ACIL ALLEN CONSULTING

REPORT TO
AUSTRALIAN ENERGY REGULATOR

11 NOVEMBER 2015

REVIEW OF DEMAND FORECASTS FOR THE AGN SOUTH AUSTRALIAN GAS NETWORKS

FOR THE ACCESS ARRANGEMENT PERIOD COMMENCING 1 JULY 2016

PUBLIC VERSION – SOME CONFIDENTIAL INFORMATION HAS BEEN REDACTED

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PART ONE INTRODUCTION

Part I of this report sets out introductory material including background on the Australian Gas Networks' South Australian gas distribution system; requirements of the National Gas Rules in relation to access arrangement information relating to gas demand; and an explanation of our approach to the review of demand forecasts.

1 BACKGROUND

The Australian Energy Regulator (AER) has engaged ACIL Allen Consulting ("ACIL Allen") to review the adequacy and appropriateness of the methodology used by Australian Gas Networks Limited ("AGN") to develop forecasts of demand in its South Australian gas distribution networks for the access arrangement period commencing 1 July 2016, as set out in the proposed access arrangement information submitted by AGN.

The National Gas Rules (NGR 72(1)(a)(iii)) require the access arrangement information provided by the service provider to include usage of the pipeline over the earlier access arrangement period showing:

- minimum, maximum and average demand
- customer numbers in total and by tariff class.

In making a decision whether to approve or not to approve an access arrangement proposal, the AER is required under rule 74 of the NGR to be satisfied that forecasts required in setting reference tariff(s) are arrived at on a reasonable basis and represent the best forecast or estimate possible in the circumstances.

The process followed by the AER for assessing proposed access arrangements and access arrangement revisions is set out in the Final Access Arrangement Guideline published in March 2009 (AER, 2009)(AER, 2009).

2 ABOUT THIS REPORT

A key part of the information submitted by a service provider in support of a proposed access arrangement is a forecast of the level of demand for the reference services provided over the course of the access arrangement period. This involves forecasting demand for services for a period of five years from the commencement date of the new access arrangement. It is important to ensure that the forecasts represent best estimates arrived at on a reasonable basis because:

— Demand forecasts may impact the forecast capital expenditure required to meet new demand from prospective users or increased demand from existing users and may therefore influence forecast revenue.

— Demand forecasts influence the tariffs set to meet forecast revenue in each year of the access arrangement period, and how this revenue is to be allocated between tariff classes for different reference services.

2.1 Approach to the review

In undertaking this review, ACIL Allen has considered the following issues:

1. the adequacy of the overall approach and methodology
2. the reasonableness of the assumptions
3. the currency and accuracy of the data used
4. the account taken of key drivers
5. whether the methodology has been properly applied.

The review has been undertaken as desktop analysis into the methodology, data and parameters, and assumptions used to develop the demand forecasts. ACIL Allen has used its own knowledge of Australian gas markets to test assumptions.

3 SCOPE OF AUSTRALIAN GAS NETWORKS SOUTH AUSTRALIAN OPERATIONS

The AGN South Australian gas distribution business is located mainly in the Adelaide metropolitan area. It also services the larger regional centres of Mount Gambier, Port Pirie, Whyalla and Peterborough as well as certain parts of the Barossa Valley and the Riverland.

The network is supplied with gas from two transmission pipelines:

— The Moomba – Adelaide Pipeline System (MAPS) which transports gas from fields to the north, principally in the Cooper Basin.

— The South East Australia Gas Pipeline (SEA Gas) which transports gas from fields in the Bass Strait region to the east (Otway, Bass and Gippsland Basins).

The origins of the network date back more than 150 years. In recent years there has been an on-going program of replacement of cast iron pipe with polyethylene pipe resulting in increased network capacity, lower system losses and improved public safety.

As at 30 June 2014, the total network length was 7,950 km (up from 7,645 km at 30 June 2010). In terms of geographical coverage, 93% of the network (by line length) is located within the Adelaide area, 2.8% in the south-eastern area around Mount Gambier, 1.6% in Port Pirie, 1.3% in Whyalla and the remaining 1.2% in Peterborough, Murray Bridge, Nuriootpa, Berri and other regional towns.

The network currently serves around 423,000 customers of which some 413,000 (97.6%) are residential customers. Gas deliveries through the network currently total around 23 PJ/year of which 31% is to residential customers, 13% to small commercial and industrial customers, and 55% to large commercial and industrial customers.

3.1 Historical gas demand

The historical customer numbers for the AGN South Australia distribution network are shown in **Table 3.1**.

TABLE 3.1 AGN SOUTH AUSTRALIA—HISTORICAL CUSTOMER NUMBERS BY CLASS

Number of connections	2010	2011	2012	2013	2014
Residential Connections	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commercial Connections	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Tariff V Connections	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Demand Connections	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Connections	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

SOURCE: (CORE ENERGY, 2015B)(CORE ENERGY, 2015B)

Historical gas demand, by customer class, is summarised in **Table 3.2**.

TABLE 3.2 AGN SOUTH AUSTRALIA—HISTORICAL GAS DEMAND BY CUSTOMER CLASS

Customer Class | TJ/a	2010	2011	2012	2013	2014
Residential Demand	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Commercial Demand	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Tariff V Demand	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tariff D Demand	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Demand	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

SOURCE: (CORE ENERGY, 2015B)(CORE ENERGY, 2015B)

PART TWO
ASSESSMENT OF THE DEMAND FORECASTS

II

Part II of this report examines the forecasting methodology used by Core Energy to develop the demand forecasts for the AGN South Australia gas distribution network; reviews the key assumptions made in developing those forecasts; and provides an assessment of the reasonableness of each of the forecast components.

4 FORECAST METHODOLOGY AND ASSUMPTIONS

The demand forecasts contained in the access arrangement information provided by AGN (AGN, 2015)(AGN, 2015) have been developed by Core Energy (Core) and are detailed in a separate demand forecasts study (Core Energy, 2015a) (Core Energy, 2015a) included as Attachment 14.1 to the access arrangement information.

4.1 Forecast methodology for the 2016–21 access arrangement period

The market forecasts in the Core report (Core Energy, 2015a)(Core Energy, 2015a) were developed using the methodology described below. The forecasts cover a period from 1 July 2016 to 30 June 2021 and are based on a combination of historical load data together with Core's assessments of economic and government policy factors.

The methodology adopted by Core to derive a forecast of gas connections and gas demand for the AGN SA network, involves three primary elements:

— an approach to normalising historical demand to remove the impact of abnormal weather

— an approach to deriving a forecast of Tariff V demand

— an approach to deriving a forecast of Tariff D demand.

Core explains that the methodology it has used for these elements was finalised having consideration for all recent access arrangements submitted to the regulator, thereby allowing Core to comply with the requirement of the National Gas Rules that the forecasting methodology should reflect a "best-practice" approach.

The methodology adopted by Core includes a demand forecast model that examines factors potentially impacting on normalised demand. Core explains (Core Energy, 2015a, p. 23) (Core Energy, 2015a, p. 23) that this approach is fundamentally consistent with approaches to demand forecasting accepted by the AER in the context of past access arrangement reviews (including the AGN's South Australian and Queensland networks for the current AA period; AGN's Victorian network; and most recently Jemena Gas Network's (JGN) New South Wales network). It is also generally consistent with the methodology adopted by AEMO in the National Gas Forecasting Report ("NGFR"), as developed by ACIL Allen Consulting (ACIL Allen Consulting, 2014)(ACIL Allen Consulting, 2014). Core's forecasting approach takes into consideration the main input variables as outlined in ACIL Allen's methodology: Gross State Product ("GSP") growth, population growth, housing growth, retail gas prices and weather data.

Core explains that it was given access to detailed AGN historical data, which enabled the forecasting of demand for individual connection types within a demand segment.

Core summarises the methodology used to develop the Tariff V[1] (residential and commercial) demand forecasts as follows:

— Step 1 – normalise historical demand per connection data to remove fluctuations due to weather influences. Determine historical growth rate based on weather normalised data.
— Step 2 – identify factors materially influencing movement in demand per connection for each customer segment. Obtain data supporting analysis and forecast of demand per connection.
— Step 3 – identify factors materially influencing movement in net connection numbers for each customer segment. Obtain data supporting analysis and forecast of connection numbers.
— Step 4 – quantify drivers that are expected to cause deviation from historical growth trends, to forecast connection numbers and demand per connection.
— Step 5 – derive adjusted forecast for connection numbers and demand per connection for each customer segment.
— Step 6 – review and validate results through independent analysis, including review of third party literature.

CORE summarises the methodology used to develop the Tariff D (industrial and other large gas user) demand forecasts as follows:

— Step 1 – compile historical Annual Contract Quantity (ACQ) and Maximum Daily Quantity (MDQ) of individual Tariff D customers.
— Step 2 – identify new connections, disconnections and tariff movements expected to occur during the forecast period.
— Step 3 – identify major consuming customers and issue survey to gauge expected future load. Collate results.
— Step 4 – for Tariff D customers whose demand was observed to have a significant relationship with gross value add (GVA), apply an adjustment to future load based on expected economic outlook.
— Step 5 – for remaining Tariff D customers, apply an adjustment to future load based on historical trend in MDQ and ACQ.
— Step 6 – Consolidate outputs from Step 4 and Step 5 to derive Tariff D demand forecast.

4.2 Weather normalisation of historical data

Generally speaking, gas consumption will vary with ‘drivers’ such as economic activity, population and gas price.

In addition, gas consumption will vary in response to weather conditions, primarily as a result of space heating requirements for household and commercial buildings. Generally in a cooler year the heating requirement will be higher and so gas consumption will increase. The reverse is also generally true.

The objective of demand forecasting is not to forecast what *actual* gas consumption will be at any given time. Rather, it is to forecast what demand *would be* under ‘normal’ conditions.

Therefore it is necessary to ‘remove’ the effect of weather variations from the historical consumption data when forecasting. Failure to do this will result in a model that is incorrectly specified and may falsely attribute the impact of weather variation to other factors. This process is referred to as ‘weather normalisation’.

This requires a measure of the heating requirement for the same period for which historical consumption data are available. There are then two conceptual steps to weather normalisation:

1. estimate/ specify the relationship between consumption and ‘weather’
2. ‘remove’ the impact of variations in weather from the historical data.

This section describes:

— the data requirements for weather normalisation in section 4.2.1
— conceptual issues in section 4.2.2

[1] Note that AGN divides Tariff V customers into two tariff sub-classes: Tariff R (residential) and Tariff C (Commercial).

— AGN's approach to weather normalisation in section 4.2.3

Our conclusion is that AGN's approach to weather normalisation is reasonable.

4.2.1 Data selection

Two data sets are required for weather normalisation, one for each of the above two conceptual steps.

As a general proposition it is appropriate to use all of the available data for both steps.

Data for estimating the relationship between weather and gas consumption

The first step requires a data set comprising both consumption and weather data. Typically the length of this data set is constrained by the availability and quality of consumption data. Weather data are usually available for a long time, whereas consumption data are usually not available for more than 5 or 10 years.

Another issue to consider in selecting the dataset is whether 'old' consumption data is comparable to 'current' consumption data. For example, there have been substantial changes in appliance design and gas usage in the recent years. However, data on appliance uptake and usage are scarce and costly to collect. In the circumstances we consider it reasonable to omit consumption data that are more than approximately ten years old (even if they are available) on the basis that older data reflects consumption circumstances that no longer apply.

In this case Core considered data for the period from 2005 until 2014 and chose to disregard data from before 2010. As discussed in section 4.2 we question Core's conclusion that the break in the dataset is attributable to the Global Financial Crisis, which occurred before 2010. However we accept that, whatever the cause, there is a clear break in trend in the pre-2010 historical data for both residential and commercial consumption, and therefore consider that it is not unreasonable to omit that older data from the current forecasts.

Generally speaking, because gas is commonly used for space heating we can expect to see an inverse relationship between gas demand and temperature, with demand increasing as temperature falls. There are two basic approaches commonly used to adjust temperature data to take account of weather variations: Heating Degree Days (HDD) and Effective Degree Days (EDD).

The HDD approach uses a single measure of weather, namely temperature. HDD is calculated from meteorological data as the sum, over a year, of the negative differences between the average temperature on each day and 18^{o} Celsius.

The EDD approach (which is preferred by AEMO and which has been widely used in previous access arrangement determinations) is a multifactor method based on the concept of Heating Degree Days (HDD) but also taking into account measures of average wind velocity, sunshine hours and seasonal variations in consumer propensity to use heating. The EDD approach in effect seeks to extend the HDD method by taking into account other weather-related parameters that may affect consumer behaviour in relation to gas consumption for space heating and water heating.

A *positive* relationship is expected between gas demand and EDD (or HDD). In simple terms, as EDD increases, so should gas consumption.

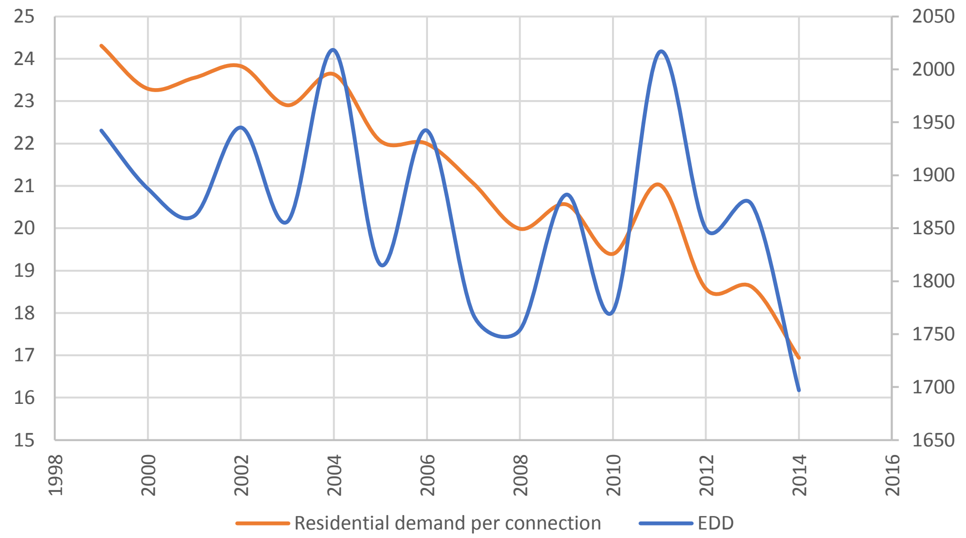
AGN has used the preferred EDD approach to weather normalisation.

Figure 4.1 shows the annual volume of gas supplied to AGN's residential customers on a per customer basis from 1999 to 2014 along with the number of EDDs observed in each of those years. The lower pane shows the natural logarithms of the same data.

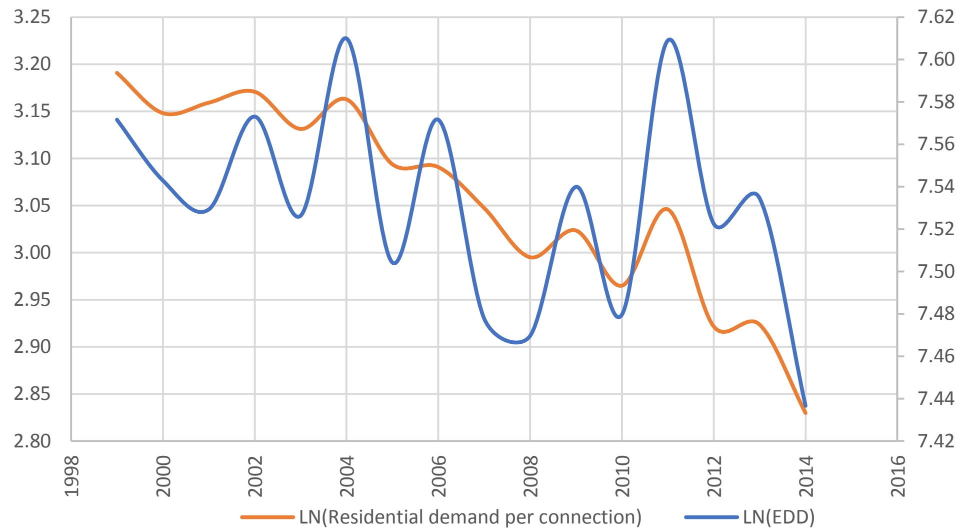
Both representations of the data show the expected relationship. The fit between the two data series is not particularly close. This does not deny the existence of a relationship. Rather, it indicates that while weather related factors are important predictors of residential gas consumption, they are not the sole determinants.

FIGURE 4.1 RESIDENTIAL DEMAND PER CONNECTION AND EDD

Levels



Natural logarithms



SOURCE: ACIL ALLEN CONSULTING

Figure 4.2 shows the corresponding data for commercial customers. Again, the data show a positive relationship, though again there are clearly other factors driving consumption as well.

