Attachment 12.1

Core Energy

Demand Forecasting Report

SA Final Plan July 2021 – June 2026

July 2020

Australian Gas Networks

Gas Demand and Customer Forecasts

Australian Gas Networks | SA Gas Access Arrangement 2022-2026

July 2020

Final Report

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Glossary

AA	Gas Access Arrangement Review
ACT	Australian Capital Territory
AGIG	Australian Gas Infrastructure Group
AGN - SA	Australian Gas Networks – South Australia
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BOM	Bureau of Meteorology
CBJV	Cooper Basin Joint Venture
COAG	Council of Australian Governments
CORE	Core Energy & Resources Pty. Limited
DD	Degree Days
EDD	Effective Degree Days
EEO	Energy Efficiency Opportunities
E-to-G	Electricity-to-Gas
GBJV	Gippsland Basin Joint Venture
GEMS	Greenhouse and Energy Minimum Standards
HDD	Heating Degree Days
JCC	Japanese Cleared Crude
LGA	Local Government Area
LRET	Large-scale Renewable Energy Target
LRMC	Long Run Marginal Cost
MD	Medium Density (Dwelling)
MD/HR	Medium Density/ High-Rise
MDQ	Maximum Daily Quantity
MEPS	Minimum Energy Performance Standards
MAP	Moomba to Adelaide Pipeline
NABERS	National Australian Built Environment Rating System
NSW	New South Wales
RET	Renewable Energy Target
SA	South Australia
SRES	Small Scale Renewable Energy Scheme
STTM	Short Term Trading Market
VIC	Victoria
WA	Western Australia

Section 1 | Summary

Section 1 | 1. Executive Summary

1.1. Scope of this Report

This report has been prepared by Core Energy & Resources Pty Ltd ("**CORE**") for the purpose of providing Australian Gas Networks ("**AGN**") with an independent forecast of gas customers and demand for the company's natural gas distribution network in South Australia ("**SA**"), for the five financial years from 1 July 2021 to 30 June 2026 ("**Review Period**").

CORE has noted that these projections (both this Report and related forecasting models[1]) will form part of AGN's Gas Access Arrangement Review ("**AA**") submission to the Australian Energy Regulator ("**AER**").

CORE acknowledges that the derivation of mid to longer range forecasts generally, and this customer and demand forecast specifically, involve a significant degree of uncertainty. Accordingly, CORE has taken all reasonable steps to ensure this Report, and the approach to deriving the forecasts referred to within the Report, comply with Division 2 of the National Gas Rules ("**NGR**") "Access arrangement information relevant to price and revenue regulation", and in particular, parts 74 and 75 as referenced below.

"74. Forecasts and estimates

(1) Information in the nature of a forecast or estimate must be supported by a statement of the basis of the forecast or estimate.

(2) A forecast or estimate:

(a) must be arrived at on a reasonable basis; and

(b) must represent the best forecast or estimate possible in the circumstances.

75. Inferred or derivative information

Information in the nature of an extrapolation or inference must be supported by the primary information on which the extrapolation or inference is based." [2]

1 The forecasting models are confidential, and an application will be sought for disclosure to be suppressed in accordance with NGR part 43 (2) (b).
2 NGR dated April 2014 and accessed from AEMC website.

1.2. Core Energy Group - Demand Forecast Experience

The following table outlines the experience held by members of CORE for both energy demand forecasting and independent expert witness roles:

Focus Area	Experience
Independent Expert/Witness	▪ A variety of independent expert roles covering: > Gas contract disputes > Gas price reviews – east and western Australia > Gas demand – electricity, industrial, distribution, transmission > Drilling activity (LNG) > Gas processing plants > Gas transmission pipelines > Gas storage > International LNG
Demand forecasting, modelling and scenario analysis	▪ Development of models and analytical tools, forecasts and demand scenarios along the gas sector value chain: > Exploration and production; > Transmission; > Distribution; > Electricity generation; > Retailing; and > Liquefaction (LNG) ▪ Demand forecasting for a diverse range of clients including energy producers, gas infrastructure companies, retailers and the market operator (AEMO- in support of the GSOO publication).
Gas Distribution	Access Arrangements > WA – ATCO > NSW – Jemena > VIC – AGN > SA – Envestra (now AGN SA) > ACT – ActewAGL (now Evoenergy) General > Demand forecasting, modeling and scenario analysis covering all Australian networks > Acquisition of Wagga Gas Network from NSW Government
Gas Transmission	▪ Development of gas demand scenarios for major transmission systems: > South West Queensland > Roma Brisbane > Moomba Sydney > Eastern Gas Pipeline > Moomba Adelaide > SEAGas > Tasmania > QCLNG transmission line
Gas Exploration and Production	▪ Development of contracted and potential demand and supply scenarios: > Cooper Basin: SA and SWQ JV; unconventional gas (shale, coal seam, tight gas) > Gippsland Basin: Gippsland Basin JV > Otway Basin: Minerva, Thylacine-Geographe, Casino > Surat/Bowen Basins: all major Queensland coal seam gas fields > WA Basins: NWS Domgas, John Brookes, Gorgon, Wheatstone, Pluto > LNG – NWS JV, Gorgon, Pluto, Ichthys, Wheatstone, GLNG, APLNG, QCLNG, Darwin LNG

1.3. Structure of Report

This report comprises two Sections:

Section 1 – Summary

A summary of the approach to forecasting network demand and customer numbers including:

- Methodology
- Tariff R and Tariff C Forecasts – connections/customer numbers and demand
  - Residential, Tariff R
  - Commercial, Tariff C
- Tariff D Forecast – Maximum Demand and ACQ Forecast
- Conclusion

Section 2 – Supporting Information and Analysis

Information and analysis undertaken by CORE to derive the forecasts set out in the Summary. This includes:

- Weather Normalisation
- Retail Gas & Electricity Price Forecast
- Price Elasticity of Demand
- Regression Analysis and Results
- Review of Appliance and Dwelling Efficiency; Associated Policy
- Review of Previous AA Forecast

Please note that all years referred to are financial years unless otherwise stated.

1.4. Overview of the AGN South Australia Network

The SA gas distribution network under review services around 455,000 customers with a mains length of approximately 8,100 kilometres. The significant populations reached by the network include Adelaide, Whyalla, Port Pirie, Nuriootpa, Berri, Murray Bridge and Mount Gambier.[3]

For the purpose of this report, reference will be made to three customer segments - Tariff R, Tariff C and Tariff D as defined in Table 1.1 below. The table also sets out the nature of the forecasts that CORE was asked to prepare. These forecasts reflect the billing structure for each customer group. For example, forecasts of MDQ are not required for residential customers as this group is charged based on the volume of gas used.

3 Source: Australian Gas Infrastructure Group 2018 Annual Review

1.4.1. Tariff Classification

For the purpose of this Report, reference will be made to three customer segments - Tariff R, Tariff C and Tariff D[4] as defined in Table 1.1 below.

Table 1.1. Customer Segments used for Tariff Classification.

Customer segment	Description
Volume Tariffs – Tariff R, Tariff C (<10TJ)	AGN's Volume Tariff customer groups consist of Residential customers (Tariff R) and Commercial customers (Tariff C) who are reasonably expected to consume less than 10 TJ of natural gas per year. As the commercial customers billed quarterly have significantly different gas usage (and drivers of demand) than residential customers, CORE has recorded forecasts for these types of customer separately under 'Commercial'. New Residential customers are further segmented as follows: ▪ E-to-G – electricity only dwellings which connect to gas ▪ Estates – typically new, free-standing houses but can include semi-detached or duplex/townhouse dwellings (1-2 dwellings) ▪ Medium Density/High Rise – houses connected as part of a higher density apartment (3 or more dwellings). Throughout this Report, the Volume Tariff customer groups will be referred to as Tariff R and Tariff C customers and the customer segments defined above will also be frequently referred to.
Demand Tariffs - Tariff D (>10TJ)	AGN's Demand Tariff customer group consists of large industrials that are reasonably expected to consume more than 10 TJ of gas per year. Throughout this Report, the Demand Tariff customer group will be referred to as Tariff D customers and MDQ will be referred to for certain historical data and analysis- this refers to the highest day's consumption within a particular year. ACQ refers to the total volume consumed within one year.

Source: CORE based on advice from AGN and AGN Schedule of Tariffs and Plans.

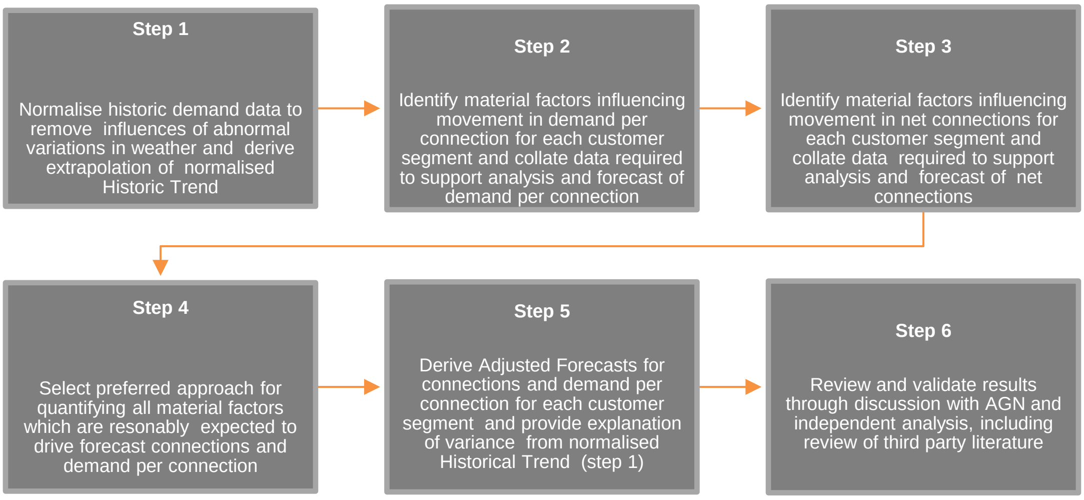
4 These types are consistent with the Volume Tariff and Demand Tariff customer groups used in tariff assignment as referenced in the 2020 AGN Schedule of Tariffs and Plans.

1.5. Methodology Overview

An overview of the methodology adopted by CORE to derive forecasts of network demand and customer numbers is provided below for both volume and demand customers. Further detail is presented in Section 2.

1.5.1. Volume Tariff Groups

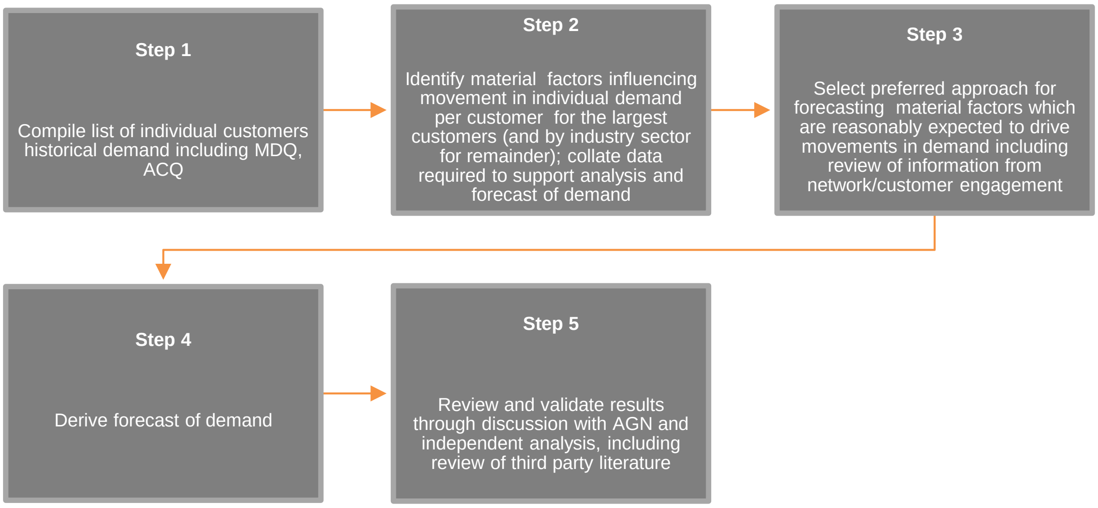
Figure 1.1. CORE Methodology – Tariff R and Tariff C.



Source: CORE.

1.5.2. Tariff D

Figure 1.2. CORE Methodology - Tariff D.



Source: CORE.

CORE is of the opinion that the rigorous application of this methodology, as presented within this Report, derives forecasts which satisfy the requirements of the NGR - as the forecasts are derived on a reasonable basis, to provide the best forecast or estimate possible under the circumstances, utilising appropriate primary information, where available, to support the extrapolations/ forecasts.

1.6. Overview of History & Forecast for R and C Tariff Groups

Table 1.2 and Figure 1.3 provide a summary of actual connections, normalised demand per connection and total normalised demand for both volume tariff groups, together with a summary of average annual growth.

Table 1.2. Historical Connections, Demand per Connection and Demand – Volume Tariff Groups.

Closing Connections	2019 Historical	AAGR 09-19 H	2026 Forecast	AAGR 22-26 F
Residential	443,043	1.59%	476,549	1.04%
Commercial	11,233	1.41%	11,644	0.62%
Total Volume Tariff Connections	**454,276**	**1.59%**	**488,192**	**1.03%**
Normalised Demand per Connection				
Residential	16.5	-2.03%	13.9	-2.55%
Commercial	295.7	-0.44%	291.5	-0.30%
Normalised Total Demand				
Residential	7,323,982	-0.45%	6,603,465	-1.54%
Commercial	3,322,122	0.95%	3,394,132	0.31%
Total Volume Tariff Demand	**10,646,105**	**-0.06%**	**9,997,597**	**-0.93%**

Source: CORE with historical data from AGN.

Figure 1.3. Total Volume Tariff Demand

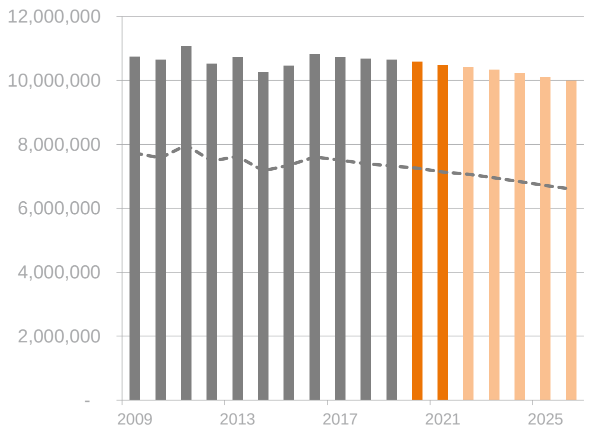
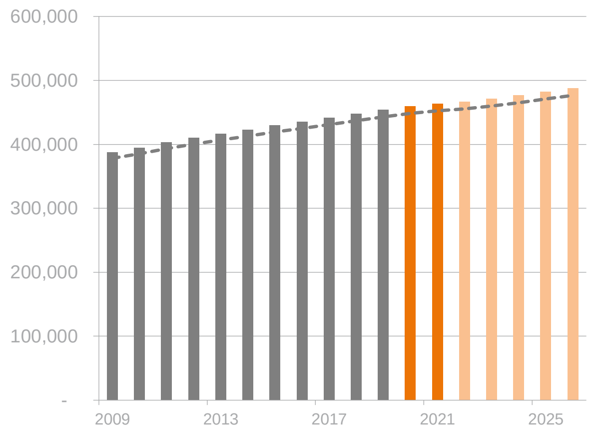


Figure 1.4. Total Volume Tariff Connections



The contribution from Tariff R is shown via the grey dashed lines; The contribution from Tariff C is represented by the remaining proportion above the line.

Source: CORE with historical data from AGN.

1.7. Overview of Historical Tariff D Demand

The following table and figures provide a summary of historical and forecast ACQ and MDQ demand for Tariff D, together with a summary of average annual growth rates.

Table 1.3. Tariff D Demand Projection | Summary

Tariff D Demand (GJ)	2019 Historical	AAGR 09-19 H	2026 Forecast	AAGR 22-26 F
ACQ	11,366,654.3	-2.09%	9,144,673.9	-2.85%
MDQ	50,486	-2.39%	39,174	-3.12%

Source: CORE based on historical data from AGN.

Figure 1.5. Total Tariff D MDQ | GJ

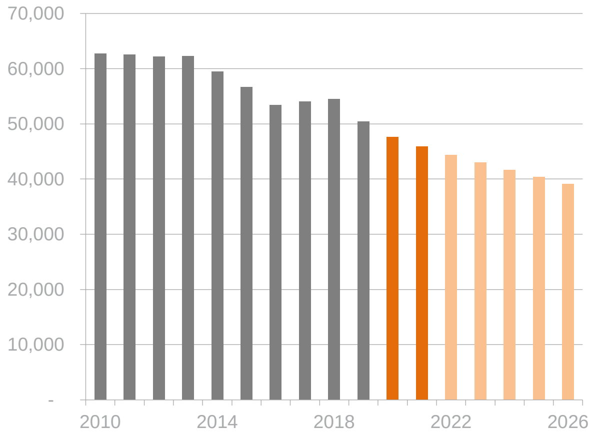
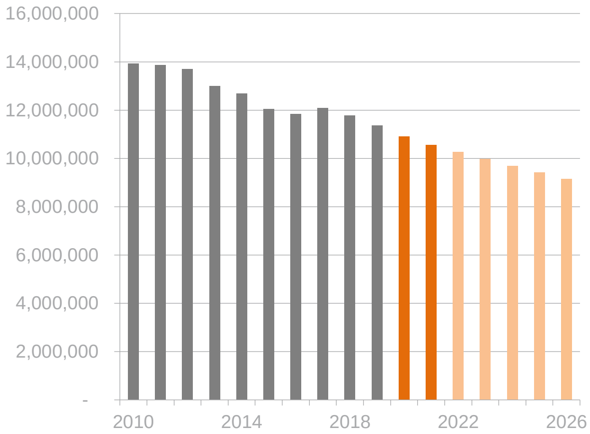


Figure 1.6. Total Tariff D ACQ | GJ



Source: CORE with historical data from AGN.

1.8. Overview of Connections and Demand Forecast

The following paragraphs provide a summary of the forecasts derived by CORE for all customer types.

1.8.1. Tariff R and Tariff C

Gas demand for volume customers is forecast to decrease at an annual average of -0.93% from 2022 to 2026. This forecast is influenced by two principal forces - an increase in connections of 1.03% p.a., offset by a reduction in demand per connection of -1.94% p.a. The contribution from each customer group is shown in the following table:

Table 1.4. Volume Tariff Connections, Demand per Connection and Demand | Summary

	2022	2022	2023	2024	2026	AAGR 2009-2019	AAGR 2022-2026
Connections							
Residential	455,278	459,953	465,169	470,924	476,549	1.59%	1.04%
Commercial	11,231	11,337	11,442	11,544	11,644	1.41%	0.62%
Total	466,509	471,290	476,611	482,468	488,192	1.59%	1.03%
Demand Per Connection							
Residential	15.5	15.1	14.7	14.3	13.9	-2.03%	-2.55%
Commercial	299.3	298.9	297.0	293.9	291.5	-0.44%	-0.30%
Total	22.3	21.9	21.5	20.9	20.5	-1.62%	-1.94%
Total Demand							
Residential	7,060,676	6,955,659	6,837,687	6,713,646	6,603,465	-0.46%	-1.54%
Commercial	3,361,039	3,388,745	3,398,272	3,392,675	3,394,132	0.95%	0.31%
Total	10,421,715	10,344,404	10,235,959	10,106,321	9,997,597	-0.06%	-0.93%

Source: CORE Demand Forecast

The major factor contributing to the reduction in volume customer demand is a reduction in demand per connection for residential customers, which is influenced by:

- continued growth in share of connections for medium and high-density connections which exhibit lower gas usage per dwelling;
- continued trends in gas appliance and dwelling efficiency, contributing to reductions in demand per connection;
- customer demand response to gas and electricity price movements whereby electricity prices are projected to move more favourably than gas during the forecast period; and
- reduced space heating usage attributable to competition with alternative energy sources, including R-C air-conditioning.

1.8.2. Tariff D

Capacity demand (as measured by MDQ) for Tariff D customers is forecast to fall by an annual average of -3.12% p.a. from 2022 to 2026 as shown in the table below. This fall is attributable to a continued reduction in gas-intensive industrial capacity and an increase in operational energy efficiencies at the individual plant level. Due to billing cycle lag and variability as to economic impact and recovery, CORE was unable to quantifiably modify the forecast to capture the impact of COVID. However, the impact of the COVID pandemic represents significant downside risk, particularly to large space heating customers (closed shopping centres and leisure centres) and manufacturers at risk of negative demand shocks.

Table 1.5. Tariff D Demand Projection | Summary

Tariff D	2022	2023	2024	2025	2026	AAGR 2009-2019	AAGR 2022-2026
MDQ	44,422	43,008	41,659	40,380	39,174	-2.39%	-3.12%
ACQ	10,269,515	9,979,838	9,695,806	9,417,434	9,144,674	-2.09%	-2.85%

Source: CORE, utilising historical data from AGN.

The decline in MDQ is modelled to continue its decline albeit at a slower long-term rate than the historical period although short term COVID pandemic demand shocks within the South Australian economy could result in larger declines:

- known and projected business closures/ capacity reductions are expected to be smaller relative to the reductions that occurred during the historical period; and
- continuing trend in energy efficiency, including peak demand as a response to increased energy costs and profit pressures more broadly.

1.9. Validation

An important part of the work program undertaken by CORE in relation to the derivation of AGN forecasts is a validation process. This involves CORE identifying independent third-party analysis which addresses one or more factors considered by CORE in deriving a final forecast. This validation process has been applied in a range of areas including, but not limited to:

- estimates of residential dwelling trends in South Australia including dwelling type and overall growth;
- projections of retail gas and electricity prices for South Australian customers;
- trends in energy efficiency at the appliance and building level; and
- trends in the South Australian economy such as economic output, business formation and manufacturing activity.[5]

In addition, CORE has reviewed all recent demand forecasts which have formed part of final AA decisions for other networks in Eastern Australia, to determine whether trend forecasts are consistent with other networks. The following charts show that the residential forecast (the majority of volume and connections) is forecast to move in the same direction as all other eastern networks with annual growth rates that are typical of other networks. It should be noted that the slowest decline in demand for connection shown for JGN is due partly to growth in a new multi-dwelling meter type whereby one metered connection is typically supporting 50-100 individual dwellings. The following sections will discuss the drivers of this forecast and demonstrate a consistency with own-history and neighbouring jurisdictions.

