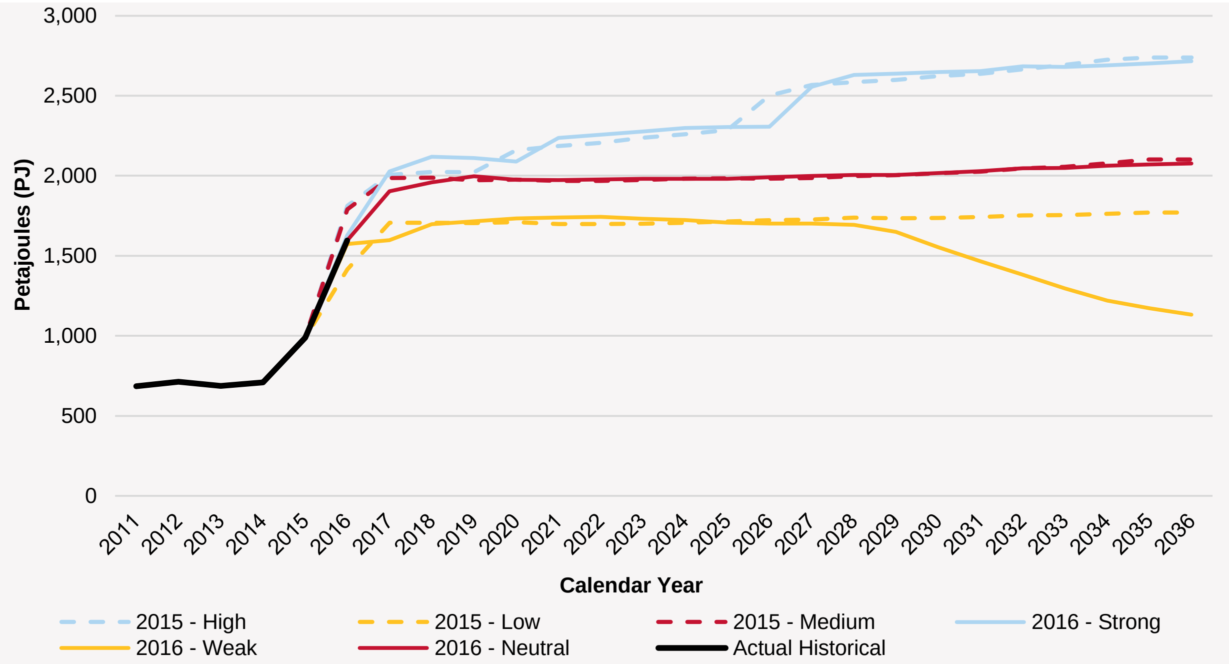
Key points

- While the Neutral scenario is considered most likely, the difference between the Weak and Strong scenarios shows a span that indicates large planning risks for decisions about policy, investment, and infrastructure planning. For context, in 2036 this span is 225% of total consumption in 2014 (the last year before LNG exports commenced).
- The modelled scenarios are designed to represent the most probable range of futures for Australia, and therefore do not capture all credible uncertainties. Once considered, these uncertainties could show an even larger span between forecasts than is reported in this NGFR. These uncertainties are discussed further in Section 4.2.

The gas sector in eastern and south-eastern Australia is facing significant risks and uncertainties over the next 20 years, and actual gas consumption may vary significantly from the Neutral scenario forecast presented in Chapter 2.

AEMO has used its Weak and Strong scenarios to explore the most probable range of outcomes. Figure 11 shows the span between Weak, Neutral and Strong forecasts over the 20-year outlook.

Figure 11 Scenario comparison – Weak, Neutral and Strong forecasts: All regions and sectors