FIGURE 4.2 COMMERCIAL DEMAND PER CONNECTION AND EDD

Levels

SOURCE: ACIL ALLEN CONSULTING

Data for quantifying 'normal' weather

The second conceptual task is to quantify 'normal' weather. The broad objective is to identify the 50th percentile value of a probability distribution of the weather measure each year. This must be done in a way that allows for the existence of climatic trends.

Core's approach was to fit a regression line with a trend variable to a time series of the weather measure EDD. The historical 'normal' weather is defined by the regression line itself. If a projection of the weather measure is required, the regression line is projected forward using the same trend.[2]

This analysis can be conducted without consumption data so the length of the time series is not subject to the same constraint as the first conceptual step. Rather, the constraint is the length of the weather time series. This is typically several decades long, although it depends which weather station is used as some are older than others.

[2] Core extrapolated the trend in consumption rather than extrapolating the weather measure. The result appears to be equivalent.

In this case Core used a relatively short time series for this purpose dating back to 1999. Core offers the following explanations for using this relatively short time series is that:

- It "maintains consistency with AEMO's forecast of SA gas demand" as reflected in email correspondence between AGN and AEMO dated 22 December 2014, provided to Core on 5 February 2015.
- The CSIRO have observed a warming trend over the past 15 years which provides further justification for normalising weather using observations from 1999 onwards. As evidence of this, Core cites CSIRO report "State of the Climate 2014, published February 2015. CSIRO is projecting that the warming trend will continue and more accuracy can be achieved with the weather normalisation process if data is restricted to the recent period when warming occurred.

4.2.2 The weather measure and weather data

Weather measure

Two measures of the heating requirement are commonly used for weather normalising 'cold' weather, namely Heating Degree Days (HDD) and Effective Degree Days (EDD). These two approaches are similar, but differ in the input data they use. EDD is a richer measure that takes account of factors not included in HDD.

The underlying concept in both measures is the same. Both calculate the sum of the (absolute) differences between weather measures and a reference threshold. The difference is that HDD is based solely on temperature data while EDD also takes account of wind velocity, sunshine hours, and seasonal variations in propensity to use gas appliances.[3]

EDDs can be calculated on various bases by incorporating weather conditions at different times of day and changing the threshold level.[4] In its 2012 review of approaches to estimating the heating requirement in Victoria, AEMO concluded that the EDD_{312} index performs better than EDD calculated over other time bases.[5] The corresponding study has not been done in South Australia to our knowledge, but the conclusion should be transferable. Core has used the preferred EDD_{312} approach, noting that:

" … the previous South Australian AA submission applied EDD_{66} methodology. However, Core considers an EDD_{312} approach to be the most suitable approach to weather normalisation for AGN gas demand. Furthermore, AEMO found that the EDD_{312} index has a slightly stronger explanatory power for winter demand data, with an R-squared (R^2) value of 0.96 versus 0.95 for EDD_{66}."

(Core Energy, 2015a, p. 24)(Core Energy, 2015a, p. 24)

Weather data

The weather data used for the weather normalisation process must be collected for the area where the gas consumption in question occurred. The Bureau of Meteorology (BOM) collects and publishes historical weather data from hundreds of weather stations around Australia. There will typically be more than one data reading in a given forecast area so a choice must be made as to the most suitable.

ACIL Allen recommends that candidate weather stations in a forecast area should be identified and chosen using the following factors:

1. prevalence of missing data at the station – if more than 10 per cent of data are missing, discard the station and move on

[3] There are two seasonal influences in play here. The first is the general expectation that some seasons will be colder than others and, therefore, that gas consumption will be greater in some seasons than others. This is accounted for by using EDDs or HDDs, which both measure how cold it was during a particular season. The seasonal variation measure within the EDD calculation is intended to account for the fact that people will be quicker to use heating appliances in cold seasons (winter) than in warmer seasons (summer). This is accounted for in addition to the greater heating requirement, which means that, as this is modelled, a cold day in winter will add more to the measured heating requirement than an equally cold day in summer.

[4] The choice of the threshold is somewhat subjective. The intention is to screen out days when there is no weather-sensitive energy use.

[5] EDD_{312} is the number of EDD calculated using average of the eight three-hourly Melbourne temperature readings (in degree Celsius) from 3am to 12am the following day inclusive as measured at the Bureau of Meteorology's Melbourne Station. See http://www.aemo.com.au/Gas/Planning/Victorian-EDD-Weather-Standards-Review for further detail.

2. length of time series available:
   a) must be at least as long as the historical consumption data series
   b) should ideally be 30 years or more to allow projection, and to avoid overreliance on (relatively) short-term influences such as drought and issues around the choice of series start points/end points
3. availability of important weather variables such as humidity, rainfall, sunshine, and wind speed if these are to be used.

The correlation between demand and weather should then be examined for each remaining candidate weather station and a preferred option chosen based on the results. If multiple weather stations perform similarly, the choice will be relatively arbitrary. Generally, ACIL Allen recommends choosing a weather station that:

— has been well correlated with gas consumption over an extended period
— has been more closely correlated with gas consumption recently.

In some cases these criteria may be contradictory and some judgement may be required.

It is clear from Core's report that the data it used were collected at Kent Town weather station, which is close to the centre of Adelaide and is widely used as an indicator of Adelaide's weather. It is not clear from the report that alternative stations were considered. However, we note that computing EDD requires detailed data that have not been collected at all weather stations.

It would be preferable to consider the possibility that data from other weather stations may perform better in the weather normalisation models, though we note that there may be few, if any, practical alternatives. For clarity, we would not consider it necessary to compare *HDD* models at some weather stations with *EDD* models from others.

4.2.3 AGN's approach

Core Energy's weather normalisation model is based on EDD as the weather measure. The trend in EDD was estimated using data from 1 July 2004 until 16 April 2012. The end date of the regression was truncated by a gap in the available sunshine data (an input to EDD), which is not available for Kent Town between 17 April 2012 and 30 June 2012.

The relationship between weather and gas was based on consideration of considered the various regression models, with the choice of model based on standard empirical considerations. .

The relationship between weather and residential consumption

The following four regression models were considered as candidate weather normalisation models for the residential sector.

Model 1 – $\textit{Demand per connection} = \beta_0 + \beta_1 \textit{EDD}$

Model 2 - $\textit{Demand per connection}_t = \beta_0 + \beta_1 \textit{EDD} + \beta_2 \textit{Demand per connection}_{t-1}$

Model 3 - $\textit{Demand per connection}_t - \textit{Demand per connection}_{t-1} = \beta_0 + \beta_1 (\textit{EDD}_t - \textit{EDD}_{t-1})$

Model 4 - $\textit{Demand per connection} = \beta_0 + \beta_1 \textit{EDD} + \beta_2\ \textit{2011 dummy} + \beta_3 \textit{Trend}$[6]

The regression results for these models are in **Table 4.1**. Those results led Core Energy and AGN to select model 4 over the others. The details are described in Attachment 14.2 to AGN's proposal. In summary, models 2 and 4 both met empirical criteria regarding significance, autocorrelation and heteroskedasticity so both were candidates. Model 4 was chosen as it also demonstrated the best fit.

[6] Model 4 tested 2011 as an outlier in the dataset which could distort the effects of the EDD variable. A dummy variable for 2011 was included to account for this effect.

TABLE 4.1 WEATHER NORMALISATION – RESIDENTIAL EDD MODELS

	Model 1	Model 2	Model 3	Model 4
Dependent Variable	**RDC**	**RDC**	**RDC_fDif**	**RDC**
EDD	0.01480	0.00955		0.00621
LagRDC		0.85		
EDD_fDif			0.0071	
Dummy (2011)				0.58
Trend				(0.40)
_cons	(6.31)	(14.93)	(0.3750)	13.1320
N	16.00	15.00	15.00	16.00
R-sq	0.38	0.91	0.83	0.97
adj. R-sq	0.34	0.89	0.81	0.97
AIC	66.06	34.91	21.89	19.38
RMSE	1.80	0.71	0.47	0.40
Autocorrelation	Yes	OK	Yes	OK
Heteroskedasticity	OK	OK	OK	OK

SOURCE: AGN – ATTACHMENT 14.3 TO REGULATORY PROPOSAL

It is not written up in Core Energy's report to AGN but, from the supporting spreadsheets, it appears that Core also considered models based on HDD as the weather measure. The regression results of those models are shown in **Table 4.2**. The empirical results in terms of auto correlation and heteroscedasticity are very similar. [redacted]

If the HDD models were taken into account as well as the EDD models, which may have been the case, it seems likely that the same selection would have been made. That is, model 4 seems to be the best choice from among the 8 available options.

In our view model 4 is a reasonable model for weather normalisation in this context. Our own approach is to include weather data in a forecasting model rather than to normalise as a separate step, but the approach taken by Core on AGN's behalf is reasonable.

TABLE 4.2 WEATHER NORMALISATION – RESIDENTIAL HDD MODELS

	Model 5	Model 6	Model 7	Model 8
Dependent Variable	RDC	RDC	RDC_fDif	RDC
HDD	[redacted]	[redacted]		[redacted]
LagRDC		[redacted]		
HDD_fDif			[redacted]	
Dummy (2011)				[redacted]
Trend				[redacted]
_cons	[redacted]	[redacted]	[redacted]	[redacted]
N	[redacted]	[redacted]	[redacted]	[redacted]
R-sq	[redacted]	[redacted]	[redacted]	[redacted]
adj. R-sq	[redacted]	[redacted]	[redacted]	[redacted]
AIC	[redacted]	[redacted]	[redacted]	[redacted]
RMSE	[redacted]	[redacted]	[redacted]	[redacted]
Autocorrelation	[redacted]	[redacted]	[redacted]	[redacted]
Heteroskedasticity	[redacted]	[redacted]	[redacted]	[redacted]

SOURCE: AGN – ATTACHMENT 14.3 TO REGULATORY PROPOSAL

The relationship between weather and commercial consumption

The same four regression models were considered as candidate weather normalisation models for the commercial sector. The regression results for these models are in Table 4.3. As with the residential model, the results support the choice of model 4 for normalisation of commercial gas consumption data.

TABLE 4.3 WEATHER NORMALISATION – COMMERCIAL EDD MODELS

	Model 1	Model 2	Model 3	Model 4
Dependent Variable	CDC	CDC	CDC_fDif	CDC
EDD	0.14	0.11		0.09
LagRDC		0.47		
EDD_fDif			0.09	
Dummy (2011)				0.22
Trend				(2.60)
_cons	56.97	(39.19)	(2.67)	175.45
N	16	15	15	16
R-sq	0.50	0.69	0.66	0.88
adj. R-sq	0.46	0.64	0.64	0.86
AIC	13.449	10.203	9.240	6.950
RMSE	130.43	114.900	111.12	110.84
Autocorrelation	Yes	OK	Yes	OK
Heteroskedasticity	OK	OK	OK	OK

SOURCE: AGN – ATTACHMENT 14.3 TO REGULATORY PROPOSAL

As with the residential models the spreadsheet that supports Core's report includes models based on HDD as the weather measure. The regression results of those models are shown in **Table 4.4**. The empirical results in terms of auto correlation and heteroscedasticity are very similar. Models two and six, which correspond to one another, have the same fit as one another. [redacted]

If the HDD models were taken into account as well as the EDD models, which may have been the case, it seems likely that the same selection would have been made. That is, model 4 seems to be the best choice from among the 8 available options.

TABLE 4.4 WEATHER NORMALISATION – COMMERCIAL HDD MODELS

	Model 5	Model 6	Model 7	Model 8
Dependent Variable	**CDC**	**CDC**	**CDC_fDif**	**CDC**
HDD	[redacted]	[redacted]	[redacted]	[redacted]
LagRDC		[redacted]		
HDD_fDif			[redacted]	
Dummy (2011)	[redacted]	[redacted]	[redacted]	[redacted]
Trend	[redacted]	[redacted]	[redacted]	[redacted]
_cons	[redacted]	[redacted]	[redacted]	[redacted]
N	[redacted]	[redacted]	[redacted]	[redacted]
R-sq	[redacted]	[redacted]	[redacted]	[redacted]
adj. R-sq	[redacted]	[redacted]	[redacted]	[redacted]
AIC	[redacted]	[redacted]	[redacted]	[redacted]
rmse	[redacted]	[redacted]	[redacted]	[redacted]
Autocorrelation	[redacted]	[redacted]	[redacted]	[redacted]
Heteroskedasticity	[redacted]	[redacted]	[redacted]	[redacted]

SOURCE: AGN – ATTACHMENT 14.3 TO REGULATORY PROPOSAL

Our conclusion is that the approaches taken by AGN/Core to weather normalisation of residential and commercial consumption data is reasonable and is generally consistent with "best practice" approaches to normalisation of gas consumption data to take account of weather effects.

4.3 Historical demand

Core notes that over the past two access arrangement periods, the forecast levels of gas demand have generally not been met. They also observe what they refer to as a "structural change" in the historical trend data from around 2010. As a result, they have placed reliance on historical data for the period 2010 to 2014 and have generally excluded earlier data from trend analysis.

"Specifically, the forecast of demand per connection has consistently overstated the level of demand relative to actual results. Core has ensured that this realisation does not bias the approach, but there has been an elevated level of focus on demand per connection drivers … statistical analysis reveals a structural change in the data occurred around 2010. A natural explanation for this is the deteriorating economic climate brought about by the Global Financial Crisis ("GFC") and a change in the competitiveness of gas relative to alternative energy sources. Where it is consistent with a best-practice approach, this structural change guided the selection of time series data used in the forecast. Core considers that the more recent historical trend provides an appropriate benchmark for the forecast period."

(Core Energy, 2015a, p. 16)(Core Energy, 2015a, p. 16)

While ACIL Allen does not necessarily accept Core's attribution of the change in trend to the GFC (we note that the GFC occurred in 2008 rather than 2010, but acknowledge that there may have been some lag in the response of South Australian gas demand to the GFC) we agree that the consumption data for both residential and commercial consumers show trend discontinuities around 2010, as illustrated in **Figure 4.3** and **Figure 4.4**. While residential demand has declined since 2005, the downward trend appears to have steepened since the anomalously high result in 2011. On the other hand, the upward growth trend in commercial gas consumption apparent over the period 2002 to 2008 appears to have stalled since that time.

FIGURE 4.3 SOUTH AUSTRALIA HISTORICAL RESIDENTIAL GAS CONSUMPTION

[redacted]

Note: Weather normalised historical data

SOURCE: ACIL ALLEN CHARTING OF HISTORICAL DATA PRESENTED BY CORE ENERGY (CORE ENERGY, 2015B)(CORE ENERGY, 2015B)

FIGURE 4.4 SOUTH AUSTRALIA HISTORICAL COMMERCIAL GAS CONSUMPTION

[redacted]

Note: Weather normalised historical data

SOURCE: ACIL ALLEN CHARTING OF HISTORICAL DATA PRESENTED BY CORE ENERGY (CORE ENERGY, 2015B)(CORE ENERGY, 2015B)

4.3.1 Historical Tariff V Demand

Core's analysis of historical consumption data indicates that rates of reduction in residential and commercial gas consumption in South Australia have accelerated over the past four years, with the decline in gross residential demand increasing from around -0.5% per year over the period 2007-2010 to around -1.4% per year over the period 2011-2014 (Core Energy, 2015a, p. 16)(Core Energy, 2015a, p. 16). In the commercial sector, the earlier period showed average demand growth of around 1.6% per year while the latter period showed a slight decline (<0.1%) in demand (Core Energy, 2015a, p. 16)(Core Energy, 2015a, p. 16) Core's estimates of historical Tariff V annual growth rates is reproduced in **Table 4.5**.

TABLE 4.5 HISTORICAL TARIFF V DEMAND

Sector	2014 Demand (GJ)	Average Growth %	Sector
		2007-2010	
Residential	7,154,434	-0.46%	Residential
Commercial	3,065,891	1.64%	Commercial
Total	10,220,324	0.11%	Total

SOURCE: (CORE ENERGY, 2015A, P. 16)(CORE ENERGY, 2015A, P. 16)

Because of the year-on-year variability in weather adjusted demand levels, the average rates of decline vary considerably depending on the starting year chosen, as illustrated in **Table 4.6**. Nevertheless there does appear to have been an acceleration in the average rate of decline in residential gas consumption since 2009.

TABLE 4.6 VARIATION OF 4-YEAR AVERAGE ANNUAL RATE OF CHANGE IN RESIDENTIAL GAS DEMAND WITH STARTING PERIOD

2002	2003 to 2006	– 0.44%
2003	2004 to 2007	+ 0.12%
2004	2005 to 2008	– 0.72%
2005	2006 to 2009	– 0.76%
2006	2007 to 2010	– 0.46%
2007	2008 to 2011	– 0.44%
2008	2009 to 2012	– 1.12%
2009	2010 to 2013	– 1.07%
2010	2011 to 2014	– 1.39%
2002	2003 to 2006	– 0.44%

SOURCE: ACIL ALLEN ANALYSIS OF HISTORICAL DATA PRESENTED IN (CORE ENERGY, 2015B)(CORE ENERGY, 2015B)

Core notes that the fall in demand per connection has been the main driver of lower Tariff V consumption although some decline in rate of growth of connection numbers has also had an impact.

