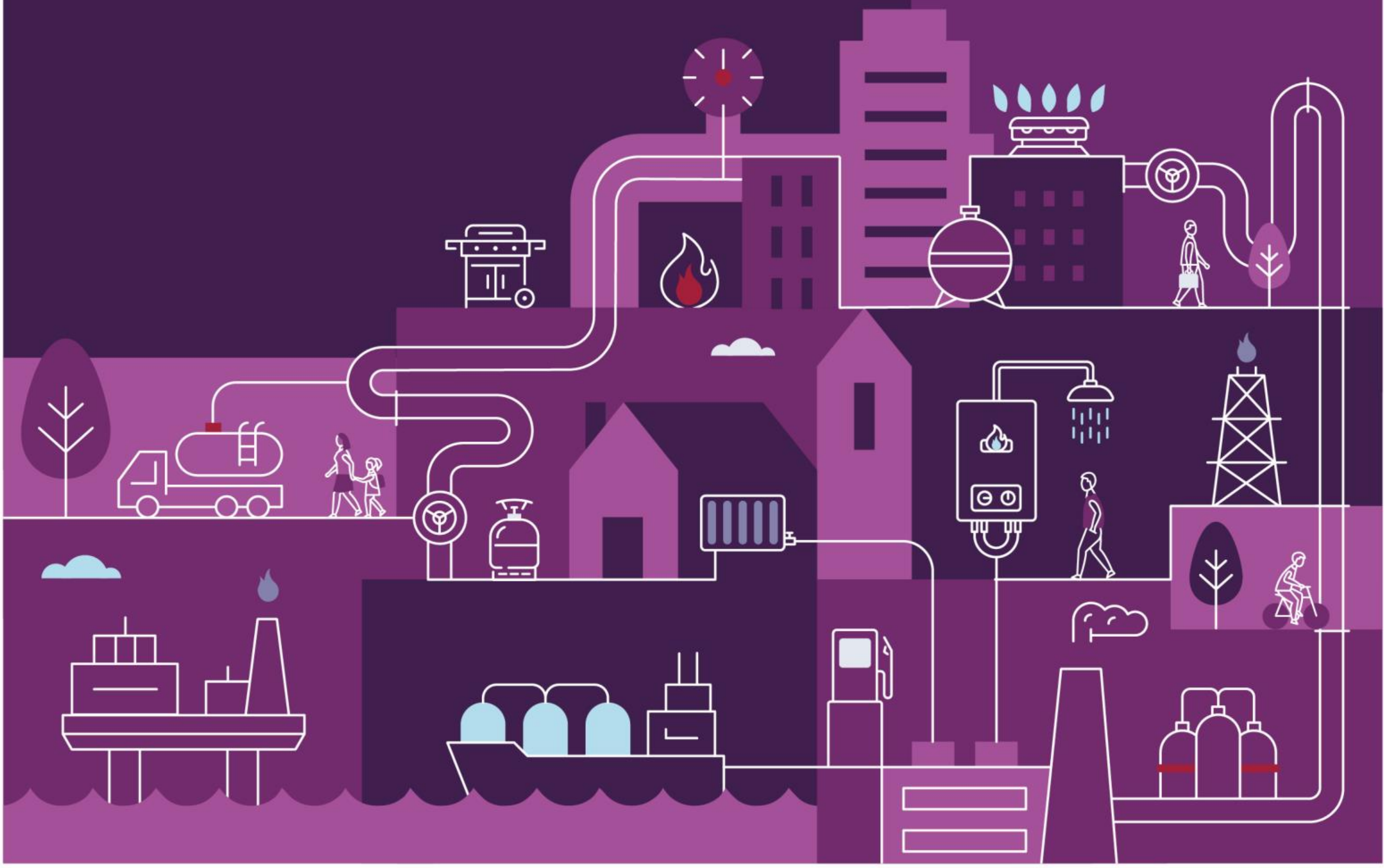
Gas Demand Forecasting Methodology Information Paper

March 2024

For the 2024 Gas Statement of Opportunities covering Australia's East Coast Gas Market



Important notice

Purpose

AEMO has prepared this document to provide information about the methodology and assumptions used to produce gas demand forecasts for the 2024 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 gas supplied through the natural gas transmission system in the modelled area, and are the sum of a number of component forecasts, each having a distinct forecasting methodology. The components (defined in the Glossary) are:

- Liquefied natural gas (LNG).
- Gas-powered generation (GPG).
- Industrial.
- Residential and commercial.
- Network losses and other unaccounted for gas (UAFG).

For annual consumption, each of these component forecasts is modelled separately, then summed at the regional level. Chapters 2 through 5 describe the methodologies used for each of the first four components. Network losses and other UAFG are covered in Appendix A3.

Maximum demand forecasts provide an annual projection of maximum daily demand for each region. The maximum demand methodology uses an integrated modelling approach that forecasts the component models jointly to produce a forecast of maximum coincident daily demand (see Chapter 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 2024 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 one 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 herein.

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

2 Liquefied natural gas (LNG) consumption

There are three LNG projects located on Curtis Island in Queensland – APLNG, GLNG and QCLNG. The annual consumption forecasts for this demand sector include:

- 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 are developed using a combination of LNG consortia survey responses and stakeholder feedback.

In preparing the 2024 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 2023 IASR[3] and aligned to corresponding International Energy Agency (IEA) forecasts, as reported in the 2023 World Energy Outlook[4].

Prior to finalising AEMO's LNG consumption forecasts, AEMO engaged with stakeholders including AEMO's Forecasting Reference Group[5] in November 2023 to provide feedback on these forecasts.

[3] See https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[4] See https://www.iea.org/reports/world-energy-outlook-2023.

[5] 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 chapter describes the methodology and key assumptions AEMO used to forecast annual gas consumption as the fuel required for GPG (sometimes referred to as gas generation) to supply electricity to the National Electricity Market (NEM)[6].

AEMO performed electricity market modelling techniques for the NEM consistent with the Draft 2024 ISP to forecast GPG consumption for the 2024 GSOO[7].

The GPG consumption projections for the 2024 GSOO applied the electricity transmission developments, generation capacity outlook, and demand forecasts consistent with the Draft 2024 ISP[8] (see Phase 1 below). Information for committed generation projects was updated based on the July 2023 Generation Information update[9] and gas price forecasts were used consistent with the Draft 2024 ISP for forecast GPG consumption, consistent with the gas prices used in forecasting the other demand sectors in the 2024 GSOO[10]. In forecasting the level of GPG dispatch, the methodology applied updated bidding behaviours to increase the accuracy of the gas consumption forecast.

AEMO applied affine linear heat rate curves rather than constant average heat rates to better reflect the overall consumption of natural gas in producing the dispatched electrical energy from GPG. The use of affine heat rates improves the accuracy of both the forecast as well as estimates of historical GPG consumption by power station.

To forecast GPG AEMO conducted market modelling in two stages.

Phase 1 – capacity outlook modelling

The first long-term (LT) phase determined the optimised generation expansion plan for the NEM using AEMO's Capacity Outlook model. The modelling incorporated various policy, technical, financial and commercial drivers to develop the least-cost NEM development path. This included state and national renewable energy targets, technology cost reductions, and electricity demand and consumption forecasts over the forecast period. The approach considered the variability of renewable energy resources and the transmission developments required to access potential renewable energy zones (REZs). It also considered the need to replace ageing thermal generation, and the role that energy storage technologies and flexible thermal generation technologies may have, such as GPG, given increased penetration of variable renewable energy sources at utility scale and from consumer energy resources (CER).

[6] This includes the vast majority of GPG in the eastern and south-eastern gas markets. Any GPG outside this, such as in Mount Isa, is captured as Industrial (Tariff D) demand.

[7] Further detail on market modelling methodology, and the ISP Methodology in particular, is available at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf.

