Review of gas demand forecasts for Australian Gas Network (SA)

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1 Introduction

1.1 Background and context

Australian Gas Networks (SA) (AGNSA) is the gas distribution service provider for South Australia. AGNSA's next regulatory period is for the period 1 July 2026 to 30 June 2031 (2026-31 access arrangement period). AGNSA has submitted a gas access arrangement proposal to the AER for the 2026-31 access arrangement period.

Demand forecasts are one of the inputs into AGNSA's gas access arrangement proposal. AGNSA engaged Core Energy & Resources (Core Energy) to develop detailed gas demand forecasts for the 2026-31 access arrangement period.

1.2 Frontier Economics' engagement

The Australian Energy Regulator (AER) has engaged Frontier Economics to provide advice on the reasonableness of AGNSA's demand forecasts for the 2026-31 access arrangement period. Specifically, Frontier Economics has been engaged to review AGNSA's forecasts of:

- Customer numbers for residential and commercial customers for the 2026-31 access arrangement period.
- Consumption per connection for residential and commercial customers for the 2026-31 access arrangement period.

2 Review of AGNSA's forecasts

This section sets out our evaluation of the reasonableness of AGNSA's demand forecasts. Specifically, we are evaluating the reasonableness of AGNSA's forecasts of gas connection numbers and gas consumption per connection for residential and commercial customers for the 2026-31 access arrangement period.

AGNSA has engaged Core Energy to develop its demand forecasts for residential and commercial customers (and for industrial customers, which we have not reviewed). Core Energy's forecasts of connections and demand, including the methodology and inputs used for these forecasts, are discussed in Core Energy's report for AGNSA (Core Energy Forecasting Report).[1]

In addition, the AER provided two spreadsheet models developed by Core Energy in producing these forecasts:

- AGNSA_Attachment 13.2_Core Energy Demand Forecast Model_20250701_CONFIDENTIAL (Core Energy Forecasting Model)
- AGNSA_Attachment 13.3_Weather Normalisation Model_20250701_CONFIDENTIAL (Core Energy Weather Normalisation Model)

Our evaluation of the reasonableness of AGNSA's demand forecasts are based on our review of the Core Energy Forecasting Report, the Core Energy Forecasting Model and the Core Energy Weather Normalisation Model.

2.1 Summary of approach

Core Energy's methodology for forecasting AGNSA's demand encompasses three aspects. These are:

- **Weather normalisation.** Core Energy uses historical demand and weather data, and derives an estimate of underlying gas consumption that removes abnormal weather conditions. This is achieved by deriving an Effective Degree Day (EDD) index to determine the effect of weather on gas consumption.
- **Deriving annual residential consumption forecasts.** Core Energy separately forecasts residential consumption per connection and the number of residential gas connections, and uses these to determine total residential demand. Consumption per connection is forecast based on historical trends in weather-normalised residential consumption per connection. The number of connections is forecast using assumed rates of change and adjustments for out-of-trend effects.
- **Deriving annual commercial consumption forecasts.** Core Energy uses a similar approach of separately forecasting commercial consumption per connection and the number of commercial gas connections, and uses these to determine total commercial demand. Consumption per connection is forecast based on historical trends in weather-normalised commercial consumption per connection. The number of connections is forecast using assumed rates of change and adjustments for out-of-trend effects.

[1] Core Energy & Resources, *Australian Gas Networks (SA) Gas Access Arrangement July 2026 to 30 June 2031, Gas Demand and Connections Forecasts*, 25 June 2025.

2.2 Summary of issues with Core Energy's forecasting approach

In our view, there are several issues with Core Energy's forecasting approach that we expect will affect the reasonableness of Core Energy's demand forecasts.

In terms of weather normalisation, the issues that we have identified are:

- Core Energy provides limited justification for the functional form of its EDD specification
- Core Energy provides limited justification for the parameters of its EDD specification
- Alternative weather normalisation specifications provide better results than Core Energy's EDD specification
- There are problems with the way that Core Energy determines 'average' weather
- Core Energy appears to use the incorrect measure of weather sensitivity to normalise demand
- Core Energy does not normalise demand for other drivers
- Core Energy's data may have embedded a wind speed measurement error.

In terms of deriving forecasts from the weather-normalised demand, the issues that we have identified are:

- There are potential data errors in the more recent monthly consumption data
- Core Energy's assumptions on connections and disconnections are hardcoded and not supported by systematic quantitative or qualitative analysis
- Core Energy's assumptions on consumption per connection are hardcoded and not supported by systematic quantitative or qualitative analysis
- There may be issues with the way Core has addressed AGNSA's zero-consuming meters.

We discuss these issues in the sections that follow.

However, at this stage we have not attempted to assess the impact of these issues on Core Energy's demand forecasts. A key reason for this is that Core Energy's forecasts are ultimately determined by hardcoded values in its models, which are not supported by systematic quantitative or qualitative analysis. As a result, we are not able to assess how Core Energy's forecasts would vary as a result of any change to an input assumption or any change to an aspect of the forecasting methodology.

2.3 Weather normalisation model

Core Energy's approach to weather normalisation is described in Box 1. The issues with this approach to weather normalisation that we expect will affect the reasonableness of Core Energy's demand forecasts are described in the sections that follow.

Box 1: Core Energy's approach to weather normalisation

Core Energy's weather normalisation model involves the following steps:

- Core Energy gathers daily weather station data (for the Adelaide airport weather station) from 1 July 1977 to 30 June 2024. The weather station data includes 3-hourly average temperature, 3-hourly average wind speed, daily sun hours and daily maximum temperature and minimum temperature.
- Degree Days (DD) is calculated as:

$$DD = max(DD\ threshold - 3\ hourly\ average\ temperature, 0)$$

  Where $DD\ threshold$ is assumed to be 18.49 °C.

- EDD is calculated as:[2]

$$EDD = \max\left(DD + \gamma_{wind\ chill} * DD * wind\ speed + \gamma_{insolation} * sun\ hours + max\left(\gamma_{seasonality} * 2 * cos\left(\frac{2 * \pi * (day\ no. - seasonality\ factor)}{365}\right), 0\right), 0\right)$$

  Where:

  - $\gamma_{wind\ chill}$ is a coefficient on wind chill, and is assumed to be 0.0273. This adjusts the impact of wind on perceived temperature, with a higher value for the coefficient increasing the effect of wind speed on EDD.
  - $\gamma_{insolation}$ is a coefficient on sunshine hours, and is assumed to be -0.1000. This adjusts for solar heating beyond ambient temperature, with a higher negative value for the coefficient decreasing the contribution of sun hours to EDD.
  - $\gamma_{seasonality}$ is a coefficient on seasonality, and is assumed to be 3.6950. This captures seasonal variations that are not explained by temperature, wind or sun alone.
  - $sesasonality\ factor$ indicates the day of the year on which the seasonal peak occurs. This is assumed to be 200.9037, meaning the peak of the seasonal effect on EDD occurs 20 July of each year.

  Core Energy explains how these parameters are derived as follows, "The EDD Index model aims to solve for the best-fit EDD coefficients by minimising the sum of squared residuals according to the demand specification:

$$Demand = a + b1 * EDD + b2 * Friday + b3 * Saturday + b4 * Sunday\text{"}$$

  And "EDD Index coefficients have been used to normalise residential and commercial demand following extensive scenario analysis and reference to factors used by AEMO, including the temperature assumption".[3]

- Core Energy calculates a daily linearised EDD series, which represents average weather conditions. This is done by fitting a straight line through the calculated EDDs from

[2] The EDD formula expressed here is the formula as applied in the Core Energy Forecasting Model. It is slightly different to the formula set out in the Core Energy Forecasting Report (in the report the total value of EDD is not limited to a minimum of zero).

[3] Core Energy Forecasting Report, page 20.