TABLE 4.7 HISTORICAL TARIFF V CONNECTION NUMBERS

Sector	2014 Demand (GJ)	Average Growth %	
		2007-2010	2011-2014
Residential	412,860	1.85%	1.75%
Commercial	10,446	1.61%	1.39%

SOURCE: (CORE ENERGY, 2015A, P. 17)(CORE ENERGY, 2015A, P. 17)

Tariff V connection numbers (both residential and commercial) have continued to grow over the past four years, but at somewhat lower rates than for the previous period (**Table 4.7**). However, average demand per connection for existing residential and commercial connections has been declining at an increasing rate as shown in **Table 4.8**. Once again, there is considerable year-on-year variability in the data, so that the choice of starting year can significantly affect the observed changes in annual average demand per connection. Core attributes the annual declines in average utilisation to efficiency trends and the substitution of gas appliances for non-gas appliances such as reverse-cycle RC (“RC”) air-conditioning and solar water heating.

TABLE 4.8 HISTORICAL TARIFF V DEMAND PER CONNECTION

Sector	2014 Demand (GJ/connection)	Average Growth %	
		2007-2010	2011-2014
Residential	17.33	-2.26%	-3.08%
Commercial	293.5	0.04%	-1.42%

SOURCE: (CORE ENERGY, 2015A, P. 17)(CORE ENERGY, 2015A, P. 17)

4.3.2 Historical Tariff D demand

In the large customer (Tariff D) sector the historical annual and maximum daily demand continued to fall over the period 2010 to 2014, but not as sharply as over the prior period 2007 to 2010 when South Australia experience a significant contraction in manufacturing activity (see **Table 4.9**). Between 2011 and 2014, maximum daily quantity (MDQ) and annual contract quantity (ACQ) in the Tariff D segment fell by an annual average of 1.32% and 2.30% respectively. Core attributes the recent decline in Tariff D primarily to two factors: efficiency gains and reduced fuel requirements for newer technology, and declining gross value add in the SA manufacturing sector.

TABLE 4.9 HISTORICAL TARIFF D ANNUAL AND MAXIMUM DAILY DEMAND

Load	2014 Demand	Average Growth %	
		2007-2010	2011-2014
Annual Quantity (PJ)	12.73	-3.18%	-2.30%
Maximum Daily Quantity (TJ/d)	59.7	-4.36%	-1.32%

SOURCE: (CORE ENERGY, 2015A, P. 17)(CORE ENERGY, 2015A, P. 17)

4.4 Projecting historical trends

Core's approach to forecasting gas consumption operates at the "per connection" level. In broad terms, Core has projected consumption per connection and the number of customers separately. Total forecast demand is then calculated as the product of the two.[7]

To forecast demand per connection, Core first analysed historical demand per connection before projecting this forward along the (downward) trend observed in the historical period. In doing this, Core has analysed the change in consumption per connection for each of the following connection types:

— Residential connection types:
  - Incumbent customers (Core calls these customers 'existing')
  - New dwellings – new estates
  - New dwellings – medium high density
  - New electricity to gas (E to G) connections
— Commercial connection types:
  - Incumbent (Core calls these existing)
  - New commercial

Separate projections of the number of connections in each of these categories were prepared using the methodology described in section 4.4.1. This section relates to Core's analysis of average consumption for connections (customers) of each type.

As discussed below, Core's analysis suggests that in both the residential and commercial sector there are different 'types' of customers and that they:

— use different amounts of gas
— have shown different rates of change in the amount of gas they use.

In the forecasts, Core takes account of the first of these findings, but not the second. That is, consumption of the four residential and two commercial customer 'types' has been forecast to grow at the same (negative) rate over time.

From a conceptual perspective we see this as a 'second best' approach. Ideally, the consumption for each customer type should be projected taking into account the historical trends in consumption for that particular customer type. However, having considered whether AGN's forecasts would be improved if the differential rates (shown in **Table 4.15**) were used, we do not recommend such an approach in this case because the observed differential rates are implausible as indications of long-term trends. For example, as shown in **Table 4.15** adopting these rates in the forecasts would amount to forecasting that consumption of E to G connections would fall to little more than half of its current level within 11 years (lower for other types of connection). We concur with AGN and Core's implied view that this projection could not be supported by the available data.

In view of the growth rates observed for the different customer types we agree that application of a single growth rate to all categories, rather than applying individual growth rates, is appropriate in this instance. However, we are concerned that the way this has been done has in effect "double-counted" the reduction of gas consumption due to changes in house type. For the reasons discussed in section

[7] (Core Energy, 2015a, p. 38)

4.4.3, we therefore recommend that the AER should replace Core's aggregate residential forecasts with the values shown in **Table 4.10**. We have not attempted to disaggregate these forecasts to the household 'type' level.

TABLE 4.10 PROPOSED REVISIONS TO TARIFF V CONSUMPTION FORECASTS

Year	2014	2015	2016	2017	2018	2019	2020	2021
	GJ/a	GJ/a	GJ/a	GJ/a	GJ/a	GJ/a	GJ/a	GJ/a
Residential connections								
AGN/ Core forecast	7,154,434	6,720,782	6,446,907	6,258,721	6,071,982	5,897,659	5,733,964	5,583,903
Recommended forecast	7,154,434	6,764,836	6,529,500	6,375,499	6,218,183	6,072,174	5,937,029	5,807,417
Difference	-	44,055	84,694	120,785	151,082	180,240	209,643	230,917
Difference %	0%	1%	1%	2%	2%	3%	4%	4%
Commercial								
AGN/ Core forecast	3,065,891	2,938,052	2,877,119	2,838,515	2,819,789	2,788,096	2,759,758	2,742,183
Recommended forecast	3,065,891	2,963,297	2,920,874	2,909,806	2,904,930	2,884,557	2,861,440	2,849,001
Difference	-	25,245	43,755	71,292	85,140	96,461	101,682	106,818
Difference %	0%	1%	2%	3%	3%	3%	4%	4%

SOURCE: ACIL ALLEN ANALYSIS

4.4.1 Connection numbers

In the historical period the number of connections in each type changes. Broadly, 'incumbent' connections decline, while other connection types increase at various rates. AGN provided Core with data relating to historical consumption of each customer type as well as the number of customers of each type. From this, Core computed the average annual change in consumption per customer for each customer type.

Historical connections are summarised by type in **Table 4.11**

TABLE 4.11 AGN SOUTH AUSTRALIA – HISTORICAL CONNECTION NUMBERS

	2011	2012	2013	2014
Residential				
Opening Connections	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]
Less disconnections	[redacted]	[redacted]	[redacted]	[redacted]
Residual connections	[redacted]	[redacted]	[redacted]	[redacted]
Plus E to G	[redacted]	[redacted]	[redacted]	[redacted]
Plus New Estates	[redacted]	[redacted]	[redacted]	[redacted]

	2011	2012	2013	2014
Plus MHR	[redacted]	[redacted]	[redacted]	[redacted]
Total residential connections	[redacted]	[redacted]	[redacted]	[redacted]
		Commercial		
Opening Connections	[redacted]	[redacted]	[redacted]	[redacted]
Less disconnections	[redacted]	[redacted]	[redacted]	[redacted]
Residual connections	[redacted]	[redacted]	[redacted]	[redacted]
Plus new connections (cumulative)	[redacted]	[redacted]	[redacted]	[redacted]
Total commercial connections	[redacted]	[redacted]	[redacted]	[redacted]
Total commercial connections as reported	[redacted]	[redacted]	[redacted]	[redacted]
Discrepancy	[redacted]	[redacted]	[redacted]	[redacted]
Total connections	[redacted]	[redacted]	[redacted]	[redacted]

SOURCE: ACIL ALLEN ANALYSIS OF DATA FROM ATTACHMENT 14.2 TO AGN'S REGULATORY PROPOSAL

As **Table 4.11** shows there is a small discrepancy between the reported total number of commercial connections and its component parts.

4.4.2 Consumption per connection by type

Analysis of the historical consumption of the various customer types shows that average consumption per connection for different connection types has declined over time. Core's analysis of historical consumption by the various connection types is shown in **Table 4.12**.

TABLE 4.12 HISTORICAL CHANGE IN AVERAGE CONSUMPTION BY CUSTOMER TYPE (CORE ANALYSIS)

	2010	2011	2012	2013	2014	Avg. 2010-2014
	GJ/a	GJ/a	GJ/a	GJ/a	GJ/a	%
			Residential			
Residual connecti ons	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
% Change		*0%*	*-8%*	*-1%*	*-4%*	*-3.1%*
Electricit y to Gas	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
% Change		*-11%*	*3%*	*-13%*	*-3%*	*-6.3%*
New Estates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
% Change		*-11%*	*-3%*	*-13%*	*-3%*	*-7.4%*

	2010	2011	2012	2013	2014	Avg. 2010-2014
Medium density & high rise	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
% Change		*-10%*	*-14%*	*-2%*	*-3%*	*-7.5%*
Commercial						
Residual connections	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
% Change		*-3%*	*-2%*	*-1%*	*0%*	*-1.42%*
New connections	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
% Change		*-9%*	*33%*	*1%*	*-11%*	*3.39%*

SOURCE: CORE ENERGY

From the spreadsheets that accompanied AGN's regulatory proposal, it is clear that the 'residual connections' row of **Table 4.12**, which Core refers to as 'existing connections', is calculated by dividing total consumption by total connections, including the new estates, E to G and MHR connections.

In our view it is a conceptual error to interpret changes in this value as the decline in residual customers as Core has done. This approach double counts the consumption of the 'other' connection types. It also overstates the decline in the consumption of 'residual' (existing) connections. This is illustrated in **Table 4.13**, in which the consumption of the residual customers is 'backed out' of total consumption. The key result is that the average consumption per connection for the residual 'existing' customers is understated by Core's methodology.

TABLE 4.13 COMPUTING CONSUMPTION BY RESIDUAL RESIDENTIAL CUSTOMERS

	2011	2012	2013	2014
Total residential consumption	[redacted]	[redacted]	[redacted]	[redacted]
Electricity to Gas				
Average consumption	[redacted]	[redacted]	[redacted]	[redacted]
Number (cumulative)	[redacted]	[redacted]	[redacted]	[redacted]
E to G consumption	[redacted]	[redacted]	[redacted]	[redacted]
Annual change in average consumption	[redacted]	[redacted]	[redacted]	[redacted]
New Estates				

	2011	2012	2013	2014
Average consumption	[redacted]	[redacted]	[redacted]	[redacted]
Number (cumulative)	[redacted]	[redacted]	[redacted]	[redacted]
New estate consumption	[redacted]	[redacted]	[redacted]	[redacted]
Annual change in average consumption	[redacted]	[redacted]	[redacted]	[redacted]
Medium density high rise				
Average consumption	[redacted]	[redacted]	[redacted]	[redacted]
Number (cumulative)	[redacted]	[redacted]	[redacted]	[redacted]
MHR consumption	[redacted]	[redacted]	[redacted]	[redacted]
Annual change in average consumption	[redacted]	[redacted]	[redacted]	[redacted]
Residual customers				
Implied residual consumption	[redacted]	[redacted]	[redacted]	[redacted]
Residual connections	[redacted]	[redacted]	[redacted]	[redacted]
Implied average residual consumption	[redacted]	[redacted]	[redacted]	[redacted]
Annual change in average consumption	[redacted]	[redacted]	[redacted]	[redacted]

SOURCE: ACIL ALLEN AND AER ANALYSIS OF AGN DATA

The corresponding calculation for residual commercial customers is shown in **Table 4.14**.

TABLE 4.14 COMPUTING CONSUMPTION BY RESIDUAL COMMERCIAL CUSTOMERS

	2011	2012	2013	2014
Total commercial consumption	[redacted]	[redacted]	[redacted]	[redacted]
New connections				
Average consumption	[redacted]	[redacted]	[redacted]	[redacted]
Number	[redacted]	[redacted]	[redacted]	[redacted]
Consumption by new connections	[redacted]	[redacted]	[redacted]	[redacted]

	2011	2012	2013	2014
Annual change in average consumption	[redacted]	[redacted]	[redacted]	[redacted]
Residual				
Implied residual consumption	[redacted]	[redacted]	[redacted]	[redacted]
Residual connections	[redacted]	[redacted]	[redacted]	[redacted]
Implied average residual consumption	[redacted]	[redacted]	[redacted]	[redacted]
Annual change in average consumption	[redacted]	[redacted]	[redacted]	[redacted]

SOURCE: ACIL ALLEN AND AER ANALYSIS OF AGN DATA

The annual percentage change in average consumption by connection type is summarised in **Table 4.15**.

TABLE 4.15 ANNUAL CHANGE IN HISTORICAL AVERAGE CONSUMPTION BY CONNECTION TYPE

	2011	2012	2013	2014	Average
Residential customers					
Residual	0.39%	-7.03%	-0.19%	-3.10%	-2.48%
E to G	-11.12%	2.52%	-13.31%	-3.08%	-6.25%
New Estates	-11.15%	-2.60%	-12.79%	-3.08%	-7.40%
MHR	-10.29%	-14.33%	-2.43%	-3.08%	-7.53%
All residential connections	0.13%	-7.50%	-1.23%	-3.73%	-3.08%
Commercial customers					
Residual	-2.07%	-2.48%	-0.53%	3.00%	-0.52%
New connections	-8.96%	32.57%	1.00%	-11.07%	3.39%
All commercial connections	-2.88%	-2.00%	-1.13%	0.33%	-1.42%

SOURCE: ACIL ALLEN ANALYSIS OF AGN DATA

Table 4.15 shows that the historical average change in annual consumption by 'residual' residential connections was –2.48 per cent, only about 81 per cent of the figure reported by Core (–3.08 per cent). This is because Core's figure for residual connections is in fact the average for all connections, and therefore includes the more rapid decline in consumption of the other connection types.

The position is similar in the commercial sector. The 'all customers' decline per commercial connection reported by Core is –1.42 per cent per annum. By contrast analysis shows that average consumption per connection for residual commercial customers declined at an average rate of 0.52 per cent per year.

A further issue arises from the fact that the 'data' from the last year (2014) of the short time series used for these projections are not historical data points but rather calculated values: AGN notes that:

"New Estate and E to G; Weather normalised, consumption in 2007 corresponds to a connection installed in 2005; consumption in 2008 corresponds to a connection installed in 2006, and so on. This provides best estimate of new connection as consumption of a new connection will be mature by the third year after installation. Due to the lag in the time series, 2014 value is an estimate based on the observed change in demand per connection of existing connections (consistent downward trends are observed for both existing and new connections)."

(Core Energy, 2015b)(Core Energy, 2015b)

In our view it is conceptually superior to incorporate different growth rates for different customer types as well as the different consumption levels as Core did. However, we are concerned that, in this case, the growth rates for some of the customer types may not provide a reliable basis for forecasting future consumption within those customer classes.

In the residential sector, the rates of decline in consumption per connection for all customer types other than residual customers (that is, E to G conversions, new estates and medium density & high rise) are up to three times that of residual customers. All three show decline rates (based on a short historical series) in excess of –6 per cent per year. If taken into the forecasts this would imply that consumption per customer for these customer classes would halve within ten years. This does not seem plausible.

In the commercial sector, the consumption of new connections appears to have grown. However, on closer inspection this is due to a large growth in one year. The four years for which data are available consist of a very large increase, two large decreases and one very small change (increase). This suggests that the relatively small number of new commercial customers are diverse in nature and that the average consumption may be influenced heavily by the entry or exit of one or two large gas users.

