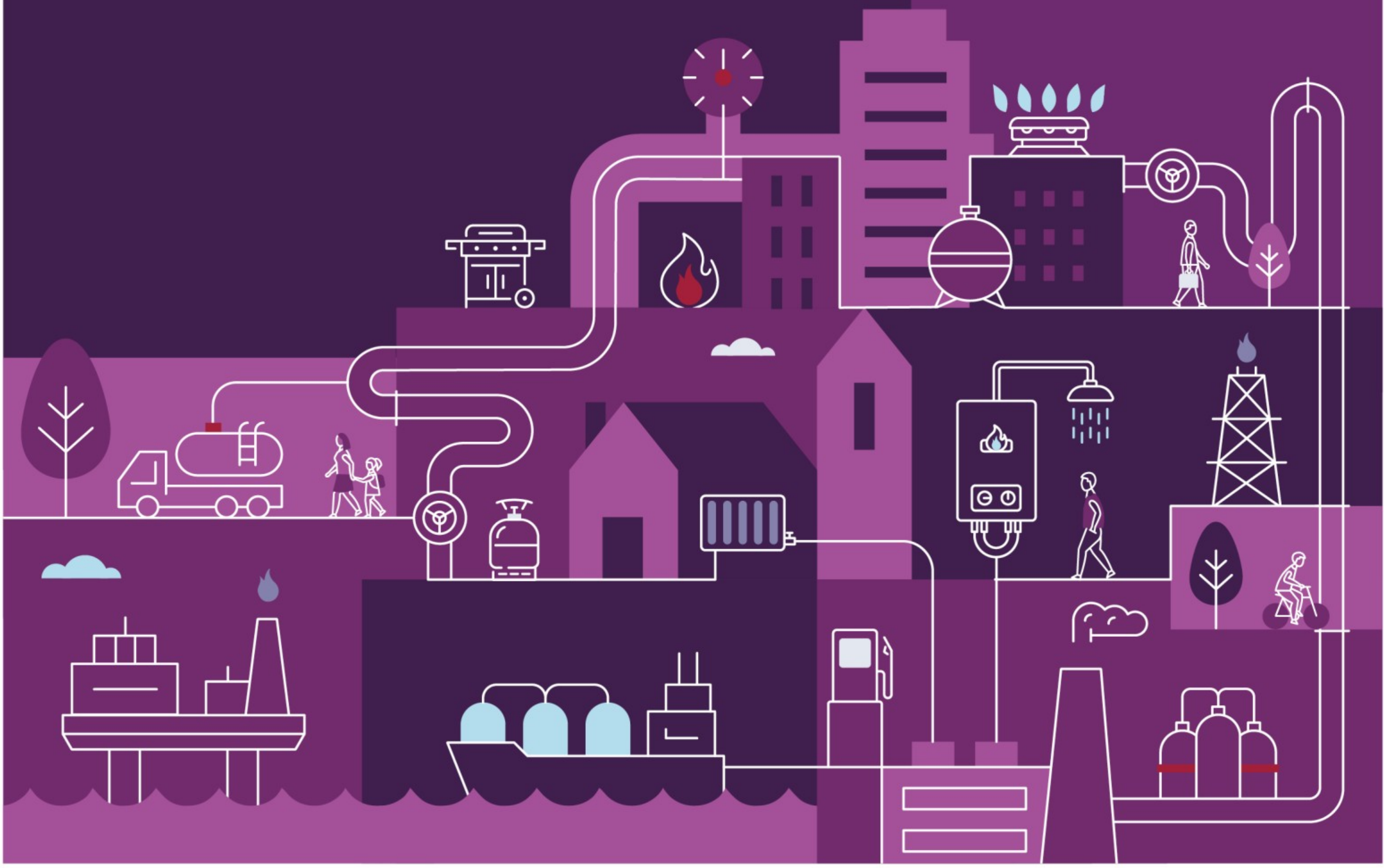
Gas Demand Forecasting Methodology Information Paper

March 2026

For the 2026 Gas Statement of Opportunities covering Australia's East Coast Gas Market



We acknowledge the Traditional Custodians of the land, seas and waters across Australia. We honour the wisdom of Aboriginal and Torres Strait Islander Elders past and present and embrace future generations.

We acknowledge that, wherever we work, we do so on Aboriginal and Torres Strait Islander lands. We pay respect to the world's oldest continuing culture and First Nations peoples' deep and continuing connection to Country; and hope that our work can benefit both people and Country.

'Journey of unity: AEMO's Reconciliation Path' by Lani Balzan

AEMO Group is proud to have launched its first Reconciliation Action Plan in May 2024. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate our ongoing journey towards reconciliation – a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

Important notice

Purpose

AEMO has prepared this document to provide information about the methodology and assumptions used to produce gas demand forecasts for the 2026 Gas Statement of Opportunities under the National Gas Law and Part 15D of the National Gas Rules.

This document describes the methodologies deployed for forecasting the expected gas consumption within the Australian jurisdictions other than Western Australia. Although AEMO deploys broadly similar methodologies to forecast gas consumption for the Western Australian Gas Statement of Opportunities, these may differ from the methodologies described in this document.

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1 Introduction

The *Gas Statement of Opportunities* (GSOO) incorporates regional gas consumption and maximum daily demand forecasts for the East Coast Gas Market (ECGM) covering all Australian jurisdictions other than Western Australia[1].

These forecasts represent demand to be met from covered gas supplied through the natural gas transmission system in the modelled area and are the sum of component forecasts, each having a distinct forecasting methodology. The components (defined in the Glossary) are:

- liquefied natural gas (LNG) (**Section 2**),
- gas-powered generation (GPG) (**Section 3**),
- industrial and large commercial (**Section 4**),
- residential and small commercial (**Section 5**), and
- network losses and other unaccounted for gas (UAFG) (**Appendix A3**).

For annual consumption, each of these component forecasts was modelled separately, then summed at the regional level.

Maximum daily demand forecasts provide an annual projection of maximum daily demand for each region. The maximum daily demand methodology used an integrated modelling approach that forecasts the component models jointly to produce a forecast of maximum coincident daily demand (see **Section 6**).

Accounting for uncertainty in input drivers

The GSOO uses scenarios to explore the impact of different drivers of consumption and maximum daily demand, from economic growth to energy efficiency investments and other economic and technological developments. Specific detail on scenarios used in the 2026 GSOO is available in the GSOO report, available on AEMO's website[2].

Probabilistic modelling is used in the maximum daily demand forecast to reflect outcomes based on weather. This results in distribution of forecast outcomes. Two values of this distribution are presented for use in the GSOO:

- the 50% probability of exceedance (POE) forecast (the forecast value that on average will be exceeded one in two years), and
- the 5% POE forecast, which on average will be exceeded only one in 20 years.

[1] This document describes the methodologies deployed for forecasting the expected gas consumption within the Australian states and territories other than Western Australia. AEMO deploys broadly similar methodologies to forecast gas consumption for the Western Australian *Gas Statement of Opportunities*, though these may differ slightly from the methodologies described here.

[2] At https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

2 Liquefied natural gas (LNG) consumption

Three LNG export facilities[3] are located on Curtis Island in Queensland, being APLNG, GLNG and QCLNG. The annual consumption forecasts for this demand sector included:

- all gas that the three LNG projects plan to export from Curtis Island to meet international LNG demand, plus
- all the gas consumed in producing, transporting and compressing these export quantities, plus
- pipeline transportation losses directly related to transporting gas from production centres to Curtis Island.

LNG consumption forecasts were developed using a combination of LNG consortia survey responses and stakeholder feedback.

In preparing the 2026 GSOO, AEMO engaged directly with the east coast LNG consortia to obtain their best estimates of their forecast gas consumption to produce LNG for export. The forecasts were provided covering a high outlook, an expected outlook and a minimum contract level, projected ahead to 2035. AEMO then developed forecasts to the end of the GSOO forecasting horizon, consistent with the scenario narratives in the 2025 *Inputs, Assumptions and Scenarios Report* (IASR)[4] and aligned to corresponding International Energy Agency (IEA) forecasts, as found in the 2025 World Energy Outlook[5]. Prior to finalising AEMO's LNG consumption forecasts, AEMO engaged with stakeholders including AEMO's Forecasting Reference Group[6] in November 2025 to provide feedback on these forecasts. The application of these assumptions is shown in **Table 1**.

Table 1 Assumptions for LNG export in each scenario

	IASR Scenario		
	Slower Growth	***Step Change***	***Accelerated Transition***
WEO scenario	Current Policies Scenario (CPS)	Stated Policies Scenario (STEPS)	Net Zero Emissions (NZE)
Assumption for long-term exports	Exports constant from 2035	Extrapolates for expected decline in expected east coast exports compared to WEO Asia Pacific demand. This was then fit to an orderly shutdown of terminals.	Adjusted to account for participant data and declines to achieve net zero
Applied assumptions	Exports constant from 2035	Linear decline in the number of LNG trains and terminals to one facility in 2050[A]	Linear decline in the number of LNG trains and terminals to zero LNG facilities in 2055[A]

A. While the applied assumptions extend beyond the outlook period, the outlook period and forecast for this GSOO concludes in 2045.

[3] Under the National Gas Rules (NGR), Northern Territory LNG facility operators and field owners are exempt from participation in the GSOO survey and therefore were not included in the GSOO.

[4] See https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/2025-26-inputs-assumptions-and-scenarios.

[5] See https://www.iea.org/reports/world-energy-outlook-2025.

[6] See https://aemo.com.au/en/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/forecasting-reference-group-frg.

3 Gas consumption for electricity generation

This section describes the key assumptions AEMO used to forecast gas consumption as the fuel required for GPG (sometimes referred to as gas generation) to supply electricity to the National Electricity Market (NEM)[7].

