Attachment 14.1

Gas Demand Forecasts

A report by Core Energy Group

2016/17 to 2020/21 Access Arrangement Information

Australian Gas Networks

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Gas Demand Forecasts

Australian Gas Networks | SA Gas Access Arrangement 2017-21

June 2015

FINAL

CORE ENERGY GROUP

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Glossary

AA	Access Arrangement
ABS	Australian Bureau of Statistics
ACQ	Annual Contracted Quantity
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGN	Australian Gas Networks Limited
AIC	Akaike Information Criterion
ANZSIC	Australian and New Zealand Standard Industrial Classification
AUD	Australian Dollar
CBJV	Cooper Basin Joint Venture
COAG	Council of Australian Governments
Core	Core Energy Group Pty Ltd
D/C	Demand per Connection
DD	Degree Day
E to G	Electricity to Gas
EDD	Effective Degree Day
ESCOSA	Essential Services Commission of South Australia
FRC	Full Retail Contestability
GFC	Global Financial Crisis
GHDI	Gross Household Disposable Income
GJ	Gigajoule
GSP	Gross State Product
GVA	Gross Value Add
HDD	Heating Degree Day
IMF	International Monetary Fund
kWh	Kilowatt-hours
LGA	Local Government Area
MAP	Moomba to Adelaide Pipeline
MD/HR	Medium Density/High Rise
MDQ	Maximum Daily Quantity. Actual MDQ consumed.
MEPS	Minimum Energy Performance Standards
NGFR	National Gas Forecasting Report
NGR	National Gas Rules
OECD	The Organisation for Economic Co-operation and Development
PED	Price Elasticity of Demand
PJ	Petajoule
PV	Photovoltaic

R^2	Coefficient of Determination
RC	Reverse Cycle
Review Period	The Access Arrangement Period: 1st July, 2016 to 30th June, 2021
RMSE	Root Mean Squared Error
SA	South Australia
SEAGas	South East Australia Gas Pipeline
SFD	State Final Demand
SRES	Small-Scale Renewable Energy Scheme
STC	Small-Scale Technology Certificates
Tariff C	Commercial customer connections
Tariff R	Residential customer connections
Tariff V	Term encompassing Tariff R (residential) and Tariff C (commercial) customers
TJ	Terajoule
US	United States
Vic	Victoria

1. Introduction and Executive Summary

1.1. Scope of Report

This report has been prepared by Core Energy Group Pty Ltd ("**Core**") for the purpose of providing Australian Gas Networks Limited ("**AGN**") with an independent forecast of gas customers and gas demand for the company's natural gas distribution network in South Australia ("**SA**"), for the five year Review Period from 1 July 2016 to 30 June 2021 ("**Review Period**").Core notes that these projections (presented in this report and related forecasting models) will form part of AGN's Revised Access Arrangement ("**AA**") Proposal submission to the Australian Energy Regulator ("**AER**").[1]

Core has taken all reasonable steps to ensure this report, and the approach to deriving the forecasts referred to within the report, comply with Part 9, Division 2 of the *National Gas Rules* ("***NGRs***").[2] This division outlines 'access arrangement information relevant to price and revenue regulation', and a particularly relevant provision that Core has complied with is provided in ss 74; 75:

74. Forecasts and estimates

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

(2) A forecast or estimate:

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

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

75. Inferred or derivative information

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

1.2. Report Structure

This report is divided into two sections. The first section outlines the demand forecasts for Tariff V (term encompassing Tariff R and Tariff C customers) and Tariff D customers as well as describing the methodology used to arrive at these forecasts. The second section comprises several annexes which provide further detail and transparency as to how these forecasts were derived. For the remainder of the report, all years refer to the financial year unless stated otherwise. For instance, '2015' refers to the period from the 1st July, 2014 to the 30th June, 2015.

Section 1 – Forecast Summary

A concise summary of the approach to forecasting AGN demand:

- Executive Summary
- Methodology
  - Weather Normalisation

[1] The forecasting models are confidential and an application will be sought for disclosure to be suppressed in accordance with *NGR* part 43 (2)(b).
[2] *National Gas Rules 2008.*

  - Tariff V Demand
  - Tariff D Demand
- Tariff V Demand Forecast
  - Residential Connections and Demand per Connection ("**D/C**")
  - Commercial Connections and D/C
- Tariff D Demand Forecast
  - Connections
  - Maximum Daily Quantity ("**MDQ**") and Annual Contract Quantity ("**ACQ**")
- Conclusion

Section 2 – Supporting Information and Analysis

Information and analysis undertaken by Core to derive the forecasts discussed in Section 1.

- Terms of Reference
- Retail Gas Price Forecast
- Retail Electricity Price Forecast
- Price Elasticity of Demand Analysis
- Macroeconomic Variables
- Tariff V Residential Connections Forecast
- Continued Demand per Connection Drivers
- Tariff D Customer Survey
- Tariff D Economic Outlook and Efficiency Trends

1.3. Overview of AGN

AGN is one of the largest gas distribution businesses in Australia, servicing around 1.2 million domestic, small business and large industrial customers. AGN owns over 23,000 kilometres of natural gas distribution networks and 1,100 kilometres of transmission pipelines in South Australia, Victoria, Queensland, New South Wales and the Northern Territory. AGN is owned by the Cheung Kong Hutchinson Group based in Hong Kong

AGN is the rebranding of Envestra following the increased shareholding of Cheung Kong Hutchinson Group, and the subsequent delisting of Envestra from the Australian Securities Exchange. The SA gas distribution network under review services 423,436 customers with a mains length of 7,950 kilometres. The significant populations reached by the network include Adelaide, Whyalla, Port Pirie, Nuriootpa, Berri, Murray Bridge and Mount Gambier.[3]

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

[3] Source: AGN

Table 1.1 Customer Segments used for Tariff Classification.[4]

Customer Segment	Description	Customer No.	Volume	MDQ
Tariff V (<10TJ)	Tariff V is a term used in this report to encompass Tariff R (residential customers) and Tariff C (commercial customers). AGN's volume tariff customer group (Tariff V) consists of residential (Tariff R) and business customers (Tariff C) who are reasonably expected to consume less than 10 terajoules ("**TJ**") of natural gas per year. For the purpose of this report the volume tariff customer group has been further segmented as follows: ▪ Residential (residential customers who are billed quarterly) | Tariff R ▪ Tariff C | Commercial (business customers who are billed quarterly) | Tariff C New residential customers are further segmented as follows: ▪ Electricity to gas ("**E to G**") – i.e. electricity only houses which connect to gas ▪ New Estates – i.e. detached houses ▪ Medium Density/High Rise ("**MD/HR**") – houses connected as part of a higher density apartment or high rise dwelling. Throughout this report, the volume tariff customer group will be referred to as Tariff V customers.	✓ sum of components	✓ sum of components	Not required
Tariff D (>10TJ)	AGN's demand tariff customer group consists of industrial customers that are reasonably expected to consume more than 10 TJ of gas per year. Throughout this report, the demand tariff customer group will be referred to as Tariff D customers.	✓	✓	✓

Source: Core Energy Group based on advice from AGN; Envestra South Australian Access Arrangement Information, 2010.

1.4. Principles of the Approach

Leading Economic and Statistical Theory

Arising from a strong foundation of economic theory and empirical methods, Core's approach dissects real world phenomena by utilising a rigorous methodology. Where appropriate, this forecast integrates leading economic research and industry standards.