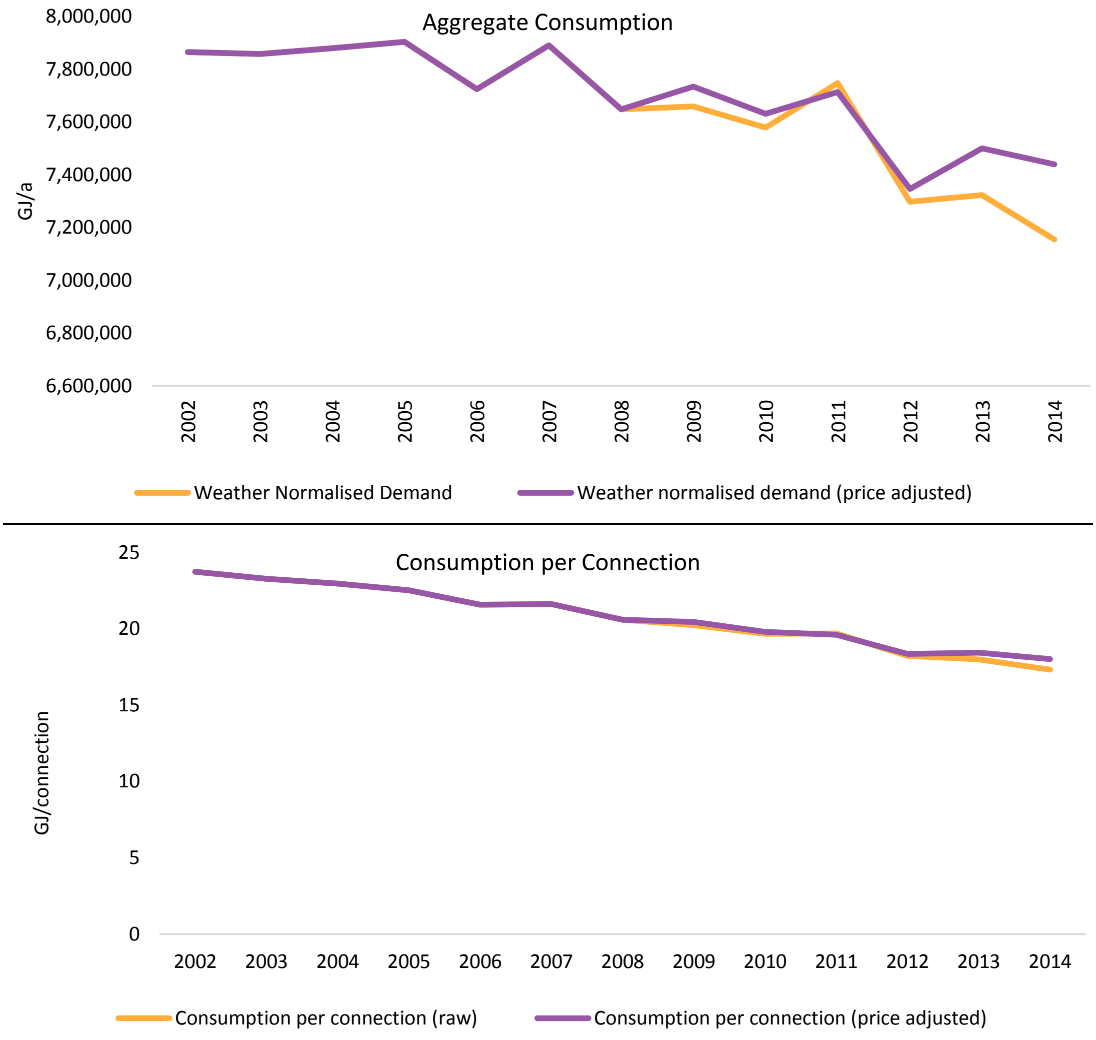
Given that the differential growth rates are implausible and the dataset is small, we concur with Core's decision not to use the differential growth rates in the forecast, notwithstanding that we consider such an approach to be conceptually preferable.

If the differential growth rates are not used, the alternative is to use the aggregate level growth rate instead. In our view, the way that Core has calculated the aggregate growth rate has overstated the decline in gas consumption. The reasons for this conclusion, and our proposed solution, are discussed in the following section.

4.4.3 Forecasting consumption per connection

Figure 4.5 shows total gas consumption by AGN's residential customers since 2002. It is clear from the figure that consumption has declined over that period. The annual (negative) growth in weather-normalised gas consumption by residential customers averaged -0.8 per cent per annum in aggregate and -2.6 per cent per annum on a per customer basis. Taking into account adjustments for price effects (own-price elasticity and cross price elasticity) the annual (negative) growth in price-adjusted gas consumption by residential customers was -0.5 per cent per annum in aggregate and -2.3 per cent per annum on a per customer basis.

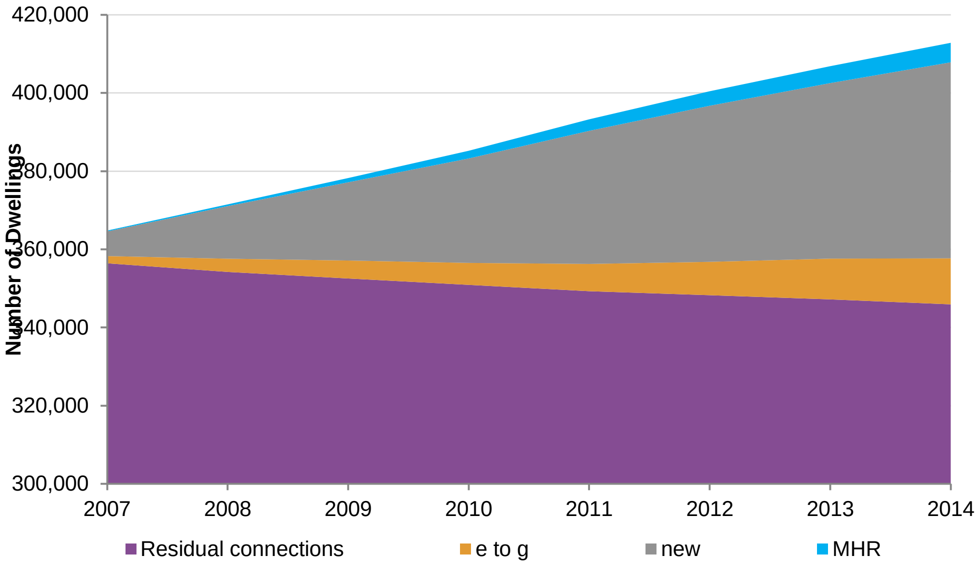
FIGURE 4.5 ANNUAL GAS CONSUMPTION, RESIDENTIAL CUSTOMERS



DATA SOURCE: CORE/AGN

Two key factors have contributed to the decline in gas consumption by residential customers. The first could be described as 'dwelling substitution'. Over time, 'old' dwellings are replaced by new dwellings, which tend to be more energy efficient and use less gas on average. The changing make up of South Australian residences is summarised in **Figure 4.6** which shows the growth in 'new;' homes (defined for the purpose of this analysis as 'homes first connected to the gas network after 2007').

FIGURE 4.6 UPTAKE OF NEW DWELLINGS IN SOUTH AUSTRALIA, 2007 TO 2014



Note: "e to g" = electricity to gas conversion; MHR = Medium and High Rise Dwellings

DATA SOURCE: CORE/AGN

The second factor contributing to the decline in residential gas consumption is a more general efficiency effect whereby average gas consumption per connection has been declining over time as a result of factors such as improvements in appliance efficiency, behavioural change in response to increased environmental awareness, and price effects.

The declining consumption patterns shown in **Figure 4.5** incorporate both of the above factors. For the period from 2010 to 2014 the price-adjusted decline rates for the residential customer group as a whole were –0.6 per cent (aggregate) and –2.3% (per connection).

AGN's consumption projections were calculated by applying an aggregate growth rate of –2.3% per annum to project average consumption by each connection type individually. This effectively double counts the decline in consumption because the aggregate growth rate includes the effect of 'dwelling substitution', which is also accounted for directly by increasing the number of connections in the new types.

To avoid this double counting, it is necessary to apply the aggregate growth rate to total consumption levels. For residential customers, the effect of doing this is illustrated in **Table 4.16** and **Figure 4.7**. For commercial customers, the effect is illustrated in **Table 4.17** and **Figure 4.8**.

In summary, these show that:

— Projected annual consumption is the same in the first year under each method.

— The Core method causes annual consumption to decline more quickly than the recommended method.

A similar methodological issue arises in Core's assessment of consumption per connection decline rates in the commercial sector.

In our view the additional decline in the Core method is due to a double counting effect and should be removed as shown above in **Table 4.10**.

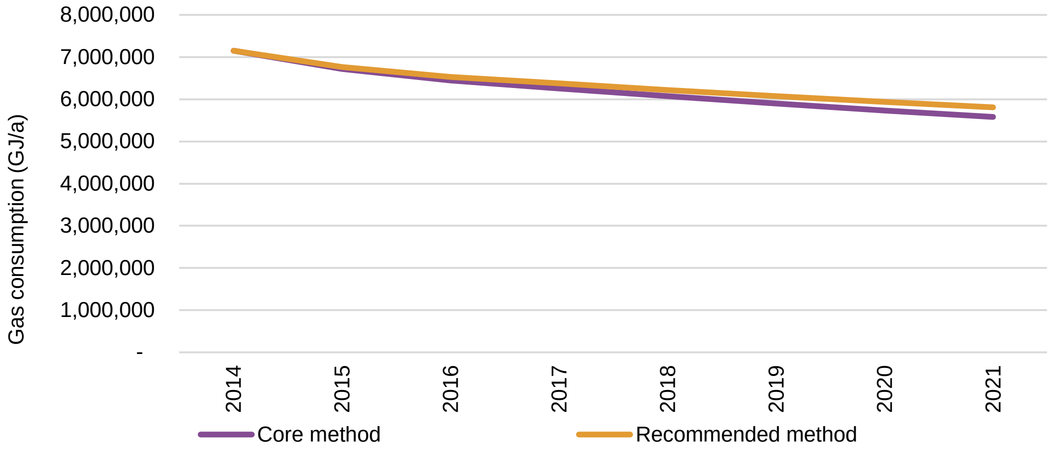
TABLE 4.16 COMPARING APPROACHES FOR APPLYING AGGREGATE GROWTH RATES TO RESIDENTIAL CUSTOMER CLASSES

	2014	2015	2016	2017	2018	2019	2020	2021
				Recommended method				
Total connections including zero consuming meters	**412,860**	**418,754**	**424,633**	**430,029**	**435,084**	**440,311**	**445,916**	**451,712**
Zero consuming meters adjustment	0	0	3,805	1,903	0	0	0	0
Total connections (per CORE)	**412,860**	**418,754**	**420,828**	**424,321**	**429,376**	**434,603**	**440,208**	**446,004**
Consumption per connection (before adjustment for zero consuming meters)	17.3	16.2	15.4	14.8	14.3	13.8	13.3	12.9
annual change (%)	*N/A*	*-6.8%*	*-4.8%*	*-3.6%*	*-3.6%*	*-3.5%*	*-3.5%*	*-3.4%*
Revised forecast	7,154,434	6,764,836	6,529,500	6,375,499	6,218,183	6,072,174	5,937,029	5,807,417
annual change (%)	*N/A*	*-5.4%*	*-3.5%*	*-2.4%*	*-2.5%*	*-2.3%*	*-2.2%*	*-2.2%*
Operative connections	407,152	413,046	418,925	424,321	429,376	434,603	440,208	446,004
Consumption per operative connection	17.6	16.4	15.6	15.0	14.5	14.0	13.5	13.0
annual change (%)	*N/A*	*-6.8%*	*-4.8%*	*-3.6%*	*-3.6%*	*-3.5%*	*-3.5%*	*-3.5%*

	2014	2015	2016	2017	2018	2019	2020	2021
Core method								
Number of connections								
Residual connections	412,860	411,463	406,241	402,915	401,480	400,027	398,557	397,068
Electricity to Gas	0	1,435	2,870	4,306	5,741	7,176	8,611	10,046
New estates	0	5,158	10,439	15,326	19,918	24,699	29,792	35,098
Medium density/ high rise	0	697	1,277	1,774	2,238	2,701	3,248	3,792
Consumption per connection								
Residual connections	17.3	16.2	15.5	15.0	14.5	14.0	13.5	13.0
annual change (%)	*N/A*	*-6.8%*	*-3.9%*	*-3.1%*	*-3.6%*	*-3.5%*	*-3.5%*	*-3.4%*
Electricity to Gas	13.8	12.5	12.0	11.6	11.2	10.8	10.4	10.2
annual change (%)	*N/A*	*-9.0%*	*-4.2%*	*-3.6%*	*-3.6%*	*-3.5%*	*-3.4%*	*-1.7%*
New estates	10.95	9.97	9.55	9.20	8.88	8.57	8.27	8.13
annual change (%)	*N/A*	*-9.0%*	*-4.2%*	*-3.6%*	*-3.6%*	*-3.5%*	*-3.4%*	*-1.7%*
Medium density/ high rise	6.85	6.23	5.97	5.75	5.55	5.35	5.17	5.08
annual change (%)	*N/A*	*-9.0%*	*-4.2%*	*-3.6%*	*-3.6%*	*-3.5%*	*-3.4%*	*-1.7%*
Total consumption	7,154,434	6,720,782	6,446,907	6,258,721	6,071,982	5,897,659	5,733,964	5,583,903
Difference (GJ)	**44,055**	**82,593**	**116,778**	**146,201**	**174,515**	**203,064**	**223,514**	**44,055**
Difference (%)	**0.0%**	**0.7%**	**1.3%**	**1.9%**	**2.4%**	**3.0%**	**3.5%**	**4.0%**

SOURCE:ACIL ALLEN ANALYSIS OF AGN DATA

FIGURE 4.7 TOTAL RESIDENTIAL CONSUMPTION AS PROJECTED USING DIFFERENT APPROACHES TO DETERMINING AGGREGATE GROWTH RATE



Note: Results presented on price-adjusted basis.
SOURCE: ACIL ALLEN ANALYSIS OF AGN DATA

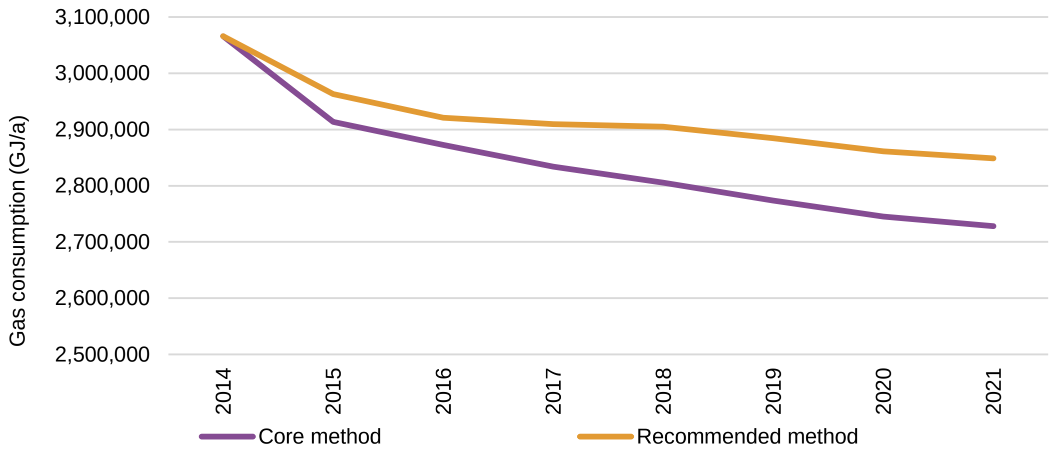
TABLE 4.17 COMPARING APPROACHES FOR APPLYING AGGREGATE GROWTH RATES TO COMMERCIAL CUSTOMER CLASSES

	2014	2015	2016	2017	2018	2019	2020	2021
Recommended method								
Total connections including zero consuming meters	**10,446**	**10,586**	**10,710**	**10,872**	**11,003**	**11,176**	**11,351**	**11,529**
Zero consuming meters adjustment	0	0	728	364	0	0	0	0
Total connections (per CORE)	**10,446**	**10,586**	**9,982**	**9,780**	**9,911**	**10,084**	**10,259**	**10,437**
Consumption per connection (before adjustment for zero consuming meters)	293.5	279.5	272.3	267.2	262.7	256.8	250.8	245.9
annual change (%)	N/A	-4.8%	-2.6%	-1.9%	-1.7%	-2.2%	-2.3%	-2.0%
Total consumption (before adjustment for tariff transfer)	3,065,891	2,959,002	2,916,579	2,905,511	2,890,634	2,870,261	2,847,144	2,834,705
annual change (%)	N/A	-3.5%	-1.4%	-0.4%	-0.5%	-0.7%	-0.8%	-0.4%
Tariff D transfer (gas volume as per CORE)		4,296	4,296	4,296	14,296	14,296	14,296	14,296
Tariff D transfer (connection numbers)	0	1	1	1	2	2	2	2
Revised forecast	**3,065,891**	**2,963,297**	**2,920,874**	**2,909,806**	**2,904,930**	**2,884,557**	**2,861,440**	**2,849,001**
Operative connections	9,354	9,495	9,619	9,781	9,913	10,086	10,261	10,439
Consumption per *operative* connection	328	312	304	297	293	286	279	273
annual change (%)	N/A	-4.8%	-2.7%	-2.0%	-1.5%	-2.4%	-2.5%	-2.1%

	2014	2015	2016	2017	2018	2019	2020	2021
Core method								
Number of connections								
Residual connections	10,446	10,351	9,528	9,067	8,968	8,869	8,768	8,665
New Connections	0	235	455	714	943	1,215	1,492	1,773
Consumption per connection								
Residual connections	293.5	279.5	293.1	298.3	293.3	286.7	280.0	274.5
annual change (%)	N/A	-4.76%	4.87%	1.78%	-1.69%	-2.24%	-2.34%	-1.98%
New Connections	170.6	172.0	176.1	181.0	185.8	190.0	194.7	197.2
annual change (%)	N/A	0.83%	2.37%	2.81%	2.62%	2.30%	2.43%	1.29%
Tariff D transfer (gas volume as per CORE)	0	4,296	4,296	4,296	14,296	14,296	14,296	14,296
All connections (total consumption)	3,065,891	2,938,052	2,877,119	2,838,515	2,819,789	2,788,096	2,759,758	2,742,183
Difference (GJ)	**0**	**25245**	**43755**	**71292**	**85140**	**96461**	**101682**	**106818**
Difference (%)	**0.0%**	**0.9%**	**1.5%**	**2.5%**	**3.0%**	**3.5%**	**3.7%**	**3.9%**

SOURCE: ACIL ALLEN ANALYSIS OF AGN DATA

FIGURE 4.8 TOTAL RESIDENTIAL CONSUMPTION AS PROJECTED USING DIFFERENT APPROACHES TO DETERMINING AGGREGATE GROWTH RATE



SOURCE: ACIL ALLEN ANALYSIS OF AGN DATA

4.5 Tariff V customer forecasts

AGN describes the approaches it has adopted to forecasting Tariff V customer demand (including residential (Tariff R) and commercial (Tariff C) components:

1. Calculate weather normalised historic demand using an Effective Degree Day (EDD) measure;
2. Forecast the number of connections:
   a) for Tariff R, sum together forecasts for existing connections, new electricity-to-gas connections, new estate and new medium-to-high density connections:

i) existing connections and new electricity-to-gas connections were forecast having regard to historic trends. A step-change adjustment was made to existing connections to account for the assumed removal of zero consuming meters; and
ii) new dwelling (new estate and new medium-to-high density) connections were forecast having regard to independent forecasts of total new dwellings in South Australia from BIS Shrapnel and AGN's historic gas network penetration;
iii) The resultant forecasts were checked by Core Energy using a bottom-up forecasting approach, which referenced projections of population from the Australian Government;

a) for Tariff C, forecast the total number of connections (new and existing) having regard to the historic relationship between total connections and the Gross State Product (GSP) outlook for South Australia. A step-change adjustment was made to account for the assumed removal of zero consuming meters.