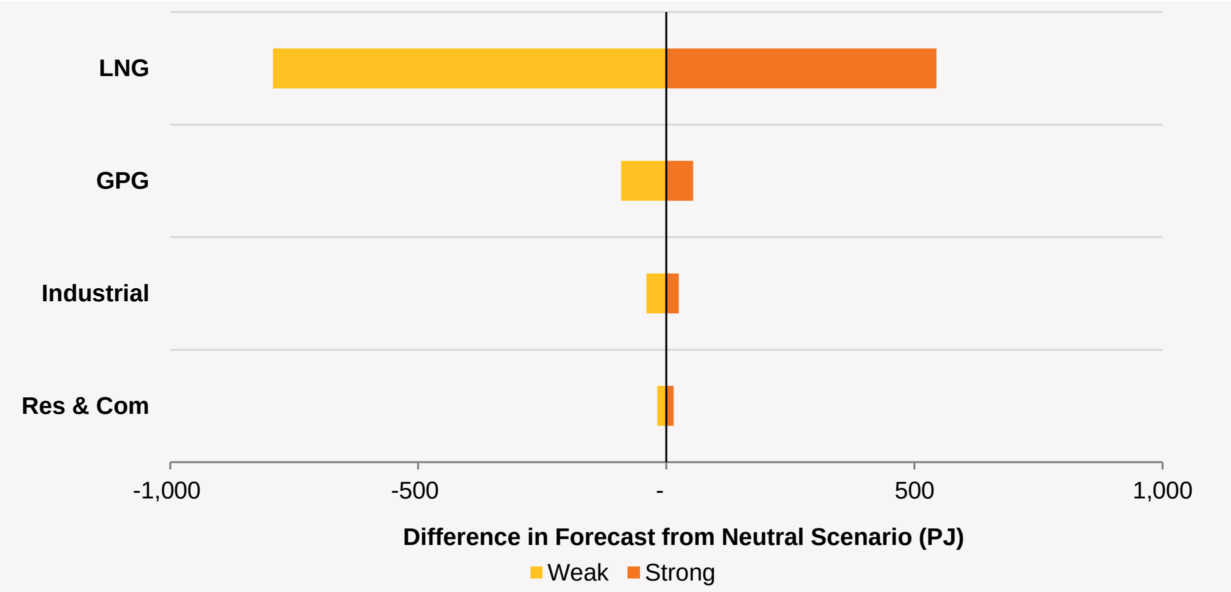


AEMO's Neutral, Weak, and Strong scenarios all provide credible future paths. While the Neutral scenario is considered most likely, uncertainties make it important to consider the range of projections in planning. The difference between Weak and Strong gas consumption projections is almost 1,600 PJ by 2036. This highlights the risks facing gas infrastructure planners. If, for instance, assumptions in the Weak scenario eventuate, there is a risk of stranded assets if they are developed considering the Neutral projections for gas consumption in isolation.

More than ever before, this means planning solutions will need to prioritise flexibility, innovation, and options to defer investment until some uncertainty is resolved.

Figure 12 shows the contribution to this span in 2036 from each major sector.

Figure 12 Forecast difference from the Neutral scenario (PJ in 2036, all regions)



Compared to the Neutral scenario:

- AEMO's modelling in the Strong scenario adds 639 PJ to annual gas consumption in 2036.
  - Much of this gas volume is attributable to the LNG sector.
  - The Strong scenario assumptions included high international LNG prices, a robust economy, and a confident consumer.
  - The Strong scenario projects more coal generation retirements, and LNG production from existing plants above nameplate capacity, with optimised operation of the liquefaction plants and the construction of a seventh LNG supply train from 2027.
- Forecasts for the Weak scenario in 2036 are 943 PJ lower. AEMO considers the Weak scenario more probable than the Strong scenario, a position informed by industry advice. The Weak scenario tests forecasts by assuming:
  - The closure of numerous energy-intensive businesses, causing large falls in projected gas and electricity use.
  - Weaker population and economic growth projections, flattening energy demand in general.
  - The challenging global gas market driving LNG production down from 2030, as CSG wells are not replaced and LNG exporters supply contracted gas from sources outside eastern and south-eastern Australia.

4.2 Catalogue of major uncertainties

Key points

- The future of gas in Australia, among rapid recent developments, is characterised by an unprecedented level of uncertainty. Factors include the increasingly complex interaction between the gas and electricity sectors, the changing relationship of energy demand and supply, increasing energy prices, a shift in competition dynamics, and linkages with the international gas market.

- In the short term, new gas supply for domestic gas consumption is likely to come from higher-cost reserves. This comes at a time where prices are now at new highs with limited supply-side competition potentially further impacting gas prices.
- Australia's gas and electricity sectors are more tightly linked than ever before. National and state emissions reduction targets are likely to influence the timing and magnitude of coal-fired generation retirements and expected investment in GPG to meet Australia's electricity needs in the short term. GPG growth is likely to also challenge supply and raise gas and electricity prices.
- The domestic role of gas is changing. Energy-intensive sectors that are trade-exposed face challenging business conditions, including rising energy prices compared to their global competitors.
- On the consumer market side, there are large drivers for fuel switching and energy efficiency along with new dwelling constructions that have no gas connectivity. Customers are also becoming more engaged with their energy usage and choices representing additional forecasting complexity to capture this shift.