1 December 1978 to 30 June 2020. Core Energy continues this fitted trend until 30 June 2024.

- Core Energy aggregates both the daily EDD series and the daily linearised EDD series to a monthly basis, and calculates the difference between monthly EDD and linearised monthly EDD. Core Energy notes that by comparing the linearised EDD value to the calculated EDD value, one can get a sense of how much warmer or colder a given month is when compared to the average. If calculated EDD is above the linearised trend, that month is assessed to be colder than average. If calculated EDD is below the linearised trend, that month is assessed to be warmer than average.
- Core Energy then appears to regress monthly residential consumption per connection on monthly EDD to produce a coefficient β_{EDD}, which represents the contribution of EDD to residential consumption per connection. Core Energy multiplies the difference between monthly EDD and linearised monthly EDD by this coefficient to determine the impact of abnormal weather on monthly residential consumption per connection. Core Energy multiplies this by the number of residential connections, and nets this off total monthly residential demand to produce total monthly normalised residential demand.
- Core Energy repeats the above step to calculate monthly normalised commercial demand.

Core Energy aggregates the monthly series to calculate annual normalised residential demand and annual normalised commercial demand.

2.3.1 Core Energy provides limited justification for the functional form of its EDD specification

Core Energy explain that the EDD methodology is consistent with the EDD 312 specification in AEMO's 2012 "Weather Standards for Gas Forecasting" Report.[4] Upon review of this report, this does not seem to be the case. The EDD formula set out in AEMO's 2012 "Weather Standards for Gas Forecasting" report is:

$$EDD = DD + \gamma_{wind\ chill} * DD * wind\ speed + \gamma_{insolation} * sun\ hours + 2 * \cos\left(\frac{2 * \pi * (day\ no. - seasonality\ factor)}{365}\right)$$

Core Energy's EDD specification is different to this approach from AEMO's 2012 "Weather Standards for Gas Forecasting" Report and also different to approaches that AEMO currently use for weather normalisation. Core Energy's EDD specification is most similar to the EDD specification outlined in AEMO's 2012 "Weather Standards for Gas Forecasting" Report and used by AEMO for demand forecasts for Victoria (used for instance to develop demand forecasts for AEMO's 2025 Gas Statement of Opportunities (GSOO)).[5] Even here, however, Core Energy specifies the seasonality factor in a different way to AEMO.

For South Australia, AEMO currently uses two different types of degree day specifications, both of which differ from Core Energy's approach for AGNSA. These approaches are:

4 AEMO_2012 review of the weather standards for gas forecasting part 1.pdf

5 AEMO, *Gas Demand Forecasting Methodology Information Paper*, For the 2025 Gas Statement of Opportunities covering Australia's East Coast Gas Market, March 2025.

- For the 2025 GSOO, AEMO uses a heating degree day (HDD) specification[6], where degree days are based only on outside air temperature:

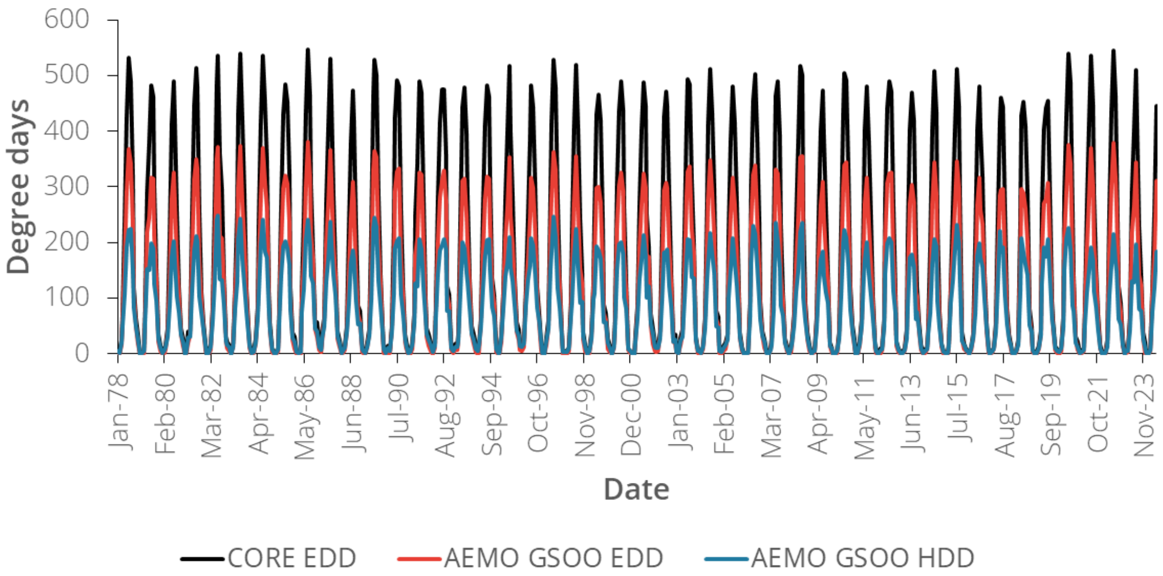
$$HDD = \max\left(0, DD\ threshold - 3\ hourly\ average\right)$$

- For AEMO's Retail Market Procedures (RMPs), which set out obligations to produce an estimated meter read if meter data is not available, AEMO specifies an HDD methodology, but an HDD methodology than is based on lagged EDDs. However, the EDDs in that methodology are a different functional form to that used by Core Energy, including only temperature and insolation.[7]

Core Energy does not provide an explanation for preferring an EDD methodology for South Australia, compared to an HDD approach. Core Energy also does not provide an explanation for preferring its EDD specification, compared to the EDD specification that AEMO uses for Victoria in the 2025 GSOO, or the EDD specification used as an input in AEMO's RMP for South Australia.

Figure 1 compares Core's EDD series with AEMO's EDD and HDD series from the 2025 GSOO. The chart shows that the choice of methodology has a material impact on the measured degree days.

Figure 1: Different monthly degree day series



Source: Frontier Economics analysis, based on weather data from Core Energy Weather Normalisation Model

The fact that Core Energy uses a different EDD functional form is not, in itself, a problem. Ideally the choice of functional form would be justified in Core Energy's report, and the functional form would provide better weather normalisation results than alternatives. We consider the evidence for whether this is the case further below.

[6] AEMO, *Gas Demand Forecasting Methodology Information Paper*, For the 2025 Gas Statement of Opportunities covering Australia's East Coast Gas Market, March 2025, page 28.

[7] AEMO, Retail Market Procedures (South Australia), 3 March 2025.

2.3.2 Core Energy provides limited justification for the parameters of its EDD specification

As described above, there are several EDD parameters in Core Energy's approach, being:

- A degree day threshold
- A wind chill coefficient
- An insolation coefficient
- A seasonality coefficient
- A seasonality factor

It is not entirely clear how Core Energy has determined these EDD parameters. The Core Energy Forecasting Report variously refers to solving for the best-fit EDD coefficients "by minimising the Sum of Squared Residuals according to a demand model specification"[8] and refers to "extensive scenario analysis and reference to factors used by AEMO".[9]

It is also unclear whether Core Energy has investigated specifying different EDD parameters for residential and commercial customers. Our view is that this would be worth investigating since residential and commercial customers are likely to respond differently to weather variations.

Since the EDD parameters are hardcoded into the Core Energy Forecasting Model, and no results for a best-fit model are provided, we cannot confirm the validity of Core Energy's approach to determining the EDD coefficients.

2.3.3 Alternative weather normalisation specifications provide better results than Core Energy's EDD specification

Ultimately, our view is that the choice of the weather normalisation specification and the coefficients used should be based on the methodology that provides the best model fit.

We have replicated the regression analysis in Core Energy's Weather Normalisation Model to test the results of using AEMO's HDD approach for South Australia from the 2025 GSOO and to test the results of using AEMO's EDD approach for Victoria from the 2025 GSOO. The results from these are presented in Table 1. The results suggest that AEMO's HDD approach provides a better estimate of weather variability (with a higher adjusted R-squared, a lower AIC and a lower BIC) for both AGNSA's residential consumption per connection and commercial consumption per connection.