Figure 1.7. Forecast Benchmarking | Residential Demand per Connection

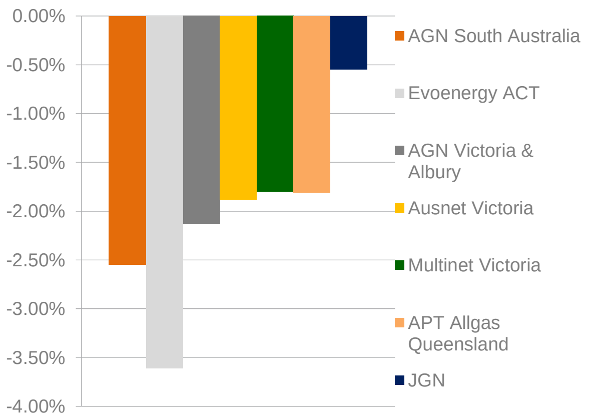
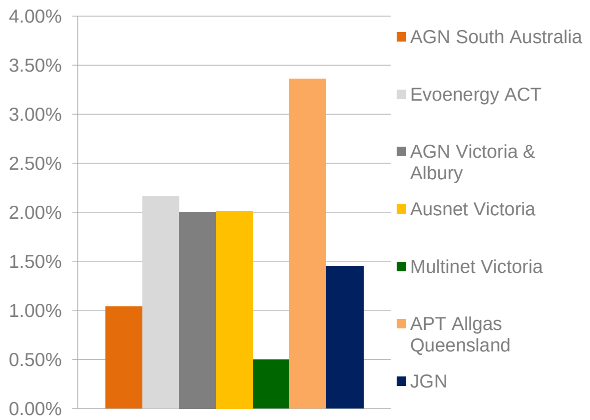


Figure 1.8. Forecast Benchmarking | Residential Connections



[5] These macroeconomic drivers are exposed to significant downside risk due to the ultimate impact of the COVID pandemic, an impact that was not yet visible when analysis was undertaken.

Section 1 | 2. Methodology

The methodology adopted by CORE to derive a gas demand forecast for the South Australian gas distribution network, involves four primary elements. Each element is expanded upon in the relevant section of this report.

1. An approach to normalising historical demand to remove the impact of abnormal weather and prices
2. An approach to deriving a forecast of Residential demand
3. An approach to deriving a forecast of Commercial demand
4. An approach to deriving a forecast of Tariff D Industrial demand

The methodology adopted by CORE considers all recent AA demand forecast proposals, draft decisions and final decisions, which allowed the development of a best-practice approach whilst also remaining compliant with the NGR.

The methodology favours a highly transparent approach, including a demand forecast model that examines all factors that could potentially impact normalised demand. This approach is fundamentally consistent with the methodology presented by AEMO in its latest National Gas Forecasting Report ("**NGFR**").[6]

This report sets out the underlying facts and assumptions that were necessary when analysing gas demand. The requested comprehensive data set as provided by AGN covers the 2009 to 2019 period, enabling CORE to review at least one full decade of historical trends for the volume tariff class and demand tariff class. CORE was also able to append the pre-2009 mass market historical trends observed and approved for the prior GAAR submission. This has enhanced the forecast by incorporating a longer time period of demand drivers and reduces the impact of one-off fluctuations. Tariff D analysis is performed on an individual customer basis with more focus on recent/proposed operational changes and macroeconomic influences hence a 10-year history was deemed a sufficient period for this forecast.

CORE considers this process to be compliant with s 74(2) of the NGR. Forecasts are constructed on a reasonable basis whilst representing the best forecasts possible in the circumstances.

Tariff R Residential and Tariff C Commercial demand is derived by multiplying the forecast number of connections by the forecast demand per connection, for each customer segment. This results in separate forecasts for each customer type (residential versus) and connection type (new versus existing connections; further broken down into different types of new dwelling). Tariff D Industrial demand was completed on an individual customer basis with customers sorted according to size, ANZSIC division and demand pattern (e.g. macroeconomic influence and/or weather-induced demand). Further details of approach are set out below for residential, commercial and industrial tariff classes.

[6] NGFR now delivered as part of the GSOO publication. Refer to Gas Demand Forecasting Methodology Information Paper, March 2019

2.1. Weather Normalised Demand

Gas demand is materially influenced by weather, particularly in the residential sector. Accordingly, the weather impact on historical residential and commercial demand was normalised to provide an appropriate basis for demand forecasting. CORE adopted a weather normalisation methodology based on AEMO's forecasting guidelines[7], which favours the application of Effective Degree Days ("**EDD**"). In comparing the methods of Heating Degree Days ("**HDD**") and EDD, EDD accounts for additional climatic factors such as:

- Sunshine hours.
- Wind chill; and
- Seasonality.

The coefficient of determination calculated by CORE also showed that EDD has a stronger relationship with gas demand than HDD. In addition, the Akaike Information Criterion ("**AIC**") supports the use of EDD instead of HDD as an index of weather fluctuations. For these reasons, CORE used EDD as a superior approach to weather normalisation.

2.1.1. EDD Index

The weather index selected for weather normalisation was based on AEMO's EDD_{312} methodology which has been approved by the AER in a number of previous gas access arrangements ("**AA**"). AEMO has endorsed the EDD_{312} as a more rigorous approach than EDD_{129} or HDD indices. The calculation method and resulting parameters are outlined below:

EDD Calculation:

1. Develop an EDD Index Model that calculates the EDD Index coefficients – this model is included as a supporting document to this report.
2. Derive EDD Index coefficients by regressing daily gas demand on climate data, ranging from 2005 to 2019. The start date of the regression was based on the availability of reliable daily gas demand data which spanned 15 years - deemed appropriate by CORE. Historical climate data for the Adelaide metropolitan area was obtained from the Bureau of Meteorology (temperature, wind speed, sunshine hours) who recorded the available data points at major Adelaide weather stations during the historical series (West Terrace, Kent Town and Adelaide Airport). CORE has analysed the historical relationship of sunshine hours between the three stations and come up with an adjustment factor such that one consistent historical series was derivable. Most climate observations used came from the Kent Town Weather Station and missing data was substituted using West Terrace or Adelaide Airport readings (corrected by an adjustment factor).[8] The average daily temperature and wind speed data was estimated using the average of 8x3-hourly data between 3.00 am and 12.00 am Dummy variables for certain days of the week (Friday, Saturday and Sunday) were also included in the regression to capture the additional gas demand that occurs on Sundays and the reduced demand that occurs on Fridays and Saturdays.[9]

[7] AEMO, 2012 Weather Standards for Gas Forecasting.

[8] Weather Station 023090. CORE notes that the distribution network includes customers located some distance from Adelaide. However, the majority of customers are located in the Greater Adelaide area hence the weather observations for Adelaide Metro are appropriate, as has been approved by the AER previously. CORE notes that the AER has accepted this approach in Vic and NSW for networks that also have significant latitude ranges and customers located at different altitudes.

[9] Main difference in activity includes business opening hours and the number of hours residents spend at home cooking and using space heaters.

3. Calculate EDD by using the weather normalised demand model and derived EDD index coefficients. The weather normalisation model is included as a supporting document to this report.

Below are the model structure and coefficients of CORE's EDD_{312} Index:

Daily demand per connection = $b_0 + b_1$*EDD + b_2*Friday + b_3*Saturday +b_4*Sunday.

EDD =	Degree Day ("**DD312**")	temperature effect
	+ **0.0242** * DD312*average wind speed	wind chill factor
	- **0.10** * sunshine hours	warming effect of sunshine
	+ max(**3.58***2* Cos $\left(\frac{2\pi(\text{day}-201)}{365}\right)$)	seasonality factor

Where DD_{312} is the degree day as calculated by the following table:

DD_{312} =	$T_2 - T_1$ if $T_1 < T_2$	Daily temperature above threshold temperature
	0 if $T_1 > T_2$	Daily temperature below threshold temperature

- T_1 is the average of 8 three-hourly temperature readings (in degrees Celsius) from 3.00am to 12.00am from the Bureau of Meteorology's Kent Town Weather Station- deemed by CORE to be an appropriate weather station for the network.
- T_2 is equal to 18.49 degrees Celsius and represents the estimated threshold temperature for gas heating within the AGN SA Network.
- Average wind speed is the average of the 8 three-hourly wind observations (measured in knots) from 3.00am to 12.00am measured at the Kent Town Weather Station.
- Sunshine hours are the number of hours of sunshine above a standard intensity as measured at the Weather Bureau's Kent Town Weather Station until June 2015 when this dataset was discontinued. To complete the historical series, observations from Adelaide Airport were used with a correction factor (derived from historical periods where both weather stations recorded this data point).[10]
- The seasonality factor models variability in consumer response to different weather. It indicates that Residential and Commercial consumers more readily turn on, adjust heaters higher or leave heaters on longer in winter than in the shoulder seasons given 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 and consumers are potentially in the habit of using heating appliances once the middle of winter is reached. This change in consumer behaviour is captured in the Cosine term in the EDD formula, which implies that for the same weather conditions heating demand is higher in winter than in the shoulder seasons or in summer.[11]

[10] CORE has set this coefficient to 0.10 as this provided a higher R squared result than a coefficient of 0 which was the coefficient achieved using the Excel Solver add-in. Given the higher predictive power and greater consistency with historical precedent (e.g. prior AA), the decision was made to use 0.10 rather than defer to the 0 coefficient which was likely being achieved due to an upper limit of iterations imposed by Solver. The same process was applied to other variables, but this did not lead to a superior statistical result.

[11] As described in; AEMO, *Victorian EDD Weather Standards – EDD312 (2012)*

2.1.2. Weather Normalised Demand Model

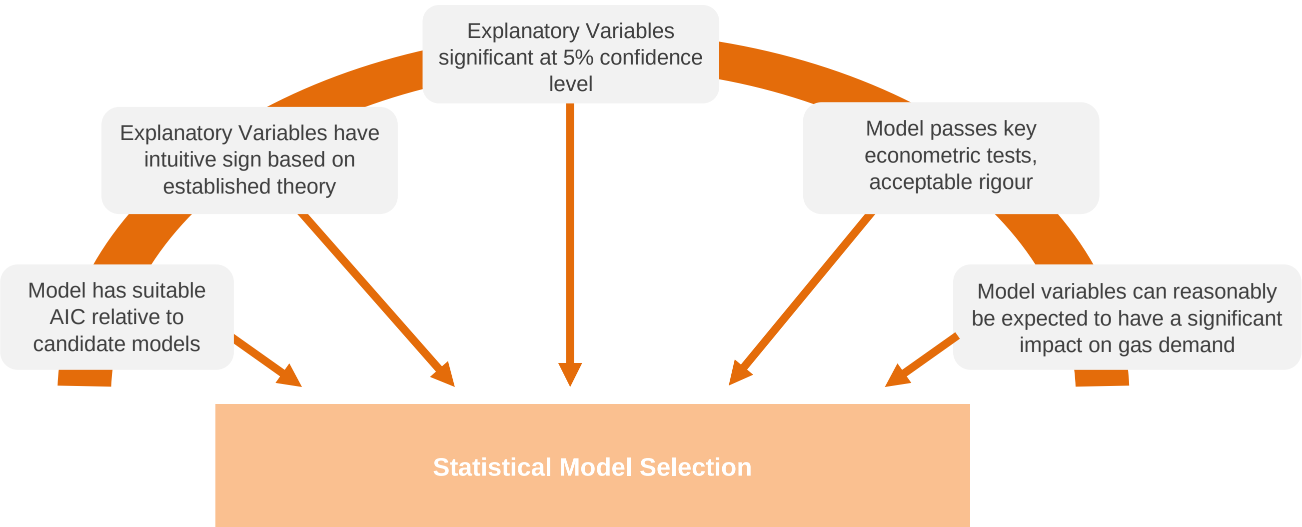
The EDD_{312} Weather Index was then used for regression analysis on AGN residential and commercial demand data.

1. Residential and commercial data was regressed separately on historical EDD data, on a monthly basis
2. The optimum statistical relationship between customer gas demand and weather fluctuations was obtained
3. The regressions were performed with the two main data sets:
   - Monthly sum of EDDs (calculated from the daily EDD series obtained from the first stage)
   - Monthly sum of gas demand (AGN demand data)

A variety of model specifications and model terms were tested for their predictive power and statistical rigour, including:

- Lagged values of the gas demand data
- Logarithmic and differencing transformations of the weather/demand data
- Variables that capture the impact from events specific to one part of the data series (dummy variables)

Please see Appendix A1 for a full summary of the regression model output and statistical test results. The statistical models selected for the forecast of residential and commercial demand satisfied the following criteria:



CORE considers this process to be compliant with s 74(2) of the NGR. Forecasts are constructed on a reasonable basis whilst representing the best forecasts possible in the circumstances.

2.2. Weather Normalisation | Tariff D

In addition to the residential and commercial tariff groups detailed in the previous section, CORE adopted the same methodology to weather normalise a portion of the industrial tariff group. After segregating these customer groups into their respective ANZSIC code sectors, it was clear that certain sectors exhibit strong weather-induced patterns whereas others do not. For instance, the following charts compare the monthly sum of demand for manufacturing customers and industrial customers within the Health Care & Social Assistance sector. For manufacturers there are fluctuations around December and January which are typically driven by maintenance periods and reduced operations during the festive season. In comparison, the Health & Social Assistance sector comprises large medical facilities and residential premises which exhibit a strong winter peak. For this sector, weather-induced heating load is a key determinant.

Figure 2.1. Seasonal Demand Pattern | Manufacturing Sector Average Monthly ACQ

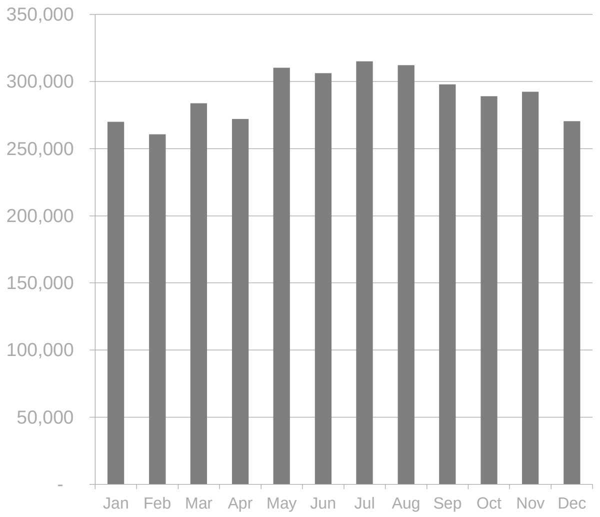
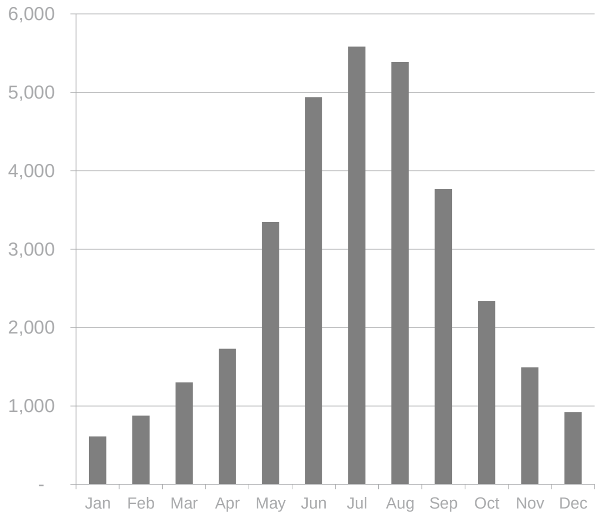


Figure 2.2. Seasonal Demand Pattern | Education and Training Sector Average Monthly ACQ



CORE then weather normalised the following industrial customer groups:

- Accommodation and Food Services
- Professional, Scientific and Technical Services
- Administrative and Support Services
- Public Administration and Safety
- Education and Training
- Health Care and Social Assistance
- Arts and Recreation Services
- Other Services

The remaining sectors were forecast using GVA[12], GSP[13] and other regression analysis (refer Appendix A4 for additional details):

- Agriculture, Forestry & Fishing
- Mining
- Manufacturing
- Electricity, Gas, Water and Waste Services
- Construction
- Wholesale Trade
- Retail Trade
- Transport, Postal and Warehousing
- Information Media and Telecommunications
- Financial and Insurance Services
- Rental, Hiring and Real Estate Services

Statistical model types, regression post-estimation and overall methodology was consistent with the previous description for Tariffs R and C above. Please refer to Appendix A1 and A4 for a full description of weather normalisation regression analysis and results.

CORE notes that the approach is consistent with AEMO's GSOO 2019 methodology whereby GVA is used to project annual volume and large customers are individually analysed, separate to the trends applied to the pool of smaller industrials. CORE notes also that the same econometric model (natural logarithmic transformation) was used by AEMO to derive the relationship between ACQ and sector output.[14]

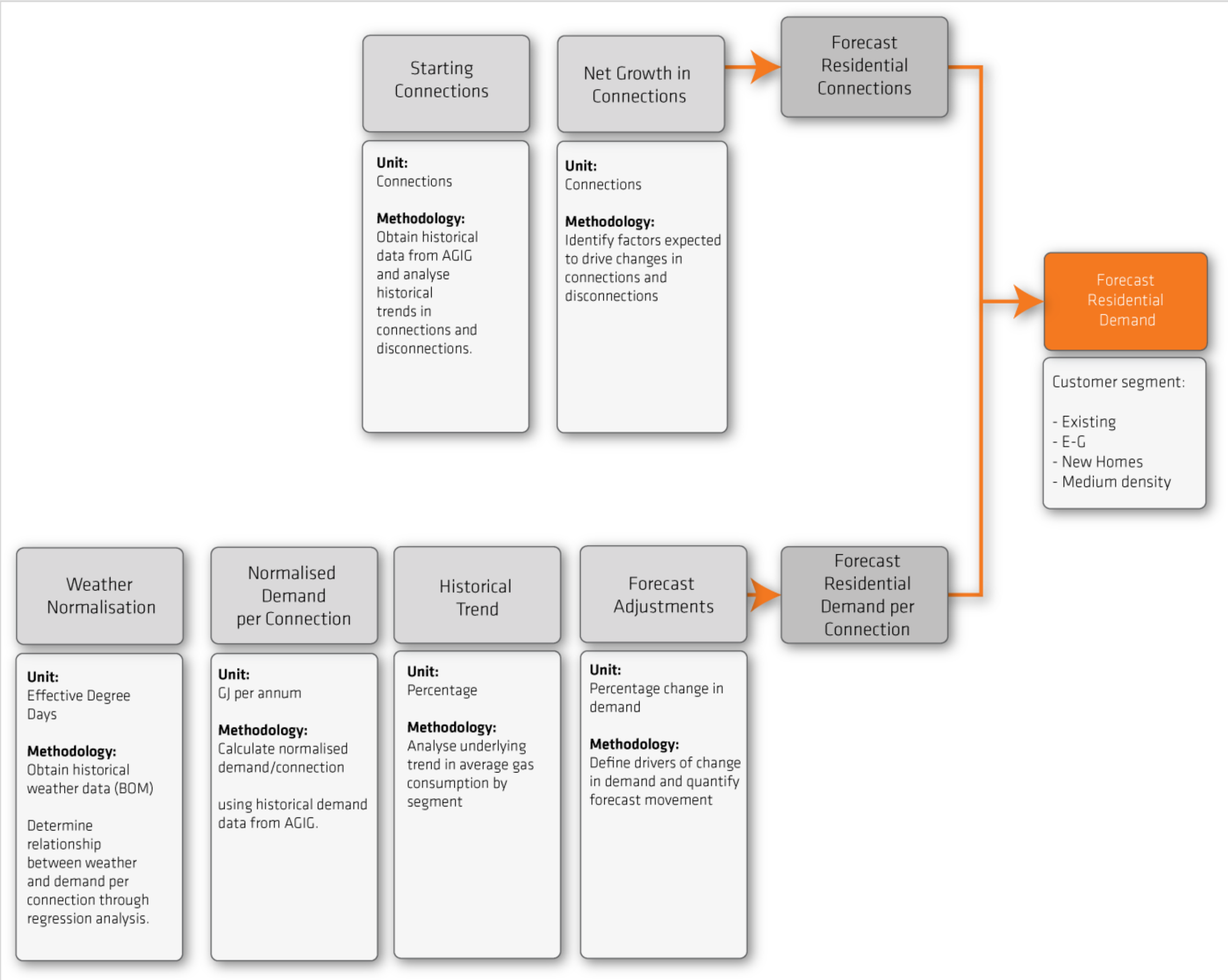
[12] Gross Value Add refers to the economic output of an economic sector
[13] Gross State Product refers to the economic output of a State/Territory
[14] Gas Demand Forecasting Methodology Information Paper, March 2019

2.3. Volume Tariffs Demand Methodology

2.3.1. Residential | Tariff R

The figure below provides a diagrammatic representation of the approach used by CORE to derive a forecast of Tariff R demand, including a forecast of connections and demand per connection.

Figure 2.3. Tariff R Residential Demand Forecast Methodology



Source: CORE.

2.3.1.2. Connections

This section details the approach undertaken to derive residential connections. Due to the different types of dwellings, CORE reconciles bottom-up and top-down approaches based on the connection type (e.g. single estate, medium-density, high-rise). Separate analysis is also undertaken for the pool of existing connections versus a forecast of new connections. The integration of third-party forecasts is inherent to this approach and provides a natural source of validation.

- The bottom-up approach analyses historical trends and major factors which influence gas connections; and

- The top-down approach surveys the relevant forecasts completed by qualified third parties. The specific focus here is on dwelling completions within the distribution network.