AEMO performed electricity market modelling techniques for the NEM consistent with the Draft 2026 *Integrated System Plan* (ISP)[8] to forecast GPG consumption and demand for the 2026 GSOO.

The GPG projections for the NEM in the 2026 GSOO used the electricity transmission developments and generation capacity outlook as determined by the capacity expansion model in the Draft 2026 ISP optimal development path (ODP) with the following modifications:

- Information for committed generation projects was updated based on the NEM October 2025 Generation Information update[9] and updated gas price forecasts were used consistent with the gas prices used in forecasting the other demand sectors in the 2026 GSOO[10].
- Consistent with the *ESOO and Reliability Forecast Methodology Document*[11], committed projects were delayed six months, anticipated projects were delayed 12 months, and both committed and anticipated projects also had hold point commissioning (progressive increases to the maximum power rating of new projects) applied, consistent with delays observed.
- Specific coal closure dates have been applied when one has been provided by the power station operators, and post-winter closure timing (1 September) for generators when the coal closure date is not yet specified (but identified as either a closure year, or forecast to close ahead of the formal closure year in the Draft 2026 ISP).

With these changes to key inputs, the GSOO built directly on the time-sequential model and methodology used in the Draft 2026 ISP. Further detail on this time-sequential modelling methodology is available in the *ISP Methodology*[12].

For some sensitivity analysis in the GSOO, the GPG consumption forecasts included the impact of unexpected events that can impact the NEM generation mix. In practice, these events can include power station outages, coal supply chain disruptions, or even major environmental interruptions such as bushfires and flooding. Rather than try to predict these specific events, AEMO approximated these events by assuming a reduction in the availability of coal-fired generators, and the potential for new generation and storage developments to be delayed during construction and commissioning.

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[7] This included the vast majority of GPG in the eastern and south-eastern gas markets. Any GPG outside this, such as in Mount Isa, was captured as Industrial (Tariff D) demand. Industrial forecasts included facilities such as Yarwun GPG in Gladstone, Queensland, which supplies electricity to the Yarwun Alumina Refinery.

[8] At https://www.aemo.com.au/consultations/current-and-closed-consultations/draft-2026-isp-consultation.

[9] At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[10] ACIL Allen, 2025 Natural gas price forecast report, at https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2026/2026-acil-allen-2025-projections

[11] At https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2025/esoo-and-reliability-forecast-methodology.pdf.

[12] At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2026-isp-methodology/isp-methodology-june-2025.pdf.

4 Industrial and large commercial (Tariff D) consumption

This section outlines the methodology used to develop annual gas consumption forecasts for large commercial and industrial customers. Also known as Tariff D consumption, it is defined as consumption by network customers who are billed on a demand basis[13]. These consumers typically consume more than 10 terajoules (TJ) per year.

AEMO defined two categories of industrial customer for analysis purposes:

- Large industrial loads (LILs) consume more than 500 TJ annually at an individual site. Typically, this includes aluminium and steel producers, glass plants, paper and chemical producers, oil refineries and GPG that are not included in GPG forecasts as described in Section 3[14].
- Small to medium industrial loads (SMILs) consume more than 10 TJ but less than 500 TJ annually at an individual site. These sites include food manufacturing, casinos, shopping centres, hospitals, sporting arenas, universities, and large commercial users.

4.1 Data sources

The industrial sector modelling relied on a combination of sources for input data, shown in **Table 2**. For more details and source references, please see Appendix A4.

Table 2 Historical and forecast input data sources for industrial modelling

Data series	Source 1	Source 2	Source 3	Source 4
Historical consumption by region	AEMO databases	CGI	Distribution and industrial surveys	Gas Bulletin Board (GBB)
Weather	Bureau of Meteorology (BoM)			
Economic data	Economic consultancy			
Wholesale gas prices	ACIL Allen			
Retail gas prices	ACIL Allen (Wholesale gas prices)	Various gas retailers and distributors	Australian Energy Regulator (AER)	AEMO databases
Energy Efficiency	Strategy.Policy.Research (SPR)			
Electrification and dedicated hydrogen	CSIRO			

4.2 Forecast Tariff D annual consumption methodology

The energy-intensive industrial sector was split between LILs and SMILs because of differences in the underlying drivers for their energy consumption. This used a combination of survey and economic modelling approaches:

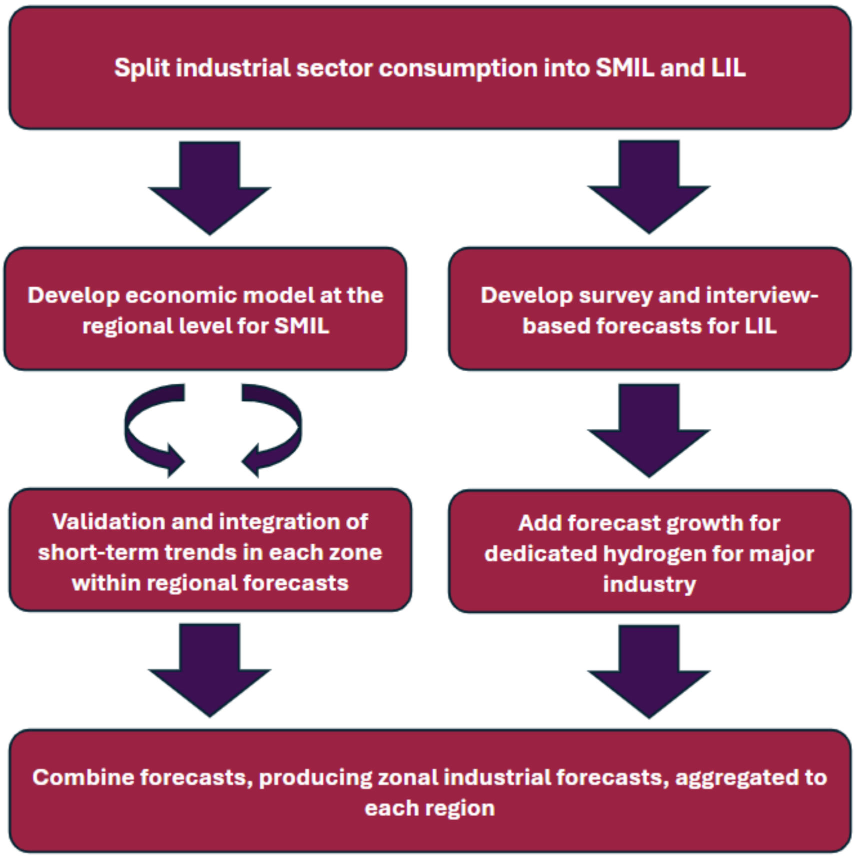
[13] Customers are charged based on their Maximum Hourly Quantity (MHQ), measured in gigajoules (GJ) per hour.

[14] This includes GPG which is not connected to the NEM and large co-generation.

- SMIL used economic modelling.
- LIL used survey and interview-based forecasts.

Figure 1 highlights the modelling process, from disaggregating the industrial consumption for each region, to modelling the two components separately before combining to produce the total forecast for each region. For the 2026 GSOO, AEMO applied the outcomes of multi-sectoral modelling related to electrification and included all covered gases.

Figure 1 Tariff D consumption forecasting method



4.2.1 Develop economic model and forecast for the small to medium industrial load sector

The SMIL sector accounted for a quarter of Tariff D consumption across the ECGM in 2025, and was forecast using a regional long-term causal model, blended with a short-term time series of historical trends. Conceptually the SMIL modelling process can be described by the following equation:

$$\text{Forecast} = f(\text{weather seasonality, trend, causal factor(s), unexplained variance})$$

Applying broad forecasting principles[15], this equation captures the key elements in the forecasting method:

- The short-term time-series analysis examined how historical time-series data is impacted by trends and weather-related seasonal patterns, along with testing additional factors such as historical weather and possible structural break variables.

[15] AEMO adapted principles from two sources – Demand Driven Forecasting: A Structured Approach to Forecasting, 2nd Ed. Chase, C.W. Wiley Publishing (2019), and Forecasting Principles and Practice, Hyndman RJ & Athanasopoulos G. Monash University (2020), at https://otexts.com/fpp2/.

- The long-term (causal) model captured features that are determined by the scenario definition.
- A weighted average of the short- and long-term model outputs produced the regional consumption forecasts.

To forecast gas consumption and apply to AEMO's gas adequacy models for the GSOO, AEMO disaggregated regional forecasting to a sub-regional level, at the GSOO zone granularity defined in **Table 3**.

Table 3 GSOO zone breakdown used for sub-regional analysis

Region	GSOO zone	Description*
NSW	ACT	Nodal point for the Australian Capital Territory
NSW	EGP	Nodal point on the Eastern Gas Pipeline
NSW	MSP	Nodal point on the Moomba to Sydney Pipeline
NSW	SYD	Nodal point for the Sydney region
NT	AGP	Nodal point for the Amadeus Gas Pipeline
QLD	QGP	Nodal point on the Queensland Gas Pipeline
QLD	RBP	Nodal point on the Roma to Brisbane Pipeline
SA	ADL	Nodal point for Adelaide
SA	MAP	Nodal point on the Moomba to Adelaide Pipeline
SA	SEA	Nodal point on the Southeast Australia Gas Pipeline
TAS	TGP	Nodal point on the Tasmanian Gas Pipeline (all of Tasmania)
VIC	BROOKLYN	Nodal point for Brooklyn
VIC	MELBOURNE	Nodal point for Melbourne
VIC	PAKENHAM	Nodal point for Pakenham
VIC	PORT CAMPBELL	Nodal point for Port Campbell
VIC	WOLLERT	Nodal point for Wollert

* Nodal points from where gas leaves the transmission network. Refer to Figure 3 in *the Gas Supply Adequacy Methodology* for the nodal network topology, located at https://aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo.