8 Core Energy Forecasting Report, page 20.

9 Core Energy Forecasting Report, page 20.

Table 1: Comparison of model fit results across different regressions of DD specifications

Dependent variable	Independent variable	Adjusted R squared	AIC	BIC
Residential consumption per connection	Core's EDD	0.812	72.88	79.40
Residential consumption per connection	AEMO's HDD	0.833	49.90	56.41
Residential consumption per connection	AEMO's EDD	0.813	71.81	78.32
Commercial consumption per connection	Core's EDD	0.782	1,147	1,154
Commercial consumption per connection	AEMO's HDD	0.820	1,110	1,117
Commercial consumption per connection	AEMO's EDD	0.788	1,142	1,149

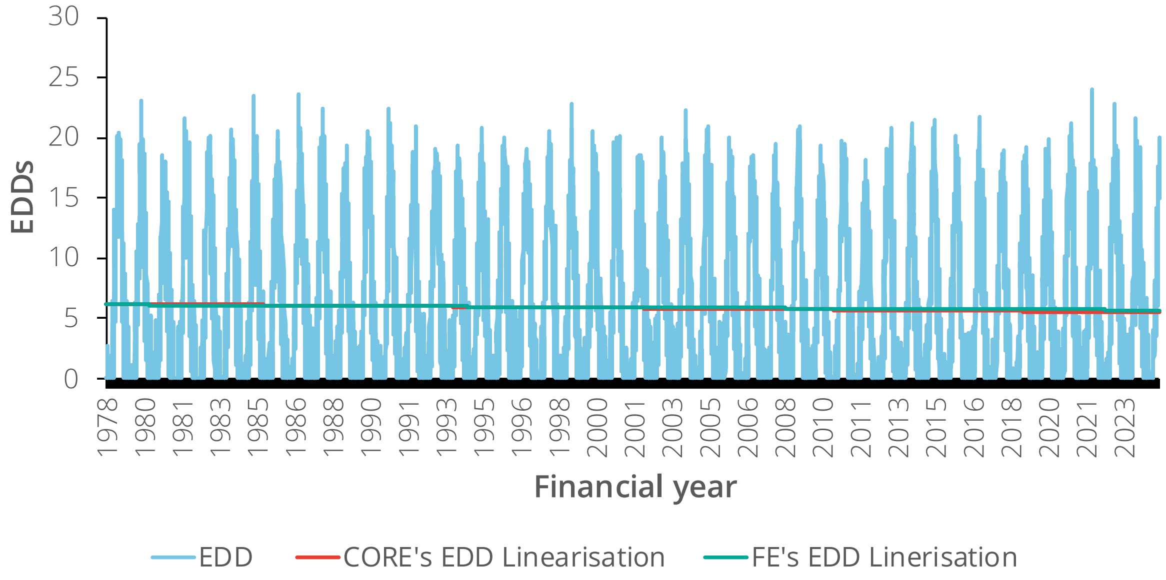
2.3.4 There are problems with the way that Core Energy determines 'average' weather

Core Energy uses historical EDD outcomes as the basis for determining average weather conditions. These average weather conditions are used to normalise demand –these average weather conditions are used as the baseline against which actual weather conditions are compared, to determine whether actual weather conditions are warmer or cooler than average. These average weather conditions are also used to forecast future average weather conditions.

There are two concerns with the way that Core Energy determines average weather conditions.

The first concern is that Core Energy determine average weather conditions by applying a trend to historical EDD outcomes. However, Core Energy applies this trend to historical EDD outcomes over the period from 1 December 1978 to 30 June 2020. Core Energy does not consider more recent historical EDD outcomes up to 30 June 2024, which are otherwise included in the Core Energy modelling. Given that part of the reason for determining average weather conditions is to account for any warming trends, our expectation is that an assessment of average weather conditions would incorporate the most recent available information. The exclusion of data from 1 July 2020 to 30 June 2024 from the assessment of average weather conditions is material. Using Core Energy's calculation of historical EDDs, the difference between the trend in EDD outcomes that Core Energy uses to determine average conditions (red trend line), and the equivalent trend in EDD outcomes that includes data up to 30 June 2024 (green trend line), is shown in Figure 2. It is clear from this that the exclusion of the most recent data has an impact on the assessment of average weather conditions, suggesting that EDDs are declining more slowly than Core Energy has assessed to be the case.

Figure 2: Core's daily linearised EDD

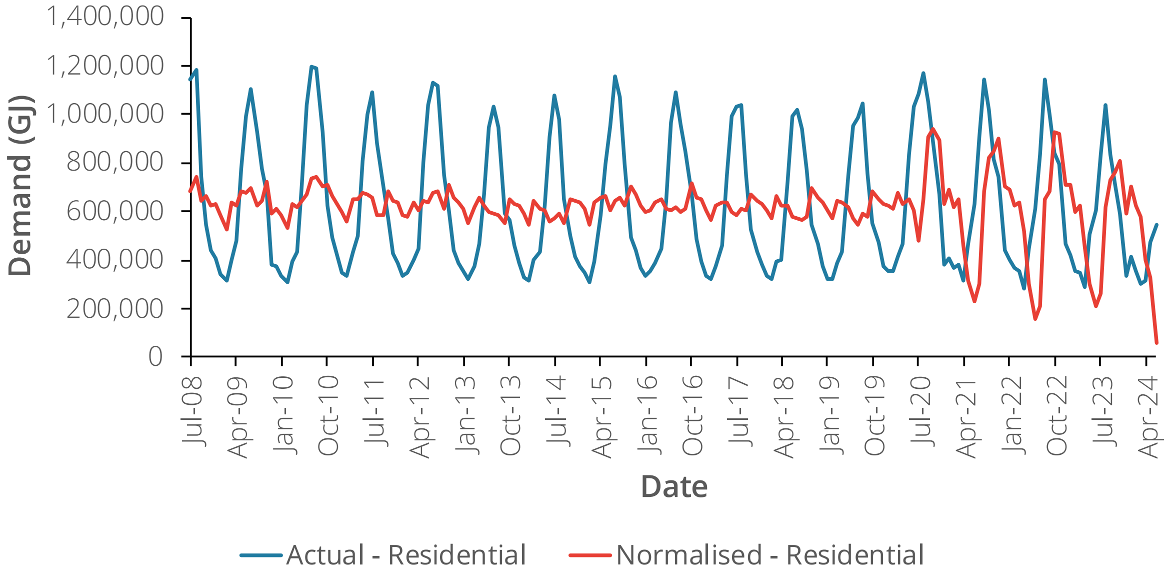


Source: Frontier Economics analysis based on Core Energy calculation of historical EDD

The second concern is that Core Energy assesses average weather by using a daily linearised trend in EDD. This results in an expectation of 'average' weather that exhibits the same average EDD outcome for each day of the year (aside from the gradual downward trend over time), suggesting that the 'average' number of EDDs in summer is the same as the 'average' number of EDDs in winter. Linearising EDDs on a daily basis removes the seasonal pattern in weather, causing expected EDDs to be overstated in summer and understated in winter. Normalising demand on this basis then removes the seasonal pattern in gas demand (normalised summer demand is increased, because actual EDDs are lower than 'average' EDDs through the year and normalised winter demand is decreased, because actual EDDs are higher than 'average' EDDs through the year). This distorts the seasonal pattern of normalised gas demand, as shown in Figure 3. The normalised demand is much more constant through the year, particularly during the period to 2020. Over this period normalised demand does not exhibit the expected seasonal shape to demand. Since 2020, normalised demand does exhibit seasonality again, although out of phase with the underlying demand – we expect this may be an issue with the underlying demand rather than the approach to normalisation, as discussed in Section 2.4.

Typically, we would expect normalised demand to have a similar seasonal pattern to actual demand. Unusual weather effects should be adjusted for, but seasonal variation should remain. For example, in a colder than average winter, normalised demand would be expected to be below actual demand while in a warmer than average winter, it would be above demand, but in both cases winter demand would be expected to remain above summer demand.

Figure 3: Core Energy's normalised residential demand and actual residential demand



2.3.5 Core Energy appears to use the incorrect measure of weather sensitivity to normalise demand

The Core Energy Weather Normalisation Model reports the results of weather normalisation regression models for residential customers and commercial customers. We have tested these models and been able to replicate the results almost exactly.[10]

However, when weather normalisation is applied in the Core Energy Weather Normalisation Model, it is not applied using the reported results from the regression model. Rather, the weather normalisation is applied using a different hardcoded coefficient:

- The reported coefficient for EDD in the residential regression model in the Core Energy Weather Normalisation Model is 0.0033 but the hardcoded coefficient for EDD that is used to apply the residential weather normalisation in the Core Energy Weather Normalisation Model is 0.0037.
- The reported coefficient for EDD in the commercial regression model in the Core Energy Weather Normalisation Model is 0.0494 but the hardcoded coefficient for EDD that is used to apply the commercial weather normalisation in the Core Energy Weather Normalisation Model is 0.0603.