AEMO has consulted broadly with this NGFR to identify and understand major uncertainties relevant to the 20-year outlook. These have been assessed with a major focus on those uncertainties that are credible and have a high potential impact on the gas industry, as illustrated in the table below.

Table 23 Ranking uncertainties by impact and credibility

	Low Impact	Medium Impact	High Impact
More credible			Focus
Medium			
Less credible			

Table 24 summarises the key uncertainties identified.

Overall, the outcomes of this assessment support the wide span of probable future gas consumption outcomes discussed in Section 4.1, but also highlight significant uncertainties that may cause the consumption to vary from the range spanned by the Strong, Neutral, and Weak scenarios.

There is a need for further analysis to complement the forecasts of this NGFR, which are intended to represent the most likely range of outcomes for eastern and south-eastern gas markets. The NGFR provides a base case against which further analysis should be managed, to better appreciate the full range of credible forecast futures that may be relevant to planning, policy-making, and strategic investment decision-making.

Table 24 Catalogue of major uncertainties (2016 to 2036)

Uncertainty	Description	Implication for NGFR
Emission reduction policies	Policy initiatives to deliver emission reduction targets are yet to be agreed. AEMO has assumed achievement of CO_2 emission reductions of 26–28% by 2030, relative to 2005. To model this assumption, a "proxy abatement cost" has been used to reflect possible impacts on the pricing mechanisms of industry.	AEMO assumptions have resulted in reductions in consumption as an outcome of the price effects of the "proxy abatement cost", and higher GPG as a result of assumed closure of some coal-fired power generation

Uncertainty	Description	Implication for NGFR
Technical end-of-life of coal-fired generation	Almost 10 GW of coal generation is at its technical end-of-life in the 2030s. In many cases it is possible to extend the life of these plants. Fixed retirement assumptions force the modelling to assume new investments in generation, rather than consider economic life extension. Any investment in plant life extension is highly dependent on emissions reduction policies and the certainty of these policies going forward.	Given high uncertainty in the 2030s, AEMO, in this NGFR, has assumed it is less expensive to extend the life of coal generators than to build new generation. This means the NGFR assumes less GPG than might eventuate during this period.
Gas supply adequacy and pricing	Summary analysis suggests gas supplies are close to the limit of available 2P reserves, analysis that will be investigated more closely in the 2017 GSOO. A tight supply-demand balance can cause price increases and raise questions of supply reliability.	The NGFR has assumed sufficient gas is available, at elevated prices. Given high variability in GPG, this assumption may be tested
Resilience of energy intensive businesses to business conditions	AEMO's surveys and interviews with large energy intensive businesses have found a large amount of demand is associated with operations with weak resilience to macro-economic shocks and increased energy prices. There is a high closure risk associated with this gas demand.	AEMO has included more business closures in the Weak scenario to capture this uncertainty.
Cost reductions of emerging technologies	This is more relevant for electricity demand that is a determinant of GPG. Current cost trajectories show wind generation plus storage becoming economic in the 2030s, and small-scale energy storage around 2020. These assumptions, along with assumptions for the cost of solar generation, have big implications for the economics of new fossil-fuel generation, and for the viability of existing thermal plant.	The robustness of the GPG forecasts become increasingly questionable beyond 2030.
International trends in gas supply	The international market for gas supply is currently in surplus, with this expected to continue into the 2020s. This has created low prices generally, and a separation between spot pricing and contract pricing in Asia. This outlook is not advantageous to the investment assumptions of Queensland's LNG projects.	The long-term operating assumptions of the LNG forecasts assume export contracts will be delivered in the Neutral scenario. This assumption is heavily reliant on the outlook for gas supply and pricing in the international market. The Weak scenario attempts to show the impact of sustained "weak" conditions for the LNG sector.

APPENDIX A. SCENARIOS SUMMARY

These Strong, Neutral, and Weak scenario assumptions were modelled in the 2016 NGFR and are now being used in all AEMO major reports.