Generally, each dwelling type exhibits its own growth cycle. By including a bottom-up approach, the total connections forecast will likely be more accurate. This is consistent with other views within the industry such as AEMO who noted that underlying causes of growth cannot be ascertained when distribution businesses report aggregated customer numbers - the full picture of growth only becomes apparent when each dwelling type is separated.[15] CORE agrees with AEMO's views in regard to the distinct growth factors for different dwelling types. The method specific to each dwelling type is outlined as follows:

Existing Connections

- Residential connection numbers were compiled by CORE based on data provided by AGN- including disconnections, net and gross/new connections.
- The closing 2019 connections are defined as existing connections in the forecast. This forms a basis to derive a forecast for the period 2020 to 2026. The forecast of existing connections for a given year is derived by removing the predicted disconnections in the previous year from the opening number of connections in the previous year. Forecast disconnections are based on the historical average of disconnections as a percentage of the year-opening number of connections.
- There are meters on the AGN SA Network for which there is no associated demand. This situation may occur if a property is vacant or if supply has been cut off as a result of non-payment. A significant removal program has been disclosed to CORE that will remove zero-consuming meters ("ZCMs") at the outset of the forthcoming review period if the meter has continued in a state of non-consumption for the previous two years. An adjustment has been made to the forecast to capture this impact.

New Connections

CORE has derived an estimate of new dwelling connections in the 2022 to 2026 period via a four-step process:

1. Estimate new dwellings in SA
    - CORE has undertaken an extensive literature search as a basis for projected dwelling completions. Additionally, CORE has incorporated an independent third-party housing starts forecast published by HIA. This historical and forecast series indicates that the 2018 increase in new dwellings growth in SA was underpinned by MDHR activity. It had been expected that new dwellings will remain at or slightly above 2015-2017 levels after significant increases in 2018 followed by a correction in 2019. However, the impacts of the COVID pandemic give rise to a projection that 2021 dwelling commencements will decrease significantly. Given the uncertainty associated with economic recovery, CORE has opted to install a gradual recovery between 2022 and 2024.
    - The key results of this forecast are that total new dwellings growth is expected to remain steady for 2020 (sufficient activity prior to pandemic commencement in March 2020), fall steeply in 2021 and return to 2015-2017 levels by 2024.
2. Estimate the proportion of new SA dwellings within AGN's area that will be connected to the gas network
    - CORE has undertaken analysis of the historical AGN SA Network penetration rate and applied this to the forecast of SA new dwellings.

[15] AEMO, *Forecasting Methodology Information Paper*, December 2014.

3. Determine the apportionment of network connected dwellings in the AGN area that are single versus medium density/ high-rise dwellings

   > CORE has undertaken analysis of the historical average increase of each connection type and then applied HIA dwelling type projections to arrive at a new dwelling forecast by connection type. MD/HR is a faster growing source of new dwellings and AGN captures a lower percentage of these dwellings relative to single estates.

2.3.1.3. Demand per Connection

CORE has undertaken a qualitative assessment of the alternative methodologies which can reasonably be used to derive a forecast of Demand per Connection for the Residential segment of the AGN SA Network. CORE has determined that an approach which analyses the Historical Trend and adjusts for the impact of each material factor which is reasonably expected to influence Demand per Connection (with appropriate rigour and data quality), to be the best available approach under the AA circumstances. Further, CORE is of the opinion that such analysis must be set out in a transparent fashion using a model which clearly sets out assumptions/ inputs, calculations and results, in a manner which facilitates efficient scenario and sensitivity analysis.

Therefore, the steps taken to arrive at forecast demand per connection are as follows:

1. Develop models for calculation of EDD, normalised demand and forecast of Demand per Connection (these have been provided to AGN).
2. Normalise total demand per annum for the effects of weather using the methodology discussed in Section 1| 3.
3. Divide total historical demand by number of connections to determine average demand per connection. This includes an assessment of the relative demand per connection exhibited by different connection types (new versus existing; new detached estate versus E2G, medium-density/ high-rise).
4. Determine the historical trends in demand per connection, by connection type.
5. Derive an adjusted forecast of demand per connection having regard to the historical trend and the influence of factors which are not present in the historical trend.

Section 1.3 presents a detailed description of this process.

2.3.1.4. Forecast Demand

The product of forecast residential connections and forecast demand per residential connection is total forecast demand for the Tariff R residential segment. CORE notes that its approach is consistent with the volume market forecasting methodology relied upon by the market operator AEMO. AEMO also use dwelling completion forecasts to project new connections and has also reverted to a historical average connections trend for non-residential connections (just as CORE did after reviewing the historical volatility in the gross new connections series and relationship with historical GSP). AEMO's trend in demand per connection is primarily driven by a weather normalised trend (same EDD_{312} methodology as CORE) and price responses. However, CORE notes that an ex-post adjustment was then made to account for energy/appliance trends and climate change. CORE has reviewed available data sets and believes historical trends captured in the weather normalised demand per connection series, sufficiently incorporate the anticipated and continuing impact of these drivers in the AA period (noting that AEMO has to account for appliance and climate changes to 2040, a far longer time horizon and sufficient time for larger scale technology switch-out).[16]

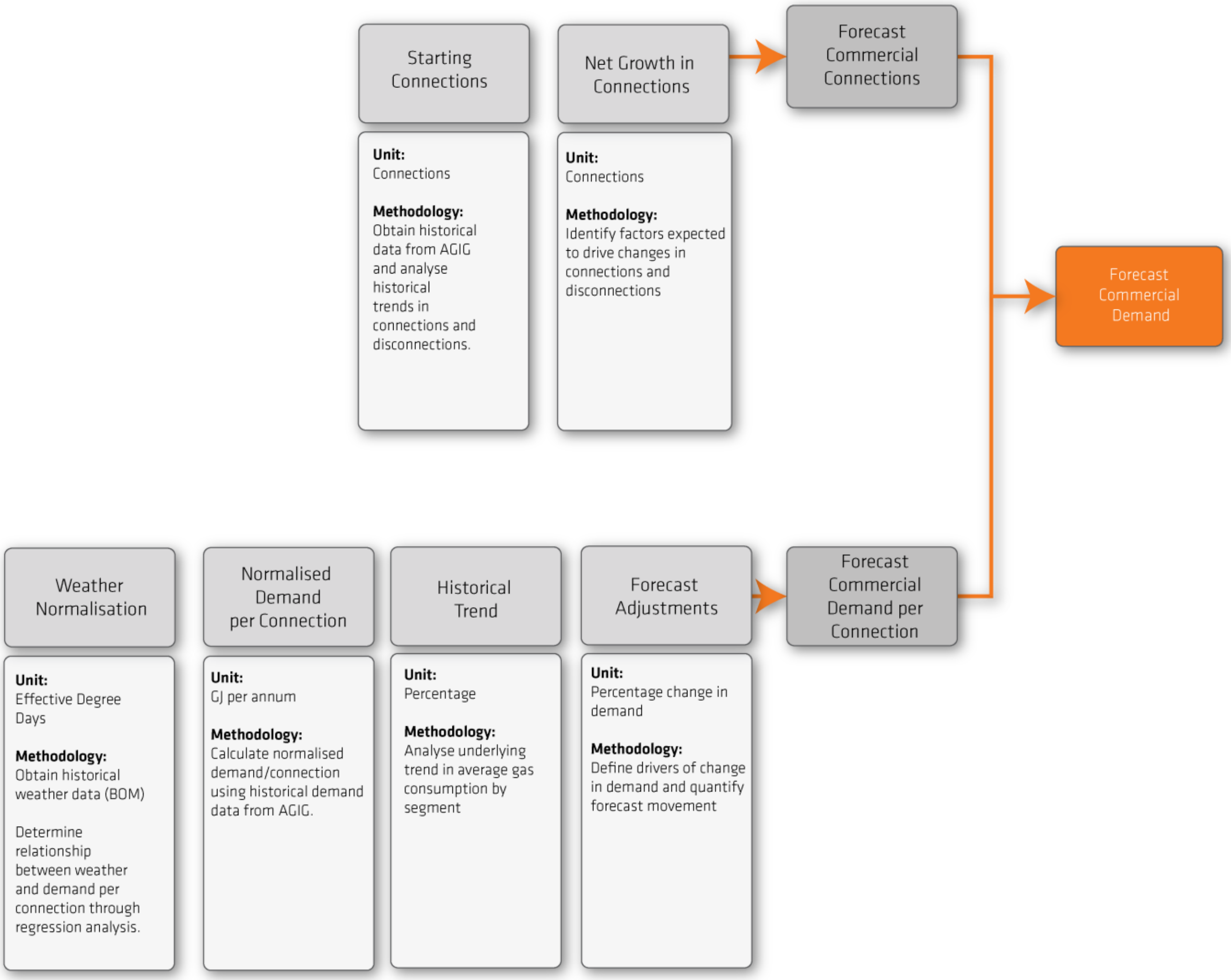
CORE also considers there to be downside risk to volume market gas demand due to the potential introduction of new renewable energy schemes. At the time of writing there is considerable political uncertainty, the resolution of which could lead to different energy policies and emissions targets (and policy mechanisms to achieve those targets). This uncertainty prohibits robust quantitative adjustments to the demand forecast but CORE believes there is more significant downside risk to demand per connection than upside risk.

2.3.2. Tariff C Commercial Demand

This section provides a summary of the methodology used to derive a forecast for Commercial customers in Tariff C.

Figure 2.3 provides an outline of the Methodology and explanations of key elements of the approach are provided below.

Figure 2.4. Tariff C Commercial Methodology



[16] Gas Demand Forecasting Methodology Information Paper, March 2019

2.3.2.2. Connections

The following steps were taken to derive a forecast for total commercial connections.

1. Collate connections data based on inputs provided by AGN.
2. Initially, analysis was undertaken to assess the relationship between historical GSP, other potential macroeconomic factors, and growth in commercial connections.
3. Upon review of volatility in the historical data and uncertainty as to the commercial response to projected wholesale gas price increases, the connections forecast then reverted to a historical annual average gross new/ disconnections series.
4. Apply the connections forecast growth rates to closing commercial connection numbers in 2019 to derive a forecast of total commercial connections between 2022 and 2026.
5. These steps were carried out before total connections were then disaggregated into existing connections and new connections. Existing connections are derived by taking the number of connections in 2019 and adjusting for the forecast in annual disconnections to 2026. The disconnections forecast is calculated using the average historical proportion of disconnections as a percentage of opening connections for a given year. The new connections forecast is derived by adding the disconnections forecast to the total net connections forecast.

The specific assumptions used for these projections are outlined in Section 1.3 and Section 2.

2.3.2.3. Demand per Connection

CORE has undertaken a qualitative assessment of the alternative methodologies which can reasonably be used to derive a forecast of demand per connection for the Commercial segment of the AGN SA Network. CORE has determined that the preferred approach would be to analyse specific factors of relevance to specific customers or customer groups/ clusters. However, the lack of transparency of information relating to specific customers makes such an approach impractical. CORE is of the opinion that the next best alternative under the AA circumstances is an approach which analyses the historical trend and adjusts for the impact of material factors which are reasonably expected to influence demand per connection across industry sectors (with appropriate rigour and data quality). Further, CORE is of the opinion that such analysis must be set out in a transparent fashion using a model which clearly sets our assumptions/ inputs, calculations and results, in a manner which facilitates efficient scenario and sensitivity analysis and general scrutiny by AGN and the AER.

Therefore, the following steps have been taken to derive a forecast of demand per connection:

1. Develop model logic to accommodate Commercial demand per connection forecasting.
2. Normalise historical actual demand for the effects of weather using the methodology discussed above.
3. Divide historical annual demand by actual annual connections to determine average demand per connection.
4. Determine the historical trend in demand per connection across new connections and existing connections.
5. Analyse all factors such as GSP and macroeconomic structural trends which are reasonably expected to influence future connections; define net impact of each factor; and
6. Derive an adjusted forecast of demand per connection by adjusting for any factors which are not present in the Historical Trend.

The specific assumptions and analysis used to derive these projections are outlined in Section 1| 3.

2.3.2.4. Forecast Total Demand

The product of forecast connections and forecast demand per connection is Total Forecast Demand for the Tariff C Commercial segment.

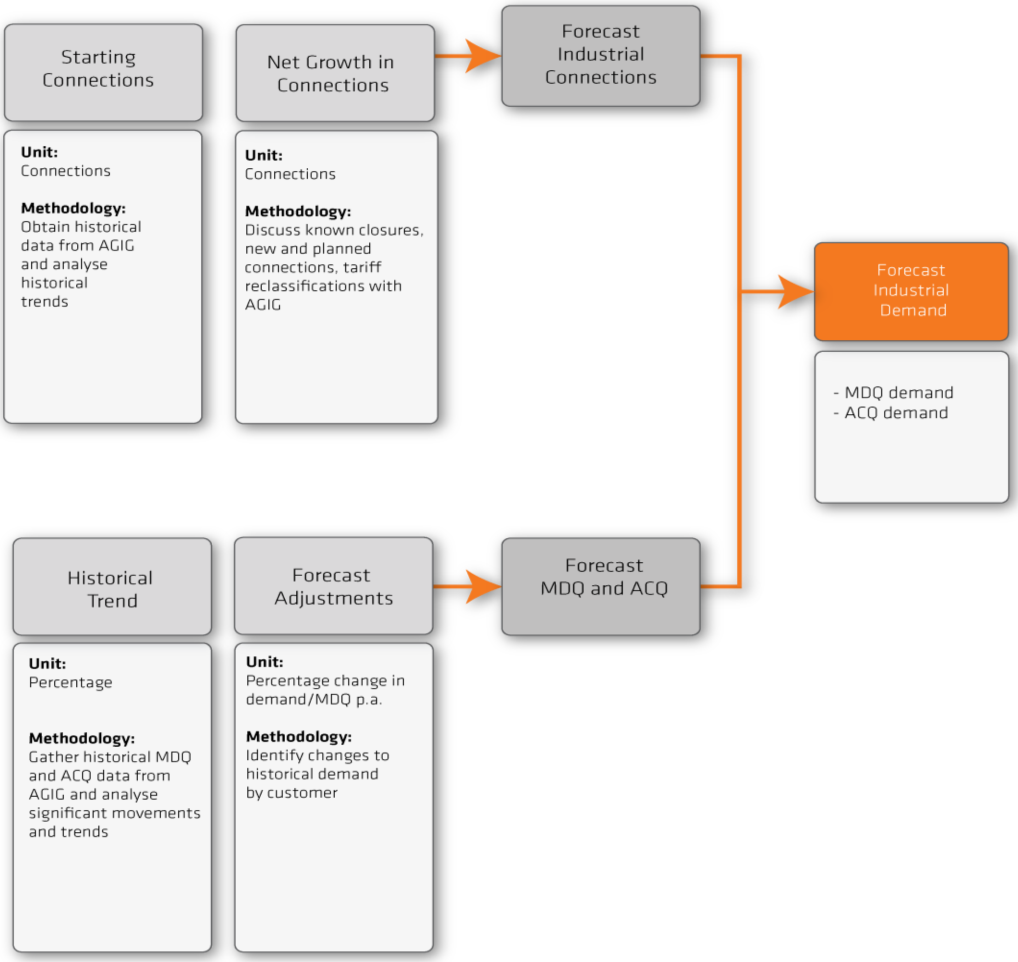
2.4. Tariff D Demand Methodology

This section provides a summary of the methodology used to derive at a forecast for Tariff D demand.

CORE's forecast of Tariff D demand considered the total annual quantity of demand (ACQ), the maximum daily demand (MDQ- the highest day of consumption within a particular year) and the total number of connections.

The following figure and subsequent sections provide an outline of the methodology and explanations of key elements of the approach.

Figure 2.5. Tariff D Industrial Methodology



Source: CORE.

2.4.1. Annual Quantity

The methodology adopted to arrive at forecast annual quantity at the customer level was as follows:

- Review list of Tariff D customers and allocate to industry sectors.
- Identify individual customers and industry sectors which have potential to experience material change in demand (via public domain evidence and any movements disclosed to AGN via regular ongoing correspondence and individual customer engagements with larger customers).
- Adjust for any known closures, new connections, tariff reallocation and expected material load changes.
- Adjust demand for remaining customers via analysis of the output of industry segments; and
- Incorporate a historical connections trend.

2.4.2. Connections

As the methodology used does not rely upon use of any form of average demand per customer, the connection or customer number statistic for Tariff D is deemed to be somewhat immaterial. However, an adjustment to ACQ and MDQ is made to account for the historical net connections trend and the associated loss of load. CORE has therefore assumed that connection numbers follow historical trend throughout the period, while allowing for:

- Known closures.
- Known new connections; and
- Customers reasonably expected to switch between Tariff D and Tariff C over the review period.

2.4.3. MDQ

To derive the Adjusted Forecast CORE has considered the following:

- Information provided by AGN regarding known Tariff D customer business closures and tariff reclassifications.[17]
- CORE forecast of additional underlying movements in demand relative to forecast ACQ movements.

2.4.4. Model Outputs

CORE has provided AGN with the Excel-based models and all underlying data that has been used to project Tariff D gas demand and connections.

2.5. Limitations of Forecast Methodology

While CORE believes that the adopted methodology (outlined throughout Section 1 | 2 above) gives rise to the best forecasts possible in the circumstances, there are some limitations which have the potential to bias the demand forecasts. These include:

- **Non-linearities in demand** – CORE's trend analysis of key demand drivers relies on the assumption that the relationship with demand is linear in nature. For example, the own price elasticity effect on demand assumes a

[17] Several closures were readily discernible from information disclosed in the public domain or disclosed to AGN via the standard interactions it has with its industrial customer base. These were primarily customers that have already disconnected or revealed their closure to AGN. A large manufacturing customer also revealed its future planned gas consumption which is moderately lower than historical volumes.

linear relationship between gas prices and gas usage, when in reality there may be some price thresholds where a larger demand response is observed (e.g. more severe declines in demand as gas prices move beyond a certain level). The analysis required to address these non-linearities is deemed to be overly complex and have not been undertaken. Nevertheless, CORE is of the opinion that the projections resulting from its current methodology to be the best estimate possible under reasonable circumstances.

- **Degrees of Freedom** – CORE’s historical trend analysis of annual data generally uses the most recent 10-12 years of data points, meaning that the resulting regression equations contain around 10 degrees of freedom when using linear trends. As this is fewer than the widely accepted range of 15-20 degrees of freedom the coefficients may not fully converge with their true population values and some forecasting error may be present.

  Nevertheless, CORE is of the opinion that a ten year period of historical data is adequate (given the generally fast rate of change in energy markets and associated technology observed over time) and that the projections resulting from its current methodology are the best estimates possible under reasonable circumstances.

  In the case of CORE’s EDD and Weather Normalisation models, thousands of daily data points are used in generating a daily EDD series, contributing to a monthly normalised demand. The degrees of freedom in these models are deemed to be adequate.

Section 1 | 3. Weather Normalisation Process

3.1. Introduction

CORE's analysis of historical demand was based on normalised data to remove fluctuations caused by weather factors. This section summarises the results of the weather normalisation process. CORE's proprietary Excel-based models were used to calculate EDD index coefficients to weather normalise demand. For greater detail, the EDD index model and weather normalised demand model should be read in conjunction with this report. These models have been submitted to AGN and form a confidential attachment to AGN's Access Arrangement Information.

3.2. EDD Index

Historical demand data was normalised to remove the impact of weather on demand and demand per connection for each of the residential and commercial customer groups respectively. The EDD Index presented in the following figure and table was used to normalise both the residential and commercial groups as daily demand data was only available as a combined series (as is typical for Australian gas distribution networks). The long-term trend of EDD is compared to the fluctuations in weather in the following figure. Actual EDD in 2010, 2012-2014, 2016, 2018 and 2019 is lower than the EDD trend, which implies that weather in this year was warmer than normal. The warmer weather induces lower demand per connection, as less gas is required for heating. The opposite is shown in 2009, 2011, 2015 and 2017, when EDD was higher than the trend. Colder weather in these years required more heating - hence actual demand per connection was higher.

Figure 3.1. EDD Index

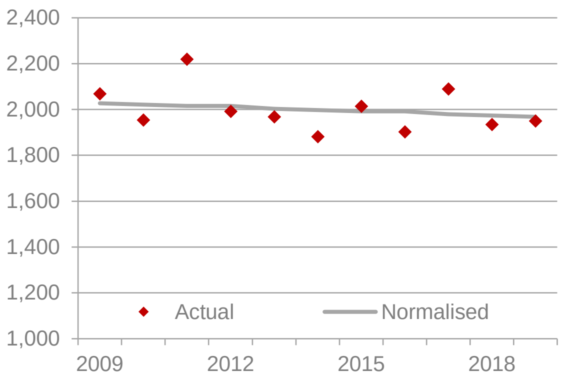


Table 3.1. EDD Index

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Normalised EDD	2,027	2,021	2,015	2,015	2,004	1,998	1,992	1,991	1,980	1,974	1,968
Actual EDD	2,069	1,954	2,219	1,992	1,969	1,882	2,015	1,902	2,090	1,935	1,951
Difference	42	(67)	204	(23)	(35)	(116)	23	(89)	110	(39)	(18)

3.3. AGN Weather Normalised Demand Results | Tariff R and Tariff C

For the residential customer group, historical normalised demand per connection exhibits a steady -2.04% declining trend, whereas total volume has decreased at a rate of -0.46%, offset partially by growth in connections. Normalised commercial demand has experienced steady growth of 0.95% on average despite a steady -0.47% decline in demand per connections. Connections growth has more than offset this demand per connection decline. Please note that Appendix A1 provides an overview of statistical techniques and analysis used to derive the normalised values shown below.