2.3.6 Core Energy does not normalise demand for other drivers

Aside from weather conditions, there are also other factors that will have affected historical demand, which could be normalised in order to provide a clearer picture of historical trends. Indeed, Core Energy identifies a number of these in the Core Energy Forecasting Report:

- Prices – Core Energy states that in the absence of identifying a significant regression model for consumption per connection, Core Energy considered that "weather and price-

10 We believe that our inability to replicate the results exactly may relate to the fact that different reported values for EDD appear at different points in the Core Energy Weather Normalisation Model.

normalised historical average growth rates were a more reliable alternative."[11] However, Core Energy subsequently noted that it assessed the impact of own-price and cross-price elasticities to be negligible, based on elasticity analysis undertaken by AEMO for the 2025 GSOO.[12] We are not sure what the basis for this conclusion is. In its methodology report for the 2025 GSOO, AEMO adopted an own-price elasticity of demand of -0.1 for the Progressive Change scenario and -0.05 for other scenarios for heating load.[13] While these are relatively low elasticities, even these elasticities would mean that prices could explain some part of the observed reduction in consumption per connection observed in recent years, given an environment of increasing gas prices (noting that ABS data indicates that prices of gas and other household fuels in Adelaide have increased by 30% over the period from 2019/20 to 2023/24).[14]

- Covid-19 – Core Energy identifies that covid-19 seems to have an effect on demand, observing that residential demand has trended downward since 2026 "except for the COVID influenced period".[15] But we can see no evidence that Core Energy has attempted to normalise for the effect of covid-19, meaning that the historical trends that Core Energy are observing may be influenced by the impact of covid-19 on gas demand.
- Changing appliance mix – the sensitivity of gas demand for weather conditions will depend on the mix of appliances that customers have. For instance, a higher proportion of customers with gas space heating installed, would be expected to lead to a lead to consumption that is more sensitive to weather conditions.

2.3.7 Core Energy's data may have embedded a wind speed measurement error

Our analysis of the wind speed data used by Core Energy in its calculation of EDD, and therefore of its calculation of normalised gas demand, suggests that there is a data error. Figure 1 shows average daily wind speed for each month from July 1977 to July 2024. Our view is that there seem to be two structural breaks in the data: one from around 2015 (a step down in average wind speed) and a second from around 2020 (a step up in wind speed).

We asked Core Energy about this data and Core Energy agreed with our observation about the apparent step changes in the data. Core Energy noted that the wind speed data in the Core Energy Weather Normalisation model was compiled by combining data to 30 June 2020 that Core Energy had previously extracted with data from 1 July 2020 that Core Energy extracted more recently. Core Energy also provided an alternative series of wind speed data, which is materially different, and does not exhibit the same apparent step changes, as seen in Figure 4. Core Energy did not offer an explanation for the significant differences in the two datasets.

[11] Core Energy Forecasting Report, page 17.

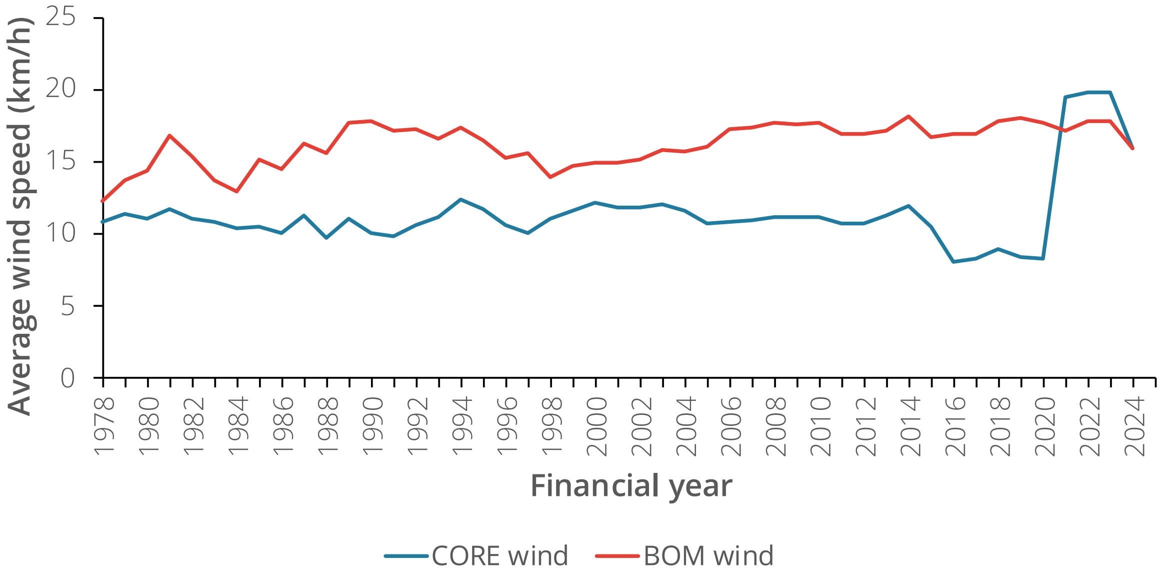
[12] Core Energy Forecasting Report, page 18.

[13] AEMO, *Gas Demand Forecasting Methodology Information Paper*, For the 2025 Gas Statement of Opportunities covering Australia's East Coast Gas Market, March 2025, page 22.

[14] ABS CPI, Series ID A2331896R.

[15] Core Energy Forecasting Report, page 25.

Figure 4: Average daily wind speed at Adelaide Airport by financial year



Source: Frontier Economics of wind speed data from Core Energy Weather Normalisation Model

2.4 Residential demand forecasts

Core Energy's approach to forecasting residential demand is described in Box 2. The issues with this approach to forecasting residential demand that we expect will affect the reasonableness of Core Energy's demand forecasts are described in the sections that follow.

Box 2: Residential demand forecasting methodology

Residential connections

Core Energy forecasts residential connections through a trend-based approach. The steps involved are:

- Preparing annual forecasts for new connections within AGNSA's network. This is the sum of estimates of new annual connections for single and multi-dwellings in South Australia, which are in turn derived from HIA's forecasts of dwelling commencements in South Australia with a one-year lag. Core Energy applies an assumed penetration forecast to new single-dwelling households connecting to AGNSA's network, and a separate penetration forecast to new multi-dwelling households.
- Preparing annual forecasts for disconnections within AGNSA's network. This appears to be based on a historical trend of disconnections with adjustments for "future changes" in disconnections and electrification.
- Adjusting for zero-consuming meters (ZCMs). It appears AGNSA has advised Core Energy that there is "at least three years of no payment for 10,214 ZCMs" as of 2024.

Core Energy then determines total connections each year as:

$$\begin{aligned} & total\ connections_t \\ & \quad = total\ connections_{t-1} + new\ connections_t - disconnections_t \\ & \quad - zero\ consuming\ meters_t \end{aligned}$$

Core Energy offers the following explanations for their assumed penetration rates into the future:

- Significant South Australian dwelling growth outside the AGNSA network area
- Increase in all electric dwellings within the AGNSA network area
- The growing network of homes with solar and battery systems in South Australia
- Improving energy efficiency in new homes.

And for the assumed rate of disconnections:

- An increased trend towards electrification
- Increased awareness of the cost effectiveness and sustainability of renewable sourced electricity and energy efficiency of heat pump technology
- The required replacement of gas appliances.

Residential consumption per connection

Core Energy forecasts normalised consumption per connection using a trend-based approach based on an assumed annual growth rate in normalised consumption per connection with an adjustment made for zero-consuming meters. That is:

$$DPC_t = DPC_{t-1} * (1 + \%\Delta_{DPC} + \%\ adjustment_{ZCM})$$

Core Energy's report offers several explanations for the forecast annual change in consumption per connection:

- A declining base level over the longer term
- A growing trend toward replacement of gas heating with electric reverse-cycle air-conditioning
- Growing trend in use of alternative water heating technologies, including solar and electric heat pumps

- Advances in dwelling construction standards which favour alternative energy sources
- An increased level of new higher density dwellings with lower levels of gas connection over time and those connected to gas using lower levels of gas due to advances in building and appliance efficiency and lower levels of appliance penetration
- Increasing solar and battery storage penetration within the "existing customer" grouping, which substitutes gas use.