Discipline and Compliance

Forecasting completed by Core strictly adheres to the requirements of the *NGR*. All forecasts have been derived on a reasonable basis, utilising primary information where available to result in the best forecast under the circumstances. Core's approach coincides with the ideals promoted by the *NGR* criteria and subsequently, the methodology furthers these ideals rather than treating them as a restriction or boundary to be pushed. Ongoing review of domestic and international forecasting analysis has occurred, and precedents have been followed where appropriate. This includes previous AA decisions from the AER and ERA, and reports from the Australian Energy Market Operator (**"AEMO"**).

[4] These types are consistent with the volume tariff and demand tariff customer groups used in tariff assignment as referenced in the South Australia Schedule of Tariffs from 1 September 2014.

Additionally, material from the United States ("**US**") Department of Energy as well as the International Energy Agency is consistently reviewed. Core has considerable experience in network demand forecasting and the current approach integrates leading approaches that are demonstrated in Australia and abroad.

Balance of Top-down and Bottom-up Analysis

Core evaluates key drivers using both top-down and bottom-up analysis. This ensures that all direct and indirect factors are identified then quantified with precision. With a focus on meticulous detail, advanced econometric theory is used to account for the following elements:

- Connections:
  - Population, household density, consumer preferences (driven by competing energy sources and appliances), network penetration, economic environment, housing stock and construction trends.
- Demand per connection:
  - Energy efficiency, weather, appliance trends, dwelling type, consumer behaviour and energy substitution.

Relevant historical trends are neither overlooked nor overstated. The true underlying trends are scrupulously derived, providing a sturdy foundation before the analysis of each demand driver is introduced.

Elimination of Bias

To produce an unbiased forecast, data is carefully screened to ensure that no part of the forecast is influenced by inputs that consistently over or under-predict outcomes. Apparent outliers are reviewed and Core ensures that all data sourced from third parties is wholly independent.

Rigour, Transparency and Validation

Two levels of validation are maintained. Firstly, data outcomes and sources are validated by independent third party sources. Secondly, an extensive literature review is completed especially in sections of the approach where independent validation is not readily available. All inputs, calculations and outputs are clearly set out in a transparent manner. In some areas of the report such as macroeconomic variable analysis, Core's methodology goes beyond relying purely on statistical significance. A more sophisticated analysis of suitability (e.g. the presence of multicollinearity), model specification and qualitative analysis is used to reinforce statistical rigour. Care has been taken to ensure all models and data books can be reviewed in an efficient and consistent manner. Examples include clear model documentation, highlighting of key variables, provision of output table summaries and detailed presentation of underlying data.

1.5. Methodology Overview

An outline of the methodology adopted by Core to derive demand forecasts for Tariff V and Tariff D customers is summarised in Figure 1.1 and Figure 1.2 below.

Figure 1.1 Tariff V Demand Forecast Methodology Summary

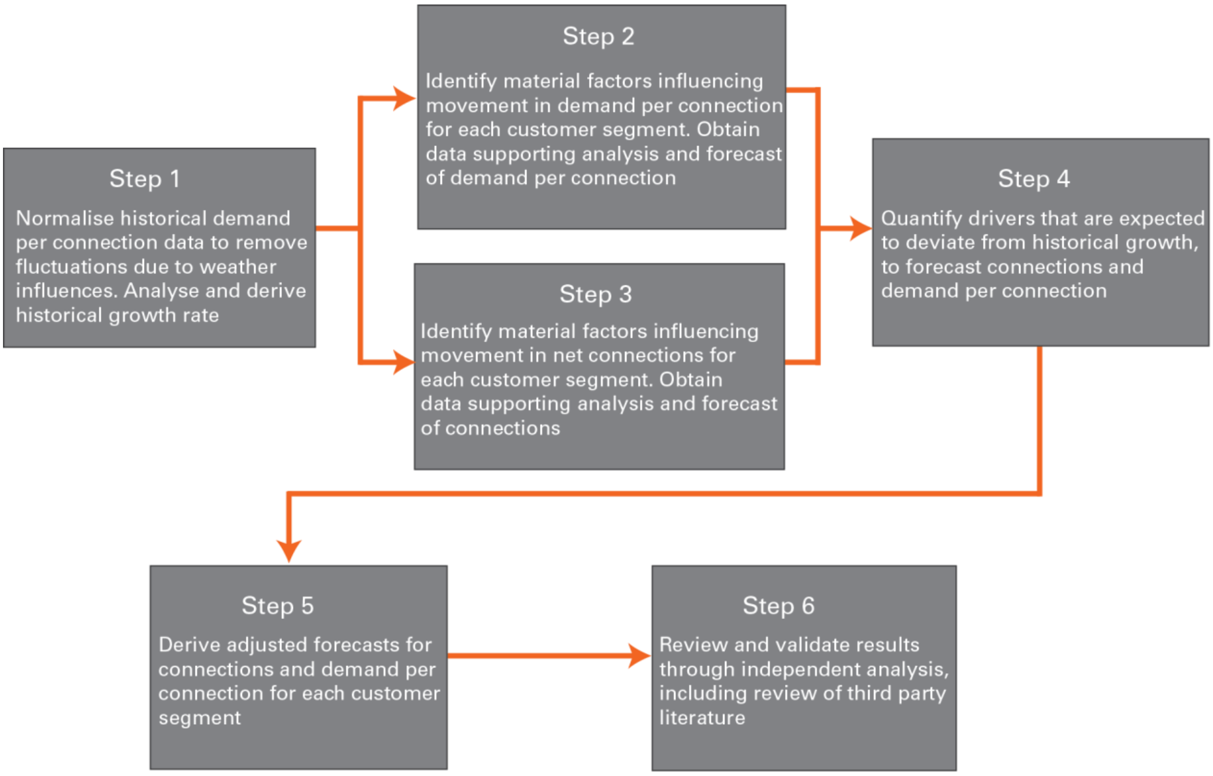
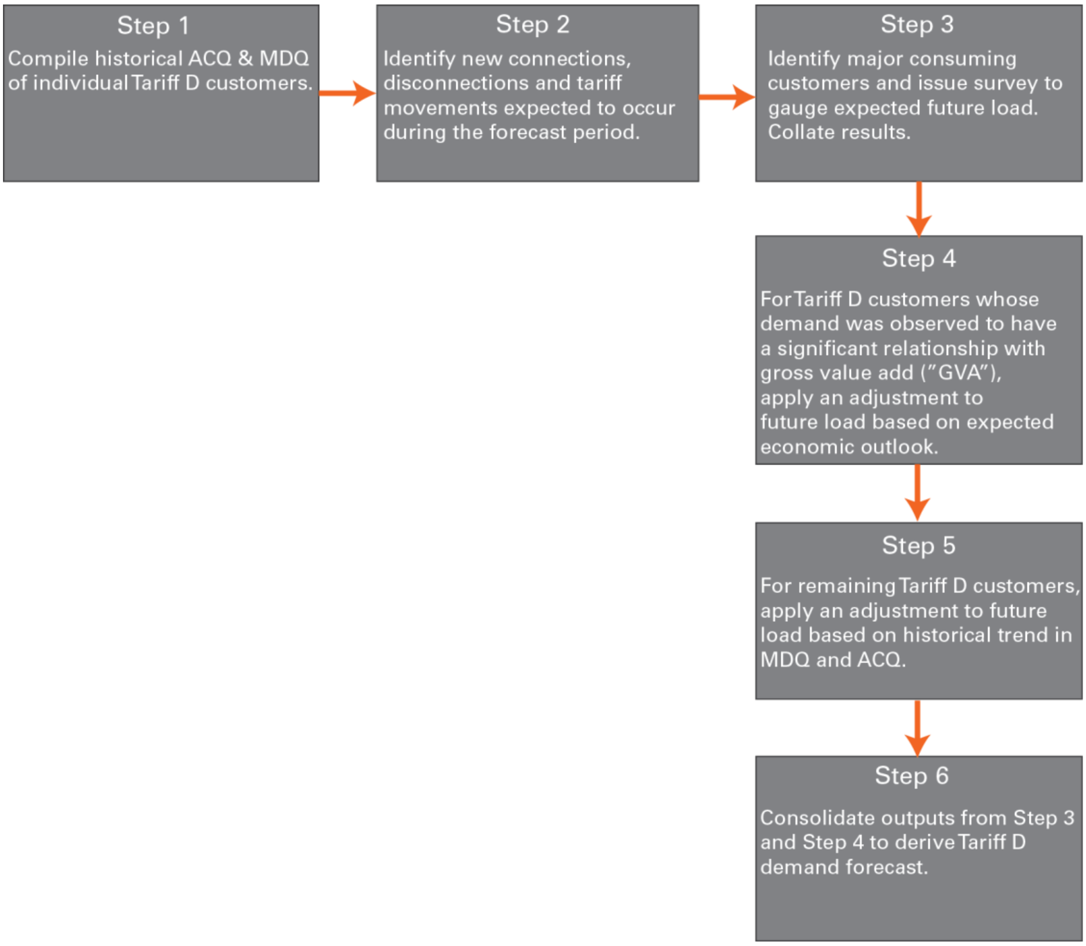