Figure 3.2. Residential Demand per Connection | GJ

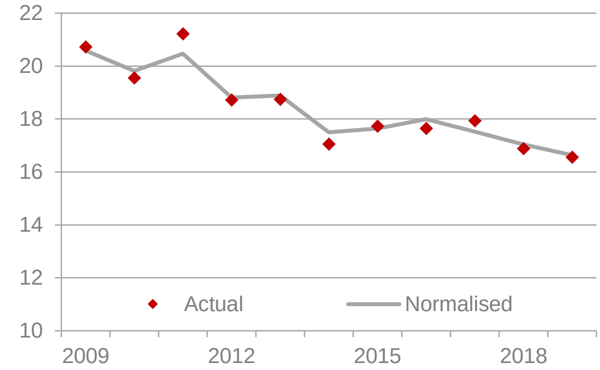


Figure 3.3. Residential Demand | GJ

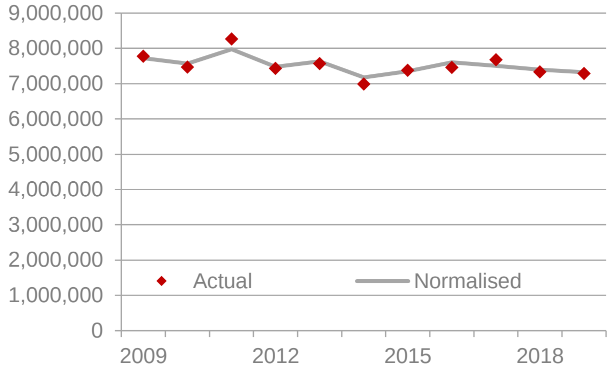


Figure 3.4. Commercial Demand per Connection | GJ

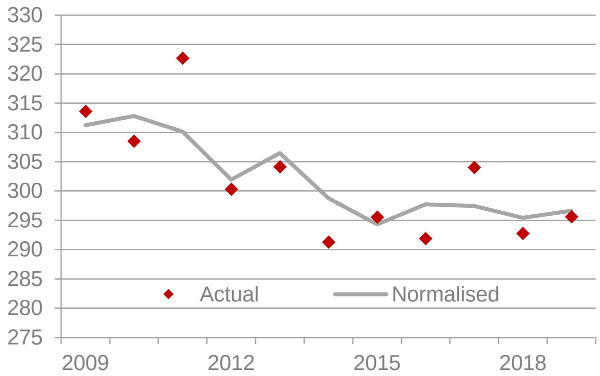
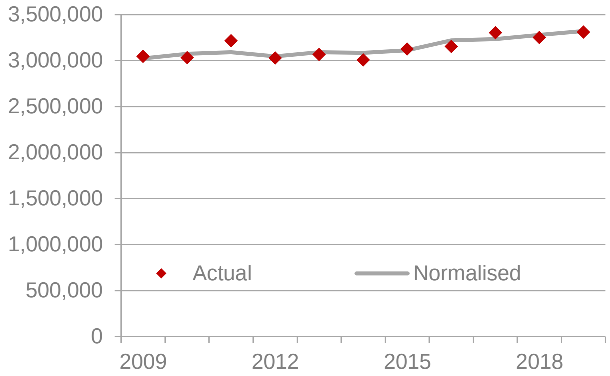


Figure 3.5. Commercial Demand | GJ



The charts above show the trajectory of demand and demand per connection once weather- induced demand is removed.

Table 3.2. Normalised Residential Demand per Connection/Demand | GJ

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Normalised Demand	7,724,171	7,572,585	7,976,789	7,475,662	7,629,050	7,178,258	7,349,657	7,605,905	7,503,793	7,398,724	7,323,982
Actual Demand	7,777,427	7,471,069	8,269,742	7,437,268	7,570,581	6,994,308	7,381,386	7,459,090	7,677,762	7,330,141	7,290,725
Difference	53,256	(101,516)	292,953	(38,394)	(58,469)	(183,950)	31,728	(146,814)	173,969	(68,583)	(33,257)
Normalised D/C	20.58	19.82	20.46	18.81	18.88	17.50	17.65	17.99	17.53	17.04	16.64
Actual D/C	20.73	19.55	21.21	18.71	18.74	17.05	17.72	17.64	17.93	16.88	16.56
Difference	0.1	(0.3)	0.8	(0.1)	(0.1)	(0.4)	0.1	(0.3)	0.4	(0.2)	(0.1)

Table 3.3. Normalised Commercial Demand per Connection/Demand | GJ

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Normalised Demand	3,024,198	3,075,622	3,090,976	3,045,371	3,092,310	3,085,245	3,112,843	3,218,950	3,233,038	3,281,219	3,322,122
Actual Demand	3,046,571	3,033,097	3,215,869	3,028,984	3,068,923	3,007,967	3,125,723	3,155,929	3,304,370	3,251,587	3,310,273
Difference	22,373	(42,525)	124,893	(16,387)	(23,387)	(77,278)	12,880	(63,021)	71,332	(29,632)	(11,849)
Normalised D/C	311	313	310	302	306	299	294	298	297	295	297
Actual D/C	314	308	323	300	304	291	296	292	304	293	296
Difference	2.3	(4.3)	12.5	(1.6)	(2.3)	(7.5)	1.2	(5.8)	6.6	(2.7)	(1.1)

3.4. Tariff D - Weather Normalisation of Select Sectors

As discussed in the methodology section, industrial customer sectors that exhibited weather-induced demand patterns were weather normalised using the same EDD_{312} Index. Regression analysis was performed using historical demand data from 33 customers that existed in the network for the entire historical period (thus removing bias from customers joining or leaving partway through). Results are presented thereafter and show an annual average decrease of -1.57% in ACQ between 2009 and 2019. The steady decline rate suggests that these sectors are experiencing similar efficiency and appliance trends to non-residential volume tariff customers.

- Accommodation and Food Services (7 customers)
- Education and Training (3 customers)
- Arts and Recreation Services (5 customers)
- Other Services (1 customer)
- Health Care and Social Assistance (14 customers)
- Public Administration and Safety (3 customers)
- Professional, Scientific and Technical Services (only new or disconnected customers but demand pattern deemed to be weather-induced).
- Administrative and Support Services (only new or disconnected customers but demand pattern deemed to be weather-induced).

Figure 3.6. Tariff D Weather Group- Demand per Connection | GJ

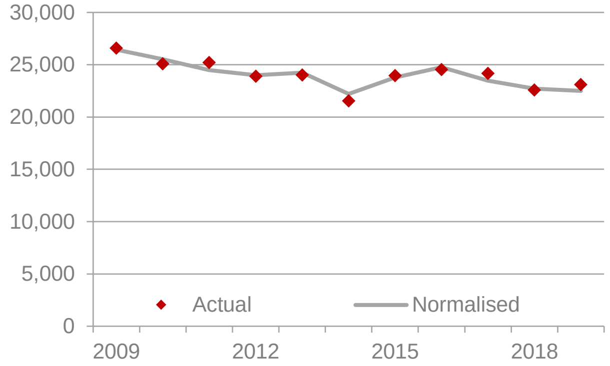


Table 3.4. Normalised Industrial Weather Group Demand per Connection/Demand | GJ

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Normalised Demand	872,550	842,228	808,200	792,208	799,707	732,904	785,174	817,422	774,984	749,421	742,131
Actual Demand	877,905	828,565	832,717	788,580	793,227	711,284	791,014	809,591	797,655	745,511	762,188
Difference	5,354	(13,663)	24,517	(3,628)	(6,481)	(21,620)	5,840	(7,831)	22,671	(3,910)	20,057

Section 1 | 4. Residential Demand Forecast

4.1. Introduction

This section of the report details the residential demand forecast in the AGN SA Network.

Total demand is derived using a bottom-up approach: the product of individual forecasts of connections and demand per connection. CORE takes into consideration historical trends as well as expectations of future drivers of demand not present in the historic data.

The demand data and forecasts presented in this section have undergone the weather normalisation process.

4.2. Residential Demand Forecast Summary

In the AGN SA Network, total residential demand is forecast to increase from 7,060,676 GJ in 2022 to 6,603,465 GJ in 2026, equivalent to an average annual decrease of -1.54% over the Review Period. The forecast shows a continuance of a trend decrease in residential gas demand evident in the historic gas demand data. The major factors driving the trend in projected gas demand include:

- A sharp decrease in 2021 dwelling commencements reflecting HIA dwelling starts forecast within the context of the COVID pandemic.
- Connections growth recovery albeit at a moderately reduced rate- beyond the COVID pandemic recovery, moderately lower dwellings growth is expected in SA relative to recent history;
- An increasing preference for medium density and high-density dwelling types, such as multi-unit apartments. These dwellings typically exhibit lower energy demand due to smaller floor space and lower number of average residents per dwelling;
- Continued improvements in the energy efficiency of buildings and appliances, as controlled by appliance switch out rates, renovation and construction levels; and
- An increasing preference for electric appliances and other energy sources instead of gas appliances- particularly in MD/HR dwellings where there is a higher incidence of gas used only for water heating. Frequently, gas space heating and cooking is not supported by large apartment building designs.

The following table presents historical data and forecasts for residential demand:

Table 4.1. Residential Demand Forecast | GJ

	2019	2020	2021	2022	2023	2024	2025	2026
Existing 2019		7,214,756	7,008,240	6,852,507	6,677,303	6,489,557	6,295,687	6,117,434
New Dwelling | Estate		31,108	99,267	162,955	217,520	272,108	327,108	380,806
New Dwelling | E2G		6,317	19,879	33,216	45,500	56,714	66,889	76,296
New Dwelling | MD/HR		2,393	7,635	11,998	15,335	19,308	23,962	28,928
Total Demand	**7,323,982**	**7,254,574**	**7,135,021**	**7,060,676**	**6,955,659**	**6,837,687**	**6,713,646**	**6,603,465**

The annual forecasts presented are the product of forecast connections and forecast demand per connection. These elements are addressed below.

4.3. Residential Connections Forecast

Residential connections are forecast to increase from 455,278 in 2022 to 476,549 in 2026 during the Review Period, at a rate of 1.04% p.a. The growth rate of Residential connections in the Review Period is slower than the historical period, due to a lower level of forecast new dwellings in the SA economy.

- According to HIA historical data, SA dwelling completions were relatively flat between 2008 and 2010 before falling 27% by 2013. Since then there was a mild recovery before a sharp increase in 2019 due to MDHR growth. A correction back down to 10,058 is implied for 2020 due to a corresponding fall in commencements in 2019.
- 2021 completions represent the first tranche of dwellings that are influenced by the COVID pandemic with 2022 completions (2021 commencements) expected to exhibit the largest decline. HIA has not released a longer-term outlook at this stage and CORE has deemed it appropriate to install a gradual recovery to 2024 with HIA's prior long-term outlook applying thereafter.

Key components and trends that support this longer-term forecast are summarised as follows:

- SA Population Growth is forecast to remain at levels below the average growth experienced during the historical series (~0.90% historical versus 0.82% projected). CORE has relied on the ABS Population Projections for this forecast.
- SA Dwelling Completions (per HIA commencements forecast)
  - Sharp decrease in 2020 which holds for all of 2021 before a sharp drop in 2022 due to the COVID pandemic impact.
  - Recovery momentum in the longer-term growth is expected to fade when growth turns moderately negative in 2025 and 2026.
  - After losing around 15% of completion shares between 2008 and 2019, detached houses are expected to increase their share from 63.1% to 72.9% in 2020 but then steadily be outpaced by MDHR dwellings such that only 69.2% of new dwellings in 2026 are expected to be houses.
  - CORE has also reviewed public domain commentary and believes the 2020 completions growth and expected correction is consistent with market consensus. ABS data for dwelling approvals and dwelling commencements are a key lead indicator for dwelling completions and these are consistent with the first part of the HIA forecast.
- AGN SA Network Penetration
  - The network is expected to capture around 61-66% of completed SA dwellings during the AA period- consistent with the 65% average seen over the last decade. Single estate developments with detached dwellings are expected to lose market share to MDHR which puts downward pressure on the overall AGN penetration rate given that the network has typically enjoyed a higher penetration rate for this dwelling type.
  - This reflects the trend that gas is losing market share in the residential space-heating market, but overall connection numbers are being supported by larger apartment buildings that use centralised hot water systems and hence capture 100% of all dwellings within the development (but without an associated space or cooking load).

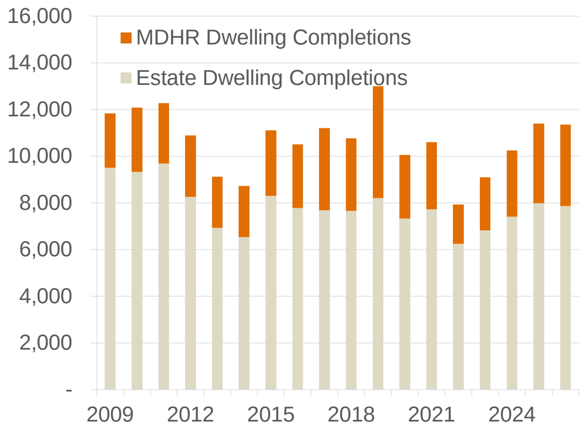


Figure 4.1. SA Dwelling Completions by Dwelling Type

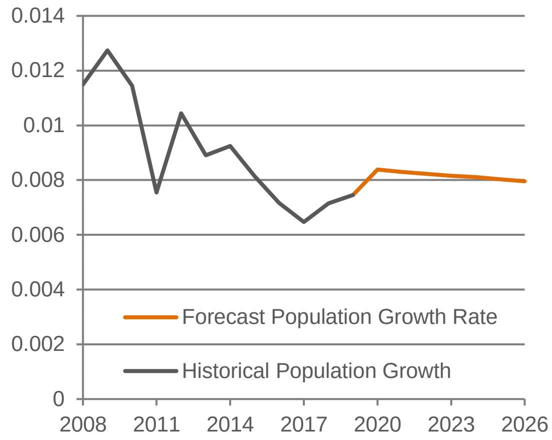


Figure 4.2. Greater Adelaide Population Growth | %

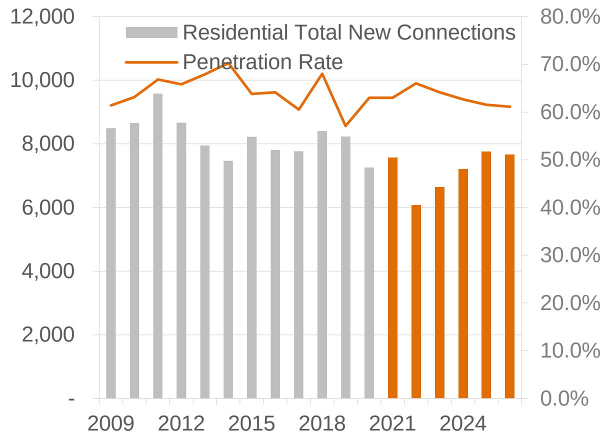


Figure 4.3. New Residential Connections (LHS, No.) versus Penetration Rate of New Dwellings (RHS, %)

The following table presents historical data and forecasts for Residential connections:

Table 4.2. Residential Connection Forecast | No.

	2019	2020	2021	2022	2023	2024	2025	2026
Opening Connections		443,043	448,400	452,592	455,278	459,953	465,169	470,924
Disconnections		1,897	1,920	1,944	1,962	1,982	2,004	2,029
Zero Consuming Meter Removals		-	1,448	1,448	-	-	-	-
Existing 2019 Connections		441,146	437,778	434,385	432,424	430,442	428,437	426,408
New Dwelling Connections | Estate		5,628	5,932	4,798	5,241	5,685	6,128	6,031
New Dwelling Connections | E2G		918	880	843	808	775	743	712
New Dwelling Connections | MDHR		708	748	437	588	738	889	911
Total Connections	**443,043**	**448,400**	**452,592**	**455,278**	**459,953**	**465,169**	**470,924**	**476,549**
Net Connections	**6,199**	**5,357**	**4,192**	**2,686**	**4,675**	**5,216**	**5,755**	**5,624**

4.4. Residential Demand per Connection Forecast

The demand per connection forecast for the AGN SA Network was derived using the methodology outlined in Section 1. The weighted average demand per connection in the network is expected to decline from 15.5 GJ in 2022 to 13.9 GJ in 2026, at a decline rate of -2.55%.

The following tables and figures outline the forecast of Residential demand per connection. Please note that the new demand per connection is a weighted average of all customers joining from July 2019 and the increase is due to the ramp-up of new customers. Historical data shows that customers typically reach their mature demand volumes during their 2nd full year on the network.

In 2020, the new customer group comprises only brand-new customers ramping up. By 2026, there are several cohorts of mature customers (customers who joined between 2020 and 2024) and 2 years of new-join customers. A breakdown of new mature demand by new customer cohort is provided below along with the weighted average demand per connection. Please be aware that first year customers are forecast to consume 42.5% of their mature demand and second year customers are forecast to consume 95.6% (as per historical average).

Table 4.3. New Customer Demand Forecast by Year, by Cohort | GJ/conn

	2020	2021	2022	2023	2024	2025	2026
New Single Estate | Mature Volume	13.0	12.6	12.2	11.8	11.4	11.0	10.7
New E2G | Mature Volume	16.2	15.9	15.7	15.4	15.2	14.8	14.6
New MDHR | Mature Volume	8.0	7.7	7.5	7.2	7.0	6.7	6.5
Weighted Average Demand per Connection	**5.5**	**8.6**	**10.0**	**10.2**	**10.1**	**9.9**	**9.8**

Existing customer demand per connection will decline steadily over the projection period albeit with moderate offset in 2021 and 2022 due to the significant ZCM removal program which will remove connections from that customer group without any corresponding loss in volume.

Table 4.4. Residential Demand per Connection Forecast | GJ/conn

	2019	2020	2021	2022	2023	2024	2025	2026
Existing 2019		16.4	16.0	15.8	15.4	15.1	14.7	14.3
New Connections | Weighted Average		5.5	8.6	10.0	10.1	10.0	9.8	9.7
Weighted Average Demand per Connection	**16.5**	**16.2**	**15.8**	**15.5**	**15.1**	**14.7**	**14.3**	**13.9**

The forecast and analysis of demand per connection was derived by identifying the following drivers:

- Drivers with historical impact that will perpetuate throughout the Review Period;
- Drivers with historical impact that will deviate in the Review Period; and
- Impact of the removal of zero consuming meters.

The significant factors driving the expected reduction in Residential demand per connection are continued gains in energy efficiency, appliance substitution, movements in gas prices and electricity prices. Additionally, the proportion of less gas-intensive dwelling types is increasing across the network and this is also contributing to a lower weighted average demand per connection forecast. These factors are described in further detail below.

4.4.2. Demand per Connection | Drivers with Continued Impact

Historical Annual Average Growth

For Residential demand per connection, the historical average annual growth removes the impact of gas and electricity prices, and weather by adjusting historical demand per connection by the estimated impact of each of these factors. The process of weather normalisation has been discussed in detail in Section 2. This normalised demand per connection was then adjusted for historical price movements by netting off the product of historical price changes and assumed historical price elasticity. However, the impacts of appliance trend, energy efficiency trend, and government policy are still captured by the normalised historical rate. Accordingly, CORE research determined the likely impact of these drivers over the Review Period. There is also considerable overlap with the efficiency, policy and appliance trend analysis that is discussed in the context of commercial demand. Ultimately it was determined that the combined impact of each of these factors is best predicted by what was observed during the historical period, captured by the normalised historical average annual growth rate, which is perpetuated in the forecast period with no expected adjustment.

Realistically, building and appliance efficiency data is not comprehensive enough to enable robust, reliable statistical relationships. Instead CORE has assessed the drivers of these factors such as policy, building commencements (as a proportion of existing housing stock) and technology. There is no evidence to suggest that these factors are losing momentum or accelerating so CORE deems it appropriate to incorporate the recent historical impact which has been captured by the weather normalised trend in demand per connection.

Macroeconomic Variables and Residential Demand per Connection

Economic variables such as household income and population growth can potentially influence residential connections but demand per connection does not typically demonstrate a robust statistical relationship. To derive an optimal forecast with maximum precision, the decision was made to exclude any additional economic variables especially given the macroeconomic influence that dwelling forecasts and other forecast inputs already carry.

4.4.3. Demand per Connection | Drivers with Changing Impact

Own-Price Elasticity

Movements in gas price significantly affect the demand per connection in a given year as well as in subsequent years. Consistent with previous AA submissions, economic literature and statistical tests, CORE forecasting captures the elasticity impact across four lagged periods (measured in years).

The gas price movements that instigate this elasticity impact are derived using CORE's proprietary model. CORE has undertaken gas price forecasting within an AA context for JGN's New South Wales distribution network and Envestra's (now AGN) Victorian distribution network. CORE has also developed gas price forecasts for each eastern Australian jurisdiction as part of its Gas Networks Sector Study, commissioned by the Energy Networks Association in August 2014. CORE has also been engaged by AEMO to develop gas price forecasts for the NGFR 2015 and provide updated forecasts for the NGFR 2016 and GSOO reports in 2018 and 2019 (a report which now incorporates the NGFR).

The approach undertaken by CORE to forecast retail gas prices consists of analysing each individual component of the retail gas price. A full listing and analysis of these components can be found in Appendix A2. The forecast is driven by the following:

- An expected increase in wholesale gas costs in the Review Period, as forecast by AEMO in the 2019 GSOO and consistent with the AER's LNG netback series.

The elasticity value used by CORE is a product of extensive third-party analysis via international literature review as well as a review of previous AA price elasticity factors that have been accepted by the ERA (WA) and AER. Accordingly, a long-run elasticity factor of -0.30 has been used for Residential demand.

The following table provides the forecast of own-price impacts on demand per connection.

Table 4.5. Own Price Elasticity Impact on Residential Demand per Connection| %

Own-Price Elasticity Impact on Demand (%)	2020	2021	2022	2023	2024	2025	2026
Change in Gas Bill	0.84%	0.99%	-2.90%	1.56%	1.73%	1.40%	1.12%
Own-Price Elasticity Impact (-0.30)	0.38%	0.03%	0.35%	-0.01%	-0.24%	-0.32%	-0.36%

Further detail on the gas price forecast and price elasticity impact can be found in Sections A2 and A3.

Cross-Price Elasticity

Cross-price elasticity measures the change in demand per gas connection that occurs when the price of electricity, a substitute energy source to gas, changes. There are two components to this effect:

- The propensity of consumers to switch between gas and electricity appliances when faced with a given price movement
- The size of the relative price movements between gas and electricity.

CORE forecasting captures the response of consumers as they face relative price changes between gas and electricity. For example, the model would capture the degree of substitution that occurs between gas heating and heating by RC air-conditioning when there is a shift in relative prices between gas and electricity.