3. forecast consumption per connection separately for new and existing connections, having regard to the weather and price normalised historic growth in consumption per connection and adjusting for any new drivers, or change in drivers that are not included in this trend, such as movements in energy prices (gas and electricity) and the removal of zero consuming meters; and
4. multiply consumption per connection by connection numbers to forecast total demand for each of the residential and commercial sectors.

We commented in section 4.2 on the AGN approach to weather normalisation and concluded that the approach adopted by AGN/Core to weather normalisation of residential and commercial consumption data is reasonable and is generally consistent with "best practice" approaches to normalisation of gas consumption data to take account of weather effects.

In section 4.4 we examined AGN/Core's approach to projecting historical data trends and concluded that there is a methodological issue relating to the calculation of average gas use per customer for 'residual' customers that causes the rate of decline of both residential and commercial customer demand to be over-stated as a result of 'double-counting' of the low average consumption rates for E to G, new houses and new medium and high rise dwellings and new commercial connections. We have recommended that this methodological issue be addressed and the forecasts amended accordingly.

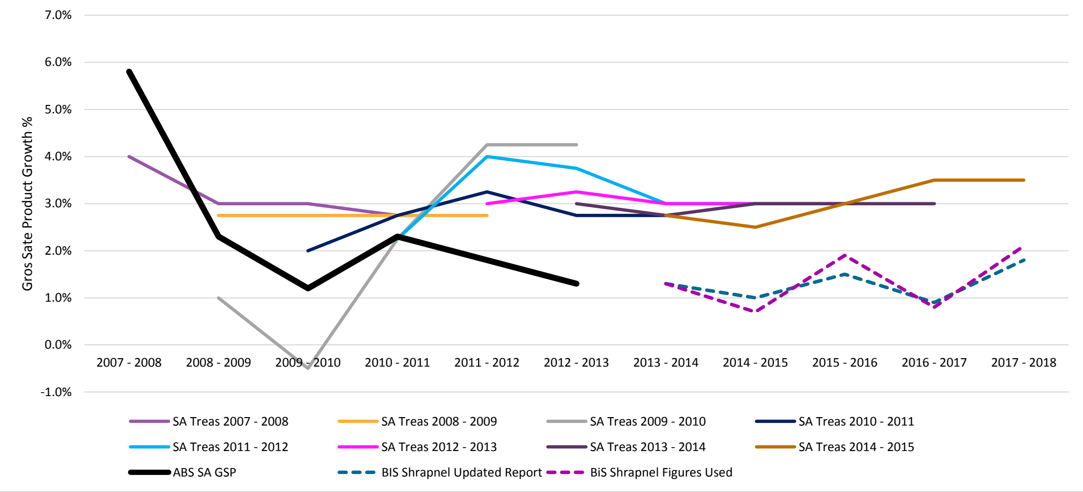
In the following section we examine other assumptions which affect the forecasts.

4.5.1 Forecasts of Gross State Product

With regard to the "Tariff C" projections, we have considered AGN's use of forecasting the historic relationship between total connections and the Gross State Product (GSP) outlook for South Australia. The notion that the rate of increase in commercial gas connections is correlated with changes in levels of economic activity is well-established, for example in the consumption forecasting methodology developed by ACIL Allen Consulting and adopted by AEMO for its National Gas Forecasting Report (AEMO, 2014).

We observed that, rather than using a forecast of South Australian GSP drawn from an official source such as SA Treasury, AGN/Core have relied on an independent forecast developed by BIS Shrapnel. We therefore considered it appropriate to consider the reliability and reasonableness of the BIS Shrapnel forecasts of South Australian GSP growth. **Figure 4.9** provides a comparison of actual South Australian Gross State Product growth rates (Australian Bureau of Statistics data) with forecast published by South Australian Treasury over the period 2007–08 to 2014–15, and BIS Shrapnel forecasts provided in the original and updated reports by AGN/Core.

FIGURE 4.9 COMPARISON OF SOUTH AUSTRALIA GSP FORECASTS AND ACTUALS



SOURCE: FORECASTS FROM SA TREASURY PAPERS, BIS SHRAPNEL; ACTUAL SA GSP GROWTH FROM ABS

By inspection it can be seen that the SA Treasury forecasts have in almost all years proven to be optimistic, with forecast growth rates of around 3% compared to actual growth rates ranging between 1.2% and 2.3% in the post-GFC era. On the other hand, the BIS Shrapnel forecasts, which range for the most part between 1% and 2% are much more in line with recent actual levels.

On this basis we consider that the BIS Shrapnel forecasts of South Australian GSP provide a sound basis for projecting future commercial gas demand in South Australia.

4.5.2 Price elasticity

Projected retail gas and electricity prices impact on gas demand through application of a measure of price elasticity and cross-price elasticity:

— **own price elasticity** – which captures the impact of changes in gas prices on consumption per connection. Account should also be taken of lags in consumer response to changes in gas price; and

— **cross-price elasticity** – which captures the impact of electricity prices on consumption per gas connection. This recognises that in many applications electricity is a reasonably close substitute for natural gas and accounts for the consumer response to the relative changes in gas and electricity prices, which for example results in the substitution of gas heating for heating by reverse-cycle air-conditioning (and vice versa).

Core Energy has assumed that:

— a lagged long-term own-price elasticity of -0.3 for residential customers and -0.35 for commercial customers; and

— a long-term cross-price elasticity of 0.1.

Core Energy's assumptions around own-price elasticity are consistent with that applied by the AER in its Final Decisions for AGN's South Australian, Queensland and Victorian networks and for JGN's New South Wales network.

Unlike own-price elasticity, cross-price elasticity has generally not been addressed widely in prior regulatory review processes. In ACIL Allen's view, this has largely been a result of the significant practical and theoretical difficulties in establishing reliable estimates of cross-price elasticity. Cross-price elasticity or fuel substitution is also not considered by AEMO in its National Gas Forecasting Report, although AEMO acknowledge that:

"Rapid technology changes and the relative pricing of gas and electricity fuel and appliances are expected to highly influence consumers' fuel selection over the forecast period [2014 to 2034] … [with respect to the impact of cross-price elasticity, also known as fuel substitution] AEMO expects that the drivers of customer connections to gas may change. This is being investigated for future reports."

(AEMO, 2014b, pp. 16-18)

Core expresses the opinion that material changes in gas prices relative to electricity price are likely to occur during the Review Period and that it is therefore reasonable to expect a cross-price demand response. ACIL Allen agrees that it is likely that gas will become more expensive relative to electricity, principally as a result of the development of large export LNG facilities in Central Queensland that are putting upward pressure on the wholesale price of gas throughout eastern Australia.

In the absence of appropriate historic information, Core Energy determined (based on literature review) that a long-term cross-price elasticity assumption of 0.10 is appropriate. ACIL Allen considers that, based on the scant information on cross-price elasticity relevant to eastern Australian gas and electricity markets, this is a reasonable assumption.

4.5.3 Gas penetration in new dwellings

Another important assumption relates to the proportion of new dwellings in South Australia that will connect to natural gas. AGN has relied on forecasts of new dwelling construction prepared by BIS Shrapnel. This is a reputable source and we consider it to be non-contentious as a basis for determining future levels of new dwelling construction.

In terms of gas penetration into these new dwellings, Core has presented data that shows historical penetration of the AGN network derived by dividing the number of new dwelling starts within the AGN network (from BIS Shrapnel) by the number of historical new connections. This data shows that the penetration rate for gas into new dwellings within AGN network area fell from 98% in 2011 (8,322 out of 8,454 new dwelling starts) to 73% in 2014 (5,912 out of 8,095). This lower rate of penetration may reflect a shift in consumer preference from gas to efficient electrical appliances. However other factors such as the level of activity by electricity and gas retailers in working with new building developers to gain a mandate for installation of gas or electrical appliances for space heating, water heating and cooking in new dwellings may also have an effect.

Core has forecast that gas penetration to new dwellings over the forthcoming access arrangement period will show a continuing decline, albeit at a much slower rate than observed over the past four years. They forecast AGN Gas Network penetration of new dwellings to fall from 72% in 2015 (down from 73% in the previous year) to 65% by 2021. This corresponds to a decrease in total new connection numbers from about 6,400 to 5,700 dwellings per year.

The Australian Bureau of Statistics has published results of three surveys of Household Energy Use and Conservation (in 2008, 2011 and 2014; ABS Cat. No. 4602.0.55.001). The information from these surveys on natural gas use in South Australian households is summarised in **Table 4.18**.

TABLE 4.18 HOUSEHOLD USE OF NATURAL GAS IN SOUTH AUSTRALIA

	Capital City	Balance of State	Total
2008 - % of household	72.1%	9.8%	55.9%
2008 – No. of households	345,300	16,500	361,800
2011 - % of household	75.2%	13.7%	58.4%
2011 – No. of households	362,500	25,000	387,500
2014 - % of household	71.2%	18.0%	56.7%
2014 – No. of households	357,100	34,800	392,100

SOURCE: ABS CAT. NO. 4602.0.55.001

In comparing the AGN forecasts with the ABS data it is important to note that the AGN forecasts relate to natural gas penetration of new dwellings in areas serviced by the AGN gas distribution network, whereas the ABS data relate to gas use in all South Australian households (divided into capital city and balance of state), whether or not they have access to natural gas through the distribution network. The penetration rates shown in the two data sources are therefore not directly comparable.

However the number of new connections observed from the two data sources can be validly compared. The ABS data shows that between 2008 and 2011, the total number of South Australian households using natural gas rose by 25,700 or about 8,570 on average. This in effect reflects the number of new connections (including electricity to gas conversions) minus disconnections. By way of comparison, AGN estimated the net number of new household gas connections in 2011 to be 8,054. The ABS data therefore suggests that the AGN estimate is reasonable. On the other hand, the ABS survey shows that between 2011 and 2014, the total number of South Australian households using natural gas rose by only 4,600 or about 1,530 on average. Growth of about 3,300 residential connection per year outside the capital city area was offset by an apparent contraction of about 1,800 connections per year in Adelaide. However, AGN estimated the net number of new household gas connections in 2014 to be 5,987. The ABS survey therefore suggests an average level of new connections over the 2011 to 2014 period that is well below the AGN estimate of net new connection numbers. Given that the AGN historical data on new connections is based on actual connection numbers, rather than consumer surveys, we would tend to place more weight on the AGN data.

Overall, the AGN forecast of total new connection numbers declining from about 6,400 to 5,700 dwellings per year over the projection period does not appear to be unreasonable in light of the ABS survey data.

4.6 Tariff D customer forecasts

The forecasts for Tariff D customers (large gas consumers using in excess of 10 TJ/a) have been developed in a fundamentally different way that considers not only annual consumption but also maximum demand (MDQ). This reflects the fact that, whereas Tariff V small customers are charged purely on the basis of the quantity of gas consumed in each billing period, a component of the charge for Tariff D customers relates to that customer's MDQ. This in turn reflects the fact that the maximum demand from large customers, and in particular the contribution of that customer to demand on the system peak demand days, has a key bearing on the system capacity that has to be maintained by the service provider in order to ensure that peak levels of demand can be met.

Core Energy has relied upon the following approach to forecast Tariff D MDQ and customer numbers:

1. forecast MDQ using actual MDQ as a starting point and adjusting for customer expansions and contractions, tariff reallocations, the economic outlook and efficiency trends; as informed by:
   a) known expansions, contractions, new connections and disconnections informed by customers;
   b) the results of a customer survey;
   c) publicly available information such as media releases and energy efficiency reporting;
   d) historic trends; and
   e) BIS Shrapnel forecasts of GSP by industry segment;
2. forecast customer numbers having regard to historic trends, known movements and the results of a customer survey.

   Conceptually this is a sound approach to forecasting of demand for large industrial (Tariff D) customers. It is a similar approach to that used by AEMO for forecasting large industrial gas consumption and maximum demand for the National Gas Forecasting Report (AEMO, 2014).

5 ASSESSMENT OF THE FORECASTS

5.1 Use of trend extrapolation for forecast verification

The Core methodology takes into consideration the key drivers affecting future gas demand and factors that may cause future gas demand growth to follow a different trajectory from past experience. As indicated in the preceding chapter, ACIL Allen considers that the approach adopted by Core to develop forecasts of gas demand for Tariff V and Tariff D customers in South Australia is basically sound (notwithstanding the identified issue regarding calculation of the residual customer average gas use per connection) and is generally consistent with recent good practice. However a sound methodology alone does not ensure that the forecasts produced by application of that methodology are reasonable. The methodology needs to be supported by accurate data and appropriate assumptions in relation to each of the input parameters.

In the following analysis we have used historical trend analysis as a cross-check on the results generated using the Core methodology. ACIL Allen recognises that forecasting on the basis of extrapolation of historical trends involves a risk of overlooking changes in market drivers that could result in future trends differing from historical trends. The fact that a forecast diverges from the historical trend cannot in itself be taken as proof that the forecast is unreasonable. Rather, such divergence may prompt us to ask whether there are good reasons for the break in trend.

For each historical data series we have established 95% confidence intervals around the linear trend in order to provide an indication of the statistical range within which the true mean can be expected to lie. The method used to establish confidence intervals is described in Appendix B. It should be noted that where historical trends continue over the forecast period, it is the trending that provides the best point estimates, not the upper or lower bounds.

5.2 Tariff V customer forecasts

5.2.1 Tariff V Residential customer numbers

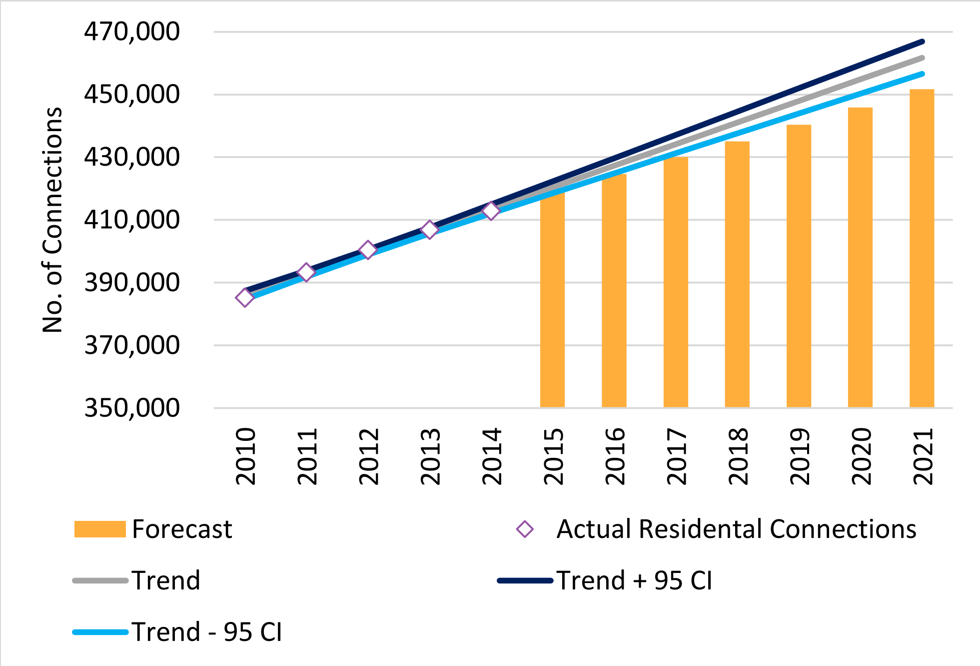
The forecast of total customer numbers for the Tariff V Residential Customer sector is summarised and compared with historical actual customer numbers in **Figure 5.1**.