Figure 1.2 Tariff D Demand Forecast Methodology Summary



1.6. Review of Historical Access Arrangement Demand Forecasts

As AGN approaches the end of their current 2012-2016 AA period, it is clear that the demand forecast used as a basis for the prevailing AA was not sufficiently accurate. A similar situation also occurred in the previous arrangement (2006-2011). 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.

As will be elaborated upon in this report, 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.

1.7. Overview of Historical Tariff V Demand

The following three sections provide an overview of the historical trends leading up to the Review Period. Time periods before and after the GFC are shown below, and the different annual average growth rates reflect the structural changes that occurred in the market around 2010.

1.7.1. Total Demand

Table 1.2 reveals the historical average annual growth rates for Tariff V demand during the 2007-2010 and 2011-2014 periods. These rates are derived by averaging the annual growth rate in each year (implicit in this, rates were not compounded). Residential demand, which accounts for approximately 70% of Tariff V demand, fell by an average of 1.39% annually between 2011 and 2014, whilst commercial demand fell by 0.04% annually over the same period. As shown in the following table, there is significant change in annual growth rates for both Tariff V segments after 2010.

Table 1.2 Historical Tariff V Demand | Gigajoule ("GJ")

Sector	2014	Average Annual Growth | %	
		2007-2010	2011-2014
Residential	7,154,434	-0.46%	-1.39%
Commercial	3,065,891	1.64%	-0.04%
Total	**10,220,324**	**0.11%**	**-1.01%**

This historical demand data is a function of the total number of connections as well as the average demand per connection. The fall in demand per connection has had a more significant influence on Tariff V demand than the fall in connections, although the fall in the connections growth rate is also material. These two components have been isolated and their respective historical trends are addressed below.

1.7.2. Connections

Table 1.3 shows the total number of Tariff V connections as well as the historical average annual growth rates during the 2007-2010 and 2011-2014 periods. Residential connections increased at an average annual rate of 1.75% over the most recent period, while commercial connections increased by 1.39%. Growth over the 2011-2014 period has been slower than occurred over 2007-2010 for both the Residential and Commercial sectors. These movements are driven mostly by population growth rates and the penetration of gas in the residential and commercial energy market.

Table 1.3 Historical Tariff V Connections | No.

Connections	2014	Average Annual Growth | %	
		2007-2010	2011-2014
Residential	412,860	1.85%	1.75%
Commercial	10,446	1.61%	1.39%

1.7.3. Demand per Connection

Growth over the 2011-2014 period has been slower than occurred over 2007-2010 for both the Residential and Commercial sectors. Table 1.4 lists Tariff V demand per connection as well as the historical average annual growth rates for the 2007-2010 and 2011-2014 periods. The significant annual declines have primarily been caused by 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 1.4 Historical Tariff V Demand per Existing Connection | GJ

Demand per Connection	2014	Average Annual Growth | %	
		2007-2010	2011-2014
Residential | Existing	17.33	-2.26%	-3.08%
Commercial | Existing	293.5	0.04%	-1.42%

1.8. Overview of Historical Tariff D Demand

Table 1.5 lists the historical average annual growth rates for Tariff D demand on an ACQ and MDQ basis. Between 2011 and 2014, MDQ and ACQ fell by an annual average of 1.32% and 2.30% respectively. The table reiterates that industrial demand in the South Australian network continues to decrease although the rate of decrease has not matched what occurred in the several years prior to 2011. The recent decline in Tariff D has been driven primarily by two aspects- firstly, the efficiency gains and reduced fuel requirements for newer technology, and secondly, the manufacturing sector in SA has recorded decreases in gross value add ("**GVA**") of 2.4% in 2013, and 2.2% in 2014.[5]

Table 1.5 Historical Tariff D ACQ and MDQ

Load	2014	2011-2014 Average Annual Growth | %
ACQ	12,727,141 GJ	-2.30%
MDQ	59.7 TJ	-1.32%

[5] BIS Shrapnel, 16 March 2015, based on ABS 1367.0 data.

1.9. Overview of the Demand Forecast

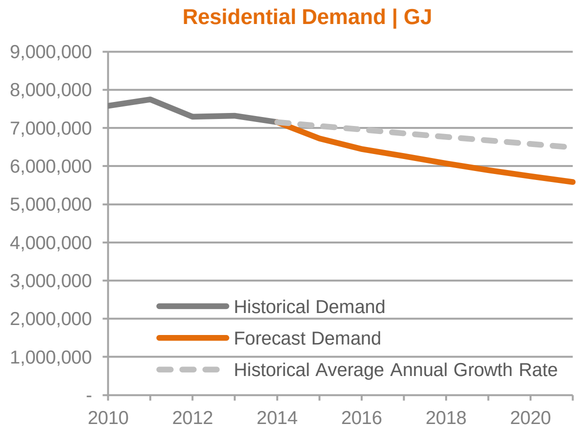
The following section provides an overview of forecast Tariff V (Tariff R and Tariff C) and Tariff D demand over the 2015-2021 period, including a brief description of the forecast drivers. Further detail is provided in Sections 2 and 3 of this report.