CORE has derived electricity retail price movements in the Review Period from AEMC projected pricing in addition to general public domain review. Further detail on the electricity price forecast and price elasticity impact can be found in Sections A2 and A3.

The following table summarises the cross-price elasticity impact on demand per connection.

Table 4.6. Cross-Price Elasticity Impact on Residential Demand per Connection | %

Cross-Price Elasticity Impact on Demand (%)	2020	2021	2022	2023	2024	2025	2026
Change in Electricity Bill	0.27%	-4.42%	-1.05%	-0.78%	-0.90%	-1.82%	0.23%
Cross-Price Elasticity Impact (0.10)	0.03%	-0.44%	-0.11%	-0.08%	-0.09%	-0.18%	0.02%

4.4.4. Disconnections

The long-term historical average disconnection rate for the Residential segment has been reviewed by CORE and determined to be an appropriate guide for future disconnections. Accordingly, the forecast disconnection rate is 0.43% of opening connections.

Table 4.7. Residential Disconnections

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Residential Disconnections (Trend)	1,540	1,483	1,671	2,160	2,046	2,275	2,095	1,897	1,920	1,944	1,962	1,982	2,004	2,029
% of Opening Connections	0.38%	0.36%	0.40%	0.52%	0.48%	0.53%	0.48%	0.43%	0.43%	0.43%	0.43%	0.43%	0.43%	0.43%
Residential Disconnections (ZCM)								1,448	1,448					
% of Opening Connections								0.32%	0.32%					

Source: CORE.

Section 1 | 5. Commercial Demand Forecast

5.1. Introduction

This section of the report details the commercial demand forecasts for the AGN SA Network.

As per the residential sector, this forecast was derived using a bottom-up approach, as the product of individual forecasts of connections and demand per connection. CORE takes into consideration historical trends as well as expectations of future drivers of demand not present in the historic data.

The demand data and forecasts presented in this section have undergone the weather normalisation process.

5.1.1. Commercial Demand Forecast Summary

Over the Review Period, commercial demand in the AGN SA Network is forecast to grow slightly, with an associated growth rate of 0.31% from 3,361,039 GJ in 2022 to 3,394,132 GJ in 2026. The overall rate is primarily driven by connections growth which essentially offsets the moderate decline in demand per connection.

COVID Pandemic Impact

Preliminary analysis released by the RBA suggests there is significant uncertainty as to the economic impact of the pandemic and timing of recovery. Programs such as Job Keeper will also influence the operations of commercial gas customers, and there is no visibility yet as to the impact on commercial closures and/or energy demand. Accordingly, CORE has tentatively deferred to its original forecast described above but notes the potential for material downside in commercial connections and demand.

The following tables summarise the different connection types within the forecast.

Table 5.1. Commercial Demand Forecast | GJ

	2019	2020	2021	2022	2023	2024	2025	2026
Existing 2019		3,296,203	3,222,947	3,159,862	3,104,821	3,032,895	2,947,965	2,869,845
New Commercial		36,977	119,289	201,177	283,924	365,377	444,709	524,287
Total Demand	**3,322,122**	**3,333,180**	**3,342,237**	**3,361,039**	**3,388,745**	**3,398,272**	**3,392,675**	**3,394,132**

5.1.2. Commercial Connections Forecast

Over the Review Period, total Commercial connections in the AGN network are forecast to grow at a rate of 0.62% from 11,231 in 2022 to 11,644 in 2026.

The AGN Commercial total connections are forecast based on the historical average net connections and historical trends in SA economic output and business numbers. Following a review of historical trends and volatility, and the relationship with GSP, CORE decided to apply a 50% weighting to the historical average net connection rate. The remaining 50% weighting comes from a historical penetration rate of SA business entries (which are extrapolated via a historical relationship with South Australian GSP. The resulting growth rate of Commercial connections in the Review Period is moderately below the average of the entire historical period based on a GSP forecast that exceeds recent historical growth (per SA Treasury forecasts)[18]. A declining ratio of business numbers to real GSP is the intervening driver in this relationship. CORE notes that the COVID pandemic will have an impact on SA GSP but a revised forecast has not yet been made available by SA Treasury.

The following tables summarise Commercial total and net connections forecasts. A ZCM removal program discussed above (in the context of Tariff R) will also apply to Tariff C which helps almost completely offsets the new connections growth forecast in 2021 and 2022.

Table 5.2. Commercial | Connections Forecast | No.

	2019	2020	2021	2022	2023	2024	2025	2026
Opening Connections		11,233	11,350	11,291	11,231	11,337	11,442	11,544
Disconnections		150	151	153	154	156	157	158
Disconnections | Zero Consuming Connections		-	168	168	-	-	-	-
Existing 2019 Connections		11,083	10,764	10,443	10,289	10,133	9,976	9,818
New Commercial Connections		267	261	261	260	260	259	258
Cumulative New Commercial Connections		267	528	788	1,048	1,308	1,567	1,826
Total Connections	**11,233**	**11,350**	**11,291**	**11,231**	**11,337**	**11,442**	**11,544**	**11,644**
Net Connections	**48**	**117**	**- 58**	**- 60**	**106**	**104**	**102**	**100**

5.1.3. Commercial Demand per Connection Forecast

Over the Review Period, total Commercial demand per connection was derived using the methodology outlined in Section 3. The following tables provide a summary of Commercial demand per connection.

- Commercial annual demand per connection is forecast to decrease from 299.3 GJ to 291.5 GJ over the Review Period, equivalent to an average annual decline rate of -0.30%.

The following tables summarise Commercial weighted average demand per connection forecast which includes a ramp-up phase for all new connections as was described in the previous section for the residential sector. For commercial customers it is estimated that first-year customers consume 44.0% of their mature demand levels and second-year customers consume 99.4% (based on historical averages).

Table 5.3. Commercial Annual Demand per Connection Forecast | GJ

	2019	2020	2021	2022	2023	2024	2025	2026
Existing 2019		297.4	299.4	302.6	301.8	299.3	295.5	292.3
New Commercial		138.7	226.1	255.3	270.8	279.3	283.7	287.2
Weighted Average Demand per Connection	**295.7**	**293.7**	**296.0**	**299.3**	**298.9**	**297.0**	**293.9**	**291.5**

The forecast and analysis of demand per connection was derived by identifying these sources of influence:

- Drivers with historical impact that will perpetuate throughout the Review Period; and

[18] SA State Treasury; Budget 2019-20

- Drivers with historical impact that will deviate in the Review Period.

The significant factors driving the expected reduction in Commercial demand per connection are the impact of own-price and cross-price elasticities, due to expected decreases in gas prices and electricity prices. These factors are described in further detail below.

5.1.4. Demand per Connection | Drivers with Continued Impact

Historical Annual Average Growth

For Commercial demand per connection, the historical average annual growth removes the impact of gas and electricity prices, and weather by adjusting historical demand per connection by the estimated impact of each of these factors. The process of weather normalisation has been discussed in detail in Section 2. This normalised demand per connection was then adjusted for historical price movements by netting off the product of historical price changes and assumed historical price elasticity. However, the impacts of appliance trend, energy efficiency trend, and government policy are still captured by the normalised historical rate. Accordingly, CORE research determined the likely impact of these drivers over the Review Period. There is also considerable overlap with the efficiency, policy and appliance trend analysis that is discussed in the context of Residential demand. Ultimately it was determined that the combined impact of each of these factors is best predicted by what was observed during the historical period, captured by the normalised historical average annual growth rate, which is perpetuated in the forecast period with no expected adjustment.

Typically, building and appliance efficiency data is not comprehensive enough to enable robust statistical relationships for the SA AGN forecast. Instead CORE has assessed the drivers of these factors such as policy, dwelling commencements (as a proportion of existing non-residential dwelling stock) and technology. There is no evidence to suggest that these factors are losing momentum or accelerating so CORE deems it appropriate to rely on their recent historical impact which has been captured by the weather normalised trend in demand per connection.

Macroeconomic Variables and Commercial Demand per Connection

Macroeconomic variables such as state output are key drivers of connections but demand per connection does not typically demonstrate a robust statistical relationship. To derive an optimal forecast with maximum precision, the decision was made to exclude any additional economic variables and instead rely on the macroeconomic influence built into the overall forecast via the connections methodology.

5.1.5. Demand per Connection | Drivers with Changing Impact

Own-Price Elasticity

Movements in gas price significantly affect the demand per connection in a given year as well as in subsequent years. Consistent with previous AA submissions, economic literature and statistical tests, CORE forecasting captures the elasticity impact across four lagged periods (measured in years).

The gas price movements that instigate this elasticity impact are derived using CORE's proprietary model. CORE has undertaken gas price forecasting within an AA context for JGN's New South Wales distribution network and Envestra's (now AGN) Victorian distribution network. CORE has also developed gas price forecasts for each eastern Australian jurisdiction as part of its Gas Networks Sector Study, commissioned by the Energy Networks Association in August 2014. CORE has also been engaged by AEMO to develop gas price forecasts for the NGFR 2015 and provide updated forecasts for the NGFR 2016 and GSOO reports in 2018 and 2019 (a report which now incorporates the NGFR).

The approach undertaken by CORE to forecast retail commercial gas prices consists of analysing each individual component of the retail gas price. A full listing and analysis of these components can be found in Appendix A2. The forecast is driven by the following:

- An expected increase in wholesale gas costs in the Review Period, as forecast by AEMO in the 2019 GSOO and consistent with the AER's LNG netback series.

The elasticity value used by CORE is a product of extensive third-party analysis via international literature review as well as a review of previous AA price elasticity factors that have been accepted by the AER and ERA (WA). Accordingly, a long-run elasticity factor of -0.35 has been used for Commercial demand.

The following table provides the forecast of own-price impacts on demand per connection.

Table 5.4. Own-Price Elasticity Impact on Commercial Demand per connection | %

Own-Price Elasticity Impact on Demand (%)	2020	2021	2022	2023	2024	2025	2026
Change in Gas Prices	0.77%	1.32%	-2.75%	2.47%	2.77%	2.17%	1.68%
Price Elasticity Impact (-0.35)	0.05%	-0.08%	-0.09%	0.16%	-0.38%	-0.74%	-0.75%

Further detail on the gas price forecast and price elasticity impact can be found in Sections A2 and A3.

Cross-Price Elasticity

Cross-price elasticity measures the change in demand per gas connection that occurs when the price of electricity, a substitute energy source to gas, changes. There are two components to this effect:

- The propensity of consumers to switch between gas and electricity appliances when faced with a given price movement
- The size of the relative price movements between gas and electricity.

CORE forecasting captures the response of consumers as they face relative price changes between gas and electricity. For example, the model would capture the degree of substitution that occurs between gas heating and heating by RC air-conditioning when there is a shift in relative prices between gas and electricity.

CORE has derived electricity retail price movements in the Review Period from AEMO's NEFR publication, together with the relevant component of the AEMC's projection (such as wholesale price movements):

Further detail on the electricity price forecast and price elasticity impact can be found in Sections A3 and A4.

The following table summarises the cross-price elasticity impact on demand per connection.

Table 5.5. Cross-Price Elasticity Impact on Commercial Demand per connection | %

Cross-Price Elasticity Impact on Demand (%)	2020	2021	2022	2023	2024	2025	2026
Change in Electricity Prices | Real 2018	0.27%	-4.42%	-1.05%	-0.78%	-0.90%	-1.82%	0.23%
Price Elasticity Impact (0.10)	0.03%	-0.44%	-0.11%	-0.08%	-0.09%	-0.18%	0.02%

Section 1 | 6. Tariff D Demand Forecast

6.1. Forecast Overview

This section of the report details the demand forecast for industrial customers.

- The AGN SA Network includes larger industrial customers that are reasonably anticipated to consume more than 10TJ per annum. In the Greater Adelaide region this typically includes manufacturing operations particularly for the manufacture of construction materials. These customers generally require gas for process heat.
- Smaller industrial customers are more likely to consume gas for large-scale space heating and water heating including shopping centres, hotels, hospitals and other large public buildings.
- For the industrial customer group, CORE has forecast annual demand volumes (ACQ) and capacity (measured by GJ of MDQ).

For the AGN SA Network, growth rates or trends are derived on a sector or whole-network basis. Each customer is then forecast individually but exposed to the relevant group's trend or growth rate. The forecast comprises forecasts of four customer groupings:

Forecast Type	Description	Forecast
Reviewed customers	MDQ and ACQ is forecast according to known load changes obtained via public domain review and AGN's ongoing correspondence with its industrial customer base (which also includes individual customer engagement although this process resulted in minimal reliable forecast inputs)	38 large, joining or disconnecting customers
GVA customers	Customers that belong to a particular segment (per ANZSIC classification) that has a demonstrated statistical relationship between gas demand and output (measured by ABS' Gross Value Add "GVA")	Customers from the following sectors: ▪ Transport, Postal and Warehousing ▪ Manufacturing (Construction materials only) ▪ Construction (GSP rather than GVA)
Weather Normalised Trend	Several sectors that exhibited a clear weather-induced demand pattern	Customers from the following sectors: ▪ Accommodation and Food Services ▪ Professional, Scientific and Technical Services ▪ Administrative and Support Services ▪ Public Administration and Safety ▪ Education and Training ▪ Health Care and Social Assistance ▪ Arts and Recreation Services ▪ Other Services
Average Trend Customers	Customers who did not fall into the above groupings have ACQ forecast according to observed historical trend[19]	Customers from the following sectors: ▪ Agriculture, Forestry & Fishing ▪ Mining ▪ Other Manufacturing ▪ Electricity, Gas, Water and Waste Services ▪ Wholesale Trade ▪ Retail Trade ▪ Information Media and Telecommunications ▪ Financial and Insurance Services ▪ Rental, Hiring and Real Estate Services

[19]Historical trend is derived from customers that existed in the customer group for the entire historical period (2009-2019). This is to capture true underlying growth and remove the impact on load that occurs when customers join or leave the customer group.

At the end of 2019, AGN had a total of 115 industrial customers which includes new or recently joined customers. 91 of these customers existed in the network for the entire 2009-2019 period.

The annual demand and MDQ forecast for industrial customers are based upon analysis of the following:

- Existing MDQ, by customer, at the end of 2019; and
- Known and forecast load changes, disconnections and new connections.

Overall CORE expects MDQ to decrease by an annual average of -3.12% between 2022 and 2026. This decrease is associated with a total ACQ which is expected to fall on average -2.85% during the same period. This is primarily driven by the significant disconnections trend (annual historical average of 6 customers per annum) and the 1.51% average annual normalised decline in the consumption of large space heating connections. The average trend group exhibited a 0.53% annual average growth in ACQ over the historical period and provides moderate support for the overall trend. Compounding the demand decline is the relative size of disconnecting customers and new customers. Over the 2009-2019 period, the MDQ of a joining customer is approximately 47% less than a disconnecting customer.

For detailed analysis on the statistically derived growth rates for industrial customer groups please refer to Appendix A4.

6.2. Tariff D Demand Forecast Summary

Table 6.1. Tariff D MDQ | GJ

	2019	2020	2021	2022	2023	2024	2025	2026
MDQ	50,486	47,692	45,900	44,422	43,008	41,659	40,380	39,174

Table 6.2. Tariff D Annual Demand Forecast | GJ

	2019	2020	2021	2022	2023	2024	2025	2026
ACQ	11,366,654	10,915,304	10,564,890	10,269,515	9,979,838	9,695,806	9,417,434	9,144,674

Table 6.3. Tariff D Closing Connections Forecast | No.

	2018	2019	2020	2021	2022	2023	2024	2025
Closing Connections	115	112	109	106	103	100	97	94

Figure 6.1. Industrial MDQ | GJ

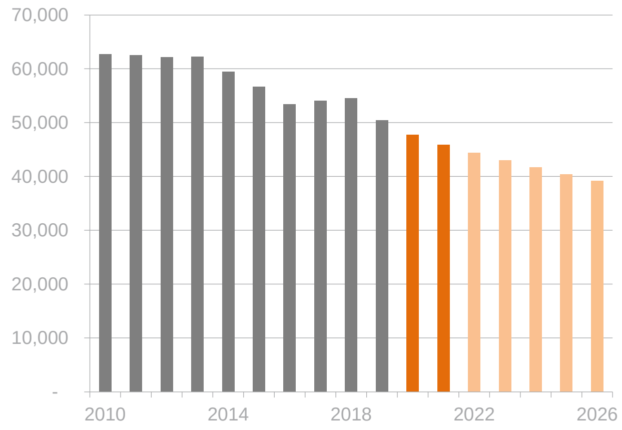


Figure 6.2. Industrial Annual Demand | GJ

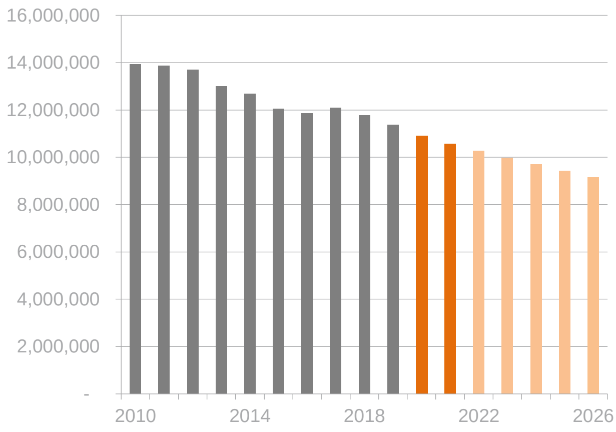
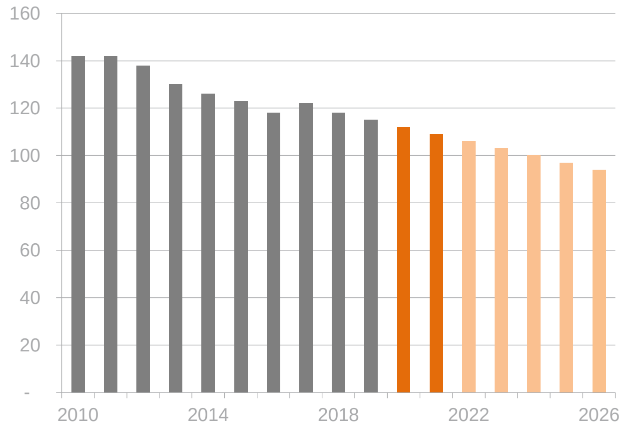


Figure 6.3. Industrial Customer Numbers | No.



The forecast of connections is primarily driven by an underlying historical trend built into the forecast which captures the annual average decrease of -2.20% (or -2.82% with the exclusion of one outlier year, 2017). This represents the average disconnection number of 6 net of 3 gross new connections on average each year.

Economic & Manufacturing Sector Outlook

CORE has considered general economic trends and specific analysis of major industry segments of significance to demand customers. As noted below, most industrial customers are grouped within the Manufacturing sector, a sector which is experiencing a sustained period of change in SA and Australia more broadly.

CORE concedes there is significant downside risk in industrial connections relative to the forecast values. This conclusion is based on economic conditions and competition faced by a lot of industrial sectors generally in Australia (including South Australia), particularly in key sectors such as manufacturing. Given that dwelling completions are expected to remain flat or decrease their growth, and international competition is an ever-present threat to manufacturing, there is significant downward pressure on industrial customer numbers.

The following major themes are weighing on the Manufacturing sector:

Table 6.4. General Economic Themes - Manufacturing Sector.

Economic Theme	Description
Manufacturing Sector Faces Structural Challenge	A range of Government and other independent reviews highlight the challenges facing the Australian manufacturing industry. Key factors include: ▪ unfavourable exchange rates although markets now indicate AUD in the 0.65-0.70 range going forward ▪ high relative labour, and other input costs- which now includes energy ▪ lower productivity than competitors ▪ smaller scale ▪ unfavourable proximity to markets
Material Increases in Energy Costs are Impacting Energy-intensive Businesses	Electricity, gas and other energy cost increases (combined with other input costs) have been widely reported to be having a material impact on the profitability of energy-intensive sectors. The impact is expected to be widespread and will be reflected in: ▪ the use of cost-effective substitutes ▪ investment in efficiency initiatives ▪ rationalisation of businesses and closures
Global Competition Forces Remain Strong	Many sectors are suffering from competition against lower cost importers.

Source: CORE Energy Group.

6.2.1.2. Additional Note | Review of MDQ and ACQ Relationship

The level of MDQ required by a company is determined by the maximum demand during a given year. The relationship between ACQ and MDQ is referred to as load factor and can be expressed as follows:

LF = Average Daily Demand/MDQ

where:

- LF = load factor; and
- average daily gas demand is calculated as the total year's demand divided by the number of days in a year
  - ACQ/ 365

The load factor quantifies the extent to which the average daily demand is below the maximum daily demand with 100% indicating a perfectly flat load and 50% indicating a maximum day that is twice the volume of the year average. The table below also expresses load factor in terms of the ratio between MDQ and average daily quantity, given that both expressions are commonly used in the industry. For example, a LF of 80% has a load factor ratio of 1.25.

The MDQ is higher than the average daily demand due to variability of activity throughout a year.

As noted in the following table, the AGN Tariff D sector had a load factor of 1.87 in 2019. This load factor is expected to be stable throughout the AA period: it is reasonable to expect Tariff D customers to respond to a weak manufacturing environment and increasing gas prices by reducing ACQ. Similarly, given that the distribution component of a customer's total gas cost is a function of MDQ, and wholesale gas contracts are typically charging more for flexible contract structures, CORE expects similar but smaller reductions in MDQ relative to any ACQ decrease. For instance, some industrial customers in the space heating market will likely seek to reduce overall heating behaviour but will still heat at levels dictated by system capacity on the coldest days of the year.

Table 6.5. Tariff D Load Factors.

Load Factor	2019	2020	2021	2022	2023	2024	2025	2026
LF	1.62	1.59	1.59	1.58	1.57	1.57	1.57	1.56

Source: CORE.

Section 1 | 7. Conclusion

CORE considers that the forecasts presented below represent the best estimate of gas demand and customer numbers for the AGN distribution network during the Review Period. CORE has taken all reasonable steps to ensure this report complies with ss 74 and 75 of the *NGR*. The methodology is consistent throughout the various sections. The statistical rigour and validation processes ensure precision and reliability.