Table 25 Detailed summary of modelling assumptions

Assumptions	Type	Weak	Neutral (most probable)	Strong
Economy	Variable	Weak	Neutral	Strong
Consumer	Variable	Low confidence, less engaged.	Average confidence and engagement.	High confidence, more engaged.
Population	Variable	Low (ABS)	Medium (ABS)	High (ABS)
Electricity network charge over 5 years	Fixed	Current AER determinations, fixed after 5 years.		
Gas network charge over 5 years	Fixed	Current AER determinations, fixed after 5 years.		
Electricity network charges – long run	Fixed	Constant real.		
Gas network charges – long run	Fixed	Constant real.		
Retail costs and margins	Fixed	Assume current margins throughout.		
Tariff structure	Fixed	Same as current.		
LREC/SRES	Fixed	Assume current to 2020, with LGCs/SSTC deemable to 2030.		
Weather	Fixed	Neutral weather assumption for consumption forecasts, probabilistic weather settings for peak demand.		
Rainfall- Hydro generation	Fixed	Median value for water availability (last 15 years).		
LNG growth	Fixed	Australian LNG export growth per oil price projections.		
Oil prices / gas prices	Variable	UD30/bbl (BR) with pricing affecting the industry as existing contracts expire.	UD60/bbl (BR) with pricing affecting the industry as existing contracts expire.	UD90/bbl (BR) with pricing affecting the industry as existing contracts expire.
Electricity wholesale prices	Variable	As per the supply-side impact of this scenario. Assumes some abatement cost affecting end-user prices.		
Electricity demand	Variable	Based on end-point consumption (behind the meter), translated back to the grid.		
Other policy and regulatory settings affecting electricity prices	Fixed	Status quo.		
Technology uptake	Variable	Hesitant consumer, weak economy.	Neutral consumer, neutral economy.	Confident consumer, strong economy.
Energy efficiency	Variable	Policy measures deliver lower uptake of EE.	Policy measures deliver medium uptake of EE.	Policy measures deliver high uptake of EE.
Technology cost and uptake curve	Variable	Technology cost and uptake curve assumptions for weak economy, low consumer confidence/engagement.	Median technology cost and uptake curve assumptions.	Technology cost and uptake curve assumptions for strong economy, high consumer confidence/ engagement.
Climate policy up to 2030	Fixed	Assume Australia's Paris commitment is achieved.		
Climate policy post 2030	Fixed	2030 status quo maintained to 2040, but including announced coal plant closures post 2030.		

Assumptions	Type	Weak	Neutral (most probable)	Strong
Climate policy impacts (energy prices)	Fixed	Scenario assumes most abatement cost hits the pricing mechanism of the industry. Proxy emissions abatement price of $25/tonne in 2020 rising to $50/tonne by 2030. Emissions Intensive Trade Exposed Industry pays only 20% of this cost in 2020, rising to 100% in 2030.	Scenario assumes most abatement cost hits the pricing mechanism of the industry. Proxy emissions abatement price of $25/tonne in 2020 rising to $50/tonne by 2030. Emissions Intensive Trade Exposed Industry pays only 20% of this cost in 2020, rising to 100% in 2030.	Scenario assumes most abatement cost hits the pricing mechanism of the industry. Proxy emissions abatement price of $25/tonne in 2020 rising to $50/tonne by 2030. Emissions Intensive Trade Exposed Industry pays only 20% of this cost in 2020, rising to 100% in 2030.
Climate policy impacts (plant shut downs and generation replacement)	Fixed	Fossil fuel plant shut-down list informs scenario, assumes 2030 targets are achieved. Announced shutdowns beyond 2030 assumed in scenario. Technology replacement options do not include coal and are least cost.		
Climate policy impacts (other)	Fixed	Energy efficiency initiatives consistent with National Energy Productivity Plan.		

KEY DEFINITIONS AND GLOSSARY

Key definitions

AEMO gas forecasts are reported as:

- **Annual gas consumption:**
  - Gas consumed over a calendar year by gas consumption region.[34]
  - Includes residential and commercial consumption, industrial consumption, gas-powered generation (GPG) consumption, and transmission and distribution losses (including other Unaccounted for Gas (UAFG)).
  - Measured by metering supply to the network rather than consumption at the point of use.
  - Gas used for liquefied natural gas (LNG) processing and exports is considered separately.
- **Maximum demand:**
  - The highest level of demand for gas at single point in time, and also refers to the highest level of daily demand occurring each year by gas consumption region.
  - Includes residential and commercial demand, industrial demand, and GPG demand as well as gas consumed or lost in transportation and delivery, such as the operational fuel of gas compressors and UAFG.
  - Gas used for LNG processing and exports is considered separately.