The historical data is tightly correlated. The forecast shows weaker growth in customer numbers than in the past, with total customers across the forecast period slightly below the 95 per cent confidence interval around the trend line. The reason for the declining growth trend is apparent in Core's explanation of its approach to estimating gas penetration of new household connections:

" … penetration of gas connections of new households was 73% in 2014. It was assumed that the penetration rate would decline at an average annual growth rate 1.6%, consistent with historical data. The forecast in network penetration was assumed to decline from 73% in 2014 to 65% in 2021."

(Core Energy, 2015a, p. 30)

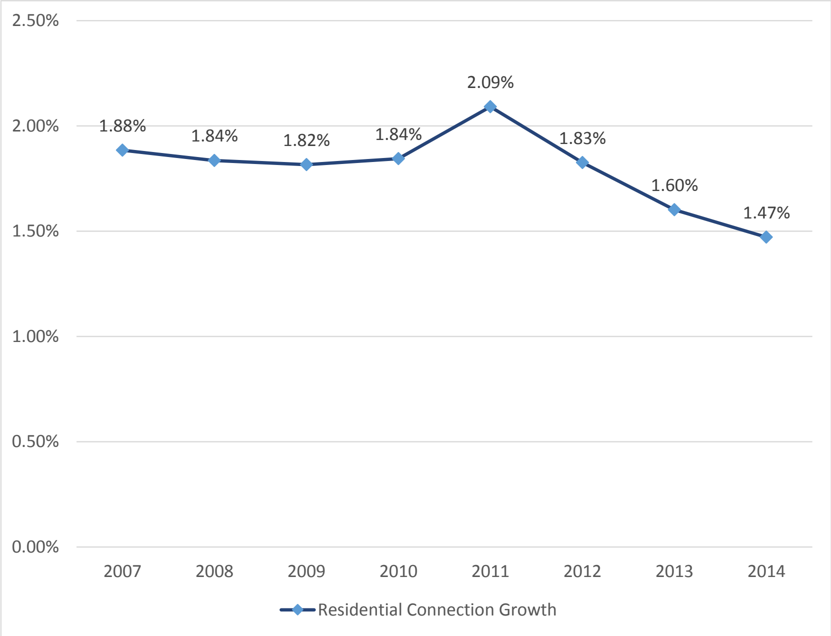
FIGURE 5.1 FORECAST TARIFF V RESIDENTIAL CUSTOMER NUMBERS



SOURCE: CORE ENERGY DATA, COMPILED AND ANALYSED BY ACIL ALLEN

Recent historical data appears to point to a slowing in the rate of growth of new residential gas connections in South Australia since 2011. This is illustrated in **Figure 5.2** which shows that, having averaged around 1.85% per year over the period 2007 to 2010, the rate of residential connections growth has fallen over the past three years and is now less than 1.5%. A continuation of this trend could therefore plausibly account for the lower rate of new connections embodied in the Core forecast.

FIGURE 5.2 HISTORICAL ANNUAL CHANGE IN RESIDENTIAL CUSTOMER CONNECTION NUMBERS



SOURCE: CORE ENERGY DATA, COMPILED AND ANALYSED BY ACIL ALLEN

A further factor leading to reduced Tariff V Residential connection numbers is the proposed implementation of a "Zero Consuming Meters" program in 2016-17. According to the data presented by Core, the program will result in the removal of some 6,800 meters that currently do not consume any gas from the count of total Tariff V customers. These are effectively idle metres that are currently included in the count of customer numbers. Some 84 per cent of these meters (a total of 5,712) are assumed to be residential meters, with the balance of 1,088 being commercial meters.

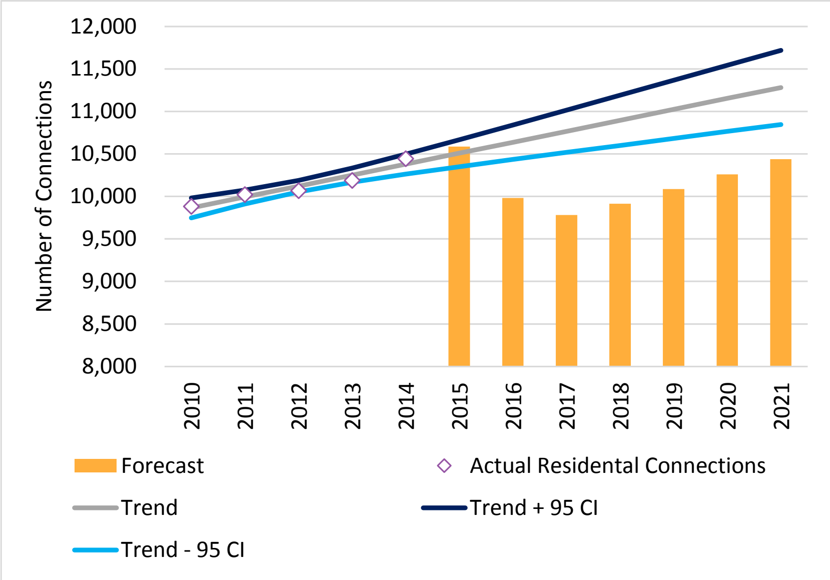
5.2.2 Tariff V Commercial customer numbers

The forecast of total customer numbers for the Tariff V Commercial Customer sector is summarised and compared with historical actual customer numbers in **Figure 5.3**.

The historical data is tightly correlated although with a significant up-kick in the most recent year (2014). The forecast shows a steep drop in commercial customer numbers over the period 2015 to 2017, with a fall from around 10,500 to 9,750 commercial connections. This represents a marked turnaround given that the longer time series historical data presented by Core show steady year-on-year growth, every year since 2006. The explanation relates to the assumed implementation of the "Zero Consuming Meters" Program in 2016 and 2017. According to the assumptions in Core's demand model, this program will result in the removal from the count of total Tariff V customers of some 6,800 meters that currently do not consume any gas. Of these, some 16 per cent meters (a total of 1,088) are assumed to be commercial meters. This implies that a little over 10% of the current commercial meters are zero-consuming. By comparison, the 5,712 residential meters assumed to be zero-consuming represents only 1.4% of residential meters.

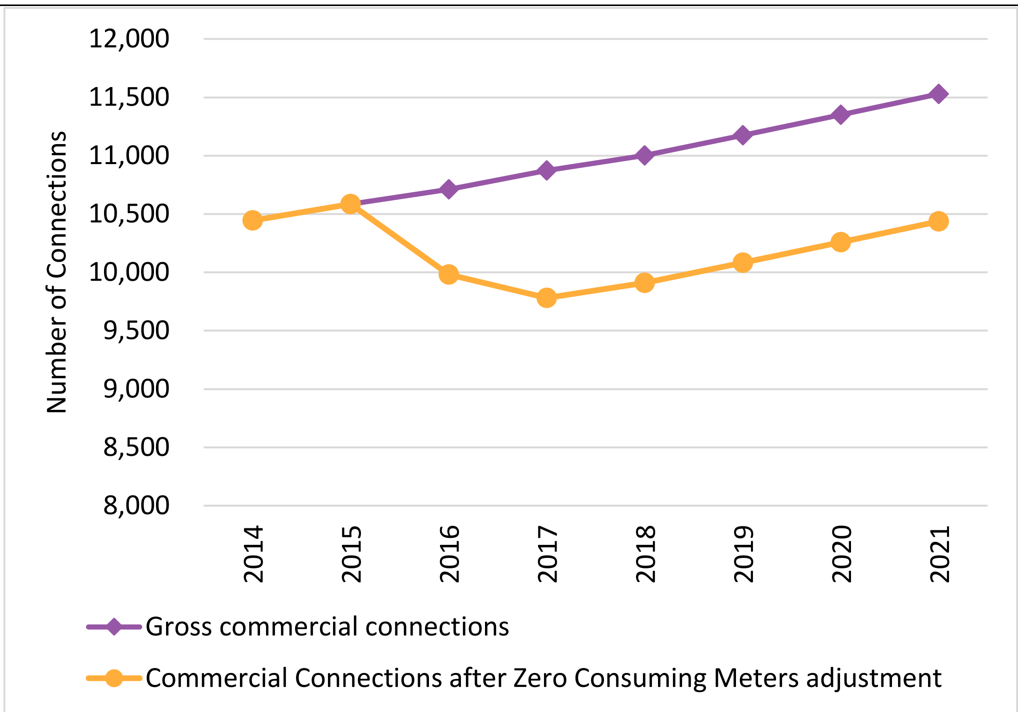
Core's forecast of Tariff V Commercial customer connections is very much driven by the assumptions surrounding the Zero Consuming Meter Program and the large proportion of existing Commercial connections assumed to be lost over the 2016 to 2017 period as a result of this program. This is clearly demonstrated in **Figure 5.4** which shows that, in the absence of the Zero Consuming Meters program, the forecast number of commercial connections would continue rising at around 150 connections per year, reaching 11,500 by 2021.

FIGURE 5.3 FORECAST TARIFF V COMMERCIAL CUSTOMER NUMBERS



SOURCE: CORE ENERGY DATA, COMPILED AND ANALYSED BY ACIL ALLEN

FIGURE 5.4 IMPACT OF "ZERO CONSUMING METERS" PROGRAM ON COMMERCIAL CONNECTION NUMBERS



SOURCE: CORE ENERGY DATA, COMPILED AND ANALYSED BY ACIL ALLEN

We asked AGN to explain the high proportion of commercial connections that are assumed to be zero-consuming. AGN responded with the following explanation:

"Core Energy Group's (Core's) demand forecasting model assumes that, as at 30 June 2014, there were 6,800 Zero Consuming Meters (ZCMs), of which 84% were residential and 16% were commercial.

This assumption is based on the actual number of meters, as at 30 June 2014, for which there had been zero consumption for a period of 12 months or more , as provided to Core by Australian Gas Networks

(AGN). More specifically, as at 30 June 2014, there were 6,872 ZCMs on our South Australian network, of which 5,789 were residential and 1,083 were commercial meters.

For the purpose of their model, Core rounded the 2014 total to 6,800, and relied upon the actual 2014 proportion of residential-to-commercial ZCMs (84% residential and 16% commercial).

It is noteworthy that, as outlined in Table 1, the number of ZCMs has been relatively consistent over recent history, but 2014 is the first time a retailer has progressed with a request to remove these meters – hence its inclusion in our proposal."

TABLE 1: HISTORIC NUMBER OF ZERO CONSUMING METERS

	2008	2009	2010	2011	2012	2013	2014	Current
Residential	4,699	5,293	5,058	5,200	5,610	5,640	5,789	6,019
Commercial	862	947	1,014	1,082	1,100	984	1,083	1,002
Total	**5,561**	**6,240**	**6,072**	**6,282**	**6,710**	**6,624**	**6,872**	**7,021**

In response to our request to explain why such a large proportion of existing commercial customer meters are zero-consuming, AGN responded as follows:

"A ZCM occurs when there has been no consumption at a MIRN for 12 months or more. As outlined in our Access Arrangement Information, a ZCM may originate if a property is vacant or if supply has been cut off as a result of non-payment. In these circumstances, there is no customer at the site for a retailer to bill.

Due to the nature of ZCMs (i.e. the fact that they only become ZCM after 12 months of no consumption) and also due to the nature of our relationship with these consumers (that is consumers generally liaise with their retailers with respect to consumption levels and non-payment of bills) we do not have records relating to the reasons a consumer has stopped consuming gas at a site. However, anecdotally we are not surprised that there is a higher proportion of business ZCMs than residential.

The nature of the business sector is that businesses can close and not re-open, particularly in the current challenging economic environment of ongoing depressed business activity in South Australia. This differs from say the residential market, where if someone leaves a home, they will, in most cases, find someone else to live in that residence.

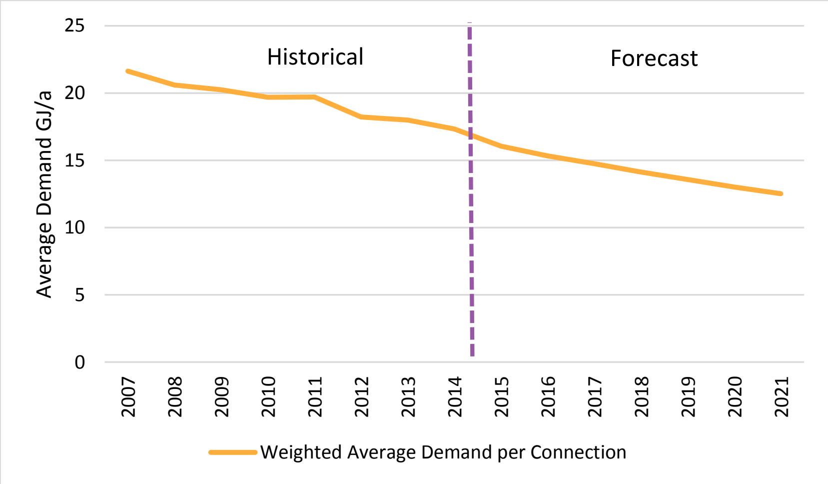
Further to the above, it is noteworthy that for the last eight years AGN has had year-on-year positive commercial net customer growth. This conflicts with Australian Bureau of Statistics (ABS) reports which show a net reduction in South Australian businesses of 3.5% over the 2010 to 2014 period. This indicates that while businesses have been closing, meters were not being removed from unused commercial sites (reflecting that these sites are not accounted for as disconnections).

We consider that AGN's responses to our enquiries establishes that there is a sound basis for the estimated numbers of zero-consuming meters in both the residential and commercial customer classes. Furthermore, we think that AGN has adequately explained why such a large proportion of the currently recorded number of commercial customers is zero consuming, and why a large adjustment to the commercial customer connection numbers is now appropriate. Accordingly we consider that the forecast of Tariff V Commercial connection numbers is not unreasonable.

5.2.3 Tariff V Residential forecast average consumption per connection

Figure 5.5 compares the historical and forecast consumption per connection for Tariff V Residential customers across all classes, on a weighted average basis. The sustained downward trend in average consumption per connection is very clear and reflects a number of well documented trends relating to improved energy efficiency, increased use of reverse cycle air-conditioning as a means of space heating, and solar water heating. The forecast trend shows a general continuation of the historical pattern.

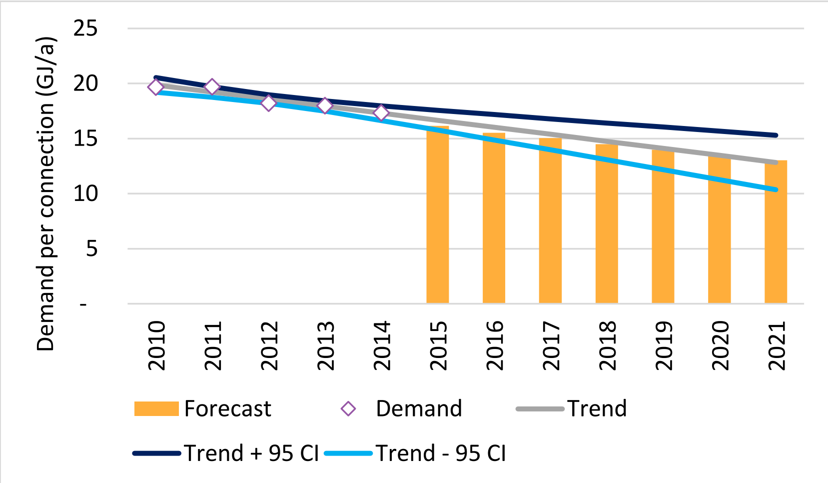
FIGURE 5.5 HISTORICAL VS FORECAST CONSUMPTION PER CONNECTION: TARIFF V RESIDENTIAL



SOURCE: CORE ENERGY DATA, COMPILED AND ANALYSED BY ACIL ALLEN

The historical and forecast average consumption per connection for the residential customer group as a whole is shown in **Figure 5.6**. The forecast lies slightly below the extrapolated linear trend of the recent historical data, but well within the 95 per cent confidence interval around the trend line. **However until the methodological issue identified in section** 4.4 **are addressed, we do not consider that the forecast can be considered reasonable.**

FIGURE 5.6 FORECAST CONSUMPTION PER CONNECTION: AVERAGE ALL RESIDENTIAL CUSTOMER CLASSES



SOURCE: CORE ENERGY DATA, COMPILED AND ANALYSED BY ACIL ALLEN

Core has separately assessed the historical trends and prepared forecasts for individual components of the Residential Tariff V demand mix: existing customers, new housing estates, new medium density and high rise customers, and new electricity to gas conversion customers. **However, because of the methodological issue discussed in section** 4.4 **the forecast average rate of decline applied to each of the residential customer sub-groups has been overstated.** This issue needs to be resolved before a meaningful comparison of the forecasts with historical trends can be undertaken.