Total residential demand

Lastly, Core Energy estimates total demand by taking the average number of connections across the current year and previous year and multiplying this by the forecast consumption per connection.

2.4.1 There are potential data errors in the more recent monthly consumption data

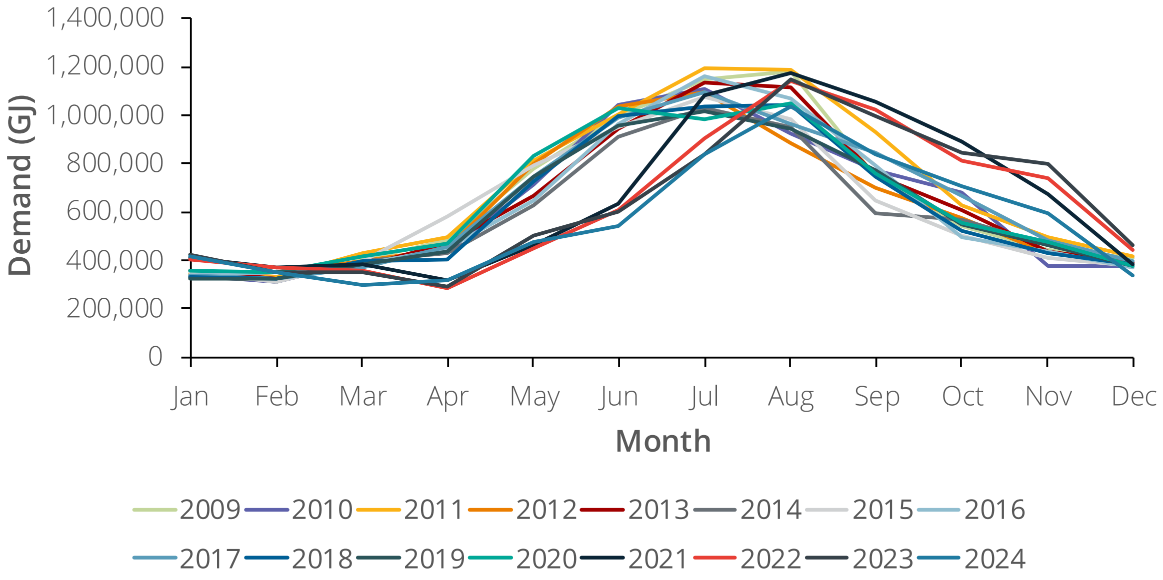
The historical monthly demand data that Core Energy is using in its model shows a significantly different seasonal pattern in the last four years (2020/21 to 2023/24), than it did over the earlier period (2008/09 to 2019/20). This is apparent when plotting monthly demand over time, as shown for residential customers in Figure 5 and for commercial customers in Figure 6.

For residential customers, the data for the period 2020/21 to 2023/24 has a winter peak that is occurring around 2 months later than the data for the period 2008/09 to 2019/20, with the monthly peak generally occurring around August (month 8) and demand remaining elevated for September, October and even November. One explanation might be that two different data series have been combined, and that the two different data series treat billing data differently (residential gas customers generally have a 3 month billing cycle).

For commercial customers, the data for the period 2020/21 to 2023/24 is more unusual, with peaks in demand occurring every 3 months, in January, April, August and October (months 1, 4, 7 and 10). In contrast, the historical data has a more regular seasonal pattern, with peak demand occurring during winter months.

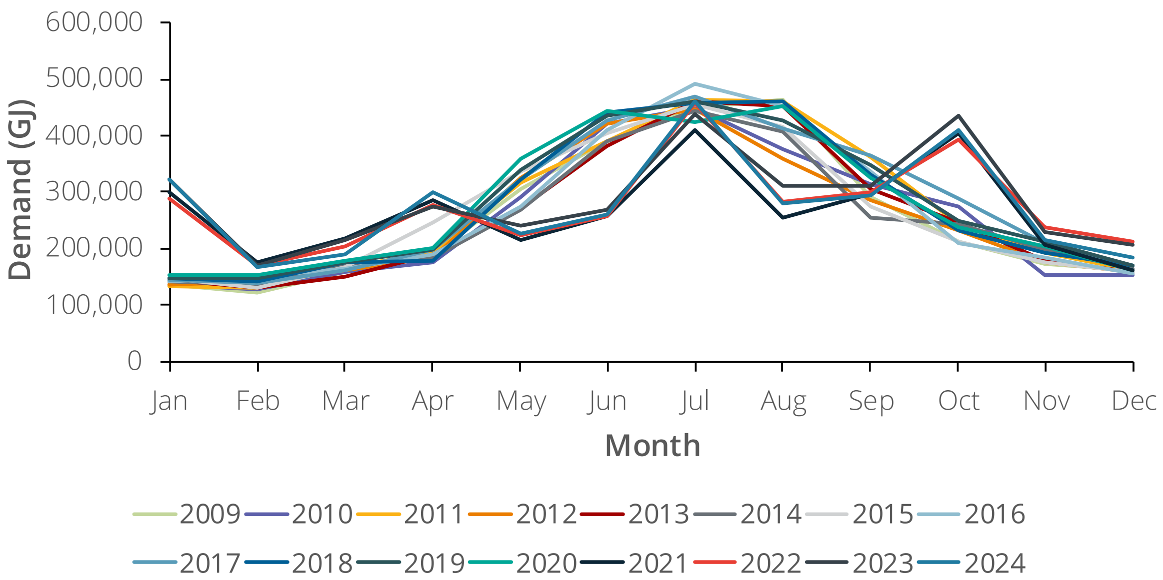
One explanation for changing seasonal patterns of demand could be changing weather conditions, but there is no obvious changing pattern in seasonal EDDs, as seen in Figure 7. All years show a similar pattern of EDDs peaking during winter months.

Figure 5: Residential monthly demand



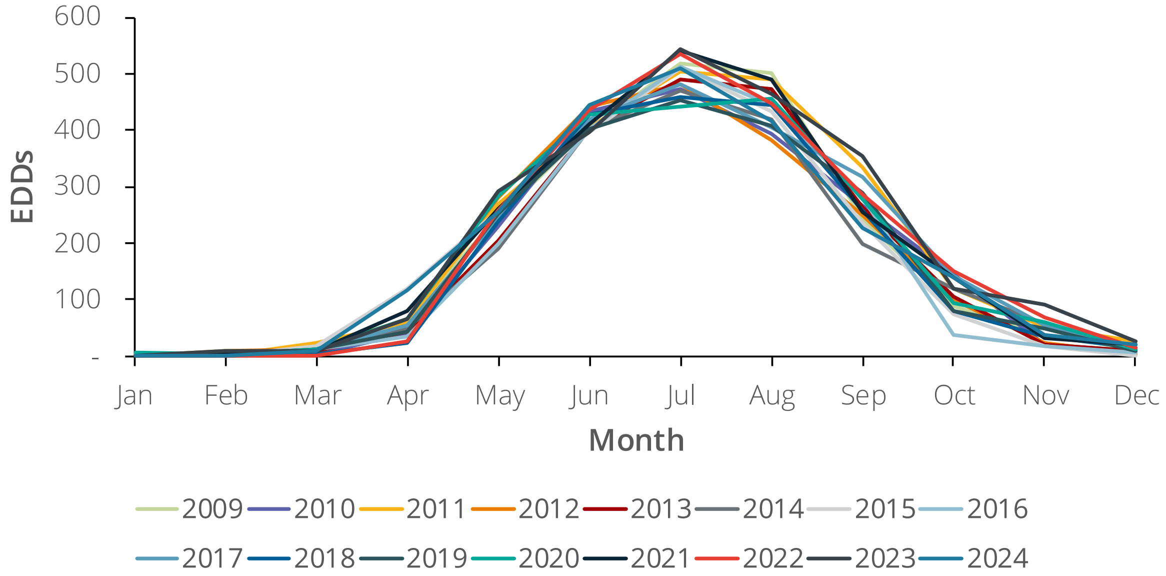
Source: Frontier Economics analysis of data in Core Energy Weather Normalisation Model

Figure 6: Commercial monthly demand



Source: Frontier Economics analysis of data in Core Energy Weather Normalisation Model