1.9.1. Tariff V

1.9.1.1 Demand

It is forecast that residential demand will fall by an annual average of 2.83% during the Review Period while commercial demand is forecast to decrease by an annual average of 0.96% over the same period. Table 1.6 and Figure 1.3 summarise the forecast for the residential and commercial segments of Tariff V demand. The figure plots the actual historical demand and then extrapolates this trend (dashed line) using the 2011-2014 annual average growth rate. The orange line plots the demand forecast until the end of the Review Period which incorporates all other key drivers such as price effects. This illustrates the degree to which the forecast deviates from the underlying, 2011-2014, historical trend.

Figure 1.3 Historical and Forecast Tariff V Residential and Commercial Demand



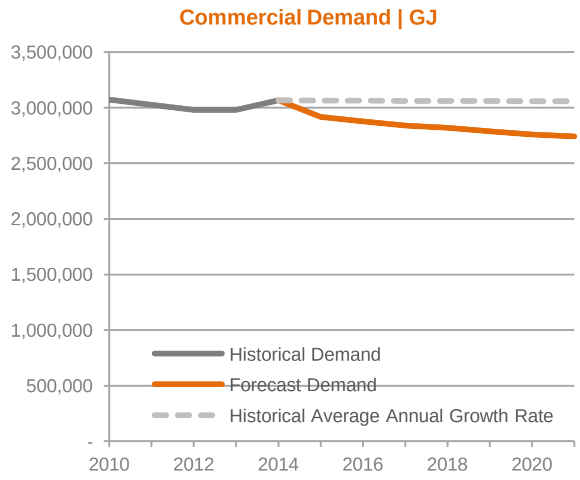


Table 1.6 Tariff V Demand Forecast | GJ

Total Demand	2015	2016	2017	2018	2019	2020	2021
Residential	6,720,782	6,446,907	6,258,721	6,071,982	5,897,659	5,733,964	5,583,903
Commercial	2,917,861	2,877,119	2,838,515	2,819,789	2,788,096	2,759,758	2,742,183
Total	**9,638,643**	**9,324,026**	**9,097,235**	**8,891,771**	**8,685,755**	**8,493,722**	**8,326,085**

Table 1.7 Comparison of Historical and Forecast Average Annual Growth in Demand | %

Average Growth	2011 - 2014	2015 - 2021	2017 - 2021
Residential	-1.39%	-3.47%	-2.83%
Commercial	-0.04%	-1.57%	-0.96%
Total	-1.01%	-2.88%	-2.24%

Figure 1.3 shows that forecast demand is below the average annual trend over the 2011 to 2014. This reflects that over the 2015-2021 period, Core expects to see a continuation of declining trends in gas connection penetration as well as a continued response to changes in gas and electricity retail prices, which results in a faster rate of decline in average consumption than that seen historically.

Tariff V demand is the product of two factors which are addressed below - connections and demand per connection. The methodology adopted for this demand forecast examined these components separately before bringing together the analysis to derive a total demand forecast. The dominant force in these forecasted rates is a fall in demand per connection. The number of connections steadily increases but this is more than offset by the falling demand per connection.

1.9.1.2 Connections

Residential connections are forecast to increase by an average annual rate of 1.17% during the Review Period, while commercial connections are forecast to increase by an annual average rate of 0.91%. The following figures and table show that the forecast growth rates are similar to what has been observed in the most recent historical period (2011-2014), with the exception of an adjustment for zero-consuming meters.

Throughout 2016 and 2017, AGN has indicated they will implement a program to remove connections that do not consume gas following a request to do so from a retailer. This will lead to a sudden spike in demand per connection and a step decline in the number of connections, but the growth rates either side of this spike are not affected and the total demand for each sector is not impacted.

The underlying growth rate for Tariff V connections is also influenced by the reduced competitiveness of gas relative to electricity. Recent trends of declining penetration of gas connections in new dwellings are forecast to continue over the Review Period, as a result of an increased preference for electricity and solar power due to appliance trends such as RC air-conditioning and solar water heating. The continued softening of building activity, underpinned by a surplus housing stock in South Australia is also a factor for slowing connections. Commercial connections are forecast based on the forecast of gross state product ("**GSP**"), which is expected to grow at a rate faster than historically observed. However, this growth is dampened by the removal of zero consuming connections in 2016 and 2017. The factors driving the forecast of residential and commercial connections are explained below in Sections 3.4 through 3.5

Figure 1.4 Historical and Forecast Tariff V Residential and Commercial Connections

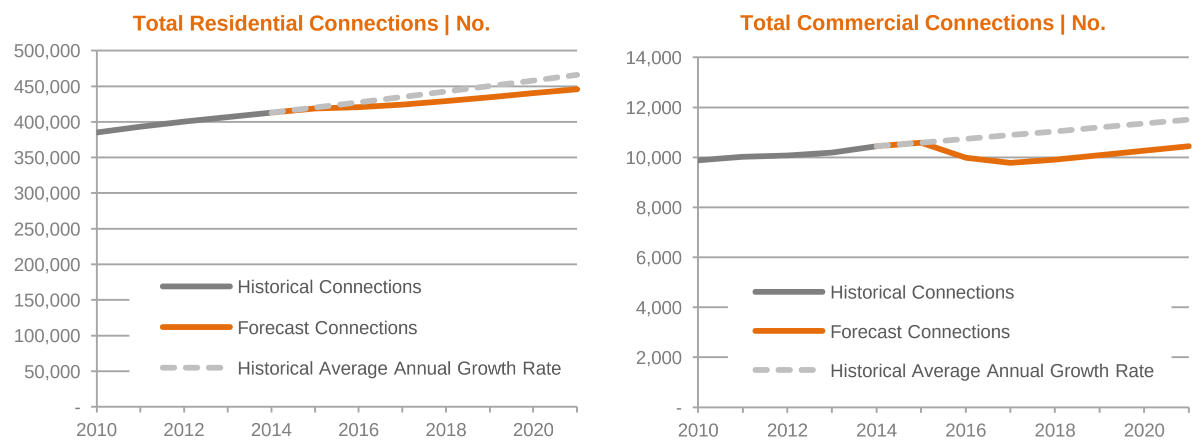


Table 1.8 Tariff V Connections Forecast | No.

Total Connections	2015	2016	2017	2018	2019	2020	2021
Residential	418,754	420,828	424,321	429,376	434,603	440,208	446,004
Commercial	10,587	9,983	9,781	9,913	10,086	10,261	10,439

Table 1.9 Comparison of Historical and Forecast Average Annual Growth in Connections | %

Average Growth	2011 - 2014	2015-2021	2017 - 2021
Residential	1.75%	1.11%	1.17%
Commercial	1.39%	0.03%	0.91%

Figure 1.4 shows that forecast connections is below the average annual trend over the 2011 to 2014.Core notes that connections growth has been slowing since 2011; annual connections growth grew at 2.09% from 2010 to 2011, while 1.47% annual connections growth was observed between 2013 and 2014. Therefore, it is not unreasonable to expect growth in connections to continue to fall during the Review Period. Further, a significant degree of the movement of residential and commercial connections away from the historical trend is due to the removal of zero consuming connections in 2016 and 2017.

1.9.1.3 Demand per Connection

Residential demand per connection is forecast to fall by an annual average rate of 3.96% during the Review Period, while commercial demand per connection is forecast to fall by 1.90%. The major factors which influence this forecast include a movement in the price of gas and electricity and a continuation of the historical decline in the household preference for gas appliances. These factors are explained below in Sections 3.4 through 3.5 and further detail can be found in Annexes 2 through 6. The underlying decline can be attributed to continuing improvements in energy efficiency and competition from energy substitutes including solar and RC air-conditioning. The zero-consumption meter disconnections described in the previous section cause a sudden spike in the demand per connection forecast.