7.1. Tariff D

CORE forecasts that Tariff D MDQ will decrease by -3.12% per annum throughout the forthcoming AA Period and ACQ will decrease by an average of -2.88% per annum. The results shown below have been influenced by:

- Significant historical trend in disconnections (relative to new connections).
- Known demand and changes due to public domain review and known new customers.
- Sector output and statistically significant relationships between demand and GVA; and
- Statistically significant relationships between demand and EDD for industrial customers that use gas for space or water heating.

CORE believes there is greater downside risk to the industrial forecast due to the following:

- Appliance and building efficiency trends which are expected to continue during the Review Period.
- The momentum towards reduction of gas demand or partial fuel switching; and
- The ongoing economic challenge faced by industrials in the network arising from competitive pressures in the Asia Pacific region and elsewhere. This challenge is seemingly increasing as energy input costs rise.

Table 7.1. Forecast of MDQ | GJ

	2019	2020	2021	2022	2023	2024	2025	2026
MDQ	50,486	47,692	45,900	44,422	43,008	41,659	40,380	39,174

Table 7.2. Forecast of Annual Demand | GJ

	2019	2020	2021	2022	2023	2024	2025	2026
ACQ	11,366,654	10,915,304	10,564,890	10,269,515	9,979,838	9,695,806	9,417,434	9,144,674

Table 7.3. Forecast Average Annual Growth in Tariff D Demand | %

Average Growth	2022 - 2026	2020 - 2026
MDQ	-3.12%	-3.23%
ACQ	-2.85%	-2.91%

Figure 7.1. Industrial MDQ | GJ

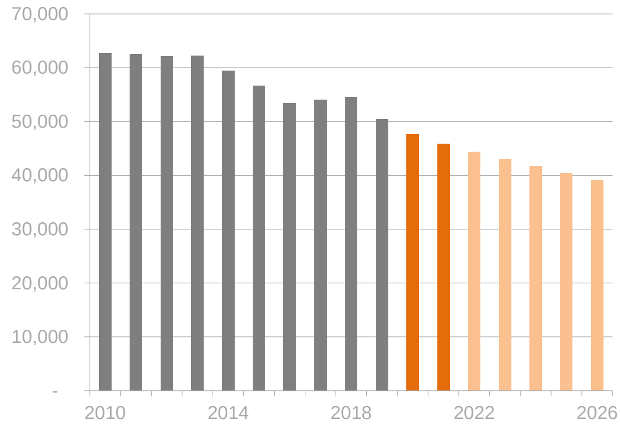


Figure 7.2. Industrial Annual Demand | GJ

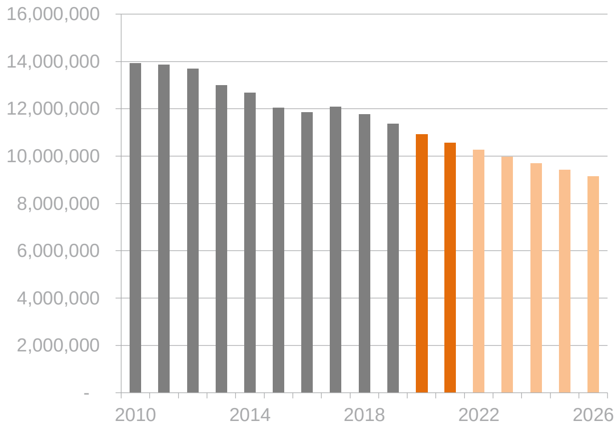
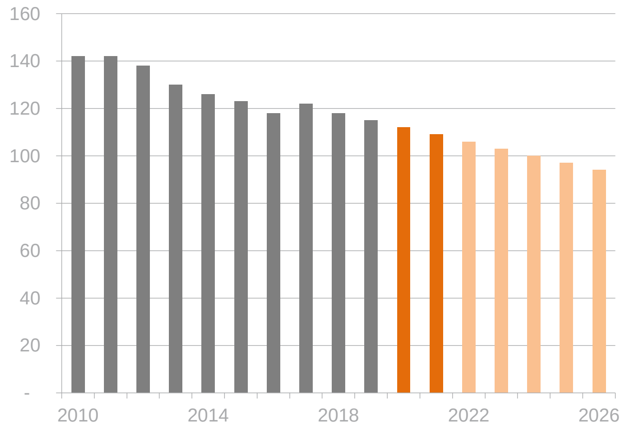


Figure 7.3. Industrial Connections | GJ



7.2. Tariff C | Commercial

7.2.1. Commercial Demand

The forecast for Commercial demand is broadly flat, incorporating a continued decrease in existing demand per connection which is offset by the continuation of historical connections growth.

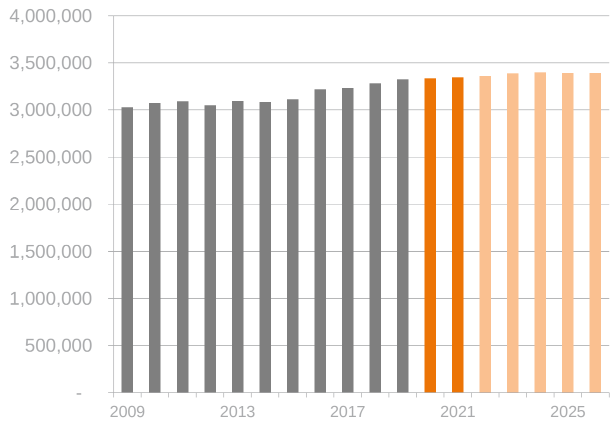
Table 7.4. Commercial Demand Forecast | GJ

	2019	2020	2021	2022	2023	2024	2025	2026
Existing 2019		3,296,203	3,222,947	3,159,862	3,104,821	3,032,895	2,947,965	2,869,845
New Commercial		36,977	119,289	201,177	283,924	365,377	444,709	524,287
Total Demand	**3,322,122**	**3,333,180**	**3,342,237**	**3,361,039**	**3,388,745**	**3,398,272**	**3,392,675**	**3,394,132**

Table 7.5. Commercial Demand | Average Annual Growth | %

	Commercial	
Average Growth	**2022 - 2026**	**2020 - 2026**
Existing 2019	-2.29%	-2.28%
New Commercial	35.61%	66.78%
Total Demand	**0.31%**	**0.30%**

Figure 7.4. Commercial Demand | GJ p.a.



7.2.2. Commercial Connections

The Real GSP conditions for most of the forecast period are forecast to sit above historical levels, but this is offset by a declining ratio of business numbers to GSP and subject to significant downside risk due to the COVID pandemic.

Table 7.6. Commercial Connections Forecast | No.

	2019	2020	2021	2022	2023	2024	2025	2026
Opening Connections	11,185	11,233	11,350	11,291	11,231	11,337	11,442	11,544
Disconnections	207	150	151	153	154	156	157	158
Disconnections | Zero Consuming Connections		-	168	168	-	-	-	-
Existing 2019 Connections		11,083	10,764	10,443	10,289	10,133	9,976	9,818
New Commercial Connections		267	261	261	260	260	259	258
Cumulative New Commercial Connections		267	528	788	1,048	1,308	1,567	1,826
Total Connections	**11,233**	11,233	11,350	11,291	11,231	11,337	11,442	11,544
Net Connections	**48**	**117**	**- 58**	**-60**	**106**	**104**	**102**	**100**

Table 7.7. Commercial Connections | Average Annual Growth | %

	Commercial	
Average Growth	**2022 - 2026**	**2020 - 2026**
Opening Connections	0.34%	0.46%
Disconnections	0.92%	0.94%
Existing 2019 Connections	-1.82%	-2.00%
New Commercial Connections	-0.20%	-0.53%
Cumulative New Commercial Connections	28.70%	40.22%
Total Connections	**0.62%**	**0.43%**
Net Connections[20]	**-1.83%**	**-2.57%**

Figure 7.5. Commercial Connections | No.

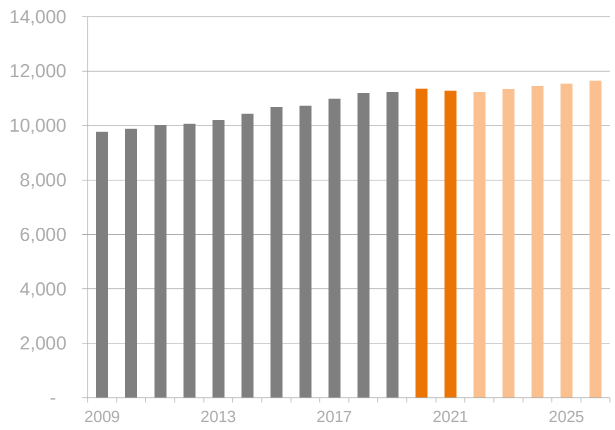
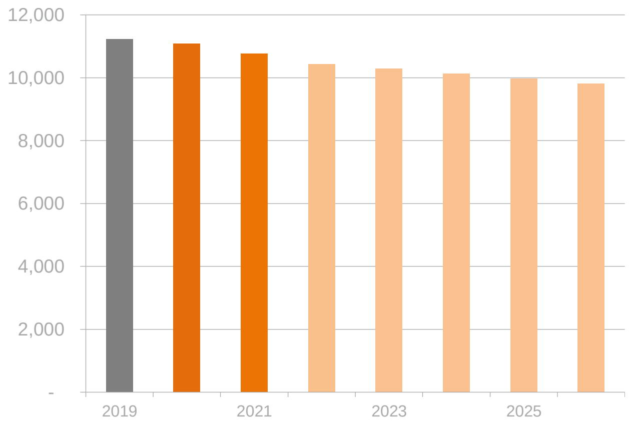


Figure 7.6. Commercial Existing Connections | No.



[20] Please note net connections growth is shown prior to any adjustment for ZCM removal and represents the underlying trend in connections.

Figure 7.7. Commercial Net Connections | No.

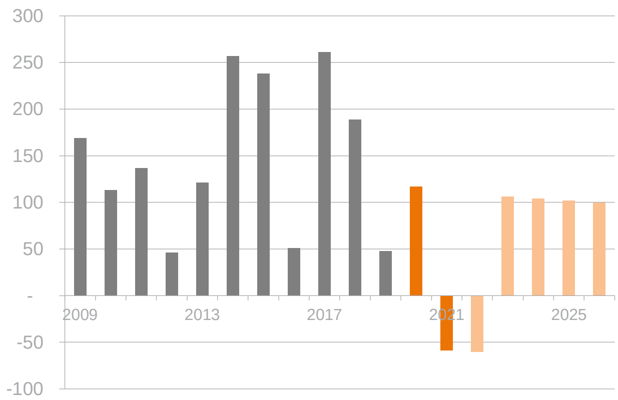
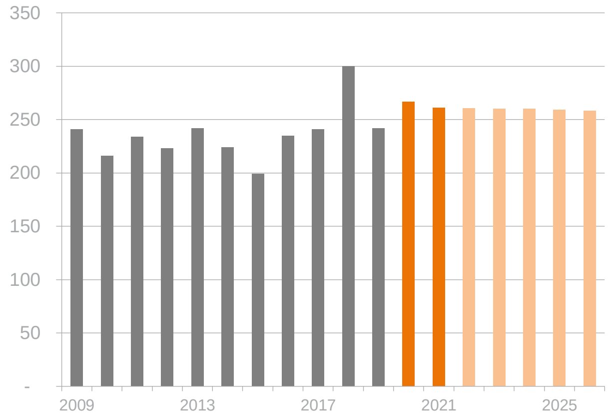


Figure 7.8. Commercial New Connections | No.



7.2.3. Demand per Connection

The forecast results for Commercial demand per connection are driven by a combination of factors. CORE's bottom-up approach has accounted for price effects (own and cross-price), weather effects, appliance trends and efficiency trends to arrive at the following growth rates.

The forecast of tariff Commercial demand per connection is presented in the following tables and charts.

Table 7.8. Commercial Demand per Connection Forecast | GJ/conn

	2019	2020	2021	2022	2023	2024	2025	2026
Existing 2019		297.4	299.4	302.6	301.8	299.3	295.5	292.3
New Commercial		138.7	226.1	255.3	270.8	279.3	283.7	287.2
Weighted Average Demand per Connection	**295.7**	**293.7**	**296.0**	**299.3**	**298.9**	**297.0**	**293.9**	**291.5**

Table 7.9. Commercial | Average Annual Growth of Demand per Connection | %

	Commercial	
Average Growth	**2022 - 2026**	**2020 - 2026**
Existing 2019	-0.48%	-0.28%
New Commercial	4.98%	14.66%
Weighted Average Demand per Connection	**-0.30%**	**-0.12%**

Figure 7.9. Commercial Total Demand per Connection | GJ/conn

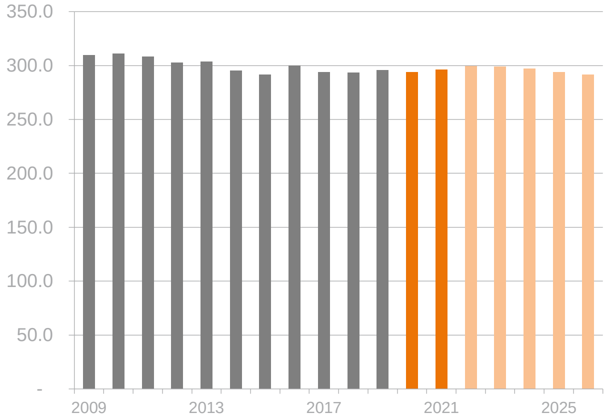
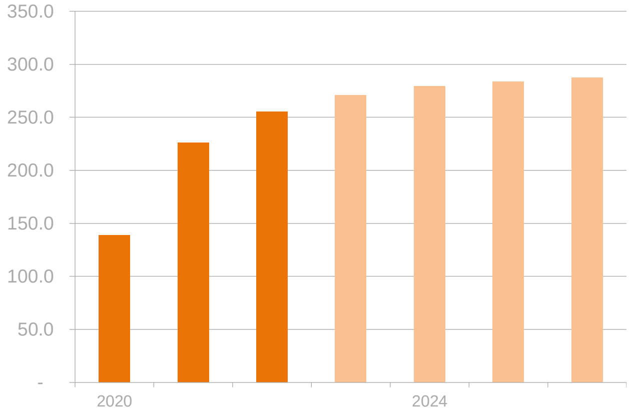


Figure 7.10. Commercial New Demand per Connection | GJ/conn



7.3. Tariff R | Residential

7.3.1. Residential Demand

The forecast decrease in residential demand is due to a continued decline in demand per connection and a sharp decrease in 2021 dwelling commencements projected by HIA as an initial projection of the COVID pandemic impact. Connections growth recovers to a steadier rate longer term but lacks the strength to offset appliance and efficiency trends. After a recovery between 2022 and 2024, dwelling completions are expected to lose momentum towards 2026. Furthermore, this momentum loss is attributable to single estates rather than multi density and high-rise dwellings. Single estate dwellings have a higher propensity to connect to gas than MDHR which explains why decreases in these dwelling completions can result in falling connections growth despite overall growth in South Australian completions.

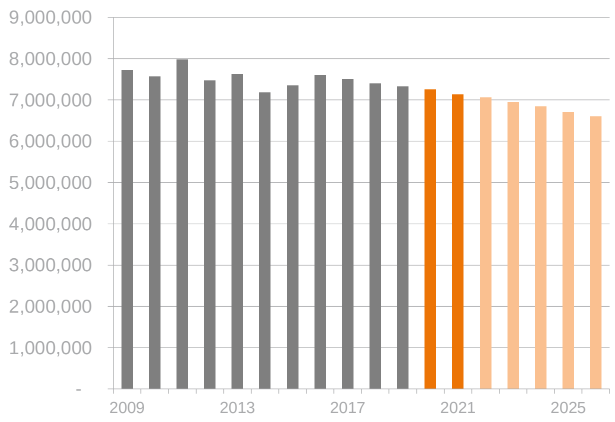
Table 7.10. Residential Demand Forecast | GJ

	2019	2020	2021	2022	2023	2024	2025	2026
Existing 2019		7,214,756	7,008,240	6,852,507	6,677,303	6,489,557	6,295,687	6,117,434
New Dwelling | Estate		31,108	99,267	162,955	217,520	272,108	327,108	380,806
New Dwelling | E2G		6,317	19,879	33,216	45,500	56,714	66,889	76,296
New Dwelling | MDHR		2,393	7,635	11,998	15,335	19,308	23,962	28,928
Total Demand	**7,323,982**	**7,254,574**	**7,135,021**	**7,060,676**	**6,955,659**	**6,837,687**	**6,713,646**	**6,603,465**

Table 7.11. Residential Demand | Average Annual Growth | %

Average Growth	2022 - 2026	2020 - 2026
Existing 2019	-2.68%	-2.71%
New Dwelling | Estate	31.87%	63.08%
New Dwelling | E2G	32.14%	62.57%
New Dwelling | MDHR	31.14%	62.45%
Total Demand	**-1.54%**	**-1.47%**

Figure 7.11. Residential Demand | GJ



7.3.2. Residential Connections

The connections growth of 1.04% over the forthcoming AA period is a function of expected new dwellings and dwelling type in the Greater Adelaide region. The historical average penetration rate of the network is also a significant driver with 76.7% of new estate dwellings and 26.0% of MDHR dwellings typically connecting to gas.

Table 7.12. Residential Connections Forecast | No.

	2019	2020	2021	2022	2023	2024	2025	2026
Opening Connections	436,908	443,043	448,400	452,592	455,278	459,953	465,169	470,924
Disconnections	2,095	1,897	1,920	1,944	1,962	1,982	2,004	2,029
Disconnections | Zero Consuming Connections	-	-	1,448	1,448	-	-	-	-
Existing 2019 Connections	443,043	441,146	437,778	434,385	432,424	430,442	428,437	426,408
New Dwelling Connections | Residential Estate	6,591	5,628	5,932	4,798	5,241	5,685	6,128	6,031
New Dwelling Connections | Residential E2G	809	918	880	843	808	775	743	712
New Dwelling Connections | Residential MDHR	830	708	748	437	588	738	889	911
Total Connections	**443,043**	**448,400**	**452,592**	**455,278**	**459,953**	**465,169**	**470,924**	**476,549**
Net Connections	**6,132**	**6,135**	**5,357**	**4,192**	**2,686**	**4,675**	**5,216**	**5,755**

Table 7.13. Residential Connections | Average Annual Growth | %

Average Growth	2022 - 2026	2020 - 2026
Opening Connections	0.99%	1.02%
Disconnections	1.11%	1.13%
Existing 2019 Connections	-0.52%	-0.56%
New Dwelling Connections | Residential Estate	0.96%	1.70%
New Dwelling Connections | Residential E2G	-4.15%	-4.15%
New Dwelling Connections | Residential MDHR	8.28%	7.82%
Total Connections	**1.04%**	**1.02%**
Net Connections	**11.55%**	**6.00%**

Figure 7.12. Residential Total Connections | No.

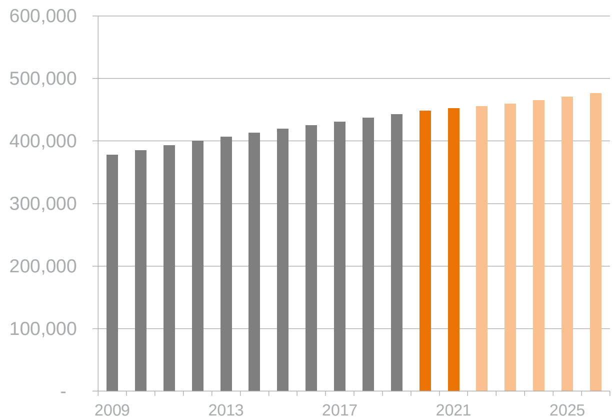


Figure 7.13. Residential Existing Connections | No.

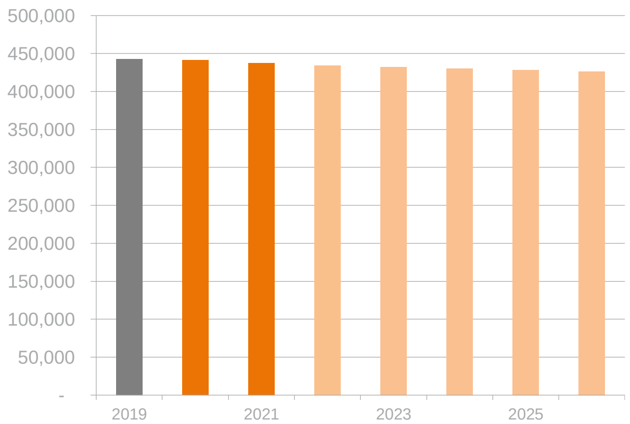


Figure 7.14. Residential New Connections | No.

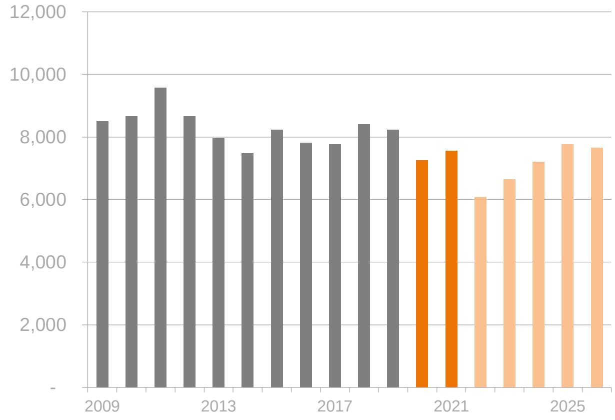


Figure 7.15. Residential Net Connections | No.[21]

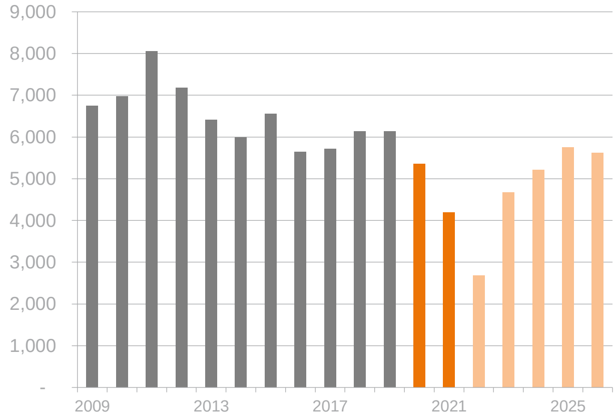


Figure 7.16. New Residential Estate Connections | No.