Short-term (trend) model

AEMO analysed historical monthly time-series data to examine the sub-regional trends at each GSOO zone, producing a short-term trend model. These sub-regional trends may not always align with the regional trend, as the number, types and size of industry within each GSOO zone are not homogenous across a region. Statistical features such as standard deviation – a measure of unexplained variance – and averages were then examined and included in a sub-regional trend-based model, assuming the values are normally distributed. These time-series methods are suitable for short-term forecasting as they capture recent trends and facilitate closer alignment with the latest consumption data. They were also used to model dispersion around the *Step Change* scenario.

Long-term (causal) model

The volume of gas consumption required to achieve forecast growth in economic activity formed the basis of the long-term (causal) consumption forecast. The most relevant economic indicator (presented in **Table 4Table 4**) for each region was selected through both analysing the indicator's correlation with historical consumption and considering the key economic drivers for each region.

Table 4 Region-specific SMIL economic indicators

Region	Economic indicator
Victoria	Gross Value Added (GVA) Manufacturing
New South Wales	GVA Manufacturing
Queensland	Gross State Product (GSP)
South Australia	GSP
Tasmania	State Final Demand
Northern Territory	GSP

AEMO engaged a suitably-qualified external consultant to forecast key economic parameters for each scenario. These forecasts were produced at the regional level using coefficients estimated from a linear regression model, subject to projected energy intensity improvements over time.

Further adjustments were made to the consumption forecast to capture:

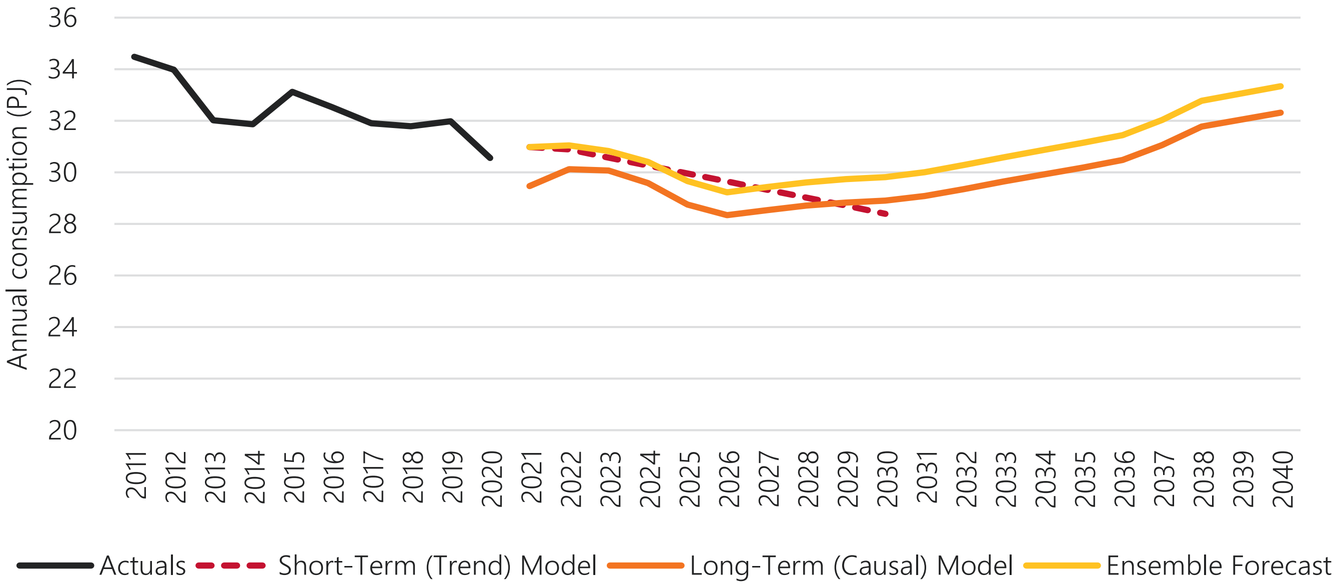
- the impact of expected price changes via modelling the response of consumers to both price increases and reductions, with the following price elasticities[16] applied:
  - -0.05 in the *Accelerated Transition* scenario,
  - -0.10 in the *Step Change* scenario, and
  - -0.15 in the *Slower Growth* scenario, and
- possible improvements in energy efficiency from state or federal schemes or programs targeting the industrial sector.

Blending of the short-term (trend) and long-term (causal) forecasts

Finally, SMIL forecasts were constructed as a weighted average of the short-term and long-term forecasts. In the first year of the forecast period, the short-term forecast was assigned an 80% weighting. This value decreased to 60% in the second year and 40% in the third. By the fifth year, the forecast was driven entirely by the long-term (causal) model. An example of this blending is shown in **Figure 2**.

[16] Note that negative price elasticity coefficients reflect a pricing model that predicts increased consumption when prices fall and conversely reduced consumption when prices increase.

Figure 2 Example of small to medium industrial load long-term (causal) model contrasted with the short-term trend model to demonstrate the resulting blended model forecast



4.2.2 Develop survey-based forecast for large industrial loads

AEMO conducted a survey and interview process with large industrial users[17] to derive the LIL regional forecasts. The survey process followed five key steps as shown:

Identify large industrial users

LILs are identified and monitored using:

- AEMO records of historical LIL gas consumption and analysis of prospective projects that may evolve to become LILs – the records include distribution and transmission connected loads and the LIL list is updated annually,
- distribution surveys, being requests from gas distribution businesses relating to existing (consuming more than 10 TJ annually), and prospective loads,
- participant information on the Gas Bulletin Board (GBB), and
- media and site-specific research.

Collect and analyse recent actual consumption data

Recent actual consumption data was analysed for each LIL site for two key reasons:

[17] Generally defined as industrial facilities that consumed more than 500 TJ per annum at least once over the previous four years, however in some cases facilities with lower consumption were also surveyed, such as where one organisation owned several facilities in the same state that in aggregate consumed more than 500 TJ per annum.

1. to understand latest trends at the site level, and
2. to prioritise the LILs for interviews (detailed in the next section).

Request survey responses and conduct interviews

Step 1: Initial survey

AEMO sent out surveys to all identified LILs requesting historical and forecast gas consumption information by site. The core economic drivers for each of the three scenarios were provided to survey recipients to ensure forecasts are internally consistent with other components.

The surveys consisted of two parts – the survey forecast and the survey questionnaire:

- The surveys requested annual gas consumption for three scenarios.
- The survey questionnaire asked for general influences on future gas consumption, such as contract lengths, the influence of the gas price, and any decarbonisation plans that affect future gas usage, such as hydrogen and alternative gases, or electrification.

For a more detailed overview of the components behind AEMO's planning and forecasting scenarios, see AEMO's website[18].

Step 2: Detailed interviews

Following the survey, AEMO interviewed some LILs to discuss their responses. This typically included discussions about:

- key gas consumption business drivers, such as exchange rates, commodity pricing, availability of feedstock, current and potential plant capacity, mine life, maintenance shutdowns, and cogeneration,
- currently contracted gas prices and contract expiry dates,
- impact of decarbonisation policies (for example, renewable energy, electrification) on future gas demand,
- gas prices, the LIL's forecast of their gas consumption over the medium and long term (per scenario), and possible impacts on profitability and operations,
- potential drivers of major changes in gas consumption (for example, expansion, closure, cogeneration, fuel substitution) including "break-even" gas pricing[19] and timing, and
- different assumptions between the scenarios.

Interviews of LILs were prioritised based on the following criteria and analysis of actual consumption:

- volume of load,
- clarification of observed variations in gas consumption, and
- to clarify responses to the GSOO LIL survey.

[18] AEMO, Planning and Forecasting inputs, assumptions and methodologies, at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[19] This is the point of balance between profit and loss.

Finalise forecasts

The site-based survey forecasts for each scenario were finalised based on interview discussion[20]. All the survey forecasts were aggregated to regional level.

4.2.3 Apply adjustments for electrification and dedicated hydrogen

AEMO applied outcomes from the multi-sectoral modelling to the Tariff D forecasts related to electrification.

Electrification

The multi-sectoral modelling projected increases in electricity demand from electrification. The following steps outline the method to derive the reduction in industrial gas consumption from electrification:

1. Review estimates of electrification from the GSOO survey of large industrial gas consumers.
2. Integrate gas usage and insights from multi-sectoral modelling undertaken by CSIRO, identifying those industries with the potential to electrify. Generally, the lower the temperature of a process, the easier it is to electrify.
3. Split the electrification adjustment between the remaining LILs and SMILs based on the ratio of actual consumption in 2025.
4. Calculate the SMIL share of electrification for each GSOO zone based on the ratio of forecast consumption.
5. Calculate the LIL share of electrification across GSOO zones based on the location of the LILs.