Although the forecast decline in residential demand per connection is faster than recent history (2011-2014), Core notes that the average annual decline in residential demand per connection observed since 2013 of 4.2% is faster than the 3.96% average annual decline forecast for the Review Period (on a weighted average demand per connection basis). Core believes that the forecast for residential demand per connection is conservative when compared to the previous two years.

Further average annual growth rate of demand per connection across new residential connection types is forecast to decline at 3.16% during the Review Period. This is slower than the decline in average annual growth rates observed between 2010 and 2013 (note 2014 demand per connection for new estate connections is forecast).

Lastly, with the addition of new residential connections each year, the weighted average demand per connections continues to decline as the growing pool of new connections with reduced demand per connection dilutes higher consuming existing connections.

Figure 1.5 Historical and Forecast Tariff V Residential and Commercial Demand per Connection

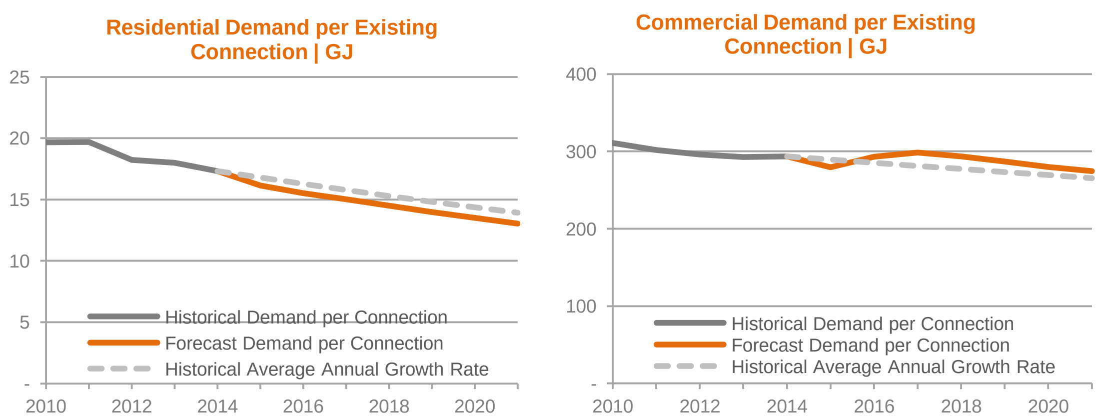


Table 1.10 Tariff V Demand per Connection Forecast | GJ/Connection

Demand/Conn.	2015	2016	2017	2018	2019	2020	2021
Residential | Existing	16.15	15.52	15.03	14.49	13.98	13.50	13.04
Residential | New Estate	9.97	9.55	9.20	8.88	8.57	8.27	8.13
Residential | MD/HR	6.23	5.97	5.75	5.55	5.35	5.17	5.08
Residential | E to G	12.53	12.00	11.57	11.16	10.77	10.40	10.21
Residential | Weighted Average	**16.05**	**15.32**	**14.75**	**14.14**	**13.57**	**13.03**	**12.52**
Commercial | Existing Connection	279.5	293.1	298.3	293.3	286.7	280.0	274.5
Commercial | New Connection	172.0	176.1	181.0	185.8	190.0	194.7	197.2
Commercial | Weighted Average	**275.2**	**287.8**	**289.8**	**283.1**	**275.1**	**267.6**	**261.4**

Table 1.11 Comparison of Historical and Forecast Average Annual Growth in Demand per Connection | %

Average Growth	2011 - 2014	2015-2021	2017- 2021
Residential | Existing	-3.08%	-3.98%	-3.43%
Residential | New Estate#	-8.84%	-4.15%	-3.16%
Residential | MD/HR#	-9.02%	-4.15%	-3.16%
Residential | E to G	-7.31%	-4.15%	-3.16%
Residential | Weighted Average	**-3.08%**	**-4.09%**	**-3.96%**
Commercial | Existing Connection	-1.42%	-0.91%	-1.29%
Commercial | New Connection#	8.20%	2.09%	2.29%
Commercial | Weighted Average	**-1.42%**	**-0.52%**	**-1.90%**

#Note: Historical growth for residential and commercial new connections has been assessed from the 2011 to 2013 period. Due to data being unavailable, 2014 demand per connection is estimated.

Figure 1.5 shows that forecast demand per connection is below the average annual trend over the 2011 to 2014 period for existing residential connections, and significantly higher for existing commercial connections. Movement away from the historical average annual growth over the 2015-2021 period is largely due to negative gas demand response to changes in gas and electricity prices for existing residential connections. Demand per connection for existing commercial connections moves higher than the average annual trend over the 2011 to 2014 period predominantly due to the impact of the removal of zero consuming connections, resulting in an artificial spike in demand per connection. Excluding this impact, demand per connection for existing commercial connections is falling, as with existing residential connections, due to negative gas demand response to changes in gas and electricity prices.

1.9.2. Tariff D

1.9.2.1 MDQ Forecast

During the Review Period, Core forecasts that MDQ will fall at an annual average rate of 1.09% as shown in the tables and figures below. This forecast average annual rate is slightly slower than the -1.32% observed historically between 2011 and 2014. The dominant factors influencing this result include an increase in energy conservation and efficiency, energy source substitution and reduced industrial activity in some areas, offset by a significant expansion for one existing customer [redacted].

Table 1.12 Forecast of Tariff D MDQ | TJ

Demand	2015	2016	2017	2018	2019	2020	2021
MDQ | TJ	56.09	59.29	60.57	56.96	56.59	56.27	56.04

Table 1.13 Comparison of Historical and Forecast Average Annual Growth in MDQ | %

Average Growth	2011 - 2014	2015-2021	2017- 2021
MDQ	-1.32%	-0.83%	-1.09%

Figure 1.6 Tariff D MDQ Forecast

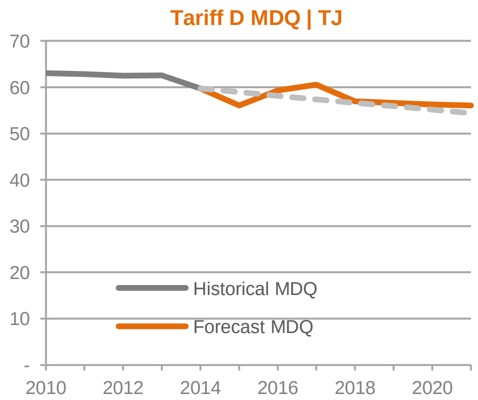


Figure 1.6 shows that Tariff D MDQ is forecast to fall below historic average annual trend between 2014 and 2016, before a significant industrial expansion drives forecast MDQ higher than the historic average annual trend between 2016 and 2018. Holden Ltd is marked for closure in 2018, resulting in a reduction in MDQ such that the forecast is in line with historic average annual trend. Tariff D MDQ is forecast to decline further to 2021 at a rate of -0.56% due to efficiency gains.

1.9.2.2 Tariff D Connections

The forecast of the network's Tariff D customer base is shown below in Table 1.14. On the basis of customer surveys, information in the public domain and any information revealed to Core by AGN, it is likely that the Tariff D customer base will fall from 125 to 118 by 2018. By the end of 2021, Core has forecast Tariff D connections to fall to 110.