Figure 7: Monthly EDDs



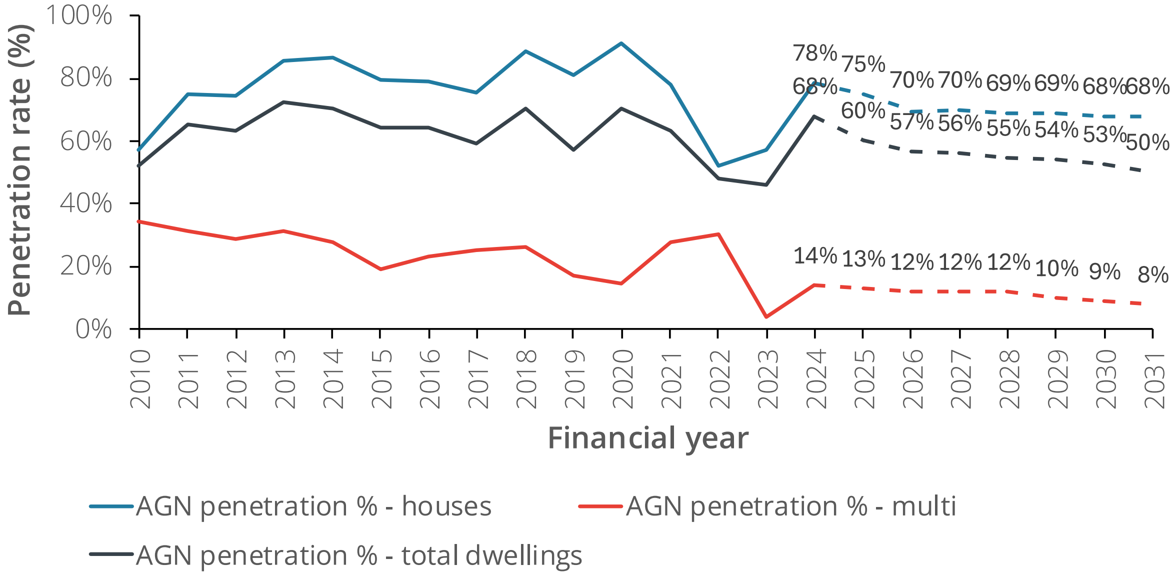
Source: Frontier Economics analysis of data in Core Energy Weather Normalisation Model

2.4.2 Core Energy's assumptions on connections and disconnections are hardcoded and not supported by systematic quantitative or qualitative analysis

Although Core Energy cites several factors underlying the assumed penetration rates, Core Energy does not provide any systematic quantitative or qualitative analysis linking these factors to the hardcoded assumptions in the model.

The hardcoded assumptions in respect of penetration rates are shown in Figure 8. For each category of dwellings, the solid lines represent historical penetration rates while the dashed lines (accompanied by data labels) represent Core Energy's forecast penetration rate.

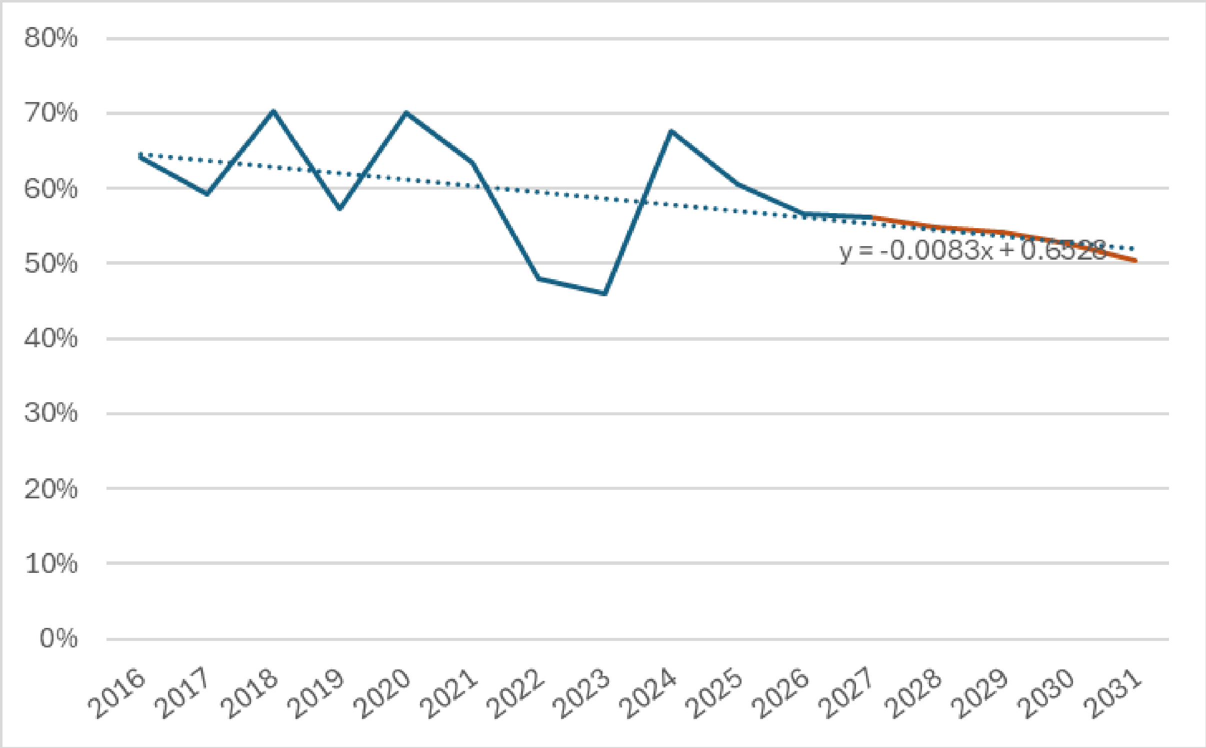
Figure 8: Historical and forecast penetration rates – residential customers



Source: Core Energy Forecasting Report

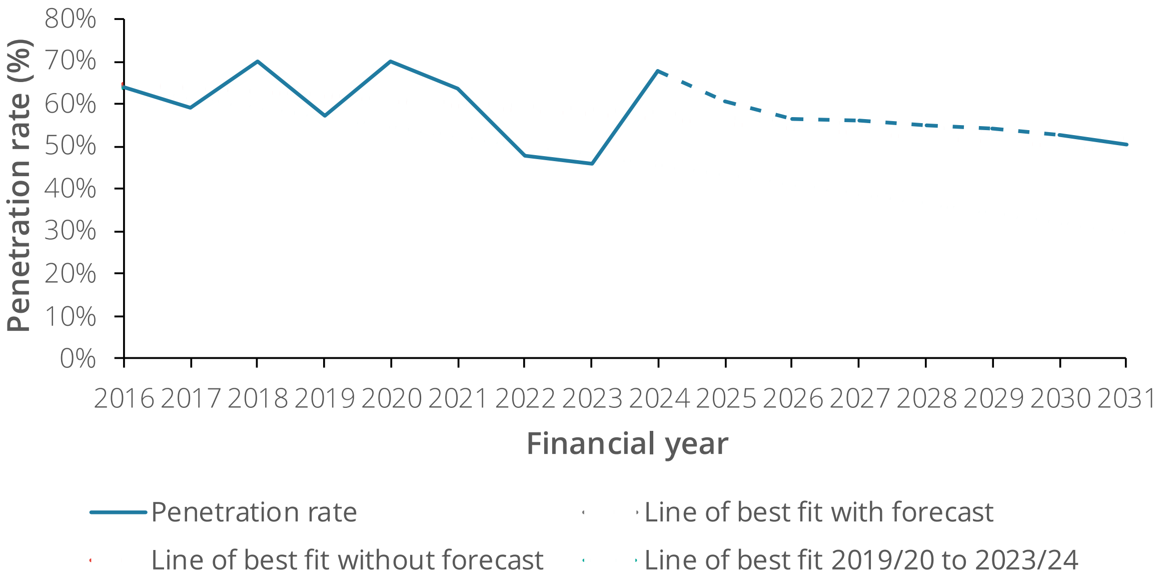
Core Energy compares the forecast average annual penetration rate of 55% from 2024/25 to 2030/31 with the historical average of 59% over 2019/20 to 2023/24. This implies that Core Energy's forecast penetration rates may have been informed by AGNSA's historical penetration rates. If this is true, and the historical rates do indeed form some basis for future rates, it raises a few issues. First, it is not clear why the period 2019/20 to 2023/24 is used as the key historical reference point; considering a shorter or longer historical period would provide a different historical comparator. Second, it is not clear why the forecasts deviate from the historical trends they are seemingly based on. Figure 6.7 of Core's report suggests that the forecast aligns with the historical trend, but in our view this figure is misleading. The figure suggests that the forecasts are guided by a line of best fit through the historical data, when in fact the line of best fit is drawn through the historical and forecast data. This is problematic, as the forecasts themselves rest on assumptions with no clear basis. When these forecasts are excluded from the line of best fit, the line of best fit changes, as seen in Figure 10. Moreover, if Core Energy are using a historical window of 2019/20 to 2023/24 to justify the forecasts, it would have made more sense to show the line of best fit based for 2019/20 to 2023/24, rather than for 2015/16 to 2030/31.