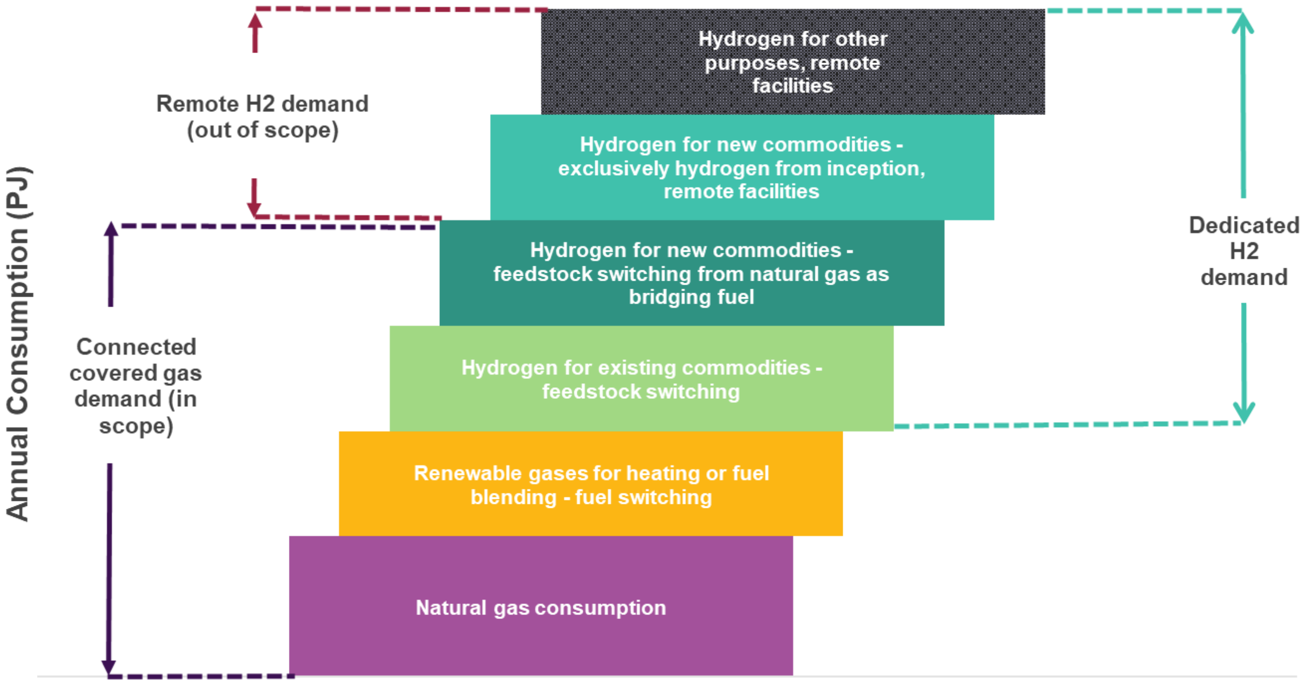
Dedicated hydrogen

Consistent with the National Gas Law, natural gas, hydrogen, biomethane, synthetic methane, and a blend of these gases are collectively defined as *covered gas*. A subset of *covered gas* demand is classified as *dedicated hydrogen*, which is *covered gas* demand that must be met by hydrogen (for example, as feedstock for green commodities, or as a fuel-switching substitute for natural gas in industrial processes such as iron production). As *dedicated hydrogen* demand cannot be met by other covered gases, a specific forecast for this demand type was included in the GSOO's assessment.

Figure 3 provides a schematic of treatment of natural gas, biomethane, and hydrogen demand.

[20] This may include override of initial survey results on the basis of AEMO's discussion with the industrial user.

Figure 3 Treatment of natural gas, biomethane, and hydrogen in the GSOO



Accordingly, consumption forecasts for LILs included all covered gases identified through the survey process described in Section 4.2.2, including where *dedicated hydrogen* demand was identified.

Hydrogen used in 'remote facilities'[21] was excluded from the GSOO forecast.

Sectors designated as 'remote' for the purpose of the GSOO hydrogen forecast are:

- exports as an energy carrier,
- transport,
- industrial facilities with no connection to the gas network, and
- selected green commodities, as outlined in **Table 5**.

Table 5 Assumed gas network connection status for green commodities

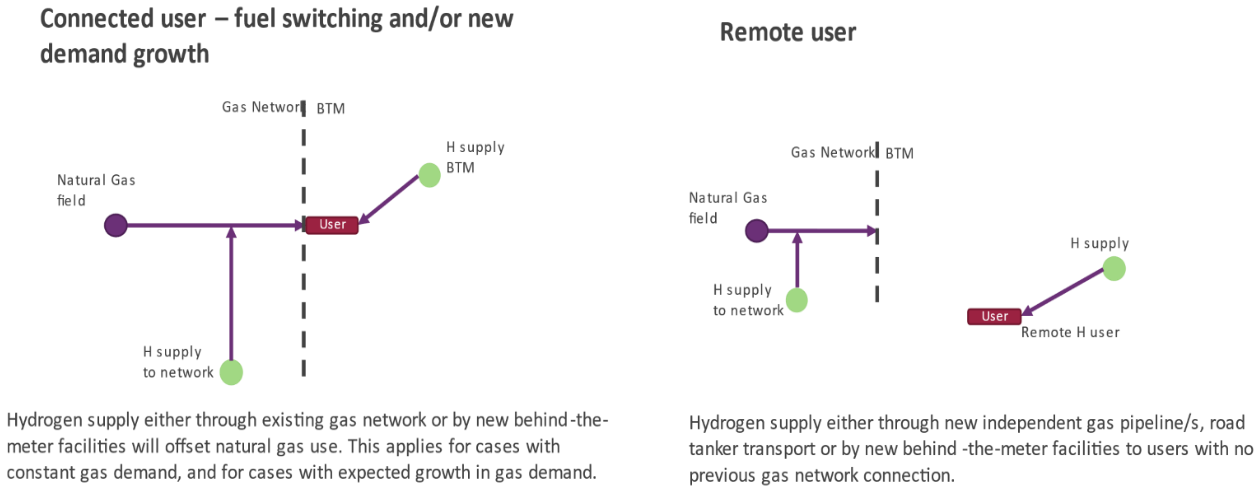
Commodity	Existing facilities, all regions	New facilities, non-Northern Territory regions	New facilities, Northen Territory region
Iron	Connected	Connected	Remote
Ammonia	Connected	Remote	Remote
Alumina	Connected	Connected	Remote
Methanol	N/A	Remote	Remote

The methodology recognises that if a project is expected to be connected to the gas network, irrespective of whether future supply may be provided through other means, then the project will remain classified as a connected user. As such, as outlined in **Table 5** above, the methodology classifies existing connected projects as connected users and assumes that some new commodities may start either as connected or remote users. The GSOO does not assume that an existing

[21] 'Remote BB facilities' as defined in Part 18 of the National Gas Rules.

connection is disconnected but may adjust that classification (and therefore inclusion of the facility's demand) if new connection information is provided for the assessment. **Figure 4** below demonstrates the connection arrangements that may apply for either user type.

Figure 4 Illustration and examples of 'remote' facilities used in GSOO hydrogen forecast assumptions



BTM: behind the meter. H: hydrogen.

4.2.4 Aggregate all sector forecasts to get total industrial (Tariff D) forecasts

The resultant industrial forecast combined the separately derived SMIL and LIL forecasts, as the following infographic details:

Climate change adjustment factors with temperature changes in consumption were not included in the Tariff D forecast due to the low weather sensitivity of industrial usage of gas when examined in regression analysis.

5 Residential and small commercial (Tariff V) consumption

This section outlines the methodology used to prepare residential and small commercial consumption. Also known as Tariff V consumption, it is defined as consumption by network customers who are billed on a volume basis. These consumers typically use less than 10 TJ/year.

Changes in Tariff V residential and commercial consumption can be attributed to several key drivers including electrification, weather, gas price, energy efficiency, and growth in gas connections. AEMO applied electrification projections from the 2024 multi-sectoral modelling[22].

AEMO's Tariff V consumption modelling used additive models to account for the impact of several key factors in developing forecasts for the networks of Victoria, South Australia, New South Wales, the Australian Capital Territory, Queensland and Tasmania. In the Northern Territory, Tariff V gas usage accounts for less than 1% of the region's gas consumption[23] and a simplified forecasting model was adopted for the region.

5.1 Forecast number of connections

Total Tariff V gas connections were split into their residential and non-residential components using survey data collected from all gas distributors in each region and forecasted separately. These projections were then adjusted to incorporate the impact of electrification on gas consumption.

Connections before the impact of electrification

Residential connections forecasts were determined by:

- Forecasting the total number of dwellings for each state.
  - To obtain the number of existing dwellings for each state, AEMO used Australian Bureau of Statistics (ABS) housing census data. To forecast the future number of dwellings, future dwelling completions were forecast by AEMO's economic consultant. The number of new dwellings is driven by demographic and social factors like household projections, which is determined by population projections and changes to household density.
- Forecasting the number of gas connections (Meter Installation Registration Numbers [MIRNs]).
  - Inspecting the long-term (5+ year) trends in MIRNs usually shows stable year-on-year growth, but as the ratio of dwellings to those with gas connections could differ, any relationship between the growth rates of dwellings and MIRNs was examined to ensure the model captures any change over time.
  - A trend was used for the first five years of MIRN growth, with growth driven completely by trend for the first year then progressively blended out over years two to five (with the standard deviation of previous year-on-year growth

[22] See CSIRO, Multi-sectoral Modelling 2024, at https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/csiro-2024-multi-sectoral-modelling-report.pdf.

[23] Darwin lacks a gas reticulation system, while Alice Springs is the only major city in the Northern Territory with reticulated gas.

used to moderate the low and high connections forecast). This trend forecast was blended into a projection linking dwelling annual growth rates to the proportion of MIRNs to dwellings to calculate annual MIRN growth applied to the long-term forecasts. The process for combining the two methods was a weighted average. For the first year of the forecast, 100% of the MIRN trend was used, dropping to 80% in year two, 60% in year three through to 0% by year six.

The growth rate for non-residential connections forecasts was determined by applying a trend to non-residential connections over the short term.