[8] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/draft-2024-isp-consultation/draft-2024-isp.pdf. Also see 2023 Input and Assumptions Workbook, at https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-iasr-assumptions-workbook.xlsx.

[9] At https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/2023/nem-generation-information-july-2023.xlsx.

[10] At https://aemo.com.au/-/media/files/major-publications/isp/2023/iasr-supporting-material/acil-allen-natural-gas-price-forecasts.pdf.

For each scenario, the Capacity Outlook model adopted the actionable ISP projects and future ISP projects timed with the optimal development path for the scenario that is matched with each GSOO scenario. Further details on the specific matchings are provided in the GSOO report.

Phase 2 – time-sequential modelling

The second phase modelled the NEM with increased granularity using half-hourly, time sequential modelling incorporating the generation and transmission mix determined by the LT phase. This short-term (ST) phase is essential to validate generation and transmission plans from the LT phase and assess detailed dispatch of electricity generators across the horizon.

This short-term time-sequential modelling phase was performed using a bidding model.

The bidding model forecast the gas required for GPG by developing NEM spot market bids for each individual generator unit, based on historical analysis of actual bidding data and benchmarked to historical generation levels. Depending on observed behaviour, the modelled bids might change on a 30-minute or monthly level, or due to certain conditions (for example, a generator outage may be balanced within a portfolio by increasing generation output across other generating units within the portfolio at a lower price).

This bidding behaviour captured current market dynamics such as contract and retail positions of portfolios which are generally not captured using other modelling methods.

The bidding model assumed that these dynamics remain unchanged over time and across scenarios. As such, the bidding model reflected a single set of bidding strategies, common across all scenarios. While the strategies are the same as the generation mix changes over time, they will produce different outcomes depending on the available generation and their variable costs in each simulated half-hour.

The bidding model methodology involved:

- Prior to optimising dispatch in any given year, the model scheduled planned maintenance and randomly assigns unplanned generator outages to be simulated using a Monte Carlo simulation engine. Dispatch was then optimised on a 30-minute basis for each forced outage sequence, given the load characteristics, plant capacities and availabilities, fuel restrictions and take-or-pay contracts, variable operating costs including fuel costs, interconnector constraints, and any other operating restrictions that were specified.
- Expected 30-minute electricity prices for each NEM region, and 30-minute dispatch for all NEM power stations, were calculated.
- The amount of gas used in each 30-minute period to generate power was calculated using the affine linear heat rate methodology on a generating unit-by-unit basis, which AEMO then aggregated into daily traces by power station to be fed into the GSOO gas model.

For some scenarios, 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 failures, coal supply-chain disruptions or even major environmental interruptions such as bushfires and flooding. Rather than try to predict these specific events, AEMO has approximated these events by assuming a reduction in the availability of coal-fired generators, and the potential for new generation developments to be delayed during construction and commissioning[11] . The GSOO report has further details on which scenarios use this methodology.

[11] The delays to projects under construction and anticipated are consistent with the approach applied in the Electricity Statement of Opportunities (ESOO) methodology, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/esoo-and-reliability-forecast-methodology-document.pdf

4 Industrial (Tariff D) consumption

This chapter outlines the methodology used to develop annual gas consumption forecasts for industrial customers. Industrial consumption, also known as Tariff D consumption, is defined as consumption by network customers who are billed on a demand basis[12]. These consumers typically consume more than 10 terajoules (TJ) per year.

AEMO defined two categories of industrial customer for analysis purposes:

- Large Industrial Loads (LIL): 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[13].
- Small to Medium Industrial Loads (SMIL): 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, and universities.

4.1 Data sources

The industrial sector modelling relied on a combination of sources for input data, shown in Table 1. For more details and source references, please see Appendix A4.

Table 1 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 Logica	Distribution and industrial surveys	Gas Bulletin Board (GBB)
Historical consumption by sector	Dept of Climate Change, Energy, the Environment and Water			
Weather	Bureau of Meteorology (BoM)			
Climate change	CSIRO			
Economic data	Australian Bureau of Statistics (ABS)	Economic consultancy		
Wholesale gas prices	ACIL Allen			
Retail gas prices	ACIL Allen (Wholesale gas prices)	Various gas retailers and distributors	AER	AEMO databases
Energy Efficiency	Energy efficiency consultancy	Various government agencies		
Multi sector modelling	CSIRO and ClimateWorks			

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

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

4.2 Forecast Tariff D annual consumption methodology

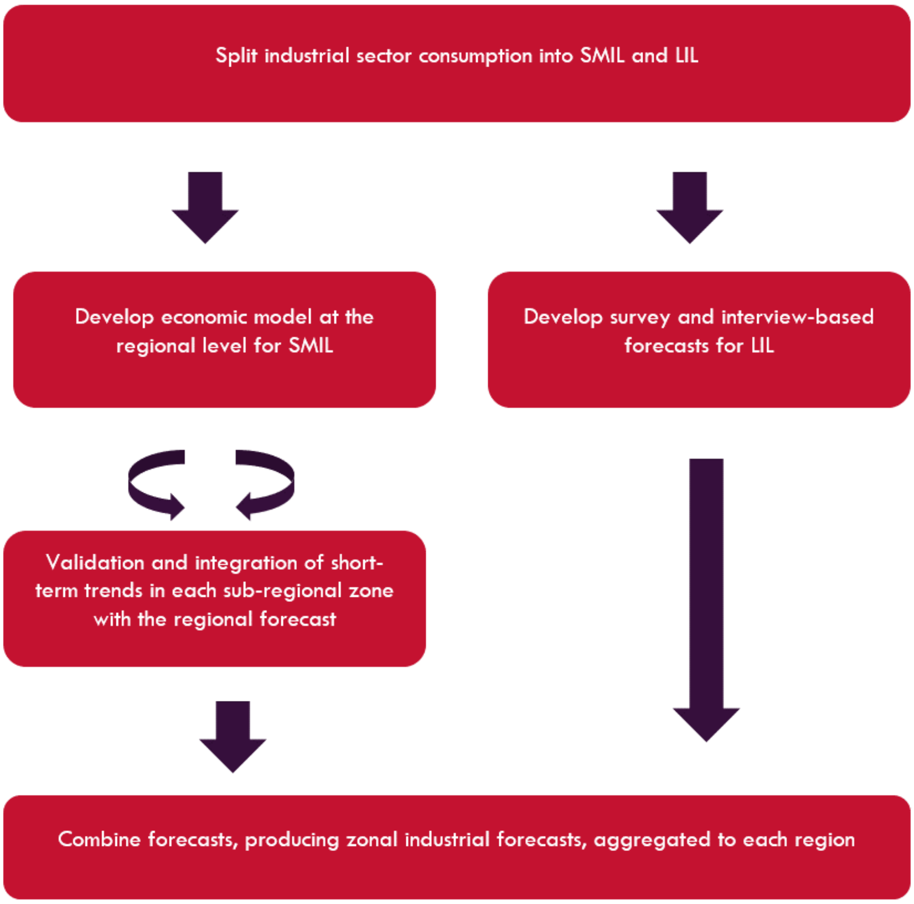
The energy-intensive industrial sector was split between LILs and SMILs, because the underlying drivers for their energy consumption are quite different.

This used a combination of survey and econometric modelling approaches to forecasting:

- 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, modelling the two components separately before combining again to produce the total forecast for each region. For the 2024 GSOO, AEMO applied the outcomes of multi sector modelling related to electrification and hydrogen adoption, as detailed in Section 4.2.3.

Figure 1 Tariff D consumption forecasting method



4.2.1 Develop economic model and forecast for SMIL

The SMIL sector accounts for approximately 25% of Tariff D consumption across the East Coast Gas Market 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:

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

Applying broad forecasting principles[14], 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 seasonality, along with testing additional factors such as historical weather and possible structural break variables.
- The long-term (causal) model captured features that are determined by the particular 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 2.