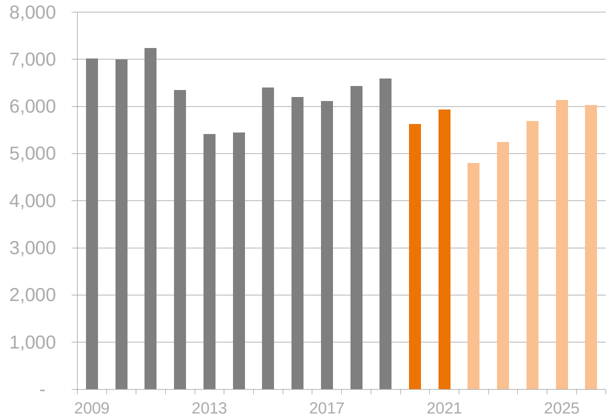


Figure 7.17. New Residential E2G Connections | No.

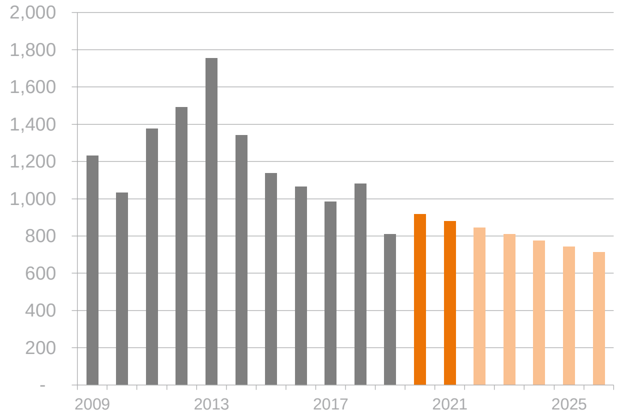
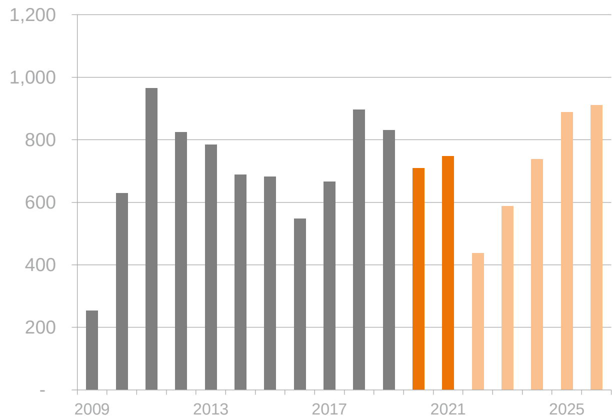


Figure 7.18. New Residential MDHR Connections | No.



[21] Please note the short term trend seen in this chart is significantly impacted by the zero consuming MIRN program.

7.3.3. Demand per Connection

The -2.55% decline is consistent with the continuation of efficiency and appliance trends experienced by this customer group in addition to the price impacts from the gas and electricity retail market. The true underlying decline per dwelling slightly exceeds this rate as the projected decline includes the impact of the ZCM removal program (which removes connections with no associated loss in volume).

Table 7.14. Residential Demand per Connection Forecast | GJ/conn

	2019	2020	2021	2022	2023	2024	2025	2026
Existing 2019		16.4	16.0	15.8	15.4	15.1	14.7	14.3
New Dwelling Connections | Residential Estate		5.5	8.6	10.0	10.1	10.0	9.8	9.7
New Dwelling Connections | Residential E2G		6.9	11.1	12.6	13.2	13.4	13.5	13.4
New Dwelling Connections | Residential MDHR		3.4	5.2	6.3	6.2	6.0	5.8	5.8
Weighted Average Demand per Connection	**16.5**	**16.2**	**15.8**	**15.5**	**15.1**	**14.7**	**14.3**	**13.9**

Table 7.15. Residential | Average Annual Growth of Demand per Connection | %

Average Growth	2022 - 2026	2020 - 2026
Existing 2019	-2.17%	-2.16%
New Dwelling Connections | Residential Estate	2.58%	11.38%
New Dwelling Connections | Residential E2G	4.09%	13.53%
New Dwelling Connections | Residential MDHR	2.30%	11.12%
Weighted Average Demand per Connection	**-2.55%**	**-2.55%**

Each year, smaller new customers increase their share of the total customer group (newer dwellings will have more modern efficient appliances and be built according to more recent dwelling efficiency requirements). These aspects decreases the weighted average demand per connection beyond the respective decline rates of each group. The weighted average is a function of existing growth rate, new growth rate and the increased representation of lower, new customers (as existing customers disconnect and new, lower customers join).

Figure 7.19. Residential Demand per Connection | GJ/conn

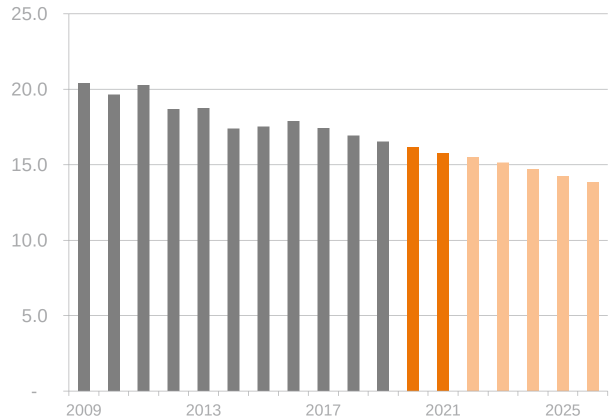


Figure 7.20. Existing Demand per Connection | GJ/conn

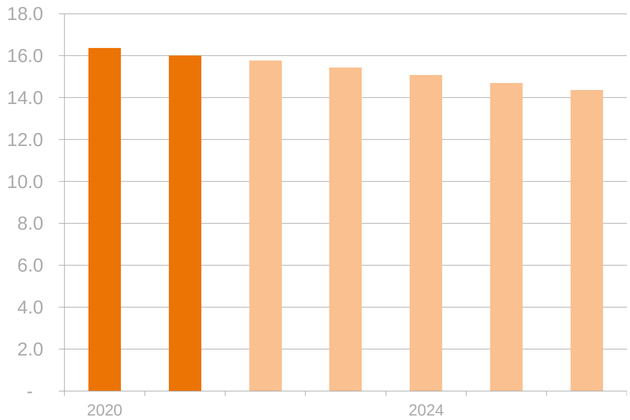
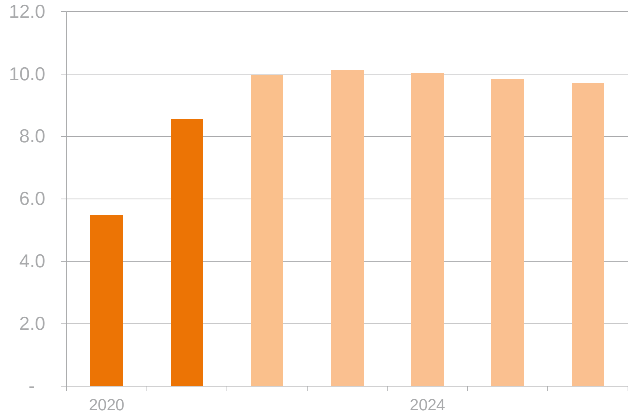


Figure 7.21. New Residential Demand per Connection | GJ/conn



Terms of Reference

Scope and Context

CORE has been engaged to deliver a gas demand forecast for the AGN South Australian Network AA 2022-2026 pursuant to the terms contained herein. The forecast addresses the level of demand arising from the residential, commercial and industrial sectors as well as forecasting customer numbers for these sectors. The methodology reviews the leading approaches to forecasting demonstrated by previous AAs and other experts in the field. The opinions formed are based entirely on quality statistical analysis, economic theory and industry experience. The analysis forecasts the customer numbers and total demand for each connection type, within each sector and under each tariff class. The approach is quantitative whenever appropriate although qualitative analysis will also be required to justify the methodology and results of the forecast. The context of the forecast and report is that of an independent expert. Accordingly, the methodology and output are a best-practice approach that complies with the *NGR*.

Relevant Considerations

Consideration and analysis occur for the aspects listed below. The relevant time frame for the forecast includes the period leading up to the Review Period as well as all years contained within the period.

- Annual gas demand for new and existing users within the AGN South Australian Network.
- Quantity and capacity-based demand for industrial users within the network.
- The historical trends in gas demand and customer numbers. The relevance of these trends should also be examined.
- The various drivers and variables that create movements in average gas usage.
- The suitability and reliability of each statistical method used for the forecast.
- Thorough analysis for all market segments but particularly those where AGN identifies or predicts significant changes.
- Appliance trends and policies driving appliance efficiency changes.
- Macroeconomic analysis such as population growth, real output and income in the areas covered by the network.

Output

CORE provides the following deliverables:

- Weather Normalised Demand and Demand Forecast
  - Preliminary and Final
- AER Report
  - Draft and Final

Upon completion of the AER Report, all results, forecasts and assumptions are clearly set out. All methodology is revealed and explained. The findings are adequately justified and compliance with the *NGR* is shown.

Key References

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A1. Weather Normalisation Results

The following section shows the regression results and key statistical tests performed during the weather normalisation stage:

- Regression analysis was performed using monthly sum of EDD_{312} units.
- Separate regressions were performed for each sector:
  - Residential
  - Commercial
  - Weather-induced industrial customers
- Statistical models and parameters that were tested included:
  - Lagged demand per connection (up to and including 12 lags)
  - Transformations such as logarithmic and differencing
  - Year dummy variables to test for outlier years (none of 2009 to 2019 consistently fell below 5% threshold across different models)
  - Time-trend dummy variable which captures constant processes/ changes over time

Residential

The regression results and statistical tests performed for these models are summarised in the following tables:

Table A1.1 Regression Output

	Residential Gas Demand
EDD Coefficient (GJ of Demand per Connection per EDD Unit)	0.0038 (p value = 0.00)
Time Trend Coefficient	-0.0026 (p value = 0.00)
Constant	1.0814 (p value = 0.00)
No. of observations	132 (132 months)

CORE’s preference is to complete a series of conventional tests for heteroskedasticity, autocorrelation and omitted variable bias. Post-estimation testing and analysis was completed where possible and CORE elected to use the coefficients from the Prais-Winsten (generalized least-squares) estimator as a safeguard against autocorrelation. As an additional safeguard against heteroskedasticity, the regression was run using robust standard errors.

Table A1.2 Post-estimation & Other Results

Test	Residential Statistics and Conclusion	
Breusch-Pagan & White Test	Unavailable due to Prais-Winsten method- robust standard errors used as a precaution (White-Huber standard errors)	
Durbin Watson	d-stat = 1.06 (transformed to 1.85)	Sufficiently close to 2 using Prais-Winsten regression.
Durbin Watson	Unavailable as post-estimation but note that Prais-Winsten method was ultimately used due to a Breusch-Godfrey result with OLS that suggested the potential for autocorrelation	
Prais-Winsten iterations	5	
Rho	0.4767	
AIC	AIC = -261.51	good predictive power relative to other model specifications
R Squared	R^2 = 0.9662	acceptable predictive power

Commercial

The regression results and statistical tests performed for these models are summarised in the following tables:

Table A1.3 Regression Output

	Commercial Demand
EDD Coefficient (GJ of Demand per Connection per EDD Unit)	0.0624 (p value = 0.00)
Time Trend Coefficient	-0.0107 (p value = 0.00)
Constant	15.5094 (p value = 0.00)
No. of observations	132 (132 months)

As with the residential regression analysis, CORE elected to use the coefficients from the Prais-Winsten (generalized least-squares) estimator as a safeguard against autocorrelation. As an additional safeguard against heteroskedasticity, the regression was run using robust standard errors.

Table A1.4 Post-estimation & Other Results

Test	Residential Tariff Statistic and Conclusion	
Breusch-Pagan & White Test	Unavailable due to Prais-Winsten method- robust standard errors used as a precaution (White-Huber standard errors)	
Durbin Watson	d-stat = 1.51 (1.91 transformed)	Sufficiently close to 2 using Prais-Winsten regression
Breusch-Godfrey	Unavailable as post-estimation but note that Prais-Winsten method was ultimately used due to a Breusch-Godfrey result with OLS that suggested the potential for autocorrelation	
Prais-Winsten iterations	5	
Rho	0.2488	
AIC	AIC = 441.4	good predictive power relative to other model specifications
R Squared	R^2 = 0.9810	acceptable predictive power

Tariff D

For the industrial tariff please refer to the separate Industrial regression analysis provided in Appendix A4 which combines the GSP and GVA based regressions that applied to different sections of those customer groups.

Conclusion

Overall, the statistical models for residential, commercial and industrial demand per connection are sufficiently robust-particularly after the shift away from simple OLS. CORE has not relied upon any coefficient that does not meet 5% critical significance.[22] Importantly, the coefficients of the regressors and constant provide an intuitive commercial interpretation in terms of magnitude and sign. The fitted regression and normalisation results also honour historical trends net of monthly or yearly EDD fluctuations.

[22] The 10%, 5% and 1% significance levels are widely considered to be appropriate benchmarks. Test results below or equal to 1% require caution and further investigation. CORE believes no test result presented here invalidates the weather normalisation process undertaken.

A2. Retail Gas and Electricity Price Forecast

Summary of Retail Gas Price Forecast

The retail gas price is assumed by CORE to consist of the cost components outlined in Table A2.1. The price forecast was developed by analysing each of these components- a process in which CORE has significant experience. Gas price forecasting has been completed by CORE for several previous AA reports and in countless other engagements. The bottom-up approach to price forecasting is a comprehensive way to capture all factors that influence final gas prices.

Table A2.1 Components of Retail Gas Price

Cost Component	Units	Description
Variable Cost		
Wholesale	AUD/GJ	The market price of gas realised by the supplier to produce and deliver gas into the transmission pipeline. This is the price for flat load gas production. ▪ Wholesale prices were forecast by analysing the reference and high case from the 2019 AEMO GSOO and the LNG future netback series published by the AER. Additionally, CORE's experience advising large Eastern Australia gas consumers through their procurement processes provides a natural source of validation within the bounds of confidentiality. ▪ CORE notes
MDQ	AUD/GJ	The cost of production (via storage or other production flexibility) to deliver maximum daily supply capacity to meet peak customer demand during the winter heating season.
Transmission	AUD/GJ	Cost of transporting gas along the MSP and EGP transmission pipelines from the supply source to the distribution network. This includes base load and an additional load factor for maximum daily quantity MDQ capacity allowance.
Distribution	AUD/GJ	Cost of transporting gas though the distribution network to the customer. AGN has supplied indicative tariffs for the forecast period.
Retail Margin	AUD/GJ	Retailer costs and profit margin- calculated from historical values and then remain largely consistent throughout the forecast period on the assumption that retail markets have reached a relatively mature level of competition and the current level of discounting is a sound representation for future discounting.
Market Charges	AUD/GJ	Cost to cover AEMO market participant fees.
Fixed Cost		
Fixed Retail Supply Charge	AUD p.a.	Annual fixed charge per customer per annum to cover certain fixed costs.

Table A2.2 SA Residential Retail Gas Price Forecast | AUD Real 2019

Cost Component	Unit	2019	2020	2021	2022	2023	2024	2025	2026
Wholesale, Transmission, Storage Growth (Adelaide weighted average)	% growth		-1.4%	1.6%	4.1%	5.7%	6.6%	4.8%	3.4%
Distribution (Indicative AGN Tariffs)	% growth		2.8%	1.7%	-9.2%	1.2%	1.2%	1.2%	1.2%
Retail Bill | Real 2019	**AUD**	**970.00**	**978.14**	**987.81**	**959.20**	**974.21**	**991.11**	**1,004.95**	**1,016.22**
Absolute Change in Retail Bill	**AUD**	**(40.42.)**	**8.14**	**9.67**	**(28.61.)**	**15.01**	**16.90**	**13.83**	**11.27**
Percentage Change in Retail Bill	%	**-4.00%**	**0.84%**	**0.99%**	**-2.90%**	**1.56%**	**1.73%**	**1.40%**	**1.12%**

Source: CORE

Table A2.3 SA Commercial Retail Gas Price Forecast | AUD Real 2019

Cost Component	Unit	2019	2020	2021	2022	2023	2024	2025	2026
Wholesale, Transmission, Storage Growth (Adelaide weighted average)	% growth		-1.4%	1.6%	4.1%	5.7%	6.6%	4.8%	3.4%
Distribution (Indicative AGN Tariffs)	% growth		2.8%	1.7%	-9.2%	1.2%	1.2%	1.2%	1.2%
Retail Bill | Real 2019	**AUD**	**5,538.00**	**5,580.75**	**5,654.34**	**5,498.99**	**5,635.00**	**5,791.36**	**5,916.80**	**6,016.20**
Absolute Change in Retail Bill	**AUD**	**(126.43.)**	**42.75**	**73.59**	**(155.35.)**	**136.02**	**156.35**	**125.45**	**99.40**
Percentage Change in Retail Bill	%	**-2.23%**	**0.77%**	**1.32%**	**-2.75%**	**2.47%**	**2.77%**	**2.17%**	**1.68%**

Source: CORE

Summary of Retail Electricity Price Forecast

Table A2.4 SA Residential Historical Retail Electricity Price | AUD Real 2018

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Retail Bill | Real 2019	1,352	1,560	1,787	1,965	1,959	1,829	1,793	1,985	2,214	2,059
Percentage Change | %	0.57%	15.41%	14.54%	9.95%	-0.29%	-6.63%	-1.96%	10.67%	11.54%	-6.99%

Source: AEMC; AEMO ESOO; ESCOSA

Table A2.5 SA Commercial Historical Retail Electricity Prices | AUD Real 2018

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Retail Bill | Real 2019	2,547	2,939	3,366	3,701	3,661	3,526	3,448	3,936	4,442	4,142
Percentage Change | %	0.57%	15.41%	14.54%	9.95%	-1.08%	-3.71%	-2.21%	14.17%	12.84%	-6.75%

Source: AEMC; AEMO ESOO; ESCOSA

Forecast

The forecast electricity bill movements for Residential and Commercial consumers are derived from the AEMC 2019 electricity price trends publication and ESCOSA retail price reporting. The following factors are key drivers for both price forecasts:

- Increased renewable growth amidst flat demand is projected to decrease the wholesale portion of retail electricity bills.
- This is offsetting regulated network costs are increasing moderately.
- CORE has accepted the AEMC's projection of flat environmental policy costs for the forecast period.

The table below summarises the forecasts for residential & commercial electricity bills adjusted to real 2019 values and their respective year on year percentage changes.

Table A2.6 SA Forecast Retail Electricity Price | AUD Real 2019

	2020	2021	2022	2023	2024	2025	2026
Residential Retail Bill | Real 2019	2,065	1,973	1,953	1,937	1,920	1,885	1,889
Percentage Change | %	0.27%	-4.42%	-1.05%	-0.78%	-0.90%	-1.82%	0.23%
Commercial Retail Bill | Real 2019	4,153	3,970	3,928	3,897	3,862	3,792	3,800
Percentage Change | %	0.27%	-4.42%	-1.05%	-0.78%	-0.90%	-1.82%	0.23%

A3. Price Elasticity of Demand Analysis

Introduction

CORE notes that it is nationally and internationally recognised that a material movement in the price of a good such as gas, is likely to cause some degree of movement in the level of demand for that good or service- ‘own-price elasticity of demand’. Further, CORE notes that it is well recognised that a material movement in the price of a good or service (electricity) is likely to cause some degree of movement in the level of demand for a close substitute good or service (gas) – ‘cross-price elasticity of demand’. These relationships have been accepted by the AER in prior AA final and draft decisions (and the ERA in equivalent Access Arrangement processes in Western Australia). For the reasons above, CORE has derived a forecast of both own-price and cross-price elasticity of demand for gas in the AGN SA Network over the AA Review period.

Approach

CORE has undertaken an assessment of the alternative approaches available to derive an estimate of the price elasticity of gas demand within the AGN SA Network, including research of approaches adopted nationally and internationally. CORE is of the opinion that the preferred approach would involve an observation of actual demand response to actual price movements over a statistically relevant period. There is not an acceptable dataset that corresponds to the circumstances of the Review Period meaning it is not possible to apply such an approach. Nonetheless CORE did conduct econometric analysis using historical AGN data, but the datasets contained significant variability and no statistically rigorous results were achieved. CORE is of the opinion that the best estimate, under the circumstances, will be derived by applying a rigorously determined elasticity factor against a detailed assessment of future gas and electricity prices in SA during the Review Period. CORE has undertaken an extensive review of historical AA’s and empirical studies relating to price elasticity of demand generally, and in relation to gas and electricity more specifically.

The two price elasticity factors CORE has quantified are:

- Own-price elasticity (the change in gas demand resulting from a change in the price of gas); and
- Cross-price elasticity (the change in gas demand resulting from a change in the price of a substitute energy source - electricity).

CORE’s analysis has considered:

- The results of third-party analysis via an international literature review regarding price elasticity factors; and
- The range of price elasticity factors previously accepted by the AER and ERA in prior AA’s.

CORE is of the opinion that the listing of own price and cross-price elasticity factors, which are summarised in Table A3.1 and Table A3.2 provide a reasonable basis for deriving an estimate of the price elasticity of demand for gas in the AGN SA Network.

Table A3.1 Price Elasticity of Gas Demand – Literature Review.

Date	Study	Country	Author / Source	Own Price Elasticity of Gas Demand	Cross-Price Elasticity of Gas Demand
1987	Residential gas demand	US	Herbert	-0.30 (Short run)	0.10 (short run)
1999	Gas demand forecast and transmission and distribution tariffs	Australia	Harman et al	-0.54 (Short run) -0.65 (Long run)	N/A
2004	The ex-post impact of an energy tax on household energy demand	Netherlands	Berkhout et al	-0.19 (Short run) -0.44 (Long run)	N/A
2005	Regional differences in the price-elasticity of demand for energy	US	Bernstein, Griffin	-0.12 (Short run) -0.36 (Long run)	0.11 (electricity price of previous year)
2010	Residential demand of gas and electricity in the US	US	Alberini et al	-0.552 (Short run) -0.693 (Long run)	0.15 (Long run)
2011	Residential gas demand	US	Payne, Loomis, Wilson	-0.264 (Long run)	0.123 (Long run)

Source: Third party expert reports and analysis

Table A3.2 Price Elasticity of Gas Demand – Prior AER Submissions.