Adjustment of connections forecasts for electrification

For the 2026 GSOO, AEMO applied an electrification adjustment from the multi-sectoral modelling to the residential and non-residential connections forecasts. This adjustment represents a transition to electric-only new buildings and a switch from gas to electric heating, hot water, and cooking in existing buildings. In other words, the adjusted connections depicted an outcome in which each connection can either continue to consume gas at the average per connection level or not at all[24]. The steps taken included:

- calculating the average per connection Tariff V residential and non-residential consumption, based on meter data for the most recent complete calendar year,
- converting the electrification adjustment in PJ for each scenario to the equivalent number of connections, using the average per connection estimate from the previous step,
- like how the economic and short-term trends were modelled for the Tariff D econometric model, adjusting the electrification data in the early years to better reflect current electrification trends – for all scenarios, AEMO applied the following electrification adjustments:
  - a 50% discount on electrification in the base and first years of the forecast,
  - a 40 % discount on electrification in year 2 of the forecast,
  - a 30 % discount on electrification in year 3 of the forecast,
  - a 20 % discount on electrification in year 4 of the forecast,
  - a 10 % discount on electrification in year 5 of the forecast,
  - a 5 % discount on electrification in year 6 of the forecast, and
  - no discounts from year 7 of the forecast onwards, and
- removing the number of connections deemed to have fuel-switched from the unadjusted connections forecasts.

The adjusted connections forecasts were then used to grow Tariff V consumption, as described in the following section.

[24] AEMO refers to these adjusted connections as “effective connections”, which are modelling artefacts and should not be interpreted as AEMO’s forecasts of physical or active gas connections.

5.2 Forecast Tariff V annual consumption methodology

5.2.1 Overview of the methodology

The methodology described in this section relates to all regions, and involved the following steps:

- The average per connection Tariff V residential and non-residential consumption – made up of base load and heating load components – was estimated. Heating load projections were based on annual effective degree days (EDD) for Victoria and heating degree days (HDD) for New South Wales, Queensland, South Australia and Tasmania, under 'standard' weather conditions.
- The forecast then considered the impact of modelled consumption drivers including connections growth adjusted for electrification, energy efficiency savings, climate change impact, and short run behavioural response to retail prices.

Data sources for the Tariff V forecast are listed in Appendix A4.

5.2.2 Methodology detail

As outlined in Appendix A4, historical Tariff V residential and non-residential annual consumption was provided by AEMO's internal database and gas distributors in stakeholder surveys. This data was used to estimate the share of residential and non-residential annual consumption of total Tariff V. The steps below outline the forecasting methodology for each of these shares of Tariff V consumption in each region.

Step 1: Decompose historical Tariff V consumption into its base and heating loads

The estimated heating load on any given day is gas that is assumed to be consumed in direct response to colder temperatures. The remaining gas consumption on that day is the estimated base load.

Total daily Tariff V consumption was regressed against average daily EDD for Victoria and average daily HDD for other regions over a two-year window (training data) leading up to the reference year.

The model is expressed as follows:

$$y_i = \alpha + (\beta_{XDD} \times XDD_i) + (\beta_H \times IS\_HOLIDAY_i) + \varepsilon_i$$

where:

- y_i is total gas consumption for the sub-sector (residential or non-residential) of Tariff V on day i,
- α is the average Tariff V daily base load,
- β_{XDD} is the average Tariff V temperature sensitivity (TJ/XDD),
- XDD_i is the average EDD or HDD, depending on region, for day i,
- β_H is the daily base load change over the weekends or public holidays,
- $IS_{HOLIDAY_i}$ is an index to flag if day i is either a weekend or a public holiday, and
- ε_i is the part of y_i which is not capture in this model and is treated as an unobserved error.

The heating load on day i, denoted y_i^H, and is estimated as

$$\hat{y}_i^H = \hat{\beta}_{XDD} \times XDD_i,$$

where $\hat{\beta}_{XDD}$ is the estimate of β_{XDD} from the regression model above.

The estimated base load, or $\hat{y}_i^B$, is the remaining consumption on day i, given as

$$\hat{y}_i^B = y_i - \hat{y}_i^H.$$

Further, the bounds for the 95% confidence interval of coefficient estimates for the intercept (α) and temperature sensitivity (β_{XDD}) introduce a point of differentiation between scenarios, with the upper bound of the coefficients used for the *Accelerated Transition* scenario, which has the higher population growth setting, and the lower bounds applied to the *Slower Growth* scenario which has lower growth in population.

Step 2: Weather-normalise Tariff V annual consumption

Weather-normalised annual consumption is the level of annual consumption under the assumption that heating requirements for the calendar year are the same as the historical average, rather than being what they truly were. Estimated weather-normalised average annual consumption for Tariff V was the base for forecasting annual consumption over the 20-year horizon.

The weather-normalised Tariff V estimated annual consumption for year j, expressed as $Y_{WN,j}$, was estimated by replacing observed weather variables with those which correspond to the assumed "standard" weather, and is therefore equal to

$$\begin{aligned}\hat{Y}_{WN,j} &= Y_j - \hat{\beta}_{XDD} * (XDD_j - XDD_{WS}) \\ &= \sum_{i \text{ in year } j} y_i - \hat{\beta}_{XDD} * \left(\sum_{i \text{ in year } j} XDD_i - XDD_{WS} \right),\end{aligned}$$

where

- Y_j is actual annual consumption for year j,
- XDD_{WS} is the calculated annual standard EDD or HDD (see Appendix A2), and
- $\hat{\beta}_{XDD}$ is as described in Step 1.

Step 3: Forecast Tariff V consumption, accounting for impact of drivers

Annual Tariff V residential and small commercial consumption forecasts were produced by incorporating the impact of consumption drivers (namely, connections growth, energy efficiency price response, and climate change) on the weather-normalised base levels (estimated in Step 2) as detailed below. For each region in a given year, k, in the forecast horizon, the total forecast gas consumption, denoted $\tilde{Y}_k$, was calculated as follows:

$$\tilde{Y}_k = \hat{Y}_{WN,BaseYear} + \Delta NewConnections_k + \Delta ClimateChange_k + \Delta EnergyEfficiency_k + \Delta PriceResponse_k,$$

where

- $\hat{Y}_{WN,BaseYear}$ is the weather-normalised consumption for the region in the base year as calculated in Step 1. For the 2026 GSOO, the base year is 2025,
- $\Delta NewConnections_k$ is the impact of new gas connections in year k from the reference year, adjusted for electrification, as described in Section 5 (note that electrification may effectively lead to this variable having a negative impact, driving consumption down),

- $\Delta ClimateChange_k$ is the impact of climate change. AEMO adjusted the consumption forecast to account for the impact of increasing temperatures with the strategic assistance from Bureau of Meteorology (BoM) and CSIRO (see Appendix A2 for further information). Climate change is anticipated to increase average temperatures, which will reduce heating load from gas heaters and hot water systems,
- $\Delta EnergyEfficiency_k$ is the impact of energy efficiency savings, which reduces consumption. In 2025, *Strategy.Policy.Research* developed energy efficiency forecasts for the residential and commercial sectors in each region, considering the impact of modelled schemes such as the national construction codes; state and federal government schemes, and hypothetical measures to meet strong decarbonisation targets for some scenarios[25], and
- $\Delta PriceResponse_k$ accounts for behavioural response to price. Response to price change that was not captured by energy efficiency and gas-to-electricity fuel-switching was modelled through consumer behavioural response. Price rises were estimated to have minimal impact on base load, as it was assumed that baseload usage is largely from the daily operation of appliances such as a cooktop or a hot water heating system that are price inelastic. If consumers change their cooktop or hot water heating system, this impact is captured in the modelling of energy efficiency and fuel-switching. Therefore, the price elasticity for base load was set to 0. For heating load, price elasticity was projected to be -0.1 in the *Slower Growth* scenario, and -0.05 in the *Step Change* and *Accelerated Transition* scenarios.

[25] For details of the scope of measures modelled, refer to Strategy.Policy.Research, *2025 Energy Efficiency Forecasts Final Report*, at https://www.aemo.com.au/-/media/files/major-publications/isp/2025/stage-2/2025-energy-efficiency-forecasts-final-report.pdf.

6 Maximum daily demand

This section outlines the methodology used to develop forecasts of maximum daily gas demand for each year in the GSOO forecast horizon for Tariff V and Tariff D, GPG and LNG.

Variations in domestic gas consumption are mostly driven by heating demand and GPG, meaning that maximum daily demand typically occurs during the winter heating season.

In Queensland, due to the low penetration of gas appliances for residential use and the warm climate, maximum daily demand may occur in either summer or winter driven by GPG, LIL consumption and LNG exports.

For Tariff V and Tariff D, the 2026 GSOO used bootstrapping techniques like those employed by electricity demand forecasting. The bootstrapping simulations produced a full demand distribution related to weather, other demand drivers and stochastic volatility for the initial forecast year. Beyond that, the demand forecasts were then driven by consumption forecasts of Tariff D and Tariff V, whose drivers are outlined in Sections 4 and 5.

Gas maximum daily demand modelling can be broken into three steps:

1. Capture the relationship between demand and the underlying demand drivers.
2. Simulate demand based on the identified relationship between demand and the demand drivers.
3. Forecast demand using long-term Tariff D and Tariff V drivers.

Step 1: Capture the relationship between demand and demand drivers

This step captures the relationship between demand and explanatory variables including calendar effects such as public holidays, day of the week and month in the year and weather effects. This step specified an array of models for Tariff V and Tariff D using the variables available and explored a range of model specifications. Step 1 then used an algorithm to cull any models that had:

- Variance Inflation Factor[26] greater than 4,
- Nonsensical coefficient signs – all the coefficients must have reasonable signs; heating degree variables should be positively correlated with demand, and weekend and public holidays should be negatively correlated with demand, and
- insignificant coefficients.

The algorithm then ranked and selected the best model, based on the model:

- goodness-of-fit – R-Squared, Akaike Information Criterion, and Bayesian information criterion,
- out-of-sample goodness-of-fit – for each model based on 10-fold cross validation[27] to calculate the out -of -sample forecast accuracy, and
- histogram of the residuals, quantile-quantile (Q-Q) plot, and residual plots.