Table 2 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 South East 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 is 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

[14] AEMO adapts 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) https://otexts.com/fpp2/.

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 forms the basis of the long-term (causal) consumption forecast. The most relevant economic indicator (presented in Table 3) 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 3 Region-specific SMIL economic indicators

Region	Economic Indicator
Victoria	GVA Manufacturing
New South Wales	GVA Manufacturing
Queensland	GSP
South Australia	GSP
Tasmania	State Final Demand
Northern Territory	N/A[15]

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[16].

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. The following price elasticities[17] were applied:
  - -0.05 in the *Green Energy Exports* scenario,
  - -0.10 in the *Step Change* scenario and,
  - -0.15 in the *Progressive Change* scenario.
- 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

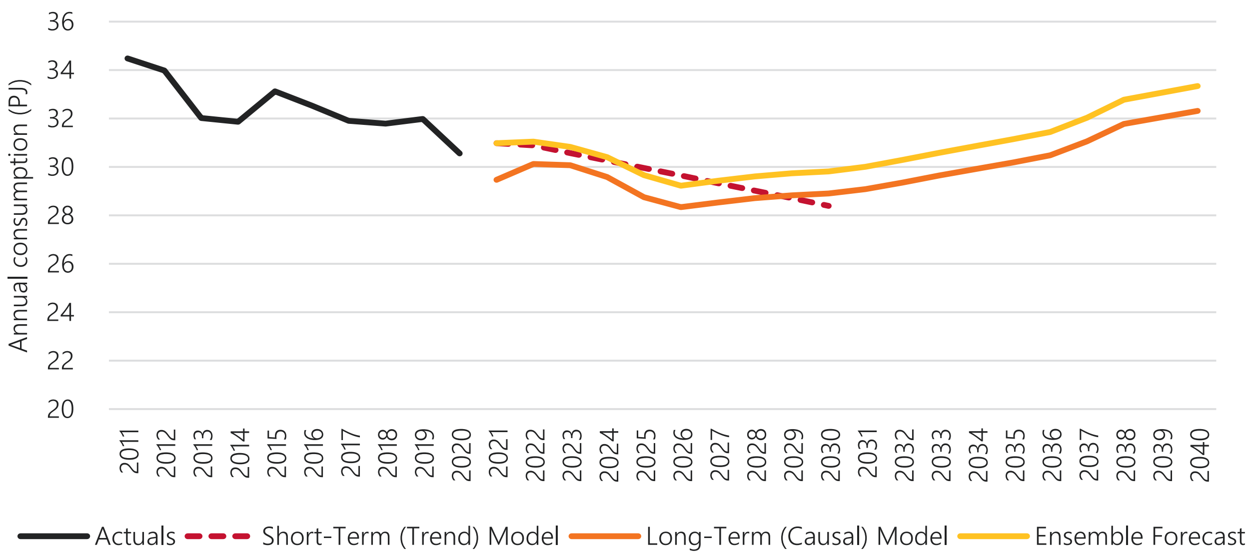
[15] Forecasts for the Northern Territory were produced using average growth rates from other regions in eastern and south-eastern Australia, as consultant inputs were not available for this region.

[16] Energy intensity refers to the amount of energy required per million dollars of economic output.

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

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.

Figure 2 The SMIL long-term (causal) model for Victoria contrasted with the short-term trend model, demonstrating the resulting blended ensemble model forecast



4.2.2 Develop survey-based forecast for LILs

AEMO conducted a survey and interview process with medium to large industrial users[18] to derive the LIL regional forecasts. The survey process followed five key steps as shown:

Identify Large Industrial users

LILs were identified through several means:

1. AEMO keeps a record of the LILs from the previous years as well as monitors prospective projects that might become LILs. The LIL list is updated according to closures and new entries each year.
2. Distribution Surveys: request information on existing loads consuming more than 10 TJ annually, as well as new large loads.
3. AEMO database: in Victoria and Queensland markets AEMO has all the registered distribution network connected industrial loads. In Victoria AEMO also has all the transmission connected industrial loads.
4. Participant information on the Gas Bulletin Board (GBB).
5. Media research.

[18] 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.

Collect recent actual consumption data and analyse

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

1. To understand latest trends at the site level.
2. To prioritise the large industrial loads 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 gas utilisation, or electrification.

For a more detailed overview of the components behind AEMO's planning and forecasting scenarios, see AEMO's website[19].

Step 2: Detailed interviews

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

- Key gas consumption 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 LILs forecast of their gas consumption over the medium and long term (per scenario), and possible impacts on profitability and operations.
- Potential drivers of major change in gas consumption (for example, expansion, closure, cogeneration, fuel substitution) including "break-even" gas pricing[20] and timing.
- Different assumptions between the scenarios.

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

- Volume of load (highest to lowest): movement in the largest volume consumers can have bigger market ramifications (for example, impact market price).

[19] 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

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

- Year on year percentage variation: assesses volatility in load. Those with highest volatility are harder to forecast.
- Year on year absolute variation (PJ): even if loads are volatile, if they are relatively small, it might be captured in the uncertainty around forecasts and not impact overall trend, whereas the largest loads will have a more material impact.
- Forecast versus actuals for historical survey responses (where available): this measure was used to assess accuracy of forecasts. For instance, if there was high volatility in actual consumption, was it anticipated it in last year's survey forecasts? If not, then it requires further investigation.
- To clarify responses: for example, if survey forecast and survey questionnaire answers do not match or are unclear.

This process was also used as a benchmark for validating the survey responses.

Finalise forecasts

The site-based survey forecasts for each scenario were finalised based on interview discussion[21]. All the survey forecasts were aggregated to regional level for each region.

4.2.3 Apply adjustments for electrification and renewable gas adoption

AEMO applied outcomes from the multi sector modelling to the Tariff D forecasts, related to electrification, hydrogen adoption, and hydrogen production.

Electrification

The multi sector modelling projected increases in electricity demand from electrification, and forecasts of consumption for other fuel types, including gas. AEMO used both to estimate the reduction in gas consumption as customers fuel-switch to electricity, and applied this adjustment to the Tariff D forecasts using the following steps:

- Reviewed LIL gas usage and advice from CSIRO/ClimateWorks to identify industries with the potential to electrify. Generally, the lower the temperature of a process is the easier it is to electrify. Further, market research for the LILs industry was used to guide the potential and intention for the electrification for the sites.
- Split the electrification adjustment between the remaining LILs and SMILs based on the ratio of actual consumption in 2022.
- Calculated the SMIL share for each GSOO zone based on the ratio of forecast consumption, and reduced the SMIL consumption forecast for each GSOO zone by this share.
- Calculated the LIL share across GSOO zones based on the location of the LILs and the ratio of actual consumption in 2022 and reduced the LIL consumption forecast for each GSOO zone by this share.