Table 1.14 Forecast Tariff D customer numbers

Connections	2015	2016	2017	2018	2019	2020	2021
Total	125	125	125	118	115	113	110

2. Methodology

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 (Section 2.1)
- an approach to deriving a forecast of Tariff V demand (Section 2.2)
- an approach to deriving a forecast of Tariff D demand (Section 2.3)

The methodology for these elements was finalised having consideration for all recent AA's submitted to the regulator. All proposals, draft decisions and final decisions were taken into consideration which allowed Core to comply with the *NGRs* and develop a best-practice approach.

The methodology favours a highly transparent approach, including a demand forecast model that examines all factors that could potentially impact normalised demand. This approach is fundamentally consistent with the methodology adopted by AEMO in the National Gas Forecasting Report ("**NGFR**"), as developed by ACIL Allen Consulting.[6] Core's forecasting approach takes into consideration the main input variables as outlined in ACIL Allen's methodology. These are; Gross State Product ("**GSP**") growth, population growth, housing growth, retail gas prices and weather data.[7] ACIL Allen's methodology also suggests that '…*it may be worthwhile examining the substitution effect, where consumption of gas is influenced by changes in the price of electricity through the cross price elasticity of demand for gas with respect to the price of electricity*.'[8] Core was given access to detailed AGN historical data, which enabled the forecasting of demand for individual connection types within a demand segment. By separating the analysis into individual connection types, the forecast gains additional precision.

This report sets out the underlying facts and assumptions that were necessary when analysing gas demand. As will be detailed accordingly, data prior to 2009 was excluded in necessary parts of the forecast. This was done due to the observed step change in the historical data sets primarily caused by the GFC (as outlined in Section 1.8). For forecast components that involved average growth rates, Core proceeded with data from 2011 onwards which avoids the 2009 data point itself and also the influence on annual growth that occurs if the 2010 average growth was included. This approach to historical data is consistent with AEMO's best practice approach to data processing for the NGFR, which states *'Check the continuity of those time series to identify any discrete jumps which may indicate system changes or changes in the way customers are classified. Any jumps that are identified could be corrected…'*.[9]

2.1. Weather Normalised Demand

Gas demand is materially influenced by weather, particularly in the residential sector. Accordingly, the weather impact on historical gas demand was normalised to provide an appropriate basis for demand forecasting. Core adopted a weather normalisation methodology based on AEMO's forecasting guidelines.[10] This favours a calculation of Effective Degree Days ("**EDD**"). In comparing the methods of Heating Degree Days ("**HDD**") and EDD, EDD accounts for additional climatic factors such as sunshine, wind chill and seasonality. The coefficient of determination also shows that EDD has a stronger relationship with gas demand than HDD. In addition, the Akaike Information Criterion ("**AIC**")

[6] ACIL Allen Consulting, *Gas Consumption Forecasting: A Methodology*, June 2014.
[7] ACIL Allen Consulting, *Gas Consumption Forecasting: A Methodology*, June 2014. p. 33
[8] ACIL Allen Consulting, *Gas Consumption Forecasting: A Methodology*, June 2014. p. 19
[9] Ibid. p. 21
[10] AEMO, *2012 Weather Standards for Gas Forecasting'.*

supports the use of EDD instead of HDD as an index of weather fluctuations. For these reasons, Core used EDD as a superior approach to weather normalisation. Core has conducted weather normalisation using weather data dating back to 1999 which maintains consistency with AEMO's forecast of SA gas demand.[11] The CSIRO have observed a warming trend over the past 15 years which provides further justification for normalising weather using observations from 1999 onwards.[12] The 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.

Core notes 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}. The individual stages of the weather normalisation approach are outlined as follows:

EDD Calculation

1. Develop an EDD Index Model that calculates the EDD Index coefficients – this model is included as a supporting document to this report.
2. Obtain EDD Index coefficients by regressing daily gas demand on climate data, ranging from 01/07/2004 to 16/04/2012. The start date of the regression is limited by daily gas demand data, available from AGN.[13] The end date of the regression is limited by sunshine data, which is unavailable between 17/04/2012 and 30/12/2012. Historical climate data for the Kent Town weather station was obtained from the Bureau of Meteorology ("**BOM**") (temperature, wind speed, sunshine hours).[14] It should be noted that in instances where data was unavailable, Core has interpolated to estimate a data point. The average daily temperature and wind speed data was estimated using two approaches; the first approach used the average of 8x3-hourly data between 3.00a.m. and 12.00a.m. The second approach used the average of same day maximum and minimum data. Core compared the regression results and selected the variables that offered the best statistical fit. In this case, the 8x3-hourly data was selected due to its superior sum of squared residuals.
3. Calculate EDD by using the weather normalised demand model and EDD index coefficients. The weather normalisation model is included as a supporting document to this report.

Weather Normalisation Regression Model Development and Selection

1. In determining the appropriate estimate for weather normalised demand the following models were considered.

   Model 1 $Dem\ per\ Conn = \beta_0 + \beta_1 EDD$

   Model 2 $Dem\ per\ Conn = \beta_0 + \beta_1 EDD + \beta_2 (Dem\ per\ Conn)_{\ t-1}$

   Model 3 $\Delta(Dem\ per\ Conn) = \beta_0 + \beta_1 \Delta(EDD)$

   Model 4 $Dem\ per\ Conn = \beta_0 + \beta_1 EDD + \beta_2 Dummy + \beta_3 Trend$

2. Use the weather normalisation model to normalise demand per connection for each customer type on an annual basis from 1999 to 2014. The deviation is computed through the multiplication of regression coefficient β_1 and deviation of weather.

[11] In accordance with email communication between AGN and AEMO, dated 22 December 2014, as provided to Core on the 5 February 2015.
[12] CSIRO, *State of the Climate 2014*, February 2015.
[13] AGN, *Supporting Document 7. Daily Tariff V Demand Data*, October 2014.
[14] Weather Station 23090.

2.1.1. EDD Index Model

Below are the coefficients of EDD which provide the best fit to daily demand, defined by the following model:

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

EDD =	Degree Day ("**DD**") (temperature effect)
	+ **0.0171** * DD x average wind speed (wind chill factor)
	- **0.0916** * sunshine hours (warming effect of sunshine)
	+ max(**3.328** *2* Cos $\left(\frac{2\pi(\text{day}-\mathbf{200})}{365}\right)$,0) (seasonal factor)

Where DD is the degree day as calculated by the following table:

DD =	**18.3** – T	if T < 18.3
	0	if T > 18.3

- T is the average of 8 three-hourly Kent Town Weather Station temperature readings (in degrees Celsius) from 3.00am to 12.00am.
- 18.3 degrees Celsius represents the threshold temperature for SA gas heating. This was derived using Core's proprietary EDD model. An optimisation process was undertaken which found 18.3 was a more accurate statistical fit (based on sum of squared residuals). 18.3 degrees was then adopted in the weather normalisation process rather than the broad assumption of 18 degrees. Adopting the 18.3 degrees as the threshold temperature is slightly more conservative than 18 degrees.
- The regression also includes dummy variables for Friday, Saturday and Sunday and this is consistent with the AEMO EDD_{312} methodology.
- Demand per connection is equal to total Tariff V daily demand divided by the estimated total Tariff V daily customer numbers (using year-end customer numbers and interpolating for each day of the year).
- The network has experienced a stable rate of customer growth historically. Thus interpolated numbers are a reasonable inference of actual daily customer numbers.