Period	Network	Source	Own Price Elasticity of Demand	Cross-Price Elasticity of Demand
2013-17	Multinet (VIC)	NIEIR	-0.28 (all customer segments)	N/A
2011-16	Envestra (SA)	NIEIR	-0.30 (residential, long-run) -0.35 (industrial, long-run)	N/A
2013-17	Ausnet (VIC)	CIE	-0.17 (residential, long-run) -0.77 (non-residential, long-run)	N/A
2013-17	Envestra (VIC, Albury)	CORE	-0.30 (residential, long-run) -0.35 (non-residential, long-run)	N/A
2015-2020	Jemena (NSW)	CORE	-0.30 (residential, long-run) -0.35 (non-residential, long-run)	0.1
2016-2021	ActewAGL (ACT, Palerang, Queanbeyan)	CORE	-0.30 (residential, long-run) -0.35 (non-residential, long-run)	0.1
2016-2021	AGN (SA)	CORE	-0.30 (residential, long-run) -0.35 (non-residential, long-run)	0.1

Source: Access arrangement demand forecast submissions.

Own Price Elasticity

CORE has adopted a long-term price elasticity factor which is consistent with Envestra's 2011-16 regulatory submission for South Australia, as prepared by NIEIR and accepted by the AER. This elasticity falls within the AER's accepted range as outlined in its Final Decision:

"*NIEIR's assumed long run price elasticity appears to be consistent with those produced by other studies. However, the AER acknowledges the limitations of this comparative analysis due to geographical factors and time differences. For this reason, it has performed a regression analysis to estimate price elasticity based on historical average residential demand data, the real retail gas price index, and ABS real household disposable income per capita data to compare against NIEIR's estimate. The regression analysis produced an indicative estimate for long run price elasticity of -0.41, with a 95 per cent confidence interval for the estimate range from -0.23 to -0.58*."

As NIEIR's estimate is broadly in line with the range of the estimates obtained in other studies and the AER's own indicative estimate, the AER considers that the assumed long run Residential price elasticity of -0.30 is reasonable and CORE believes this still represents the best estimate possible in the circumstances.[23] Given the price elasticity factors used previously for AGN's SA Network, reference values of -0.30 (Residential) and -0.35 (Commercial) as long-run elasticity factors were used for the final demand forecast model as shown in the following table.

Table A3.3 Own Price Elasticity.

Market Type	Reference
Residential	-0.30
Commercial	-0.35

Source: AER Final Decision, Envestra Limited Access Arrangement Proposal, SA Gas Network 2011 –16.

The interpretation of these elasticity factors is that for every percentage increase in retail gas price, gas demand will decrease by 0.30 percent (0.35 percent for Commercial customers). These long-run elasticity factors are a summation of the individual price elasticity factors, which are applied as shown in the table below. Demand impacts are highest in the year of the price change for Residential demand and the year after the price change for Commercial demand.

These price elasticity factors originate from Envestra's (now AGN) gas demand forecasts for the 2013-2017 Victorian AA submission, and further perpetuated in the development of gas demand forecasts for Jemena's 2015-2020 New South Wales AA submission, more recently ActewAGL's (now Evoenergy) 2016-2021 ACT, Palerang and Queanbeyan and Envestra's (now AGN) 2016-2021 South Australian AA submissions.

In the context of energy markets, this has been observed for the impact of electricity prices and AEMO states the following regarding the asymmetric response;

'*Consumer response to changes in electricity prices is asymmetric. While consumers may reduce demand in response to price rises, they do not necessarily revert to previous levels of demand when prices later fall, due to permanent changes in behaviour, or momentum. To reflect this, AEMO applied a Maximum Price Model which assumes that rather than responding to the carbon price repeal, customers will continue to respond to the highest prices they have experienced in recent years'*.[24]

Table A3.4 Price Elasticity Factors.

Elasticity	Residential	Commercial
Δp(t)	-0.13	-0.06
Δp(t-1)	-0.08	-0.16
Δp(t-2)	-0.05	-0.09
Δp(t-3)	-0.03	-0.03
Δp(t-4)	-0.01	-0.01
Total	**-0.30**	**-0.35**

These short-run elasticity factors are applied to the annual real increase in gas prices to arrive at the own-price elasticity impact in each year, for each customer segment, as summarised below.

[23] AER, *Final Decision*: *Envestra Limited Access Arrangement Proposal for the SA Gas Network 1 July 2011 – 30 June 2016*, June 2011, p103.

[24] AEMO, *Forecasting Methodology Information Paper, National Electricity Forecasting Report 2014,* July 2014. p. 12

Table A3.5 Own Price Elasticity Impact on Demand

Own Price Elasticity Impact on Demand (%)	2020	2021	2022	2023	2024	2025	2026
Residential							
Change in Gas Prices	0.84%	0.99%	-2.90%	1.56%	1.73%	1.40%	1.12%
Price Elasticity Impact (-0.30)	0.38%	0.03%	0.35%	-0.01%	-0.24%	-0.32%	-0.36%
Commercial							
Change in Gas Prices	0.77%	1.32%	-2.75%	2.47%	2.77%	2.17%	1.68%
Price Elasticity Impact (-0.35)	0.05%	-0.08%	-0.09%	0.16%	-0.38%	-0.74%	-0.75%

Cross-Price Elasticity

CORE acknowledges that cross-price elasticity was originally not addressed widely in AA reviews. However, following the previous South Australian AA submission (AGN SA AA 2016-2021), the cross-price elasticity of 0.10 has not been disputed. Subsequent endorsement came from the latest AA submissions for Victoria (AGN), New South Wales (JGN) and the Australian Capital Territory (ActewAGL - now Evoenergy).

Based on CORE's analysis, an assumed long run elasticity of 0.10 for both Residential and Commercial customers is deemed reasonable, and the impact is shown in the table below. The interpretation of the elasticity factor is that for every percentage increase in retail gas price in a given year, demand for electricity will increase by 0.10 percent in that year. Alternatively, for every percentage increase in electricity price, gas demand will increase by 0.10 per cent. These price elasticity factors are applied to the forecast annual real increase in electricity prices to arrive at the cross-price response for each customer segment as summarised below.

Table A3.6 Cross-Price Elasticity Impact on Demand

Cross-Price Elasticity Impact on Demand (%)	2019	2020	2021	2022	2023	2024	2025
Residential							
Change in Electricity Prices	0.27%	-4.42%	-1.05%	-0.78%	-0.90%	-1.82%	0.23%
Price Elasticity Impact (0.10)	0.03%	-0.44%	-0.11%	-0.08%	-0.09%	-0.18%	0.02%
Commercial							
Change in Electricity Prices	0.27%	-4.42%	-1.05%	-0.78%	-0.90%	-1.82%	0.23%
Price Elasticity Impact (0.10)	0.03%	-0.44%	-0.11%	-0.08%	-0.09%	-0.18%	0.02%

A4. Tariff D GVA Regression Results

As part of the demand forecast for Tariff D, regression analysis was performed on historical demand volumes and sector output measured by ‘Gross Value Add’ (“**GVA**”) as published by the Australian Bureau of Statistics. Additional tests using South Australian historical GSP was also tested. As discussed in the methodology section, the balance of the Tariff D group comprises sectors exhibiting weather-induced demand patterns. Historical demand for these groups was amalgamated and weather normalised.

All three species of regression analysis are detailed here in turn.

Annual Demand versus GVA

This part of the forecast incorporated any change to industrial gas demand that occurs due to a projected change in sector output. Industrial customers were classified by ANZSIC 2006 divisional structure. Historical demand for each industry segment was regressed against historical GVA using several different models. The four models are listed below followed by the regression output table:

1. $Demand = \beta_0 + \beta_1\ GVA$
2. $log\ Demand = \beta_0 + \beta_1\ log\ GVA$
3. $log\ Demand = \beta_0 + \beta_1\ log\ GVA_{t-1}$
4. $log\ Demand = \beta_0 + \beta_1\ log\ GVA_t + \beta_2\ log\ GVA_{t-1}$

Overall, 2 sectors showed statistically significant relationships between annual gas demand and sector GVA:

- Transport, Postal and Warehousing
- Manufacturing (Construction Materials)

The following table shows which model was ultimately selected for the forecast and what significance level was observed.

Table A4.1 Economic Outlook | Historical GVA and Gas Demand Regression Results

Industry Sectors	Model Selected	B_1 coefficient
Transport, Postal and Warehousing	$log\_ACQ = B_0 + B_1(log\_GVA)$	1.969**
Manufacturing (Construction Materials)	$log\_ACQ = B_0 + B_1(log\_GVA)$	0.3552 **

** Significant at the 5% level
* Significant at the 10% level

CORE excluded GVA regression analysis where the following trends were observed:

- Results did not have appropriate levels of statistical significance.
- Negative coefficients (implying an inverse relationship between GVA growth and gas demand) were observed and hence could not be interpreted logically from a commercial standpoint.
- ANZSIC sector consisted of a small number of customers rather than a significantly large group.
- Sectors with a pronounced weather-induced demand pattern were assigned to a weather normalised trend given these customers rely on gas for space and water heating.

To complete the forecast for customers in the four sectors above, the historical growth rate of GVA was regressed on SA Real GSP. The resulting statistically significant coefficient was then applied to the SA Treasury's Real GSP forecast to arrive at a forecast of sector GVA. The b1 regression coefficients from the previous table could then be applied to this forecast GVA.

GSP and Average Trend Analysis

A handful of sectors did not exhibit statistical relationships with GVA and do not have obvious weather-induced demand patterns. These customers were grouped, and historical demand was regressed against State Output (GSP) on the hypothesis that their demand is based on production levels which could be driven by economic activity generally. Across several statistical models this relationship was not statistically proven, however. It is likely that gas demand for these customers is driven by other factors and possibly specific to individual customers or influenced by a handful of large customers. CORE has honoured the historical average decline of -0.53% for the ACQ forecast of this residual group:

- Agriculture, Forestry & Fishing
- Mining
- Manufacturing (excluding construction materials manufacturers)
- Electricity, Gas, Water and Waste Services
- Wholesale Trade
- Retail Trade
- Information Media and Telecommunications
- Financial and Insurance Services
- Rental, Hiring and Real Estate Services

One ANZSIC sector (Construction) demonstrated a reliable statistical relationship with GSP and hence ACQ has been forecast using the historical average percentage change in demand given a percentage change in GSP.

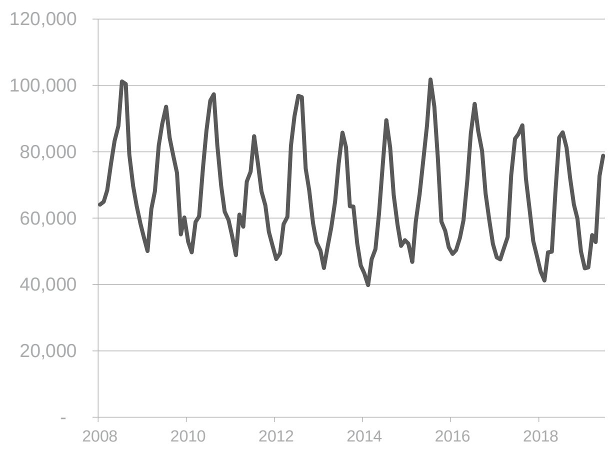
Tariff D Weather Normalisation Group

The following sectors exhibited clear weather-induced demand patterns and hence CORE has captured appliance efficiency and fuel switching trends in the space and water heating markets. Realistically, this is the approach taken for the Commercial customer group with which this group of industrial customers has significant overlap, albeit on a moderately different scale of demand.

Weather Normalisation Sectors:

- Accommodation and Food Services
- Professional, Scientific and Technical Services
- Administrative and Support Services
- Public Administration and Safety
- Education and Training
- Health Care and Social Assistance
- Arts and Recreation Services
- Other Services

Historical Weather-Induced Demand Patterns (Actual Monthly, GJ)



Normalised versus Actual ACQ per Customer | GJ[25]

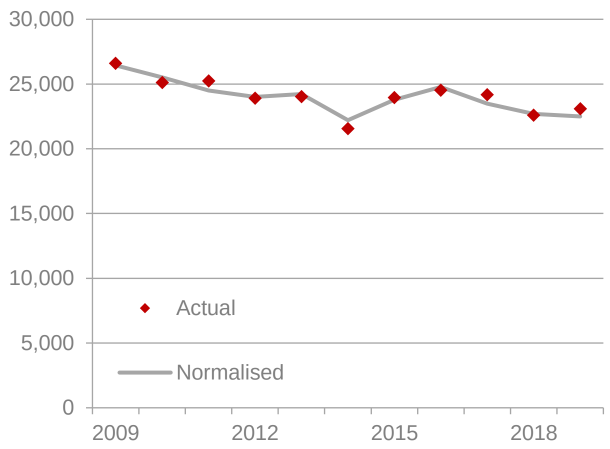


Table A4.2 Regression Output

	Tariff D Weather Group Demand
HDD Coefficient (GJ of Demand per HDD Unit)	4.8822 (p value = 0.00)
First lag of demand	0.1493
Time trend coefficient	-47.4854 (p value = 0.00)

[25] Please note that only customers that existed within the network during the 2009-2019 period were included so as to avoid bias from customers joining or leaving during the primary historical period.

Dummy Variable - 2014	4,412.3510
Constant	45,592.9300 (p value = 0.00)
No. of observations	125 (125 months)

As per Tariff R and Tariff C regression analysis, CORE elected to use robust standard errors, as an additional safeguard against heteroskedasticity. HDD provided a slightly improved statistical fit for the industrial group (relative to EDD). EDD includes elements with a partial 'real-feel' behavioural response relationship with gas demand such as wind, sunshine and seasonal shape. Accordingly, this result is not surprising as many large space heating buildings would be on a pre-determined temperature rather than a day-to-day response to weather conditions.

Table A4.3 Post-estimation & other results

Test	Tariff D Weather Group Statistics and Conclusion	
White Test	Robust standard errors used as a precaution (White-Huber standard errors)	
Durbin Watson	d-stat = 1.56	Sufficiently close to 2
AIC	AIC = 2399.776	good predictive power relative to other model specifications tested
R Squared	R^2 = 0.9495	acceptable predictive power

A5. Appliance, Efficiency and Energy Mix Trends

The following paragraphs contain analysis for the various factors that continue to drive demand per connection. These factors include:

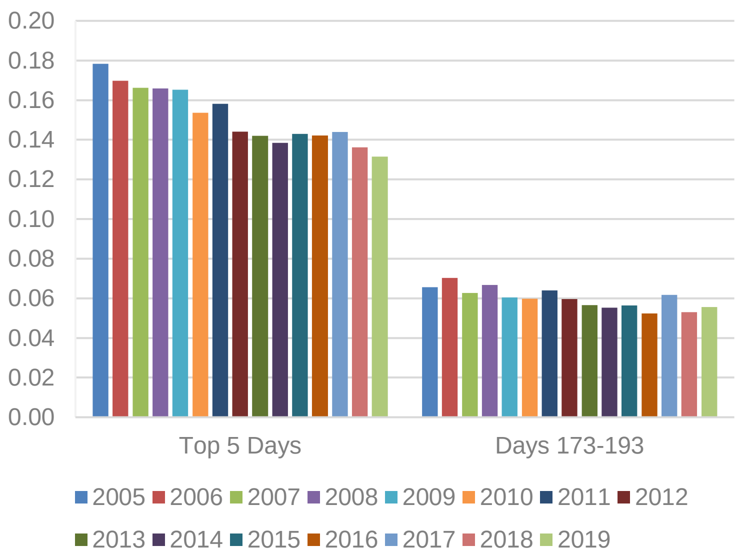
- appliance efficiency
- dwelling efficiency and dwelling type
- competition from other energy sources and fuel switching

These factors give rise to some of the observed trends and projections within CORE's forecast. Typically, data for these factors is not comprehensive enough for rigorous statistical analysis with network demand data; however, the combined effect of these drivers is captured by the historical annual average growth rates identified by CORE. The qualitative and quantitative evidence for these factors is presented below and justifies why it is likely for the combined effect of these factors to maintain the trends experienced since 2009.

Forecast Context

As discussed in the main body of this report, the volume tariff groups are exhibiting a persistent long-term decline in demand per connection. CORE has analysed the daily data (combined Residential and Commercial) to assess whether this downward trend is also holding for peak and median days. The following chart contains some key results;

Average Volume Tariff Demand per Connection | GJ/ connection/ day



- The peak demand per connection is trending downward- represented by the average demand per connection across the 5 highest days each year. CORE assumes that weather does not have an impact between years as the 5 highest days should generally represent a year's most significant EDD events and hence maximum appliance usage.
- The median band of demand per connection is also trending downward as would be expected given that weather normalised average demand per connection is also declining.
- The use of 5 and 20 days at the peak and median is to reduce the impact of any outliers.

- The charts above underpin the conclusion that appliances and dwellings are becoming more efficient with their energy demand and gas demand is falling even when appliance usage is at its highest. This suggests that gas may be losing share in the heating market (i.e. gas connections remain but there may be higher incidence of customers using gas for cooking or water heating only rather than space heating which requires a larger amount of energy). The following sections evaluate evidence and reasons for efficiency gains and gas' market share across major usage types.

South Australian Energy Use Trends

The most significant uses of gas for Australian households are space heating, water heating and cooking. Data released by the ABS in the first half of the historical series shows that gas space heating appliances are losing market share as growth in electricity and solar energy occurs.

The fuel switching activity is likely due to the increase in RC air-conditioning penetration. Consumers are likely to favour the convenience of a single appliance that has two functions, cooling and heating.

A widely sourced study entitled Are We Still Cooking with Gas? conducted by Renew (formerly the Alternative Technology Association) and supported by the ECA (formerly the Consumer Advocacy Panel) found that houses already connected to the gas network could steadily withdraw from using gas for space heating in favour of using reverse cycle air conditioners, on economic grounds. An updated publication from Renew advocates all-electric appliances for new households and fuel switching away from gas in several other situations.[26]

Overall, energy usage trends show that electricity and solar appliances represent a fuel switching risk although gas has maintained and at times increased its market share suggesting that appliance and dwelling efficiency is having a greater impact on demand per connection.

Key Policy

There are a range of Federal and State Government initiatives in place that are expected to have an impact on future gas demand. These include, but are not limited to:

- NatHERS energy star rating building standards.
- various labelling/ standards, rebate and incentive schemes favouring renewable energy and energy efficiency.

Although it is possible to determine whether a specific policy is expected to increase, decrease or have no effect on gas demand in a qualitative sense, quantifying the effect poses a significant challenge due to the lack of adequate and consistent data. As a result, the following section focuses on a qualitative assessment of the impact of energy policy initiatives.

[26] Household fuel choice in the NEM, June 2018, Renew.

Dwelling Efficiency

All new South Australian dwellings are required to meet the minimum energy efficiency requirements prescribed in the Building Code of Australia (BCA). An energy efficiency assessment is undertaken, and the following criteria are assessed – further evidence that dwelling efficiency will continue to increase:

Requirements for building thermal performance for occupancy comfort include:

- measures to reduce heating and cooling loads
- thermal insulation in roofs, walls and floors
- adequate glazing performance
- appropriate building sealing and draught proofing
- adequate ventilation and air movement.

Requirements for services to reduce greenhouse gas emissions include:

- insulation of services such as ductwork and piping
- appropriate sealing of heating and cooling ductwork
- efficient water heaters

Other Labelling, Standards and Efficiency Policies

The following policies also contribute to energy efficiency and/or fuel switching.

Policy	Description	Impact on Gas Demand
Energy Rating Label	▪ Every new household appliance displays energy rating and typical consumption allowing the consumer to easily observe the efficiency of an appliance before purchasing	▪ Underpins the continued appliance efficiency increases ▪ Increased visibility has also incentivised appliance manufacturers to develop more efficient appliances
E3 and Greenhouse and Energy Minimum Standards (GEMS)	▪ A national framework for appliances and equipment energy efficiency in Australia. The Australian GEMS Regulator has replaced the previous state regulators.	▪ Similar impact to the energy rating label program above

Shift to Electricity & Alternate Energy

CORE has reviewed several other factors that present a downside risk to residential and commercial connections (and potentially demand per connection. Emerging and renewable technologies are heavily weighted towards electricity which could act to erode gas' share of the energy mix.

Solar PV and battery storage/ microgrid configurations have the potential to drive households towards electric appliances to magnify the savings made in such technology. CORE expects the impact of such technology to be significant but gradual. The greatest risk to gas occurs during appliance switch-out at the end of economic life. Given heating appliances can operate well beyond 10 years, the switch-out influence is unlikely to present a significant risk before the end of the forthcoming AA period. However, there is still a moderate risk that substitution of gas appliances will begin to occur prior to 2026. CORE notes a particular statement from the South Australian Department for Energy and Mining, when defining their consultation process on regulatory changes for smarter homes: *'We are committed to the orderly transition to net-100 per cent renewable energy. This requires the right mix of interconnection, storage, generation and smart technology to balance supply and demand.'*[27]

Alternative	Trend	Impact on Gas Demand
Microgrids	▪ Microgrids are autonomous grids which can operate off-grid or connected to existing grids and which can combine different assets and loads. ▪ These networks connect, and coordinate power sources and loads distributed over a small area.	▪ Potential long-term impact, within assessment period it is unlikely as microgrids currently are focused on communities outside of AGN's network.
PV and Battery	▪ Competitive reduction in pricing for PV makes it a viable alternative for new buildings.	▪ Decrease in gas demand but delayed by slow appliance switch-out rates of household appliances
High Density Living	▪ 65+ population increasing, potentially moving to newer, clustered living as requirements change. ▪ High density living is trending to smaller floor area, and higher energy efficiency standards.	▪ Reduction in demand related to space heating primarily.

[27] South Australian Department for Energy & Mining (Website, June 2020): 'Consultation on Regulatory Changes for Smarter Homes'.