Renewable gas adoption

Renewable gas adoption refers to blending of hydrogen and biomethane into gas distribution networks, and direct fuel-switching. Previous GSOOs considered the Inputs, Assumptions and Scenarios Report (IASR)-assumed

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

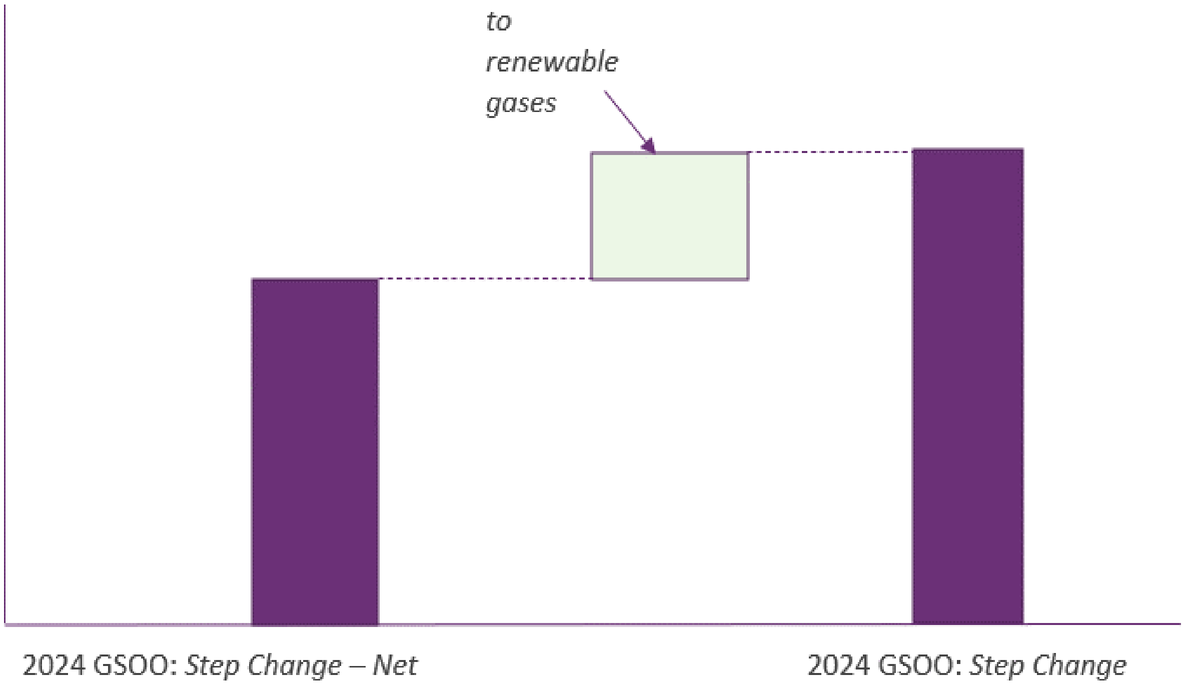
uptake of alternative fuels such as hydrogen and biomethane as alternatives to supplying volumes of natural gas, which would therefore offset demand for natural gas. The 2024 GSOO surveys did not identify any significant renewable gas supply projects that were sufficiently progressed to validate this approach.

In its treatment of renewable gases, the 2024 GSOO is intended to be consistent with regulatory changes which will take effect in the 2025 GSOO while ensuring obligations under the current NGR requirements are delivered. Regulatory changes mean that from mid-2024, natural gas, hydrogen, biomethane and synthetic methane will be defined collectively as *gas*. To prepare for this change, the 2024 GSOO considers demand and supply of all gases in the ECGM for the purposes of modelling supply sufficiency. The approach undertaken for the 2024 GSOO results from limited detail in survey responses, and inherent uncertainties in the volume and timing of renewable gas supply during the period to 2043.

This approach was used in the *Step Change* scenario and is shown graphically in Figure 3.

To meet current National Gas Rules (NGR)[22] requirements, the 2024 GSOO also includes an alternative assessment of natural gas, aligned with the IASR demand scenario assumptions for natural gas fuel-switching to renewable gases. This approach is represented in the *Step Change – Net* sensitivity, shown in the left-hand bar of Figure 3.

Figure 3 Treatment of renewable gases in 2024 GSOO vs 2023 GSOO



[22] See NGR Part 15D, at https://energy-rules.aemc.gov.au/ngr/495/306376#15D.

AEMO applied these renewable gas forecasts as adjustments, excluding hydrogen adoption in the mining sector, to the Tariff D forecasts in the *Step Change – Net* sensitivity using the following steps:

- Reviewed LIL gas usage to identify industries with the potential to directly fuel-switch to hydrogen. Based on the review, AEMO has included industries not considered for electrification as identified above, as well as oil refineries, construction industries, and glass and paper manufacturing.
- Apportioned the direct fuel-switching hydrogen and biomethane adjustment between transmission-connected LILs based on the ratio of actual gas consumption in 2022.
- Calculated the direct fuel-switching share for each GSOO zone, based on the location of the LILs and the ratio of actual consumption in 2022, and reduced the LIL consumption forecast for each GSOO zone by this share.
- Calculated the hydrogen blending share for each GSOO zone, based on the location of distribution-connected LILs, and the ratio of actual consumption in 2022 of these LILs and SMILs. Reduced the Tariff D distribution consumption forecast for each GSOO zone by this share.

A summary of the approach to developing the forecast for each renewable gas is given in Table 4, and details are provided in the subsections below.

Table 4 Summary approach – renewable gases treatment in forecast for *Step Change - Net* sensitivity

Topic	Hydrogen	Biomethane
Renewable gas adoption	Hydrogen used in 'remote facilities'* was excluded from the forecast.	All biomethane facilities were assumed to be connected to the gas network for this forecast.
Renewable gas production	Hydrogen production from natural gas via SMR is no longer included in the forecast.	N/A – production of biomethane does not consume natural gas.

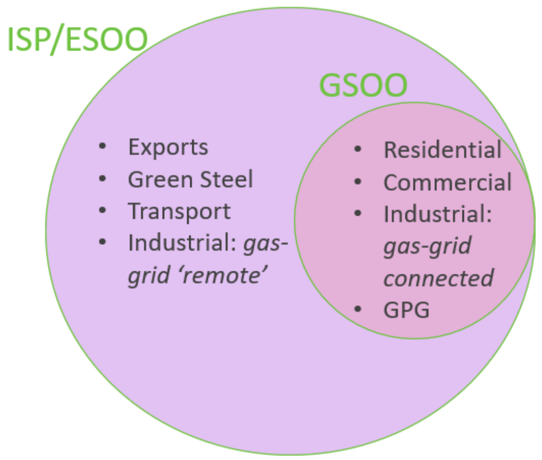
* See next section for definition of 'remote'

Hydrogen adoption

The hydrogen consumption forecast was based on the output of the 2022 multi sector modelling, with adjustments to allow for an assumed lead time of five years for any projects that are not currently committed. The forecast included domestic hydrogen used by facilities that are connected to the east coast gas system in residential, commercial and industrial sectors, and hydrogen for GPG.

Hydrogen end-use inclusions vary across AEMO publications, to reflect their purpose, as illustrated in Figure 4. The GSOO hydrogen forecast was focused on those end-uses that are connected to the gas grid, as this reduces the amount of existing and/or future natural gas that will be required. The ISP/ESOO hydrogen forecasts focus on all end uses, including those remote from the gas network, as they consume electricity to produce the hydrogen, and hence increase electricity consumption (excluding any electrolysers that are assumed to be supplied by behind-the-meter generation). See further discussion on electrolysers in the 'Hydrogen Production' subsection below.

Figure 4 AEMO hydrogen forecast definitions: end-use inclusions vary across publications



Hydrogen used in 'remote facilities' was excluded from the GSOO forecast. In keeping with the terminology used in the revised National Gas Rules[23]:

- a remote facility is defined as 'a BB (Bulletin Board) facility that is [a remote pipeline,] or is connected to a remote pipeline'.
- 'Remote pipeline means a transmission pipeline that:
  - (a) is not an STTM facility or part of a declared transmission system;
  - (b) is not a pipeline on which natural gas sold through the gas trading exchange may be physically delivered or received or through which such natural gas may be transported;
  - (ba) is not a Part 24 facility; and
  - (c) is not connected directly or indirectly to a pipeline satisfying paragraph (a), (b) or (ba) of this definition

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

- Exports.
- Transport.
- Industrial facilities with no connection to the gas network.
- Green steel.

The concept of 'remote' facilities is illustrated in Figure 5, and numerical examples are shown in Figure 6.