Consumption and demand forecasts are based on this sector breakdown:

- **Residential and commercial:** includes residential and small commercial users, typically referred to as “Tariff V” customers, which have an annual gas consumption of less than 10 terajoules (TJ) a year.
- **Industrial**: includes industrial and large commercial users, typically referred to as “Tariff D”, with a daily-read meter and an annual gas consumption of over 10 TJ/year. Recognising different drivers affecting forecasts, the industrial sector is further split into:
  - **LNG:** associated with the production of LNG for export.
  - **Manufacturing:** traditional manufacturing business sectors.
  - **Other business:** business customers not covered by the categories above, dominated by services businesses, such as education, health care, telecommunications, and finance services, and also includes transport and construction services. Food and beverage manufacturing is included in this group.

Other key definitions used in the 2016 NGFR are:

- **Probability of Exceedance (POE)**: the likelihood a maximum demand forecast will be met or exceeded. The 2016 NGFR provides both 1-in-20 POE maximum demand forecasts (expected to be exceeded, on average, only one in 20 years) and 1-in-2 POE forecasts (expected to be exceeded, on average, every second year).[35]
- **Unaccounted for Gas (UAFG)**: gas that is lost while being transported through distribution networks, that is, gas which is metered entering the network but is not consumed by end users. Typically, this gas is unaccounted for as a result of gas leaks or metering uncertainties.

[34] Regional definitions can be found in the 2016 *Gas Statement of Opportunities* for eastern and south-eastern Australia. Available at: http://www.aemo.com.au/-/media/Files/PDF/2016-Gas-Statement-of-Opportunities.pdf.

[35] These are also sometimes referred to as 5% POE and 50% POE forecasts respectively.

Glossary

Additional terms not covered in key definitions above.

Calendar

Term	Definition
1-in-2 peak day	The 1-in-2 peak day 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. Also known as the 50% peak day.
1 in 20 peak day	The 1-in-20 peak day 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. Also known as the 95% peak day.
1C contingent resources	Low estimate of contingent resources
2C contingent resources	Best estimate of contingent resources
3C contingent resources	High estimate of contingent resources
1P reserves	Estimated quantities of gas that are reasonably certain to be recoverable in future under existing economic and operating conditions. A low-side estimate also known as proved gas reserves.
2P reserves	The sum of proved-plus-probable estimates of gas reserves. The best estimate of commercially recoverable reserves. Often used as the basis for reports to share markets, gas contracts, and project economic justification.
3P reserves	The sum of proved, probable and possible estimates of gas reserves.
annual demand	Gas demand reported for a given year.
annual average growth rate	The averaged rate over a period of years at which gas demand, for example, increases or declines. Expressed as percent per year. Negative figures indicate a decline in demand.
basin	A geological formation that may contain coal, gas and oil.
beginning-of-day	The start of the wholesale gas market day (6:00 AM AEST).
Bulletin Board	See Gas Bulletin Board.
coal seam gas (CSG)	Gas found in coal seams that cannot be economically produced using conventional oil and gas industry techniques. See unconventional gas. Also referred to in other industry sources as coal seam methane (CSM) or coal bed methane (CBM).
cogeneration	Using gas to simultaneously generate electricity and steam or heat. See also trigeneration.
Coincident gas demand	Gas used by different consumers at the same time or on the same day which can lead to peak volumes being demanded on a given day. See peak day demand.
Combined-cycle gas turbine (CCGT)	A device utilising a gas turbine and heat recovery/steam generation to efficiently generate electricity. More capital intensive than open-cycle gas turbines and therefore expected to be highly utilised. See also open-cycle gas turbine.
Conventional gas	Gas that is produced using conventional or traditional oil and gas industry practices. See also unconventional gas.
Declared Transmission System	The gas Declared Transmission System (gas DTS) refers to aspects of the Victorian gas system that are a part of the declared network. According to the National Gas Law (NGL), the DTS of an adoptive jurisdiction has the meaning given by the application Act of that jurisdiction and includes any augmentation of the defined declared transmission system.
DTS-connected GPG	Gas powered generators that are directly supplied with gas from the Victorian gas Declared Transmission System. Gas powered generators in Victoria that are not supplied with gas directly from the DTS are not said to be DTS-connected.
demand area	A geographical sub-grouping within a demand group.
demand group	A geographical grouping of gas users that is used for reporting gas demand projections and modelling gas supply and demand
diversity of demand	The lack of coincidence of peak demand across several sources of demand, such as residential, industrial, and gas-fired generation.
domestic gas	Gas that is used within Australia for residences, businesses, power generators, etc. This excludes gas demand for LNG export
Gas Bulletin Board (GBB)	A website **(**www.gasbb.com.au**)** managed by AEMO that provides information on major interconnected gas processing facilities, gas transmission pipelines, gas storage facilities, and demand centres in Eastern and South Eastern Australia. Also known as the National Gas Market Bulletin Board or simply the Bulletin Board.