Figure 9: Figure 6.7 from Core's report



Source: Core Energy Forecasting Report, page 29

Figure 10: Line of best fit including and excluding Core Energy's forecasts

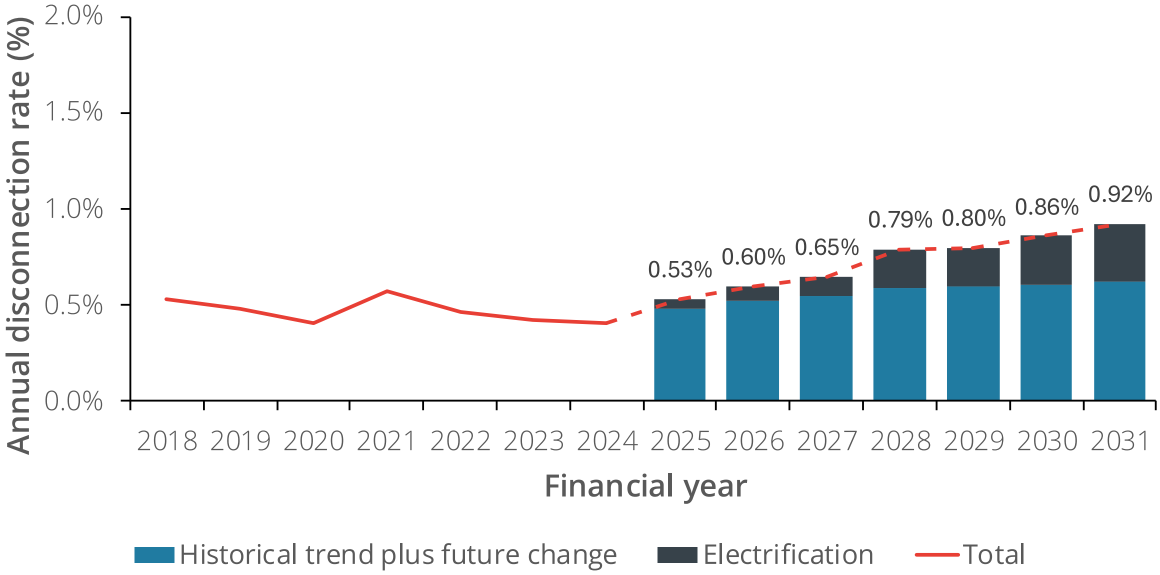


Source: Frontier Economics analysis of data in Core Energy Forecasting Model

Similarly, Core Energy provides no systematic quantitative or qualitative link between the factors driving the assumed disconnection rates and the hardcoded values in the model.

Figure 11 shows historical disconnection rates and Core Energy's forecasts of disconnection rates. Figure 11 shows Core Energy is forecasting a moderate increase in disconnections, driven mainly by electrification but also by an additional "future change". Core Energy does little to explain what accounts for the reversal of the historical trend over the forecast period (a downward trend in the number of disconnections is apparent from 2017/18 to 2023/24, as well as over the more recent period of 2020/21 to 2023/24). Core Energy provides little explanation of what is meant by "future change" and how it distinguishes from the impact of electrification, which raises potential concerns of double counting.

Figure 11: Historical and forecast disconnection rates – residential customers



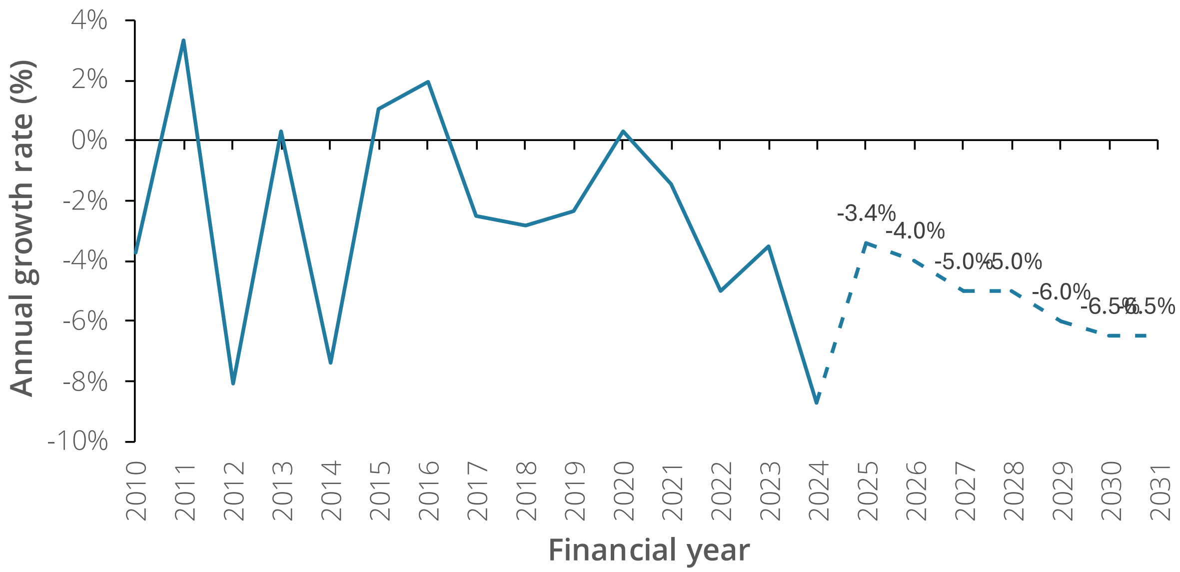
Source: Frontier Economics analysis of data in Core Energy Forecasting Model

2.4.3 Core Energy's assumptions on consumption per connection are hardcoded and not supported by systematic quantitative or qualitative analysis

Although Core Energy cites several factors underlying the assumed decline in consumption per connection, Core Energy does not provide any systematic quantitative or qualitative analysis linking these factors to the hardcoded assumptions used in the model.

The hardcoded assumptions in respect of consumption per connection for residential customers are shown in Figure 12. The solid line represents historical consumption per connection while the dashed line (accompanied by data labels) represents Core Energy's forecast of consumption per connection.

Figure 12: Historical and forecast annual growth rates in consumption per connection – residential customers



Source: Frontier Economics analysis of data in Core Energy Forecasting Model

Core Energy reports an average annual historical reduction in consumption per connection of -5.75% from 2021/22 to 2023/24[16], compared with an average forecast reduction of -5.5%. It is unclear why, given the historical downward trend, the forecast initially assumes a slower rate of decline before assuming a faster rate of decline later in the period. It is also unclear why 2021/22 to 2023/24 was chosen as the historical window for benchmarking, rather than some other period. In addition, Core Energy's treatment of the impact of covid-19 and the period of very high energy prices in 2022 on the observed trend in historical consumption per connection is unclear.

There is also uncertainty around potential double counting from electrification since Core Energy cites it as a reason for both the decline in consumption per connection, as well as the increase in disconnection rates as discussed earlier.

2.4.4 There may be issues with the way Core has addressed AGNSA's zero-consuming meters

In a note in the Core Energy Forecasting Model, Core Energy states that "AGN has advised 10,214 ZCMs (at least three years of no payment), at end 2024 and these have been assumed to be inactive (no fee) throughout the Review period." To capture this, Core Energy deduct 3,405 zero-consuming meters each year from 2025/26 to 2027/28. We are unsure of whether Core Energy has interpreted the advice from AGN correctly.