[23] As defined in the AEMC recommended NGR Group B, at https://www.aemc.gov.au/sites/default/files/2022-11/Recommended%20final%20rules%20-%20Group%20B%20-%20Parts%2015A%20to%2018A%20NGR.pdf.

Figure 5 Illustration and examples of 'remote' facilities used in GSOO hydrogen forecast assumptions

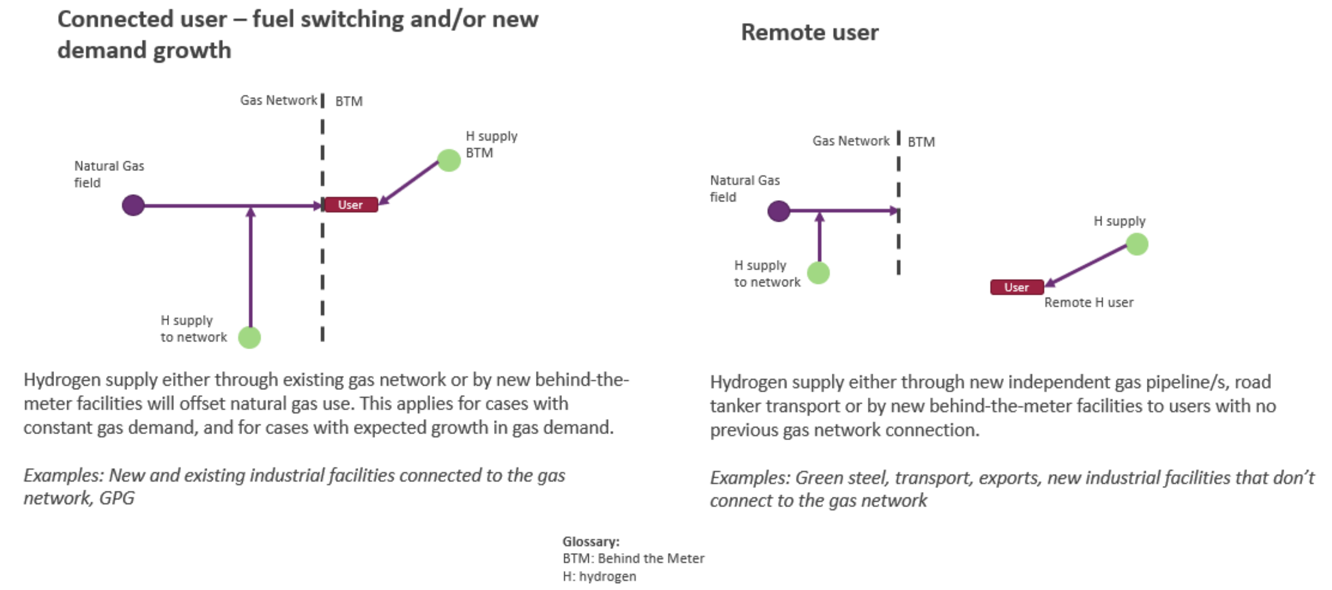
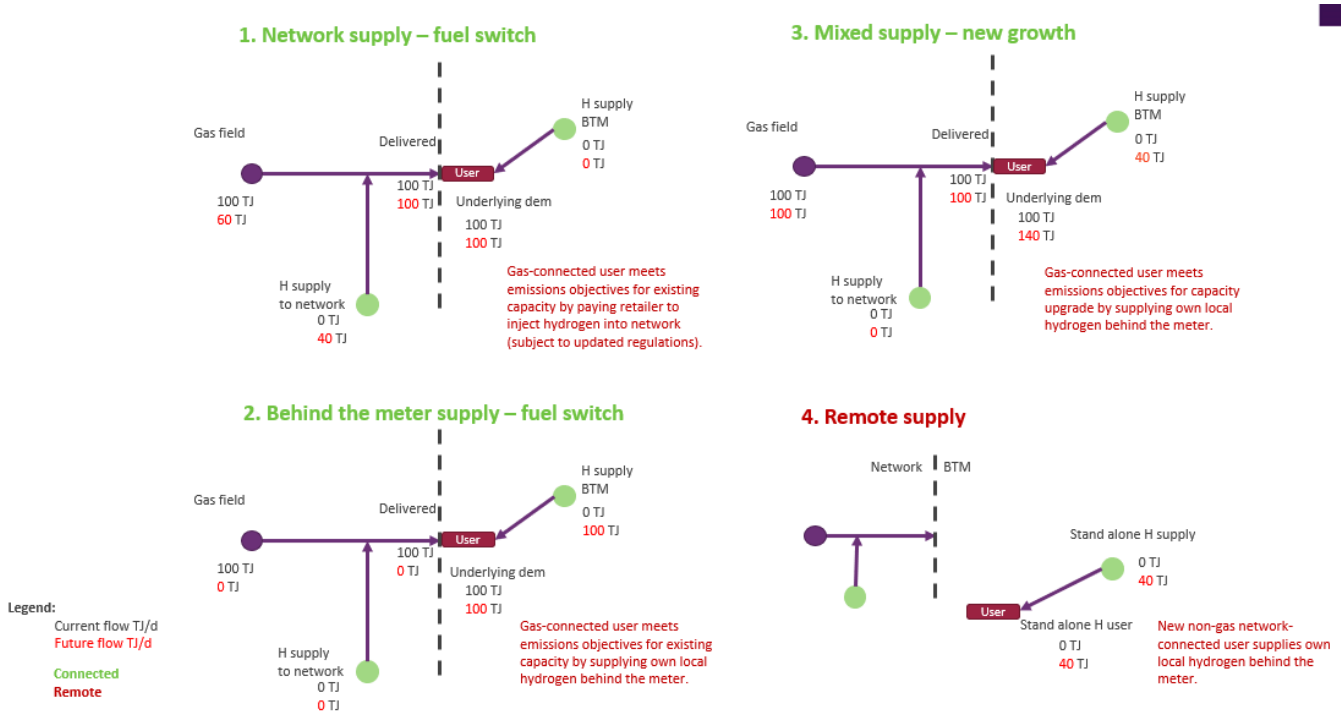


Figure 6 Numerical examples of 'Connected' and 'Remote' facilities for hydrogen forecast definitions



Potential hydrogen production

To align with feedback received on the 2023 IASR, the 2024 GSOO assumed that no hydrogen is made from natural gas (using steam methane reforming).

The operation of electrolysers will have a large impact on the electricity consumption within the NEM. This additional electricity consumption will require additional generation developments in the electricity market, impacting the GPG forecast. This electricity generation development response to the additional electrical load is considered in Phase 1 of the GPG forecasting approach, which identifies the electricity generation developments required (including gas generators) for each scenario. See Section 1 for more details regarding the Phase 1 – Capacity Outlook Modelling approach.

Potential Biomethane adoption

The biomethane consumption forecast for the *Step Change – Net* sensitivity was based on the output of multi sector modelling.

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 commercial (Tariff V) consumption

This chapter 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.

AEMO's Tariff V consumption modelling used econometric models to develop 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[24] and a simplified forecasting model was adopted for the region. AEMO continued to apply outcomes from multi sector modelling related to electrification, and potential hydrogen and biomethane adoption.

5.1 Definitions

Tariff V customers are gas consumers of relatively small gas volumes, using less than 10 TJ of gas per annum, or customers with a basic meter.

Victoria has the highest consumption and greatest number of gas customers of all the eastern and south-eastern states. Approximately 97% of Victorian Tariff V customers are residential.

Changes in consumption in both Tariff V residential and Tariff V commercial consumption can be attributed to similar key drivers including electrification, hydrogen adoption, weather, gas price, energy efficiency, and growth in gas connections.

5.2 Forecast number of connections

Tariff V gas connection forecasts were made up of two components, residential and non-residential gas connection forecasts.