[26] The variance inflation factor is a measure of multicollinearity between the explanatory variables in the model.

[27] A 10-fold cross validation was performed by breaking the data set randomly into 10 smaller sample sets (folds). The model was trained on nine of the folds and validated against the remaining fold. The model was trained and validated 10 times until each fold was used in the training sample and the validation sample. The forecast accuracy for each fold was calculated and compared between models.

Step 2: Simulate demand

Once the most appropriate model was selected, Step 2 then used the linear demand models from Step 1 to simulate demand for a range of weather effects and other explanatory variables. The simulation process randomly drew from a pool of historical weather values from 1 January 2001 to the most recent weather data available, by bootstrapping historical fortnights. The bootstrapping method samples actual historical weather blocks, preserving the natural relationship between time-of-year and temperature.

Equations 1 and 2 represent the generalised model used for forecasting prediction intervals of demand.

Equation 1 $$TJ_t = f(x_t) + \varepsilon_t$$

Equation 2 $$\widehat{TJ}_t = f(x_t) + \sigma_\varepsilon z_t$$

where:

- $f(x_t)$ is the relationship between demand and the demand drivers (such as weather and calendar effects) at time t,
- ε_t represents the random, normally distributed[28] residual at time t ($\sim N(0, {\sigma_\varepsilon}^2)$), and
- z_t follows a standard normal distribution ($\sim N(0,1)$).

Equation 2 was used to calculate daily demand for a synthetic weather year, consisting of 365 days randomly selected from history (using the $f(x_t)$ component). The prediction interval of the model was simulated (using the distribution of ε_t in Equation 1).

The simulation process created 3,500 synthetic weather years with random prediction intervals for each day of each weather year following a $N(0, \sigma_\varepsilon^2)$ distribution.

Each iteration calculated demand for Tariff V and Tariff D individually for each day in the year. The daily regional demand was calculated as Tariff V + Tariff D. The maximum daily regional demand was found for each iteration as the single day with the highest demand across both summer and winter seasons (3,500 maxima for summer and winter). The 50% POE was calculated by identifying the 50th percentile of the simulated maxima distribution for each season, and the 5% POE was computed by identifying the 95th percentile.

Step 3: Forecast demand using long-term demand drivers

The demand values produced by the previous steps reflect the relationship between demand and conditions as at the base year. The forecast process then grew the demand values by economic, demographic and technical conditions.

The long-term growth drivers affecting annual consumption were applied to maximum daily demand within the simulation process, for each of the key drivers discussed in Sections 4 and 5. The annual growth drivers were applied to demand as indexed growth from the base year. The annual growth indices were found by considering the forecast year-on-year growth. The year-on-year growth in Tariff V and Tariff D was applied to each daily demand value to grow demand for each day in the relevant forecast year.

The LNG and GPG peak day forecasts were produced and applied separately to this process. In the modelling, it was based on the daily traces used, as explained below. The reported seasonal peak day forecast values for these segments are:

[28] A fundamental assumption of Ordinary Least Squares (OLS) is that the error term follows a normal distribution. This assumption is tested using graphical analysis and the Jarque–Bera test.

- GPG – this reported the typical GPG demand seen during the regional peak days for Tariff V and Tariff D combined, and
- LNG – this was the maximum seasonal value from the LNG trace used.

7 Developing daily demand profiles

AEMO developed daily demand profiles for all demand sectors included in the gas model.

Industrial, commercial, and residential demand

AEMO developed multiple daily reference profiles for each GSOO demand centre, using historical data from either the Victorian Declared Transmission System (DTS) data (for Victorian demand only), flow data provided by pipeline operators (where available), or the GBB. These multiple annual profiles help to capture weather and seasonal variability across various historical years.

The daily reference profile was then applied to annual consumption and maximum daily demand forecasts for the 20-year outlook period. This is achieved through an optimisation where forecasts of maximum daily demand and energy consumption were constraints against the various annual reference profiles already generated. This produced 20 years of combined daily demand for the residential and small commercial (Tariff V), and industrial and large commercial (Tariff D) load.

GPG demand

Electricity market modelling simulation was used to produce daily GPG consumption profiles for use in the gas supply model as described in Section 3.

LNG export demand

AEMO developed a daily reference profile for LNG export load, using the daily load profile from the GBB of each of the three LNG projects for the most recent 12 months. This load profile applied annual demand forecasts for the three LNG projects of QCLNG, APLNG, and GLNG, to develop daily profiles over 20 years for each of the three Curtis Island LNG projects. The LNG traces were achieved through the same methodology as that used for industrial, commercial and residential demand.

A1. Gas retail pricing

Price data is a key input in forecast models across multiple sectors. AEMO calculated the retail price forecasts sourcing a combination of consultant forecasts and publicly available information.

Separate prices were prepared for three market segments:

- residential prices,
- commercial prices, and
- small industrial prices.

A1.1 Retail pricing methodology

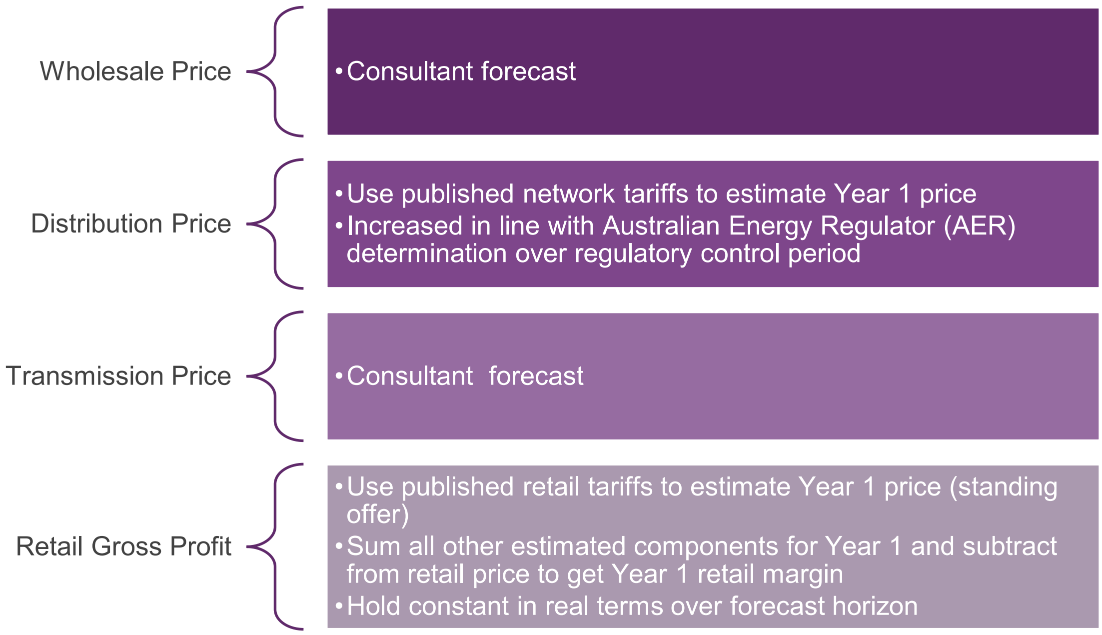
The gas retail price projections were formed from bottom-up projections based on separate forecasts of the various components of retail prices.

The key components were:

- wholesale prices,
- network costs,
- retail margin, and
- retail price.

Figure 5 gives a general outline of how the retail prices were produced. Retail Gross Profit captures both retail prices and retail margins. For details on data sources please see Appendix A4.

Figure 5 Building blocks of retail gas prices



A2. Weather standards

A2.1 Heating Degree Days (HDD)

To help determine heating demand levels, an HDD parameter was used as an indicator of outside temperature levels below what is considered a comfortable temperature. 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 (denoted as T_{base}). The HDD formula was used in forecasting Tariff V annual consumption and maximum daily demand for New South Wales, Queensland, South Australia, and Tasmania. For Victoria, EDDs (see following section) were applied instead.

To obtain the best correlation with gas consumption, high resolution (three-hourly) temperature averages (denoted as T_{312}) were calculated for the weather station in each region (denoted as T_{avg312}). T_{base} was determined by examining historical gas consumption patterns with temperature in each region to find the optimal base comfort level temperature for each region.

T_{312} was calculated using eight three-hourly temperature readings for each BoM weather station between 3:00 am of the current calendar day and 12:00 am of the following calendar day, as denoted by the following formula:

$$T_{312} = (T3AM + T6AM + T9AM + T12PM + T3PM + T6PM + T9PM + T12AM)/8$$

For each region, the station’s daily temperature formed the regional average (T_{reg312}). T_{base} for each region is shown in **Table 6**. Finally, the Degree Day (DD312) was calculated for each region, applying the standard HDD formula to the T_{avg312} for each region:

$$HDD = DD_{312} = max\left(T_{reg312} - T_{base}, 0\right)$$

Table 6 Station name and ID along with weighting and base temperature used for the 2026 GSOO, excluding Victoria

Region	Station name	Station ID	Tariff V Weight	T_{base} (°C)
New South Wales	Bankstown Airport	66137	1.00	19.57
Queensland	Archerfield	40211	1.00	19.30
South Australia	Edinburgh RAAF	23083	1.00	17.94
Tasmania	Hobart (Ellerslie Road)	94029	1.00	17.72

A2.2 Effective Degree Days (EDD)

In Victoria, an EDD was used to quantify the impact of a range of meteorological variables on gas consumption and maximum daily demand. This is due to Victoria showing a high sensitivity to seasonality, wind speed, and the hours of sunshine with its heating load.