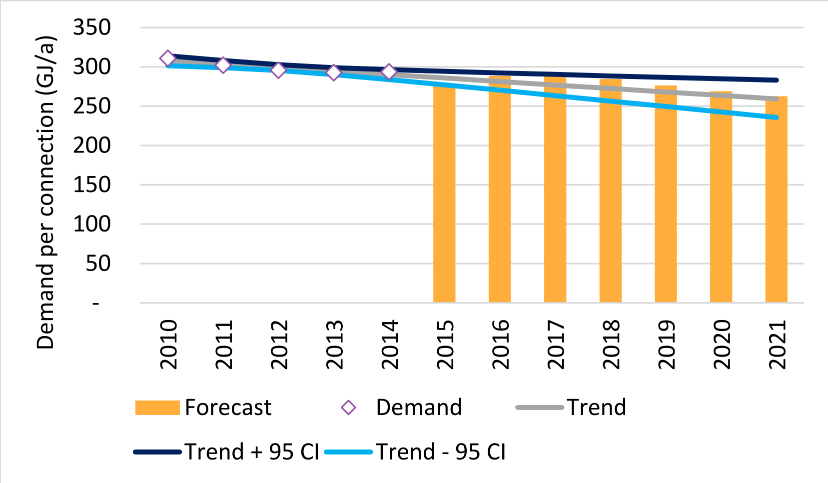
5.2.4 Tariff V Commercial gas consumption per connection

Figure 5.7 compares the historical and forecast consumption per connection for Tariff V Commercial customers. The historical data shows a mild downward trend in average consumption per connection.

The forecast trend shows a sharp reduction in average consumption per connection in 2015, down by 6% from 293.5 TJ/d in 2014 to 275.2 TJ/d. This sharp drop is anomalous and results from the methodological problem identified in section 4.4 which has the effect of diluting the average consumption per connection of the residual commercial customer group. The forecast then shows a recovery of 5.3% over the two-year period 2016 to 2017, before resuming a downward trend at an average rate of around minus 2.5% over the remainder of the forecast period. The explanation for the rise in average consumption per connection in 2016 and 2017 relates to the Zero Consuming Meters program (see section 5.2.2).

Setting aside the effects of the Zero Consuming Meters program the prevailing downward shift in average consumption per connection represents a continuation of the established historical trend. **However, because of the methodological issue discussed in section** 4.4 **the forecast rate of decline has been overstated. Until this issue is resolved the forecast cannot be considered reasonable.**

FIGURE 5.7 FORECAST CONSUMPTION PER CONNECTION: TARIFF V COMMERCIAL CUSTOMERS

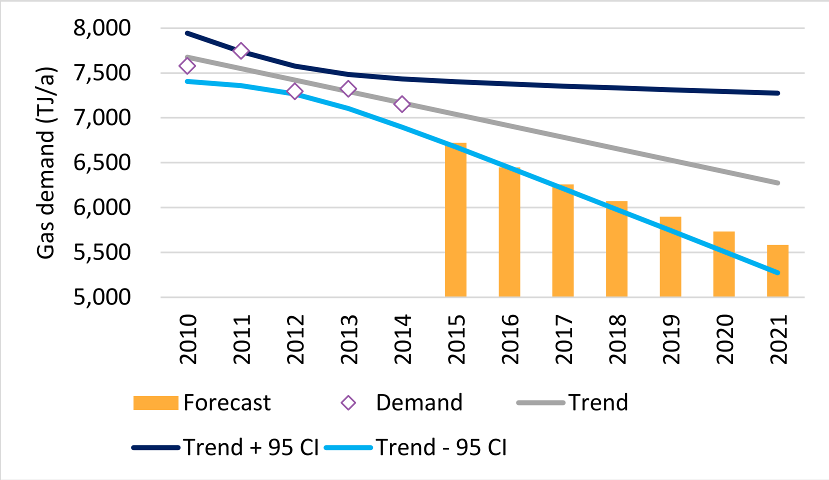


SOURCE: CORE ENERGY DATA, COMPILED AND ANALYSED BY ACIL ALLEN

5.2.5 Tariff V Residential gas demand

Total Tariff V Residential gas demand is calculated by Core from the forecasts of residential connection numbers (**Figure 5.1**) and average consumption per connection (**Figure 5.6**). The resultant forecast of total residential annual gas demand is shown in **Figure 5.8**

FIGURE 5.8 FORECAST TOTAL RESIDENTIAL GAS DEMAND



SOURCE: CORE ENERGY DATA, COMPILED AND ANALYSED BY ACIL ALLEN

The Core forecast of total Tariff V Residential gas demand sits well below the extrapolated linear trend for historical gas demand in this sector, and close to the lower bound of the 95% confidence interval around the trend. This reflects the following factors:

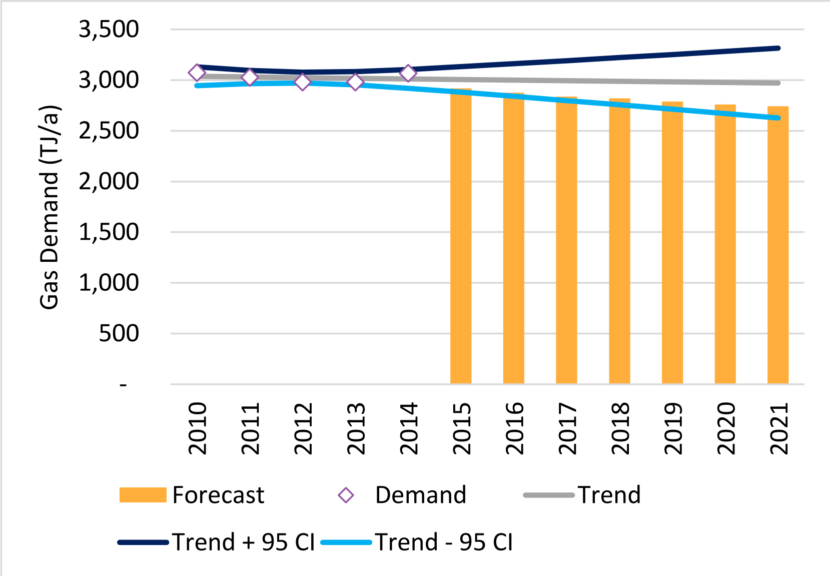
— The Core forecast of total customer numbers for the Tariff V Residential Customer sector shows weaker growth in customer numbers than in the past, with total customers across the forecast period somewhat below the 95 per cent confidence interval around the historical trend line. As discussed in section 5.2.1, recent historical data points to a slowing in the rate of growth of new residential gas connections in South Australia since 2011. Lower penetration rates of gas into new estates and medium density/high rise dwellings could plausibly account for a lower rate of new connections embodied in the Core forecast. The result also includes the effect on customer numbers of the zero-consuming meters program which, all else being equal, will reduce Tariff V customer numbers by around 6,000 connections over the period 2016–2017.

— The Core forecast of average consumption per residential connection is below the linear trend. This result has been amplified by the methodological issue identified in section 4.4 which results in Tariff V residential consumption per connection being understated. As a result there is a significant downward step change of about –6% between Core's estimate of actual total residential gas demand in 2014 and the 2015 demand forecast which is driven by the under-estimation of demand per connection in the residual customer group. **This matter needs to be addressed by AGN and the forecasts updated accordingly.**

5.2.6 Tariff V Commercial gas demand

The steep decline in gas demand for the Tariff V Commercial sector, shown in **Figure 5.9**, is largely caused by the methodological issue identified in section 4.4 which results in consumption per connection being understated. As a result, there is a significant downward step change of about –5% between Core's estimate of actual total commercial gas demand in 2014 and the 2015 demand forecast which is driven by the under-estimation of demand per connection in the residual customer group. **Again this matter needs to be addressed by AGN and the forecasts updated accordingly.**

FIGURE 5.9 FORECAST TARIFF V COMMERCIAL GAS DEMAND



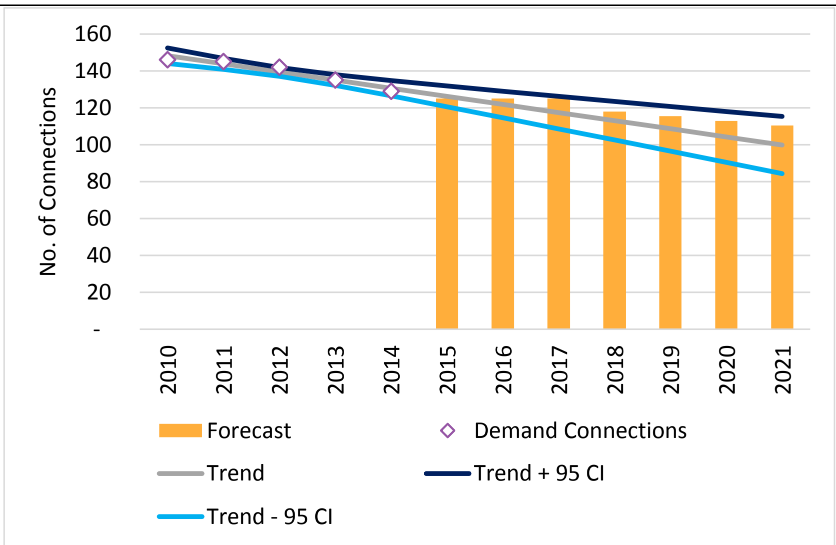
SOURCE: CORE ENERGY DATA, COMPILED AND ANALYSED BY ACIL ALLEN

5.3 Tariff D customer forecasts

5.3.1 Tariff D customer numbers

Figure 5.10 shows the comparison of the AGN/Core forecast for Tariff D customer numbers with the previous five years of historical data. As shown, the forecast sits a little above the historical linear trend. On this basis we consider that the Tariff D customer number forecasts are not unreasonable. Indeed, given the outlook for rising wholesale gas prices in South Australia, we consider that the forecast may, if anything, prove to be somewhat optimistic.

FIGURE 5.10 FORECAST TARIFF D CUSTOMER NUMBERS



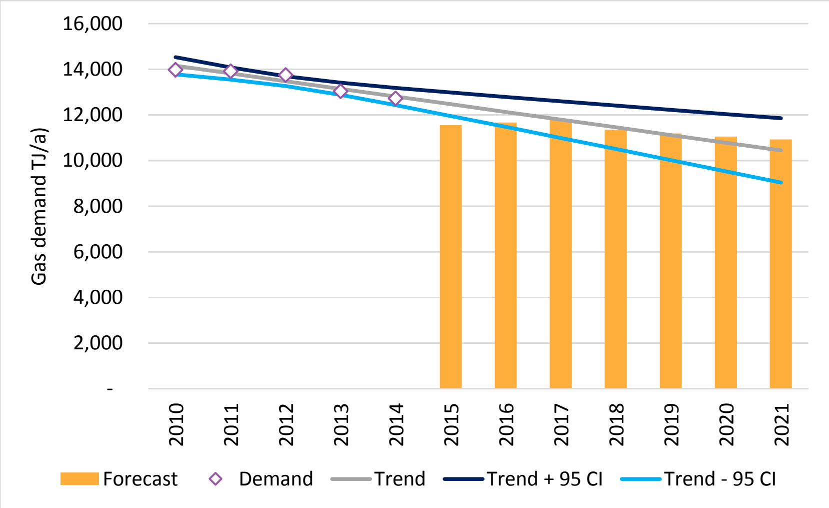
SOURCE: CORE ENERGY DATA, COMPILED AND ANALYSED BY ACIL ALLEN

5.3.2 Tariff D gas demand

Figure 5.11 compares the forecast Tariff D annual gas demand with historical trends. ACQ is forecast to drop from 11,666 TJ in 2015 to 10,931 TJ in 2021, representing an annual average decline of

–1.28%. However, this moderate average rate masks a sharp step-change downward between 2014 and 2015. The occurrence of such a step change may, in our view, be justified considering the transition to LNG exports at around this time and the consequent expectation of tight supply conditions in the eastern Australian market during the transition period. Following two years of low consumption in 2015 and 2016, Tariff D demand is forecast to move back to the historical downward trend. This decline rate is somewhat slower than the historical decline rate of around 2.30% between 2011 and 2014.Given the observed historical trends and the anticipated shift of the eastern Australian market to a major export focus, we consider that the forecast is not unreasonable.

FIGURE 5.11 FORECAST TARIFF D ANNUAL GAS DEMAND

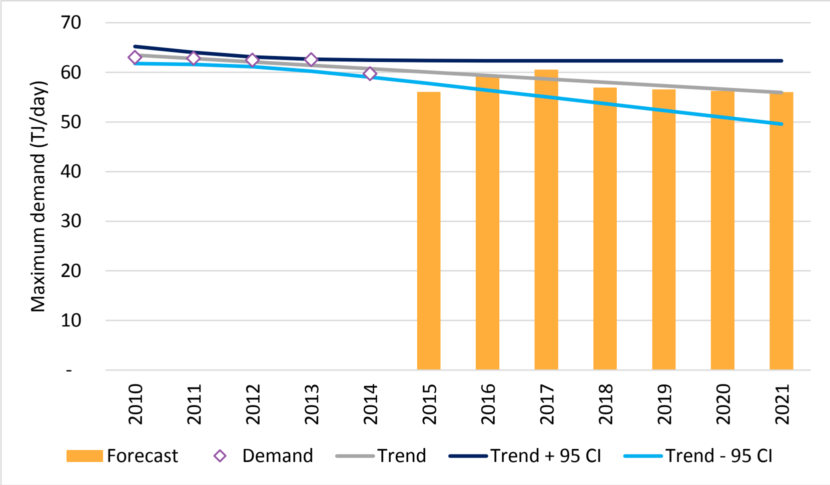


SOURCE: CORE ENERGY DATA, COMPILED AND ANALYSED BY ACIL ALLEN

5.3.3 Maximum Daily Demand forecasts for Tariff D customers

Figure 5.12 show the historical and forecast maximum daily demand for the Tariff D customer group. In recent years the peak daily demand level for the Tariff D customer group has remained relatively stable until a significant decline to less than 60 TJ/d in 2014. Core is forecasting a further decline in 2015—not unreasonable in view of the transformation currently facing the eastern Australian gas market—followed by a recovery over 2016 and 2017. The net result is that by 2021 Core expects Tariff D MDQ to be in line with the recent historical trend, resulting in an annual average decline rate over the forecast period of 1.09%. We consider that this forecast is not unreasonable in light of recent historical trends and current market developments.

FIGURE 5.12 FORECAST TARIFF D MAXIMUM DAILY DEMAND



SOURCE: CORE ENERGY DATA, COMPILED AND ANALYSED BY ACIL ALLEN

6 STAKEHOLDER SUBMISSIONS

The AER has asked us to review three stakeholder submissions which include comments regarding the South Australian gas demand forecasts proposed by AGN. The public submission were made by:

— Alternative Technology Association (ATA)
— Consumer Challenge Panel
— Energy Consumers Coalition of South Australia.

In the following section we briefly summarise the main points raised in these submissions, and provide our independent response to the issues raised.

6.1 Alternative Technology Association (ATA)

The ATA in its submission strongly agrees with AGN's assessment that there is downside risk to the forecasts as a result of "new factors on top of existing trends". It argues that gas is no longer a cheap fuel and that "awareness by consumers understandably lags, but we clearly are on the cusp of behavioural change". ATA goes on to argue that " … the objective of this and future Access Arrangements in the long-term interest of gas consumers should acknowledge the inevitable contraction of the gas network" and that on this basis the AER should not approve the 29% rise in capital expenditure proposed by AGN.

The ATA submission notes that whereas the existing methodology of forecasting connections and disconnections relies on historical trends, ATA has established that the economics of gas versus efficient electric appliances has changed. In relation to the future penetration rate of gas into new housing, which ATA notes is said by AGN "to be consistent with past history" it points out that Core reports it expects "to see a continuation of declining trends in gas connection penetration" (Core Energy, Demand Forecasts, p19). ATA states that "we were unable to find the specific assumption used by its forecasts – greater clarity on this point is needed". The assumptions used in relation to future penetration of gas into new housing, and their basis, are in fact set out in the Core report (Core Energy, 2015a, pp. 41-42).