The connections were determined by:

- Forecasting the total number of households for each state.
  - To forecast the number of households for each state, AEMO used the historical trend of electricity connections (National Metring Identifiers [NMIs]) and the Australian Bureau of Statistics (ABS) housing census data and forecasts. The methodology for forecasting the number of NMIs is available in the AEMO Electricity Demand Forecasting Methodology Paper[25].

[24] Darwin lacks a gas reticulation system, while Alice Springs is the only major city in the Northern Territory with reticulated gas. Due to the relatively small volumes; both current and projected in the Northern Territory, a simple assumption was made that the forecast is assumed to be constant over the outlook period.

[25] Refer to https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach.

- Forecasting the number of gas connections (MIRNs):
  - Inspecting the long-term (5+ year) trends in MIRNs usually shows a stable year-on-year growth, but as the ratio of households to those with gas could differ, any relationship between the growth rates of NMI 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 used to moderate the low and high connections forecast). This trend forecast was blended into a projection linking NMI annual growth rates to the proportion of MIRNs to NMIs 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.
- Splitting the MIRN forecast into residential and commercial connections:
  - The split between residential and non-residential connections was made from survey data collected from all gas distributors in each forecast region.
  - The growth rate for the non-residential connections was determined by applying a trend to the non-residential connection over the short term.
- For the 2024 GSOO, AEMO applied an electrification adjustment from the multi sector modelling to the residential and non-residential connections forecasts, to represent a transition to electric-only new buildings and a switch from gas to electric heating, hot water, and to a lesser extent cooking in existing buildings. The steps taken include:
  - 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 number of connections, using the average per connection estimate from the previous step.
  - Similar to how the economic and short-term trends are modelled for the Tariff D econometric model, the electrification data was adjusted in this manner 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.
    - No discounts were applied from year 7 of the forecast onwards.
  - Removing the number of connections deemed to have fuel-switched from the unadjusted connections forecasts.

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

5.3 Forecast Tariff V annual consumption methodology

5.3.1 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 was estimated; this is made up of base load and heating load components. This was based on projected 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 behavioural response to retail prices.
- The total TV consumption forecasts for each scenario were then adjusted for hydrogen blending, by removing the amount of gas being replaced by hydrogen, as estimated for each scenario by the multi sector modelling.

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

5.3.2 Methodology detail

Step 1: Weather normalisation of Tariff V residential and non-residential consumption

The objective of this step was to estimate weather-corrected average annual consumption for Tariff V for each region. This was to be used as the base for forecasting regional Tariff V annual consumption over the 20-year horizon.

This step required an estimation of the sensitivity of Tariff V consumption to cool weather. Average weekly Tariff V consumption was regressed against average weekly EDD, for Victoria and average weekly HDD, for other regions, over a two-year window (training data) leading up to the reference year.

The models are expressed as follows:

$$Y_i = \alpha + \beta_{XDD} * XDD_i + \beta_H * H$$

where:

Y_i = average Tariff V daily consumption for week i

i = week number

α = average Tariff V daily base load

β_{XDD} = average Tariff V temperature sensitivity (TJ/XDD)

XDD_i = average daily EDD for week i for Victoria, or average daily HDD for week i for New South Wales, South Australia, Queensland, and Tasmania.

β_H = estimate daily base load reduction over the 3 weeks Christmas – New Year business close down period

H = index to flag business close down period (= 3 for last week and first week of the year, 2 for week 2, 1 for week 3 of the New Year, 0 otherwise)

The weather normalised Tariff V estimated average annual consumption for year j was therefore equal to

$$Y_{WN,j} = Y_j - \beta_{XDD} * (XDD_j - XDD_{WS})$$

Note: XDD_{WS} is the forecast weather standard EDD or HDD. See Appendix A2.

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. These shares were further split into heating and base load, using the coefficients determined in the above regression.

The regression model for each region produced an upper 95% and lower 5% confidence interval for the heating and baseload (model intercept) coefficients and was applied across the scenarios, with the lower band applied to the scenarios that have the lowest population setting for Tariff V consumption and the upper band applied to the scenario with the highest population setting. The scenario with moderate (central) population forecast used the model mean of the regression model.

Step 2: Apply forecast trends and adjustments

The weather-corrected Tariff V residential and non-residential average consumption estimated in Step 1 were used as the base forecast consumption and was affected over the forecast horizon by the driving factors as detailed below.

For each year in the forecast, the total forecast gas consumption followed the following calculation:

- Weather normalised consumption for the region in the reference year as calculated in step one.
- Plus the positive impact of new gas connections from the reference year, adjusted for electrification.
- Plus the negative 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 and CSIRO (see Appendix A2.3 for further information). Climate change is anticipated to increase average temperatures, which will reduce heating load from gas heaters and hot water systems.
- Plus the negative impact of energy efficiency savings.
  - In 2023, Strategy.Policy.Research developed energy efficiency forecasts for the residential and commercial sectors in each region, taking into account 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[26]. AEMO discounted the energy efficiency forecasts by the percentage of connections estimated to have switched to electricity.

[26] For details of the scope of measures modelled, refer to Strategy.Policy.Research, Energy Efficiency Forecasts 2023, available at https://aemo.com.au/-/media/files/major-publications/isp/2023/iasr-supporting-material/2023-energy-efficiency-forecasts-final-report.pdf.

- Plus the negative impact of 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 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 *Progressive Change* scenario, and -0.05 in the *Step Change* and *Green Energy Exports* scenarios.
- Plus the negative impact of hydrogen blending, as described in Section 5.3.1.

6 Maximum demand

This chapter 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 2024 GSOO utilised Monte Carlo simulation techniques similar to those employed by electricity demand forecasting. The Monte Carlo 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 1.

Gas maximum demand modelling can be broken into three steps:

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

Step 1: Capture the relation between demand and demand drivers

Step 1 captured 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[27] 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 (unless in the case of a tourist economy).
- Insignificant coefficients.

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

- 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[28] to calculate the out-of-sample forecast accuracy.

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

[28] A 10-fold cross validation was performed by breaking the data set randomly into 10 smaller sample sets (folds). The model was trained on 9 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.

- Histogram of the residuals, quantile-quantile (Q-Q) plot, and residual plots.

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.

Equation 1 and 2 represents the generalised model used for predicting 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[29] residual at time t $(\sim N(0, \sigma_\varepsilon{}^2))$
- 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% probability of exceedance (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 demand within the simulation process, for each of the key drivers discussed in Chapters 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.

[29] 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.

The LNG and GPG peak day forecast was 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:

- GPG: this reported the typical GPG demand seen during the regional peak days for Tariff V and D combined.
- 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 DTS data (for Victorian demand only), flow data provided by pipeline operators (where available), or the Gas Bulletin Board. 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 demand forecasts for the 20-year outlook period. This is achieved through an optimisation where forecasts of maximum 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, commercial, and industrial 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 1.