Core has reviewed the EDD results for weather normalisation in prior AAs, including responses from the AER in relation to the Envestra Victoria ("**VIC**") 2013-17 Draft Decision. The methodology detailed above reveals that Core is using EDD consistent with AEMO's "2012 Review of Weather Standards for Gas Forecasting". This is consistent with the previous AA submitted to the AER. Daily EDD values have been calculated via historical data and multivariate regression.

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

2.1.2. Weather Normalised Demand Model

The regression output for the four possible models is summarised below. Households and businesses exhibit different patterns of energy use and different behavioural responses to changes in weather. Subsequently, the residential and commercial sectors are separated:

Table 2.1 Residential Demand per Connection Regression Outputs

	Model 1	Model 2	Model 3	Model 4
EDD Coefficient	0.0148*	0.00955***		0.00621**
Residential D/C Lag(-1) Coefficient		0.845***		
EDD (first difference)			0.00705***	
Dummy				0.58
Trend				(0.40)***
Constant	(6.31)	(14.93)**	(0.375)**	13.1**
No. of observations	16.00	15.00	15.00	16.00
R^2	0.38	0.91	0.83	0.97
Adjusted R^2	0.34	0.89	0.81	0.97
AIC	66.06	34.91	21.89	19.38
Root Mean Squared Error (“**RMSE**”)	1.80	0.71	0.47	0.40
Autocorrelation	Not Acceptable	Acceptable	Not Acceptable	Acceptable
Heteroskedasticity	Acceptable	Acceptable	Acceptable	Acceptable

*** Significant at the 0.01% level

** Significant at the 1% level

* Significant at the 5% level

Table 2.2 Commercial Demand per Connection Regression Outputs

	Model 1	Model 2	Model 3	Model 4
EDD Coefficient	0.140**	0.110**		0.089**
Commercial D/C Lag(-1) Coefficient		0.471*		
EDD (first difference)			0.0893***	
Dummy				0.224
Trend				(2.60)***
Constant	56.97	(39.19)	(2.67)	175
No. of observations	16	15	15	16
R^2	0.50	0.69	0.66	0.88
Adjusted R^2	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	Not Acceptable	Acceptable	Not Acceptable	Acceptable
Heteroskedasticity	Acceptable	Acceptable	Acceptable	Acceptable

*** Significant at the 0.01% level

** Significant at the 1% level

* Significant at the 5% level

The model selected for the forecast (Model 4) satisfied the following criteria:

- The explanatory variables are significant at the 5% confidence level
- The explanatory variables have an intuitive sign (positive or negative) based on established theory
- The model has high explanatory power (R-Squared)
- The model has a superior AIC score

Model 1 is the simple model that estimates the impact of EDD on demand per connection. This model suffers from autocorrelation and has a lower explanatory power reflected by an R-Squared value of only 0.50. This model is unacceptable for normalising demand.

Model 2 includes the first lag of demand per connection. By including the first lag, the problem of autocorrelation is removed. This model has higher explanatory power with an R-Squared of 0.91.

Model 3 changes the variable specification by estimating the annual change in demand per connection from the annual change in EDD. This model has an R-Squared of 0.83.

Model 4 includes an EDD term and a time variable. In order to account for trend in the series, a linear trend term is added to Model 4. Model 4 tests 2011 as an outlier in the dataset which could distort the effects of the EDD variable. A dummy variable for 2011 was also included to account for this effect.

Model 2 and Model 4 meet the criteria for significance, autocorrelation and heteroskedasticity. However, Model 4 is a preferred model for residential and commercial demand per connection due to the higher R-Squared and lower AIC statistic. Therefore Model 4 has been adopted for the purposes of this Revised AA Proposal submission.

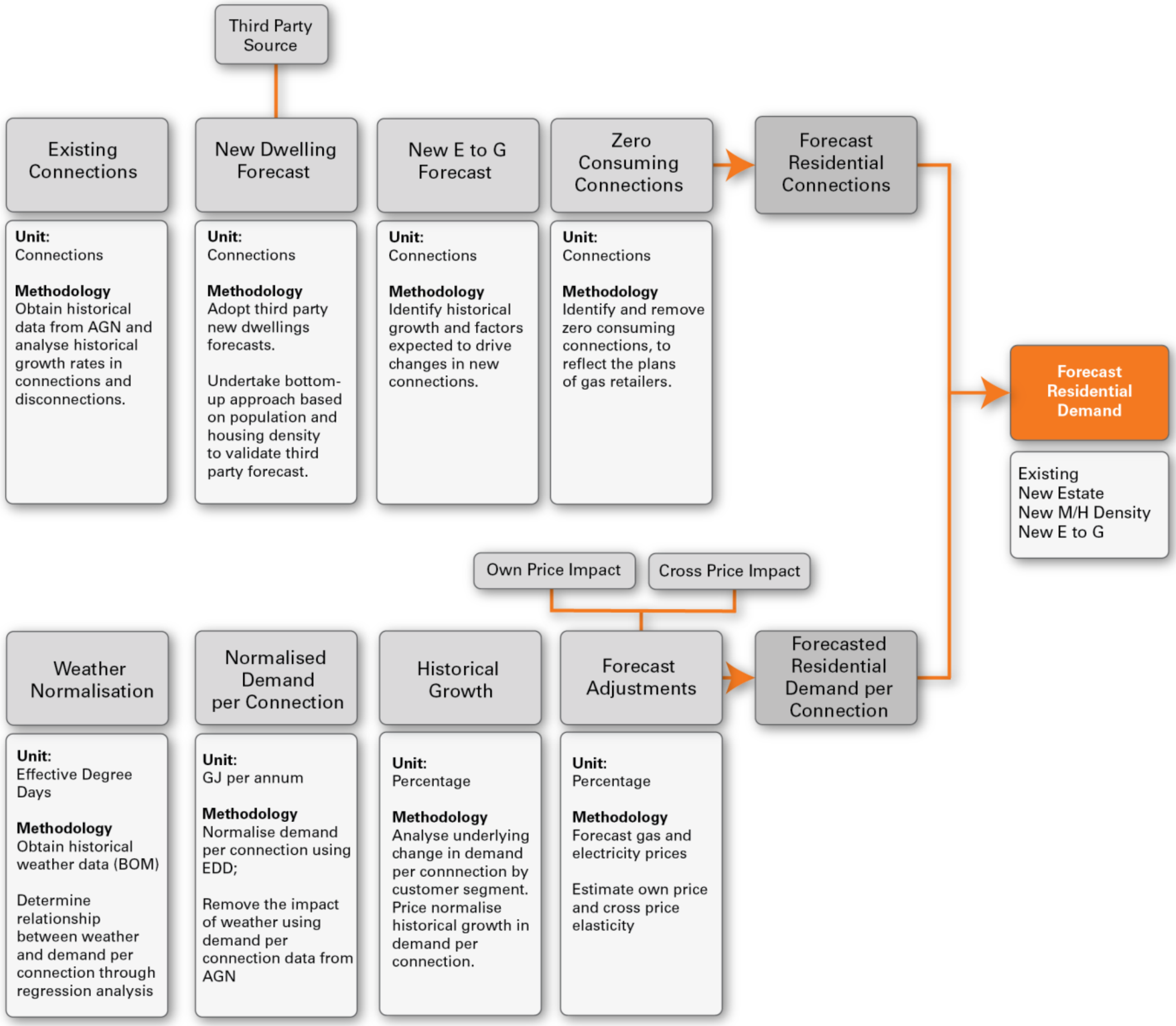
2.2. Tariff V Demand

2.2.1. Tariff V | Residential

Figure 2.1 outlines the structure and detail of the residential demand forecast. This figure shows that residential demand is the product of forecast residential connection and demand per connection.