The ATA is "highly suspicious" of the use of cross price elasticity estimates and suggests that the gas businesses or their consultants "should be required to analyse the competitive position of gas against electricity". It goes on to suggest that, in this context, "ATA's research appears to remain the only comprehensive and up-to-date body of work that has assessed competitive positioning in the AGN areas." Elsewhere the submission states that "ATA's research clearly demonstrates that **no** network expansion in South Australia is clearly in the long term economic interest of existing SA gas consumers" [original emphasis].

The main contentions of the ATA submission in relation to the gas demand forecasts put forward by AGN therefore appear to be that:

3. future gas demand is likely to be lower than the forecasts suggest;
4. capital expenditure to expand the gas network (that is, to serve new gas customers) would not be in the long-term economic interest of existing SA gas consumers; and therefore
5. the regulator should not approve the levels of capital expenditure proposed by AGN.

Apart from arguing in general terms that gas demand will decline "because of a more efficient/cost effective competitor" it does not offer any specific critique of the Core demand forecasts or the methodology by which the forecasts have been prepared.

6.2 Consumer Challenge Panel

The Consumer Challenge Panel sub-panel 8 (CCP) submission includes comments on the demand forecasts. It argues that

"The availability of new and more efficient technologies in the electricity industry has led to significant improvements in the relative cost efficiency and performance of electric household appliances as opposed to gas household appliances. Cost-reflective electricity network prices are also likely to be introduced in South Australia, which may give further cost advantage to efficient electricity usage. These factors will be likely to combine to cause electricity to replace gas as a fuel of choice in the residential sector, for both potential and existing gas customers. This will impose further downward pressure on the demand for gas over the next regulatory period, and result in an increased level of uncertainty around the forecasts for demand levels over the next five years."

(CCP Submission, p. 2)

It goes on to argue that there are "several factors that Core Energy were not able to quantify which may result in lower than expected residential consumption" including:

— the potential emergence of new technology such as battery storage and electric vehicles, which could result in customers choosing electric appliances over their gas equivalents;

— the impact of cost-reflective electricity tariffs; and

— the impact of the change to water heating policy for homes with no current gas connection.

It suggests that in order to put in place accurate demand forecasts, the AER may need to quantify the effects of these factors that have not already been taken into account in AGN's demand forecasts, and hence have also not been taken into account in AGN's capex and opex proposals.

As in the ATA's submission the main thrust of the submission, so far as it relates to demand forecasts, is that future demand may be lower than AGN's forecasts suggest, and the levels of capex and opex approved by the regulator should take this into account.

On the question of whether the demand forecasts should be revised to take into account impacts of new technology, relative cost-competitiveness of electricity and gas, and changes to water heating policy, we would observe that the Core methodology:

6. Takes into account historical trends which have embedded in them a range of technology developments (for example, the long-term emergence of reverse cycle air-conditioning as a source of heating as well as cooling) and government policy changes (for example, in relation to appliance efficiency, building standards and energy efficiency).
7. While not making specific assumptions about changes in the relative cost-competitiveness of electricity and gas does explicitly include assumptions regarding the cross-price elasticity of gas and electricity, and the expectations regarding the retail prices of gas and electricity over the projection period.

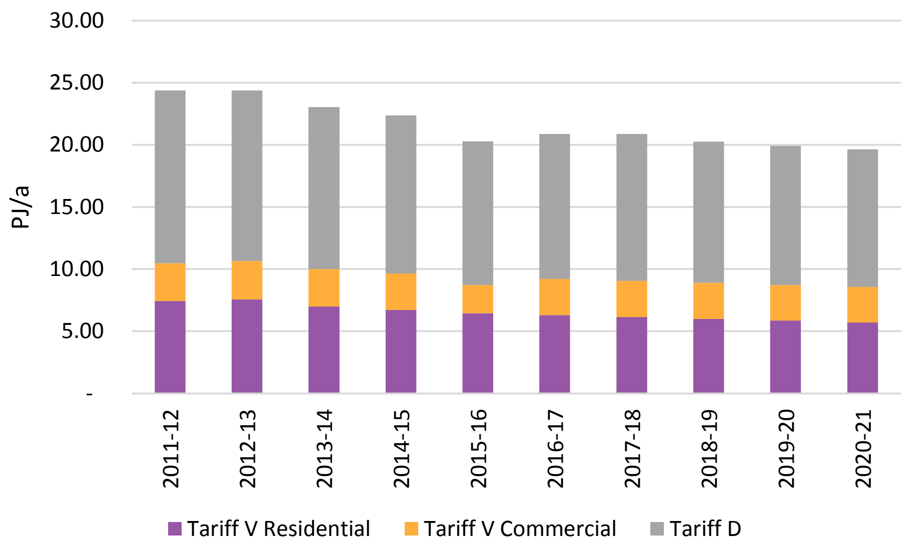
We therefore consider that the demand forecasting methodology adopted by Core adequately takes account of technological, commercial and policy changes without necessarily addressing the specific elements identified by CCP.

6.3 Energy Consumers Coalition of South Australia

The Energy Consumers Coalition of South Australia (ECCSA) represents major energy users in South Australia.

The first point raised in the ECCSA submission relating to the demand forecasts is a suggestion that the AGN revenue forecast is "dependent on a forecast significant rise in gas sales in 2015/6 and 2016/7" which they purport to demonstrate with a chart titled "AGN annualised consumption plus Tariff D MDQ – PJ/a". The source of the information presented in the chart is said to be AGN's Regulatory Impact Statement (RIN). We have reviewed the AGN RIN and are unable to replicate the chart shown in the ECCSA submission. It appears that the ECCSA may have misinterpreted the Tariff D demand information set out in the RIN—summing together annualised consumption and Tariff D MDQ produces a result that is difficult to interpret. We consider that the AGN RIN, together with the Core demand forecast information, shows that historical and forecast annual gas demand, by customer group, is as illustrated in **Figure 6.1**. The results demonstrate a slight rebound in aggregate consumption in 2016-17 and 2017-18 following a somewhat lower level of consumption in 2015-16. After 2017-18 aggregate consumption is forecast to recommence a slow, steady decline. The lower gas consumption in 2015/16 is not unexpected in view of the concurrent commissioning of the three Gladstone LNG projects at that time and is exacerbated by the under-estimation of residual demand in the residential and commercial customer group as previously discussed. The forecasts do not show any "significant rise in gas sales in 2015/6 and 2016/7".

FIGURE 6.1 AGGREGATE GAS DEMAND ON THE AGN SA NETWORK, BY CUSTOMER GROUP



SOURCE: ACIL ALLEN ANALYSIS OF AGN'S 'REGULATORY IMPACT STATEMENT' AND CORE ENERGY'S DEMAND MODEL

The main concern raised by ECCSA in their submission relates to the "massive amount of capital investment proposed by AGN, in an environment of falling gas demand." They express a view that:

"… expansions and augmentations are unlikely to provide a net positive benefit to existing and future consumers when all of the costs are included and when consumers are aware of the cost for gas is rising and the equivalent cost for electricity appliances is lower than the overall cost for reticulating gas further … Unless AGN can provide a clear business case showing that the new connections and augmentations deliver a net positive benefit to consumers through the increased gas sales, then the AER should not allow the new connections to be included in the capex."

The submission argues that "The declining amount of gas capacity sold relative to network length highlights that augmentations are not necessary. It also provides a view that expansions might not be commercially viable too."

With regard to the demand forecasts, the ECCSA submission comments that the AER "needs to get an independent assessment … to ensure that the forecasts for gas usage are validated. In this regard, the ECCSA comments that there is an incentive for AGN to overestimate the new connections and under-estimate the consumption". However, the submission goes on to acknowledge that "Equally, ECCSA does not have access to better information than the forecasts prepared by AEMO or Core Energy." Thus, ECCSA raises no concerns with regard to the demand forecasts prepared by Core for

AGN, other than a generalised concern that they be independently verified. That is precisely what ACIL Allen has been engaged by AER to do.

7 CONCLUSIONS

Overall we conclude that the forecasts presented by AGN and prepared by Core Energy have been prepared using well-established and widely accepted methodologies. In developing the demand forecasts, Core has given consideration to the key drivers affecting future gas demand. Account has been taken of factors that might cause future gas demand growth to follow a different growth trajectory when compared to past experience.

With regard to the economic growth outlook, Core has adopted forecasts prepared by BIS Shrapnel that are lower than South Australian Treasury projections but well aligned with actual average growth outcomes in South Australia during the post-GFC period, as recorded by the Australian Bureau of Statistics. We therefore these projections of GSP provide a reasonable basis for forecasting those components of gas demand that show a correlation with GSP.

Core has used an established method for weather normalisation of historical data on gas consumption in the Tariff V residential and commercial customer sectors. The EDD formula used by Core is similar to that now used by AEMO for the Victorian gas distribution network. This method has been extensively researched by AEMO. We consider that the approach that has been taken to weather normalisation is reasonable.

For the most part, the forecasts of customer numbers, demand per customer connection and the consequent estimates of total demand appear to be reasonable based upon consideration of the forecasting methodology, examination of historical trends, and allowance for current market factors that may drive outcomes in the future that are different from past patterns of gas consumption. However, there is a significant issue in relation to the calculation methodology for average gas consumption within the existing 'residual' Tariff V (residential and commercial) customer groups. Core has applied the average consumption per connection for the whole Tariff V residential and commercial customer groups to the existing 'residual' Tariff V residential and commercial customer groups. This effectively double counts the lower average rates of consumption exhibited by new estate dwellings, new medium density and high rise apartments, electricity to gas conversions, and new commercial customers. We estimate that the issue results in a significant understatement of Tariff V residential demand by up to 0.23 PJ/a by 2021, and Tariff V commercial demand by up to 0.49 PJ/a by the same time (see **Table 4.10**). **We recommend that Core/AGN should be required to revise the residential and commercial Tariff V forecasts based on correct estimates of the historical rates of consumption per connection for the existing 'residual' residential and commercial customers.**

We questioned the forecasts relating to projected customer numbers in the Tariff V Commercial sector which assume that there will be a large number of connections—in excess of 10 per cent—subtracted from the current customer inventory on the basis that they are "zero consumption" connections. The response provided by AGN leads us to conclude that that there are sound reasons for this assumption and that the resulting forecasts of Tariff V Commercial customer numbers are not unreasonable.

We find all other components of the forecast to be not unreasonable based on application of sound methodology and adoption of assumptions that are either consistent with demonstrated historical trends or else deviate from those trends for reasons that are able to be explained on the basis of known developments in the eastern Australian gas market.

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A

APPENDIX A
CURRICULA VITAE

Following are brief curricula vitae for the consulting team involved in the preparation of this report.

Paul Balfe

Paul Balfe is an Executive Director of ACIL Allen and has overall responsibility for the firm's gas business. Paul has more than 35 years of experience in the energy and resources sectors. Previously he held a number of senior executive positions in the Queensland Department of Minerals and Energy. He holds a Master of Business Administration and a Bachelor of Science (Hons.1 Geology & Mineralogy), both from the University of Queensland.

Paul is responsible for the development and commercialisation of ACIL Allen's *GasMark* model and its application to strategic and policy analysis throughout Australia, New Zealand and in South East Asia. He provides a range of analytical and advisory services to companies, government agencies and industry associations, particularly in the gas, electricity and resources sector. He has expertise in gas, electricity, resources, mining and economic impact analysis.

He has advised government and corporate sector clients on matters relating to the coal, oil and gas industries, coal seam gas, oil shale, mining safety and health, environmental management and alternative and renewable energies. With qualifications in geology and business administration, his experience ranges across both technical and commercial aspects of project evaluation and development.

Paul has worked extensively on gas industry matters, particularly gas policy reform issues; gas market analysis; gas pipeline developments, acquisitions and disposals; and gas project commercial analysis. He was closely involved in commercial and regulatory negotiations for the proposed PNG Gas Pipeline. He has also worked extensively in the Queensland coal seam gas industry as an adviser to both government and corporate sector clients on regulatory, technical, economic and commercial aspects of CSG development.

In 2009–10 Paul was the Project Director with overall responsibility for and primary authorship of ACIL Allen's reviews for the AER of the demand forecasts contained within the access arrangements proposed by Jemena, ActewAGL and Country Energy for their gas distribution networks in New South Wales and the Australian Capital Territory. He subsequently undertook a similar assignment for the AER in relation to the gas distribution networks in South Australia (Envestra) and Queensland (Envestra and APT Allgas). In 2010 he completed a review for the AER of demand forecasts for the Amadeus Gas Pipeline in the Northern Territory. In 2012 he led the team that advised the AER on the gas demand forecasts submitted by the Victorian gas distributors.

Paul has in the past advised numerous corporate clients on market and regulatory issues in relation to gas transmission and distribution pipelines throughout Australia, including:

— Roma Brisbane Pipeline

- Queensland Gas Pipeline
- South West Queensland Gas Pipeline
- Moomba – Adelaide Pipeline System
- Moomba – Sydney Pipeline
- SEA Gas Pipeline
- Eastern Gas Pipeline
- Tasmania Gas Pipeline
- Dampier Bunbury Natural Gas Pipeline
- Pilbara Pipeline
- Allgas Gas Distribution Network
- Multinet Gas Distribution Network
- West Australian Gas Network

Jeremy Tustin

Jeremy Tustin is a Principal in ACIL Allen's Melbourne office. He has a degree in Economics from the University of Adelaide. His background is in economic regulation, in particular in the energy and water sectors, and competition and consumer protection.

Jeremy's energy background includes significant experience in greenhouse and renewable policy. He represented South Australia on the National Emissions Trading Taskforce, which was the joint taskforce of Australian States and Territories that was first to propose a cap and trade emissions trading system for Australia. In this area, Jeremy and his team developed and interpreted models of the impact an emissions trading scheme would have on South Australia and in developing a mechanism for offsets. Jeremy was also closely involved with the development of South Australia's solar feed-in law.

In relation to energy efficiency, Jeremy developed a reporting methodology for the South Australian Government's target to improve the energy efficiency of its buildings. He also coordinated interdepartmental activity in relation to that target, developed strategies to achieve it and prepared public reports on progress.

In his role with the Department of Treasury and Finance (SA), Jeremy advised the Treasurer on water policy, both rural and urban. He worked with the Office for Water Security to prepare Water for Good, South Australia's water security plan. In particular, Jeremy worked on the early stages of the design of the future economic regulatory regime for the South Australian urban water sector. This included the decision to assign the regulator's role to the Commission. He also worked on a cost benefit analysis of a number of possible means of meeting South Australia's urban water demand.

Jeremy was a member of the team for the Victorian GAAR and has conducted (with others) numerous other relevant projects including:

- a review of the electricity sales, customer numbers and maximum demand forecasts submitted by the five Victorian electricity distribution businesses to the AER for the regulatory period 2011 to 2016
- a review of the demand forecasts submitted to the Essential Services Commission of South Australia by SA Water
- a review of certain principles underpinning the Essential Services Commission of South Australia's determination of the standing contract price for gas in South Australia.

APPENDIX B ESTABLISHMENT OF CONFIDENCE INTERVALS AROUND HISTORICAL TREND LINES

B

The following explanation of the construction of confidence intervals is based on information provided in the manual for the Statistica software package.

> The confidence intervals for specific statistics (for example, means or regression lines) provide a range of values around the statistic where the "true" (population) statistic can be expected to be located (with a given level of certainty).
>
> The confidence intervals for the mean give us a range of values around the mean where we expect the "true" (population) mean is located (with a given level of certainty). Confidence intervals can be calculated for any p-level; for example, if the mean in a sample is 23, and the lower and upper limits of the p=.05 confidence interval are 19 and 27 respectively, then we can conclude that there is a 95 per cent probability that the population mean is greater than 19 and lower than 27. If the p-level is reduced to a smaller value, then the interval would become wider thereby increasing the "certainty" of the estimate, and vice versa. The width of the confidence interval depends on the sample size and on the variation of data values. The calculation of confidence intervals is based on the assumption that the variable is normally distributed in the population. This estimate may not be valid if this assumption is not met, unless the sample size is large, say n = 100 or more.

Confidence Intervals (CI's) have the form:

$$Est\ \pm t_{1-\frac{\alpha}{2},(n-2)} SE_{est}$$

For the CI around the y-estimate in the linear regression equation, the CI is given by:

$$CI = Est_y\ \pm t_{1-\frac{\alpha}{2},(n-2)} SE_{est}$$

Where $t_{1-\frac{\alpha}{2},(n-2)}$ is the inverse of the Student's t-distribution for confidence level α given that n is the number of data points (so that n-2 is the number of degrees of freedom in the distribution)

and

$$SE_{est} = SE_y \times \sqrt{\frac{1}{n} + \frac{(x_i - \bar{x})^2}{\sum(x_i - \bar{x})^2}}$$

where SEy is the standard error of the y-estimate.

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