LNG export demand

AEMO developed a daily reference profile for LNG export load, using the daily load profile from the Gas Bulletin Board 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 are achieved through the same topology 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:

1. Residential prices.
2. Commercial prices.
3. Small industrial prices.

A1.1 Retail pricing methodology

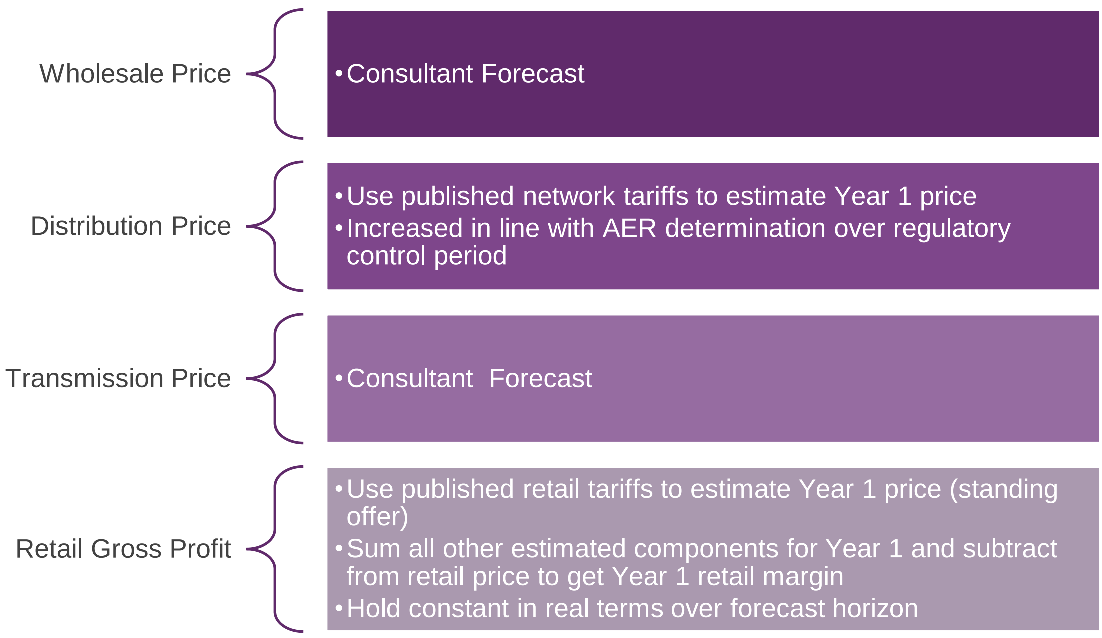
The gas retail price projections were formed from bottom-up projections based on separate forecasts of the various components of retail prices.

The key components were:

- Wholesale prices.
- Network costs.
- Retail margin.
- Retail price.

Figure 7 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 7 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 daily maximum demand for New South Wales, Queensland, South Australia, and Tasmania.

To obtain the best correlation with gas consumption, high resolution (three-hourly) temperature averages (denoted as T_{312}) were calculated for multiple weather stations in each region, then the averages were weighted according to population centres with high winter gas consumption (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 Bureau of Meteorology 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:

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

A weighted average was taken across the relevant weather stations in the region to obtain a regional average daily temperature (T_{reg312}). The station weightings and T_{base} are shown in Table 5. Finally, the Degree Day (DD312) was calculated for each region, applying the standard HDD formula to the weighted T_{avg312} for each region:

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

Table 5 Station name and ID along with weighting and base temperature used for the 2022 GSOO, excluding Victoria

Region	Station name	Station ID	Tariff V Weight	T_{base} (°C)
New South Wales	Sydney (Observatory Hill)	66062	0.00	19.57
New South Wales	Bankstown Airport	66137	1.00	19.57
New South Wales	Wagga Wagga	72150	0.00	19.57
Queensland	Archerfield	40211	1.00	19.30
Queensland	Rockhampton	39083	0.00	19.30
Queensland	Townsville	32040	0.00	19.30
South Australia	Edinburgh RAAF	23083	1.00	17.94
South Australia	Adelaide (Kent Town)	23090	0.00	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 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[30], 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 6.

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 6 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 Bureau of Meteorology; the stations used and weighting applied are given in Table 7.

[30] 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 3am and end time is 12am the next day.

Table 7 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.

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 Bureau of Meteorology at Melbourne Airport (see Table 8 for BOM station ID) using the following calibration:

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

Table 8 Weather station used for the solar insolation component of the Victorian EDD

Region	Station name	Station ID	Weight
Victoria	Melbourne Airport	86282	1.00

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 2000 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 has 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 as result of 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 Bureau of Meteorology 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.

Validation against historical weather

To include the effect of a climate change signal on the heating demand of energy consumers, an adjustment to be made on 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.

To quantify this effect, AEMO compared temperature measurements in rural and city-based weather stations in the same climate region. For example, a comparison of the average winter temperatures from 1995 until 2015 for the city-based station (Melbourne Regional Office) and in a regional area (Melbourne Airport) showed an increase in the average daily winter temperatures of 0.42 °C and 0.24 °C respectively. This finding, of the city station

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

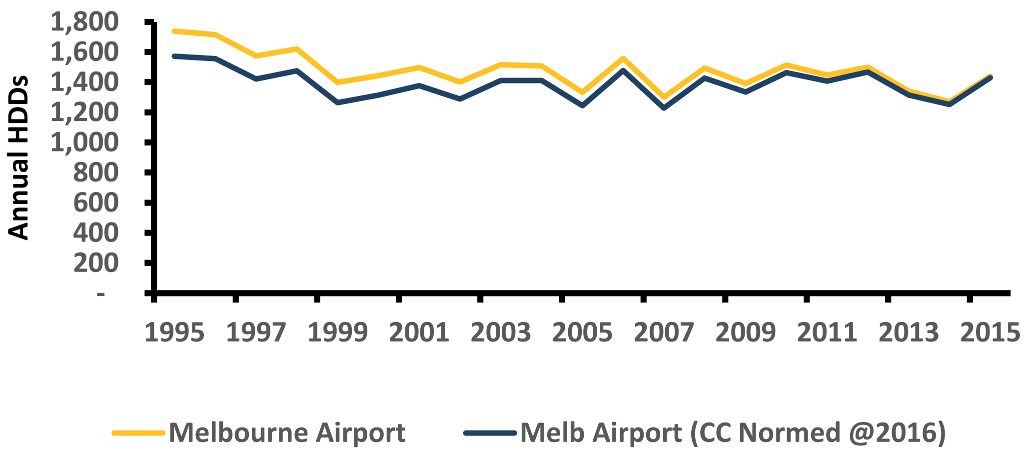
showing twice the warming of the rural station, is consistent with other work that has estimated that approximately half the warming in Melbourne city can be attributed to the UHI[32].

Figure 8 below shows how the application of the climate change trend in Melbourne Airport's temperature data (on an annual basis) can account for a large part in the observed reduction of HDDs over the last 20 years. Investigation of the other main weather stations (see Table 5) used for calculating HDDs identified only small effects of UHI, likely due to these stations being situated in less urban or open aired environments.

Using historical temperature anomaly data from the Bureau of Meteorology, AEMO adjusted the daily average temperature data against the climate change average temperature anomaly to re-baseline the last 20 years of HDDs (approximately compounding + 0.025°C per annum).

This adjustment was applied to all the weather stations as described in Table 5. The ability to quantify the historical component of climate change in HDD changes over time provided a strong validation to apply a climate change signal to the HDD forecast.

Figure 8 Comparison of HDD historical models for Melbourne Airport with and without a climate change adjustment