There are several EDD formulations; AEMO applied the EDD_{312} (2012) for modelling Victorian medium- to long-term gas demand[29], adjusted for the Melbourne Olympic Park weather station that commenced operation in 2015. The EDD_{312} standard is a function of temperature, wind chill, seasonality and solar insolation with the formulation given as:

$$EDD_{312} = \max\left(DD_{312} + Windchill - Insolation + Seasonality, 0\right)$$

The following sections outline how each of the components was calculated.

Temperature (T_{312}) and Degree Days (DD_{312})

Similar to the calculation of DD_{312} for the HDD calculation for the other regions, the average of the eight three-hourly Melbourne temperature readings from 3:00 am to 12:00 am the following day inclusive was taken. The Melbourne Regional Office weather station data was used until its closure on 6 January 2015, with the Melbourne Olympic Park weather station data used afterwards, as per **Table 7**.

To align the Melbourne Olympic Park weather station with historic data, an adjustment factor was applied such that:

$$T_{312}(OlympicPark) = 1.028 * (T3AM + T6AM + T9AM + T12PM + T3PM + T6PM + T9PM + T12AM)/8$$

Table 7 Weather stations used for the temperature component of the Victorian EDD

Region	Station name	Station ID	Weight	T_{base} (°C)
Victoria	Melbourne Regional Office (until 5 Jan 2015)	86071	1.00	18.00
Victoria	Melbourne Olympic Park (from 6 Jan 2015)	86338	1.00	18.00

Wind chill

To calculate the wind chill function, first an average daily wind speed was calculated, again using the average of the eight three-hourly Melbourne wind observations (measured in knots) from 3:00 am to 12:00 am the following day, inclusive. The average wind speed is defined as:

$$W_{312} = (W3AM + W6AM + W9AM + W12PM + W3PM + W6PM + W9PM + W12AM)/8$$

This was calculated at the weather station level, and a weighted average of the stations in the region was taken to produce a regional wind speed. The wind speed data was sourced from the BoM; the stations used and weighting applied are given in **Table 8**.

Table 8 Weather stations used for the wind speed component of the Victorian EDD

Region	Station name	Station ID	Weight
Victoria	Laverton RAAF	87031	0.50
Victoria	Moorabbin Airport	86077	0.50

The wind chill formula is a product of both the average temperature and the average wind speed, with a constant (0.037) applied to account for the perceived effect of wind on temperature.

[29] EDD_{312} refers to the specific start time and end time of the daily inputs that are used to calculate the EDD. This start time is 3.00 am and end time is 12.00 am the next day.

A localisation factor (0.604) was also applied, to account for the shift from the Melbourne wind station (closed in 1999) to the average of Laverton and Moorabbin wind stations, to align them with the Melbourne wind station reading.

$$Windchill = 0.037 \times DD_{312} \times 0.604 \times W_{312}$$

Solar insolation

Solar insolation is the solar radiation received on Earth per unit area on a horizontal surface and depends on the height of the Sun above the horizon. Insolation factor provides a small negative adjustment to the EDD when included, as a higher insolation indicates more sunlight in a day, a factor that can decrease the likelihood of space heating along with a higher output from solar hot water systems (reducing gas consumption from gas hot water systems).

An average daily solar insolation was estimated by the amount of sunlight hours as measured by the BoM at Melbourne Airport (see **Table 9** for BOM station ID) using the following calibration:

$$Insolation = 0.144 \times Sunshine\ Hours$$

Table 9 Weather station used for the solar insolation component of the Victorian EDD

Region	Station name	Station ID	Weight
Victoria	Melbourne Airport	86282	1.0

Seasonal factor

This factor models seasonality in consumer response to different weather. Data shows that Victorian consumers have different energy habits in winter than outside of winter, despite days with the same temperature (or DD_{312}). This may indicate that residential consumers more readily turn on heaters, adjust heaters higher, or leave heaters on longer in winter than in shoulder seasons for the same weather or change in weather conditions. For example, central heaters are often programmed once cold weather sets in, resulting in more regular use.

This seasonal specific behaviour was captured by the Cosine term in the EDD formula, which implies that for the same weather conditions, heating demand is higher in the winter periods than the shoulder seasons or in summer, and was defined as:

$$Seasonality = 2 \times cos(2\pi \times (day\ of\ year\ -\ 190)/365)$$

Determining HDD and EDD standards

A median of HDD/EDD weather data from 2001 to the current year was used to derive a standard weather year.

Climate change impact

To apply weather standards for the GSOO forecast horizon, AEMO estimated the impact that recent changes in climate have had on HDDs (and therefore also EDDs) and adjusted the forecast to account for expected increases in temperatures resulting from further climate change.

Approach

To consider how to incorporate the climate change impact on forecast energy demand, AEMO sought both advice and data from the BoM and the CSIRO, then analysed historical and forecast temperature changes for the different weather regions across Australia.In this process, AEMO obtained the median forecast increase in annual average temperatures for more than 40 different climate models. This median was used as a "consensus" forecast. The climate models simulate future states of the Earth's climate using Representative Concentration Pathways (RCPs) that span a range of global warming scenarios.

There are several future RCP trajectories available; however, the difference between RCP scenarios tends to be small in the first 20 years, as most of the forecast temperature increase is already locked in irrespective of future actions on climate and emissions. AEMO applied the RCP4.5 scenario, resulting in an estimated increase in average temperatures by approximately 0.5 °C over the next 20 years across all regions in Australia compared to current temperatures[30].

Validation against historical weather

To include the effect of a climate change signal on the heating demand of energy consumers, an adjustment to the HDD forecasts was proposed. Analysis of historical temperature records show that climate change effect since 1980 has been at least a 0.5 °C increase in average temperatures across Australia[31]. This increase is significant enough to have potentially affected the number of HDDs, as the variable is derived from average temperatures. AEMO sought to first observe and quantify changes in the HDD variable over time to provide historical validation, before applying a climate change trend to the HDD forecast.

In addition, investigation was required to quantify the impact of the so-called Urban Heat Island Effect (UHI). Some of the recent warming in capital cities can be attributed to the increase in urbanisation in capital cities with higher overnight temperatures as buildings and other concrete structures can absorb and retain heat much more when compared to surrounding rural environments.

Inclusion in forecast data

The median trace of the 40 RCP 4.5 models predicts a 0.5 °C increase in average temperatures from 2025-2045 across Australia. AEMO used this data to adjust the forecast weather standard used in each region over the forecast and calculate the annual HDDs.

Climate models also simulate natural year-to-year weather volatility. Applying the climate change trend to the HDD will contain this year-to-year volatility. As the GSOO uses a single reference weather year across the 20 -year forecast horizon, this variability was removed but the average annual reduction in HDDs was preserved by extracting the linear trend. This linear trend was then applied against the reference HDD (or HDD component of the EDD) forecast.

To model gas maximum daily demand, high resolution historical half-hourly temperature data was used to observe distributions of weather scenarios. As it is optimal to have large sample sizes for distribution analysis but also consider weather that is reflective of current climatic conditions, the temperature data was restricted to more recent historical weather data (2001–2025). This data was re-baselined to the reference year, by applying an adjustment using the BoM's

[30] For more information, see https://www.climatechangeinaustralia.gov.au/.

[31] See http://www.bom.gov.au/cgi-bin/climate/change/timeseries.cgi.

historical temperature anomaly data from climate change impacts since 1995. This followed a similar method to what was performed to baseline the HDDs.

A limitation of this approach is that it takes an average effect of the climate change impact only on HDDs. Temperature events such as heatwaves, which potentially show an increase in intensity faster than the average change in temperatures, have been examined. As such, AEMO will be working towards utilising higher resolution temperature forecast data, and will undertake further collaboration with climate scientists, to quantify changes in maximum daily demand from where maximum/minimum daily temperature variations show greater volatility compared to the daily average.

A3. Distribution and transmission losses

Gas is transported from high-pressure transmission pipelines to lower-pressure distribution networks before it is used. During this process, some gas is unaccounted for, and some is used for operational purposes. This quantity of gas is collectively referred to as "total losses".

In the distribution networks, losses typically result from gas pipe leakages, metering inaccuracies, theft, pressure regulation issues, gate station losses and other uncertainties. These gas losses are commonly known as unaccounted for gas (UAFG).

Transmission pipeline losses mostly relate to gas used by pipeline compressors and heaters in normal gas pipeline operations. While UAFG also occurs along high-pressure pipelines, due to the volumes of gas transported by transmission pipelines losses are addressed more rapidly than distribution losses and therefore tend to be lower.

Due to AEMO's management of the Victorian gas DTS, operational gas used to fuel compressor stations in Victoria was forecast separately.

A3.1 Annual consumption

AEMO obtained historical losses from gas transmission and distribution businesses.

Historical data was normalised before being used to estimate forecasts. Transmission losses are expressed as a percentage of total gas consumption by residential and commercial consumers, industrial consumers, GPG, and distribution losses. Distribution losses are expressed as a percentage of total gas consumed by residential, commercial and industrial consumers within the distribution-connected areas.

AEMO forecast transmission and distribution losses separately as they are driven by different underlying factors. These are then aggregated to form the final forecasts.

Transmission losses are primarily driven by operational losses, while distribution losses are driven by UAFG. Regional transmission losses were forecast to range from 0.6% to 1.6% of total consumption, while distribution losses varied between 0.1% and 6.3% for each state. These variations arose from differences in the number, size, type of users, and age of assets, network upgrades, and total gas demand for each state.

A3.2 Maximum daily demand

Losses during times of maximum daily demand were forecast by finding the highest demand days by season by tariff type. From the highest demand days, the average percentage of losses relative to demand on those days was calculated. These normalised losses (transmission and distribution) during times of maximum daily demand in history were then applied to maximum demand days in the forecast horizon.