Our interpretation of AGN's advice is that Core Energy should have deducted 10,214 ZCMs from total connections in 2024. If there is an expectation of future growth in ZCMs than presumably this would also require future adjustments for ZCMs in each forecast year (not just 2025/26 to 2027/28).

[16] Core Energy has made a typo here. The Core Energy Forecasting Report says that the decline over FY2022 to FY2025 was 5.75% per annum, but in fact it is the decline over FY2022 to FY2024 that was 5.75%.

2.5 Commercial demand forecasts

Core Energy's approach to forecasting commercial demand is described in Box 3. The issues with this approach to forecasting commercial demand that we expect will affect the reasonableness of Core Energy's demand forecasts are described in the sections that follow.

Box 3: Commercial demand forecasting methodology

Commercial connections

Core Energy applies a trend-based approach to forecasting commercial connections. Assumptions are made for both future annual growth rates in connections and disconnections.

$$total\ connections_t = total\ connections_{t-1} * (1 + \%\Delta_{connections} + \%\ \Delta_{disconnections})$$

Core Energy cites the following reasons underlying their assumed growth rates in connections over time:

- Lower level of forecast new gas-intensive commercial development activity
- Increase in all electric businesses and commercial properties, leveraging solar and electric heat pump technologies.

And for the assumed rate of disconnections:

- Increased awareness of cost effectiveness and sustainability of renewable sourced electricity and energy efficiency of heat pump technology
- Government influences on fuel switching
- Requirement for replacement of gas appliances.

Commercial consumption per connection

Core Energy forecasts normalised consumption per connection using a trend-based approach based on an assumed annual growth rate in normalised consumption per connection. That is:

$$DPC_t = DPC_{t-1} * (1 + \%\Delta_{DPC})$$

Core Energy's report offers several explanations for the forecast annual change in consumption per connection:

- Advances in construction standards which favour other energy sources
- Changing mix/type of small businesses
- Increasing solar and battery storage penetration within the "existing" customer category
- Continuing advances in energy efficiency
- Increased number of shared central low emission energy facilities used by multiple small businesses
- Growing trend in the use of alternative water heating technologies

Total commercial demand

Lastly, Core Energy estimates total commercial demand by taking the average number of connections across the current year and previous year and multiplying that by the forecast consumption per connection.

2.5.1 There are potential data errors in the more recent monthly consumption data

As discussed in Section 2.4.1 the historical monthly demand data that Core Energy is using in its model shows a significantly different seasonal pattern in the last four years (2020/21 to 2023/24), than it did over the early period (2008/09 to 2019/20).

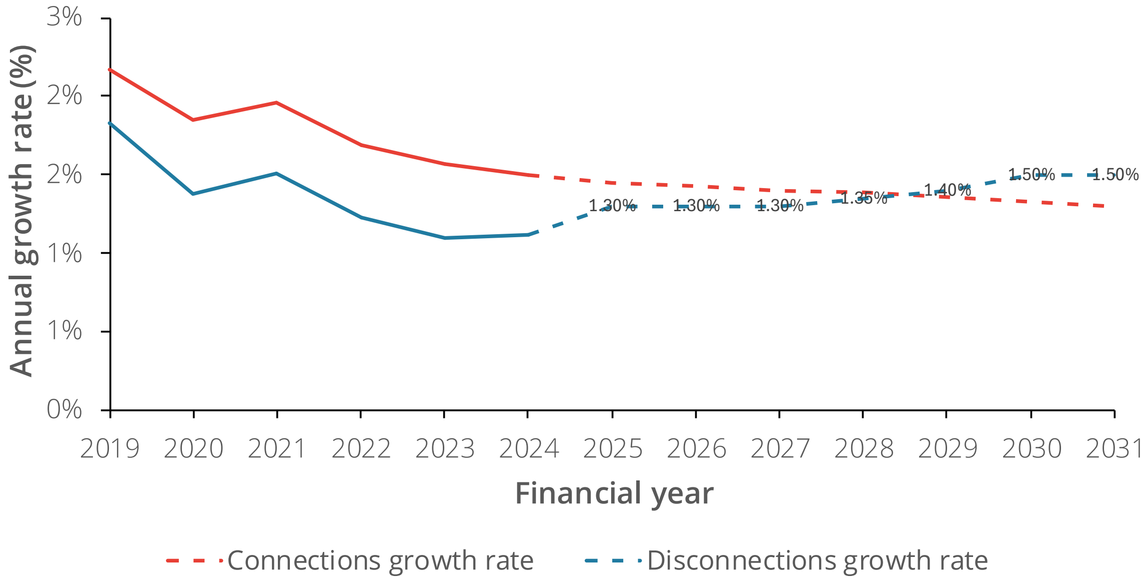
2.5.2 Core Energy's assumptions on connections and disconnections are hardcoded and not supported by systematic quantitative or qualitative analysis

Although Core Energy cites several factors underlying the assumed penetration rates, Core Energy does not provide any systematic quantitative or qualitative analysis linking these factors to the hardcoded assumptions in the model.

Core Energy observe that growth in commercial connections has been falling over time, but does not explain how this historical trend informs its forecasts.

The hardcoded assumptions in respect of penetration rates are shown in Figure 13.

Figure 13: Historical and forecast connection and disconnection rates – commercial customers



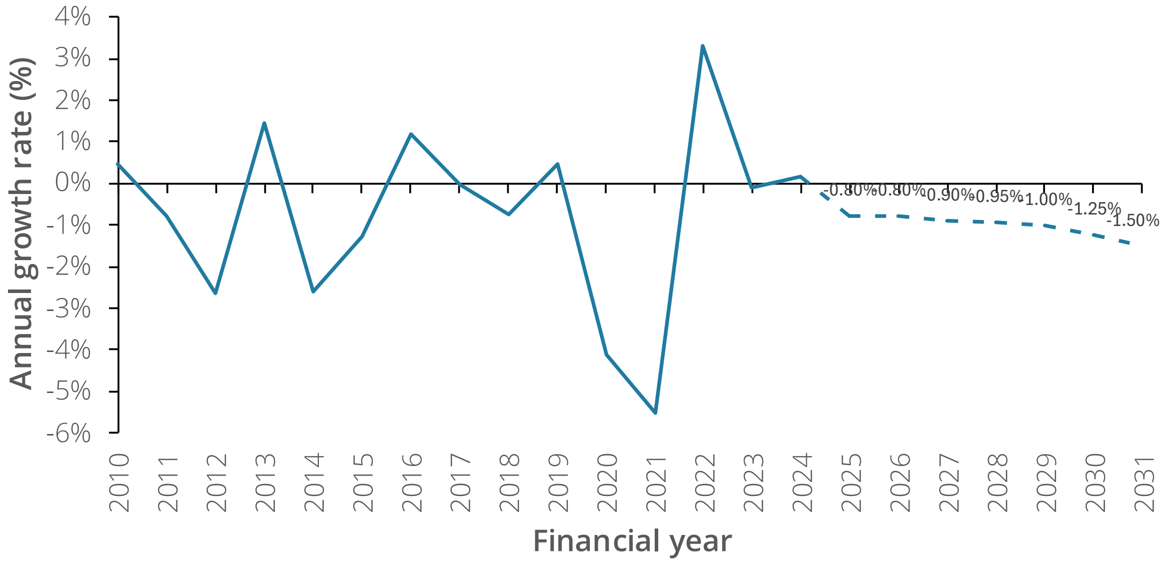
Source: Frontier Economics analysis of data in Core Energy Forecasting Model

2.5.3 Core Energy's assumptions on consumption per connection are hardcoded and not supported by systematic quantitative or qualitative analysis

Although Core Energy cites several factors underlying the assumed decline in consumption per connection, Core Energy does not provide any systematic quantitative or qualitative analysis linking these factors to the hardcoded assumptions in the model.

The hardcoded assumptions in respect of consumption per connection are shown in Figure 14. The solid line represents historical change in consumption per connection while the dashed line (accompanied by data labels) represents Core Energy's forecast of change in consumption per connection.

Figure 14: Historical and forecast annual growth rates in consumption per connection – commercial customers



Source: Frontier Economics analysis of data in Core Energy Forecasting Model

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