Inclusion in forecast data

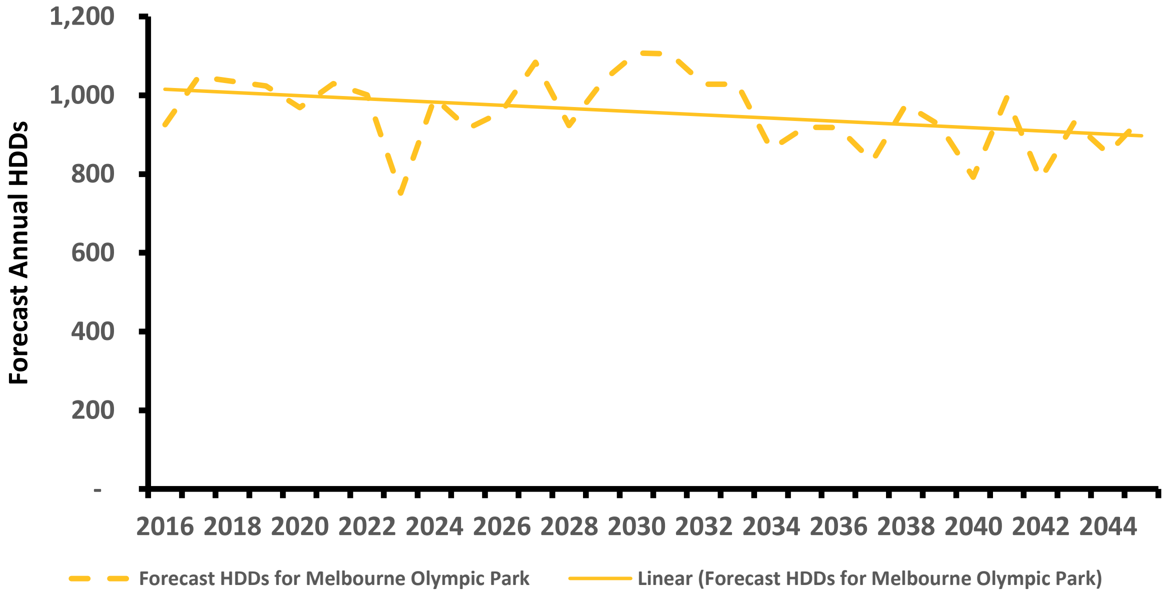
The median trace of the 40 RCP4.5 models predicts a 0.5 °C increase in average temperatures from 2018-2038 across Australia. AEMO used this data to adjust the forecast weather standard used in each region over the forecast period, and calculate the annual HDDs.

Climate models also simulate natural year-to-year natural weather volatility. Applying the climate change trend to the HDD will contains 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 (refer to Figure 9 for an example on Melbourne's Olympic Park forecast HDDs). This linear trend was then applied against the reference HDD (or HDD component of the EDD) forecast. The annual

[32] Suppiah. R and Whetton, P.H., "Projected changes in temperature and heating degree-days for Melbourne, 2012-2017". Available at https://www.aer.gov.au/system/files/Attachment%2013.2%20CSIRO%20-%20Projected%20Changes%20in%20Temperature%202012%20to%202017.pdf.

reductions for HDDs calculated for each state were 7.7 in New South Wales, -1.7 in Queensland, and - 5.6 in South Australia, and the annual reduction in EDDs for Victoria was - 6.8.

Figure 9 A climate change adjusted HDD showing annual weather variability with a linear trend for Melbourne Olympic Park



To model gas maximum 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 (1995–2015). This data was re-baselined to the reference year, by applying an adjustment using the Bureau of Meteorology's historical temperature anomaly data from climate change impacts since 1995. This followed a similar method to what was performed to baseline the HDDs, but at a finer (half-hourly) granularity, preserving historical volatility from an individual historical weather year but a data set more reflective of the climate in the reference year.

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 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 recording errors, gate station losses and other uncertainties. These gas losses are commonly known as 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 Declared Transmission System, 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 demand

Losses during times of maximum 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 demand in history were then applied to maximum demand days in the forecast horizon.

A4. Data sources

Table 9 Historical data sources

Demand component	Data source for all regions except for Victoria	Data source for Victoria
Residential and commercial	1. CGI Logica - SA and NSW 2. AEMO internal database - QLD 3. Distribution business survey - TAS	AEMO's internal database
Industrial	1. Distribution businesses (for all Tariff D customers, aggregated on a network basis) 2. Transmission data: - Transmission businesses (for all Tariff D customers, aggregated on a network basis) for data before 2019 - Gas Bulletin Board 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	Gas Bulletin Board	N/A

Table 10 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 Logica	https://forecasting.aemo.com.au/	
Historical consumption data by region	Transmission & Distribution, Industrial data	https://forecasting.aemo.com.au/	
Historical consumption data by region	Gas Bulletin Board (GBB)	https://aemo.com.au/en/energy-systems/gas/gas-bulletin-board-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/	Effective Degree Days (EDD) and Heating Degree Days (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
Economic data	Economic Consultancy	https://forecasting.aemo.com.au/	Economic consultants provide forecasts for Services sector GVA and Industrial Production. The index for these forecasts are available on AEMO's forecasting data portal

Data series	Data sources	Reference	Notes
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 11 Data sources for input to retail gas price model

Data series	Data sources	Reference	Notes
Wholesale price forecasts	ACIL Allen	Report: https://aemo.com.au/-/media/files/major-publications/isp/2023/iasr-supporting-material/acil-allen-natural-gas-price-forecasts.pdf Workbook: https://aemo.com.au/-/media/files/major-publications/isp/2023/iasr-supporting-material/acil-allen-natural-gas-price-forecast.xlsx	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	NSW: AGL SA, VIC & QLD: Origin Energy TAS: TasGas	AGL: https://www.agl.com.au/get-connected/electricity-gas-plans Origin Energy: https://www.originenergy.com.au/for-home/electricity-and-gas.html TasGas: https://www.tasgas.com.au/	For each region, a reference retailer is used to estimate current year retail prices.
Distribution published prices	NSW: Jemena SA& QLD: AGN VIC: Multinet TAS: None publicly available.	Jemena: http://jemena.com.au/about/document-centre/electricity/tariffs-and-charges AGN: https://www.australiangasnetworks.com.au/our-business/regulatory-information/tariffs-and-plans Multinet: https://www.multinetgas.com.au/tariff-pricing/	For each region, tariffs from a reference distribution network provider are used to estimate the first-year distribution price forecast.

Table 12 Input data for analysis of historical trend in Tariff V consumption

Data	Source	Purpose
Tariff V daily consumption by region and exclusive of UAFG	VIC and QLD: AEMO Settlements database. NSW and SA: Meter data agent (CGI data tables). TAS: 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 (Vic) or HDD (other regions)	BOM. Further detail provided in Appendix A2	Same as above.

Data	Source	Purpose
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	VIC and QLD: AEMO Settlements database. NSW and SA: Meter data agent (CGI data tables). TAS: 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 estimate impact of gas prices on gas Tariff V residential and non-residential consumption.

Table 13 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 5.2.	
Annual EDD/HDD standards	See Appendix A2.	Applied to forecast Tariff V heating load.
Forecast residential annual consumption savings due to fuel-switching	CSIRO and ClimateWorks	Applied to forecast the impact of fuel-switching on Tariff V residential forecasts
Forecast annual consumption savings due to energy efficiency	Strategy.Policy.Research 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
GWh	Gigawatt hours
HDD	Heating degree days
TJ	Terajoules

Abbreviations

Abbreviation	Expanded name
ABS	Australian Bureau of Statistics
AER	Australian Energy Regulator
APLNG	Australia Pacific LNG
CSG	Coal seam gas
DB	Distribution business
DoW	Day of Week
DSM	Demand side management
DTS	Declared Transmission System
ESD	Energy Statistics Data
ECGM	East Coast Gas Market
GLNG	Gladstone Liquefied Natural Gas
GPG	Gas-powered generation
GRMS	Gas Retail Market Systems
GVA	Gross Value Added
HIA	Housing Industry Association
LIL	Large industrial loads
LNG	Liquefied natural gas
LRET	Large-scale Renewable Energy Target
MHQ	Maximum Hourly Quantity
MMS	Market Management System
MPC	Market Price Cap
NEM	National Electricity Market
NGFR	National Gas Forecasting Report
NTNDP	National Transmission Network Development Plan
POE	Probability of exceedance
QCLNG	Queensland Curtis LNG
RCAC	Reverse-cycle Air-conditioners

Abbreviation	Expanded name
RCP	Representative Concentration Pathways
SMIL	Small-to-medium industrial loads
SRES	Small-scale Renewable Energy Scheme
TGP	Tasmanian Gas Pipeline
UAFG	Unaccounted for gas
UHI	Urban Heat Island Effect
VRET	Victorian Renewable Energy Target

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.
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.
Industrial, 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 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 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 commentary about underlying consumer behaviour patterns.
Probability of Exceedance (POE)	Refers to the likelihood that a maximum 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 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 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 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