A4. Data sources

Table 10 Historical data sources

Demand component	Data source for all regions except for Victoria	Data source for Victoria
Residential and commercial	1. CGI – South Australia and New South Wales 2. AEMO internal database – Queensland 3. Distribution business survey – Tasmania	AEMO's internal database
Industrial	1. Distribution businesses (all Tariff D customers, aggregated on a network basis) 2. Transmission data: – Transmission businesses (all Tariff D customers, aggregated on a network basis) for data before 2019 – GBB for data after 2019 3. Direct surveys (for specific large industrial customers)	AEMO's internal database
Transmission losses	Transmission businesses	AEMO's internal database
Distribution losses	Distribution businesses	1. Distribution businesses 2. AEMO's internal database
GPG	AEMO's internal database	AEMO's internal database
LNG	GBB	NA

Table 11 Historical and forecast input data sources for industrial sector

Data series	Data sources	Reference	Notes
Historical consumption data by region	AEMO database	https://forecasting.aemo.com.au/	This is metered data. Actual consumption is derived from aggregate of these sources are available on AEMO's forecasting data portal
Historical consumption data by region	CGI	https://forecasting.aemo.com.au/	
Historical consumption data by region	Transmission & Distribution, Industrial data	https://forecasting.aemo.com.au/	
Historical consumption data by region	GBB	https://www.aemo.com.au/energy-systems/gas/gas-bulletin-board-gbb/data-gbb	LNG export information is available on the GBB.
Historical consumption data by industry sector	Dept of Industry, Science, Energy and Resources	https://www.energy.gov.au/government-priorities/energy-data/australian-energy-statistics	Energy related data is applied in estimating long-term consumption for the Manufacturing and Other Business sectors.
Weather data	BoM	http://www.bom.gov.au/	EDD and HDD are estimated from BOM weather data.
Climate change data	CSIRO	https://www.climatechangeinaustralia.gov.au/en/climate-projections/about/	Climate Change in Australia is a CSIRO website. AEMO references this for climate change projections.
Economic data	ABS	https://www.abs.gov.au/statistics/economy/national-accounts	Historic values for Services sector GVA and Industrial Production are available on the ABS website
Wholesale gas price	AEMO estimates + Consultant Forecasts	https://forecasting.aemo.com.au/	Wholesale gas prices are inputs into the estimation of retail gas prices. The index of prices is available on AEMO's forecasting data portal.

Table 12 Data sources for input to retail gas price model

Data series	Data sources	Reference	Notes
Wholesale price forecasts	ACIL Allen	ACIL Allen: 2025 Natural gas price forecast report/workbook, at https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2026/acil-allen-workbook	ACIL Allen provides delivered gas price projections which are inclusive of wholesale and transmission costs.
Revenue determinations	AER Network Determinations	https://www.aer.gov.au/industry/registers/determinations-access-arrangements	AEMO calculates the real change from the AER determinations over the revenue reset period and applies this to the base year network price to project prices for the long term.
Retail published prices	New South Wales: AGL South Australia, Victoria and Queensland: Origin Energy Tasmania: TasGas	AGL: https://www.agl.com.au/get-connected/electricity-gas-plans Origin Energy: https://www.originenergy.com.au/electricity-gas/ TasGas: https://www.tasgas.com.au/	For each region, a reference retailer is used to estimate current year retail prices.
Distribution published prices	New South Wales: Jemena South Australia and Queensland: AGN Victoria: Multinet Tasmania: None publicly available	Jemena: https://www.jemena.com.au/gas/jemena-gas-network/ AGN: https://www.australiangasnetworks.com.au/our-business/regulatory-information/tariffs-and-plans Multinet: https://www.aer.gov.au/industry/networks/tariff-variations/multinet-2025-26-tariff-variation-notice	For each region, tariffs from a reference distribution network provider are used to estimate the first-year distribution price forecast.

Table 13 Input data for analysis of historical trend in Tariff V consumption

Data	Source	Purpose
Tariff V daily consumption by region and exclusive of UAFG	Victoria and Queensland: AEMO Settlements database New South Wales and South Australia: Meter data agent (CGI data tables) Tasmania: Provided by gas distribution business in stakeholder survey	To estimate Tariff V temperature sensitivity. This is used to estimate weather-corrected annual consumption.
Regional daily EDD (Victoria) or HDD (other regions)	BoM (further detail provided in Appendix A2)	Same as above.
Actual residential and non-residential annual consumption	Provided by gas distributors in stakeholder surveys	Applied to split Tariff V annual consumption into residential and non-residential sectors.
Actual Tariff V residential and non-residential connections	Victoria and Queensland: AEMO Settlements database New South Wales and South Australia: Meter data agent (CGI data tables) Tasmania: Provided by gas distribution business in stakeholder survey	Applied to estimate average consumption per Tariff V residential and non-residential connection.
Historical residential prices	See details in Appendix A1	Applied to forecast the future gas prices for residential sector.

Table 14 Input data for forecasting Tariff V annual consumption

Data	Source	Purpose
Forecast residential prices	See details in Appendix A1	Applied to forecast gas price impact on residential and non-residential annual consumption forecasts.
Forecast Tariff V connections	See Section 5.1	
Annual EDD/HDD standards	See Appendix A2	Applied to forecast Tariff V heating load.
Forecast residential annual consumption savings due to fuel switching-	CSIRO	Applied to forecast the impact of fuel-switching on Tariff V residential forecasts
Forecast annual consumption savings due to energy efficiency	SPR and state government institutions	Applied to forecast the impact of energy efficiency on Tariff V residential and non-residential forecasts.
Impact of climate change on Tariff V annual heating load	See details in Appendix A2	Applied to forecast the impact of climate change on Tariff V heating load forecasts.

* Forecast residential prices are used for forecasting Tariff V residential and non-residential gas consumption because both forecast price series follow similar trends.

Measures, abbreviations and glossary

Units of measure

Abbreviation	Unit of measure
DD	Degree days
EDD	Effective degree days
GJ	Gigajoules
HDD	Heating degree days
PJ	Petajoules
TJ	Terajoules

Abbreviations

Abbreviation	Expanded name
ABS	Australian Bureau of Statistics
AER	Australian Energy Regulator
APLNG	Australia Pacific LNG
DTS	Declared Transmission System
ECGM	East Coast Gas Market
ESOO	Electricity Statement of Opportunities
GLNG	Gladstone Liquefied Natural Gas
GPG	Gas-powered generation
GSOO	Gas Statement of Opportunities
GSP	Gross State Product
GVA	Gross Value Added
IASR	Inputs, Assumptions and Scenarios Report
ISP	Integrated System Plan
LIL	Large industrial loads
LNG	Liquefied natural gas
MHQ	Maximum Hourly Quantity
NEM	National Electricity Market
POE	Probability of exceedance
QCLNG	Queensland Curtis LNG
RCP	Representative Concentration Pathways
SMIL	Small-to-medium industrial loads
TGP	Tasmanian Gas Pipeline
UAFG	Unaccounted for gas
UHI	Urban Heat Island Effect

Glossary

Term	Definition
Annual gas consumption	Refers to gas consumed over a calendar year, and can include residential and commercial consumption, industrial consumption, GPG consumption, or transmission and distribution losses. Gas used for LNG processing and exports is considered separately. Unless otherwise specified, annual consumption data includes transmission and distribution losses.
Covered gas	An aggregation of natural gas, biomethane and hydrogen
Distribution losses	Refers to gas leakage and metering uncertainties (generally referred to as UAFG) in the distribution network. This is calculated as a percentage of total residential and commercial consumption and industrial consumption connected to the distribution networks.
Effective degree days (EDD)	A measure that combines a range of weather factors that affect energy demand.
Gas-powered generation (GPG)	Refers to generation plant producing electricity by using gas as a fuel for turbines, boilers, or engines. In the GSOO forecasts, this includes gas-powered generation that is connected to the National Electricity Market (NEM) or the Northern Territory electricity networks.
Region	Regions are primarily defined geographically to group jurisdictions and gas networks for supply-demand analysis.
Industrial and large commercial, also known as Tariff D	Refers to users that generally consume more than 10 terajoules (TJ) of gas per year. Industrial consumption includes gas usage by industrial and large commercial users, and some GPG that is not connected to the NEM, for example, GPG around Mt Isa.
Liquefied natural gas (LNG)	Refers to natural gas that has been converted to liquid form.
Maximum daily demand	Refers to the highest daily demand occurring during the year. This can include residential and commercial demand, industrial demand, GPG demand, or distribution losses. Gas used for LNG production is considered separately. Unless otherwise specified, maximum daily demand includes transmission and distribution losses.
Per customer connection	Refers to the average consumption per residential and commercial gas connection. Expressing consumption on this basis largely removes the impact of population growth and allows analysis of underlying consumer behaviour patterns.
Probability of exceedance (POE)	Refers to the likelihood that a maximum daily demand forecast will be met or exceeded, reflecting the sensitivity of forecasts to changes in weather patterns in any given year. The GSOO provides these forecasts: • 1-in-2 maximum daily demand, also known as a 50% POE, means the projection is expected to be exceeded, on average, one out of every two years (or 50% of the time). • 1-in-20 maximum daily demand, also known as a 5% POE, means the projection is expected to be exceeded, on average, one out of every 20 years (or 5% of the time).
Residential and small commercial, also known as Tariff V	Refers to residential and small-to-medium-sized commercial users consuming less than 10 TJ of gas per year. Unless otherwise specified, historical residential and commercial data is not weather-corrected.
Summer	December to February.
Transmission losses	Refers to gas that is unaccounted for or consumed for operational purposes (such as compressor fuel) when transported through high-pressure transmission pipelines to lower-pressure distribution networks. Transmission losses are calculated as a percentage of total residential and commercial, industrial, and GPG consumption, and distribution losses.
Winter	June to August