Term	Definition
gas powered generation (GPG)	Where electricity is generated from gas turbines (combined-cycle gas turbine (CCGT) or open-cycle gas turbine (OCGT)).
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.
lateral	A pipeline branch.
linepack	The pressurised volume of gas stored in the pipeline system. Linepack is essential for gas transportation through the pipeline network throughout each day, and is required as a buffer for within-day balancing.
large industrial	A segment of the Eastern and South Eastern gas market defined to include businesses that consume more than 10 TJ/yr. See also mass market.
liquefied natural gas (LNG)	Disconnection of electricity customer load. Natural gas that has been converted into liquid form for ease of storage or transport.
LNG train	A unit of gas purification and liquefaction facilities found in a liquefied natural gas plant.
mass market	A segment of the Eastern and South Eastern Australian gas market defined to include residential users and businesses that consume less than 10 TJ/yr. See also large industrial.
market segments	For purposes of developing gas demand projections, gas consumers are grouped into domestic market segments (the mass market, large industrial, and gas demand for GPG), and gas demand for LNG export.
National Electricity Law	The National Electricity Law set out in the schedule to the National Electricity (South Australia) Act 1996 (SA) and applied in each of the participating jurisdictions.
National Electricity Market	The wholesale market for electricity supply in Queensland, New South Wales, the Australian Capital Territory, Victoria, Tasmania, and South Australia.
National Electricity Rules	The National Electricity Rules govern the operation of the National Electricity Market. The Rules have the force of law, and are made under the National Electricity Law.
open-cycle gas turbine (OCGT)	A device utilising a gas turbine to generate electricity. Less efficient and less capital intensive than combined-cycle gas turbine (CCGT) and therefore often used only to satisfy peak electricity demand.
peak day	Over the course of a season (winter or summer), the day on which maximum gas demand occurs.
peak shaving	Meeting a demand peak using injections of vaporised liquefied natural gas (LNG).
petroleum-initially-in-place (PIIP)	A term used in the industry-standard Petroleum Resource Management System describing oil and gas within a gas reservoir that may or may not ever be recovered.
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	When used 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.
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.
proved-plus-probable	See 2P reserves.
R/P ratio (years)	A quantity, expressed in years, that is the ratio of remaining reserves divided by the current rate of production. A nearly depleted gas basin may have a low R/P ratio (e.g. 5 years) whereas a newly discovered or very large basin in the early years of its producing life may have a high R/P ratio (e.g. 20 years). Increasing the estimated reserves increases the R/P ratio, whereas increasing the production rate decreases the R/P ratio.
ramp-up gas	Coal seam gas produced during the early stages of an LNG export project.
recip. engine	A reciprocating engine in which gas may be used as a fuel on a relatively small scale to generate electricity.

Term	Definition
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.
reservoir	In geology, a naturally occurring storage area that traps and holds oil and/or gas.
reserves	Gas resources that are considered to be commercially recoverable and have been approved or justified for commercial development.
resources	See contingent resources and prospective resources.
scenario analysis	Identifying and projecting internally consistent political, economic, social, and technological trends into the future and exploring the implications.
security reserve	A quantity of LNG held by AEMO to ensure the DTS can be maintained in a secure state under emergency conditions. The current AEMO LNG security reserve is zero tonnes.
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.
shale gas	Gas found in shale layers that cannot be economically produced using conventional oil and gas industry techniques. See unconventional gas.
Short-Term Trading Market	The Short-Term Trading Market (STTM) is a market-based wholesale gas balancing mechanism established at defined gas hubs. The market uses bids, offers and forecasts to determine schedules for deliveries from pipelines to transmission users and the hubs.
tight gas	Gas found in tightly compacted sandstone that cannot be economically produced using conventional oil and gas industry techniques. See unconventional gas.
trigeneration	Using gas to simultaneously generate electricity, heat, and cooling. See also cogeneration.
Upstream gas price	Refers to the delivered wholesale gas price.
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.
within-day balancing	The balancing of supply and demand during the gas day by use of scheduled injections and depletion of system linepack. Liquefied natural gas (LNG) is used as an additional supply if linepack is predicted to fall below the minimum level required for system security.