The approach used to derive a forecast for Tariff V residential connection numbers and demand per connection is provided in Sections 2.2.1.1 and 2.2.1.2 respectively.

Figure 2.1 Residential Demand Forecast Methodology



2.2.1.1 Connections

This section details the approach undertaken to derive residential connections. Due to the different types of dwellings, Core reconciles bottom-up and top-down approaches. The integration of third party forecasts is inherent to this approach and provides a natural source of validation.

- The bottom-up approach analyses historical trends and major factors which influence gas connections; and
- The top down approach surveys the relevant forecasts completed by qualified third parties. The specific focus here is on dwelling completions and commercial entity formation within the distribution network.

The results of these two approaches are compared and differences are examined before arriving at a final forecast. Generally, each dwelling type exhibits its own growth cycle. By including a bottom up approach, the total connections forecast will likely be more accurate. This is consistent with other views within the industry such as AEMO who noted that underlying causes of growth cannot be ascertained when distribution businesses report aggregated customer numbers - the full picture of growth only becomes apparent when each dwelling type is separated.[15] Core agrees

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

with AEMO's views in regards to the distinct growth factors for different dwelling types. The method specific to each dwelling type is outlined as follows:

Existing Connections

1. Residential connection numbers for 2006 to 2014 were compiled by Core based on data provided by AGN.[16]
2. Core derived the rates for disconnections by comparing total residential connection numbers at the beginning and end of each year. New connections for a given year are left out of this calculation for the purposes of consistency.
3. The closing 2014 connections are defined as existing connections in the forecast. This forms a basis to derive a forecast for the period 2015 to 2021. The forecast of existing connections for a given year is derived by removing the predicted disconnections in the previous year from the opening number of connections in the previous year. Forecast disconnections are based on the historical average of disconnections as a percentage of the year-opening number of connections. A narrow period of 2011-2014 is more reliable and consistent given the 2009 structural change observed in the historical time series. For example, disconnections in 2008 are almost double the average annual rate between 2011 and 2014.[17] Accordingly, the average number was applied in any instance where a consistent historical annual average was not observed.
4. There are meters on the AGN network for which there is no associated consumption. This situation may occur if a property is vacant or if supply has been cut off as a result of non-payment. As at 30 June 2014, there were approximately 6,900 zero consuming meters on the Network, the majority of which (around 85%) are residential meters. In March 2015, AGN received a request from a retailer to remove these meters from our networks. Based on this precedent and advice from AGN, Core Energy has assumed that all zero consuming meters are removed from the network over an 18 month period beginning 1 July 2015.

New Connections

Core has utilised an independent, third party new dwellings forecast from BIS Shrapnel in March 2015,[18] to determine the likely forecast of new connections. A declining proportion of connections, consistent with historical trend, was applied to BIS Shrapnel new dwellings to provide a forecast of new connections. This method applies to both new estate connections and MD/HR gas connections.

To validate Core's derivation of new connections and the third party new dwellings forecast that underpinned the forecast, a bottom-up forecast was also derived by adopting the following approach:

- Derive a best estimate of growth in dwellings within AGN network reach.
  - Core compiled AGN data to arrive at historical demand for each postcode.[19] Postcodes are then sorted according to local government areas ("**LGA**"). New connections are forecast on an LGA basis.
    - Core compiled historical and projected population data for each LGA from the Australian Government Department of Social Services – Statistical Local Area Population Projections.[20] This data was used to derive a best estimate of the AGN network reach by dividing the LGA population projections within network reach by the total population projection for South Australia. This results in a projected network reach of 79%.

[16] AGN, *Supporting Document 6 Annual Tariff V Demand Data by Region*, October 2014.
[17] 2008 = 2,207; 2010-2014 average annual rate= 1323.
[18] BIS Shrapnel, *AGNL South Australia forecasts.xlsx*, as provided by AGN on 26 March 2015.
[19] AGN, *Supporting Document 6 Annual Tariff V Demand Data by Region*, October 2014.
[20] Australia Government Department of Social Services, *Statistical Local Area Population Projections, 2011 (base) to 2026, Preliminary*, November 2014.

> Core derived an estimate of housing density by reference to Australian Bureau of Statistics ("**ABS**") 2011 Census data whilst adjusting historic growth rates to reflect any forecast changes in future household density.[21]

- Derive a best estimate for the gas connection rate for new dwellings in the AGN network area (estimate of houses within the AGN network area which are actually connected to gas).
  - Core derived an estimate of the historical gas network penetration rate (the proportion of new dwellings that connect to gas), based on historical new dwellings data obtained from BIS Shrapnel.[22] Historical new connections data provided by AGN and the network reach estimate (above) also helped to shape this estimate. The 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.
- Derive a best estimate of new dwelling connections:
  - The forecast of new connections between 2015 and 2021 is a function of the forecast of new dwellings within the AGN network area and the forecast gas connection rate.[23]
- Allocate new connections between New Estates and MD/HR:
  - Finally an estimate of the allocation of dwellings between New Estates and MD/HR was derived based on the average allocation of the historical number of New Estate connections and MD/HR connections between 2011 and 2014. The allocation of 88% New Estate and 12% MD/HR was assumed to remain constant, on average, during the forecast period.

Annexure 6 details the two approaches undertaken to derive New Estate and MD/HR connections.

Electricity to Gas ("E to G") Connections

1. Historical new E to G connections data was compiled by Core based on inputs provided by AGN for the period between 2005 and 2014.[24]
2. The average number of connections was calculated for the 2011 to 2014 period (1,435). There are no significant factors that indicate a change in this rate before 2021. The average number was applied in this instance as a consistent historical annual average was not observed.

2.2.1.2 Demand per Connection

Core assessed the alternative methodologies that could reasonably be used to forecast residential demand per connection. It was determined that the most accurate estimate would be formed by analysing the historical annual average growth and then adjusting for the impact of each material factor. Regression analysis was attempted but no statistical trend fitted to the data set was significant meaning that historical average growth rates were a more reliable alternative. In carrying out this approach it was ensured that all analysis was rigorous, data of a suitable quality was utilised, the forecast was set out in a transparent fashion and any assumptions, inputs, calculations and results were displayed.

Therefore, the steps taken to arrive at a forecast of demand per connection were as follows:

1. Normalise demand per connection for the effects of weather using the methodology discussed in Section 2.1.

[21] ABS, *TableBuilder Basic Data Dwelling Characteristics*, 2011.
[22] BIS Shrapnel, *Australian Housing Outlook 2014-2017.*
[23] Ibid.
[24] AGN, *Supporting Document 6 Annual Tariff V Demand Data by Region,* October 2014.

2. Derive the historical annual average growth in demand per connection based on normalised demand per connection between 2011 and 2014 using data provided by AGN.

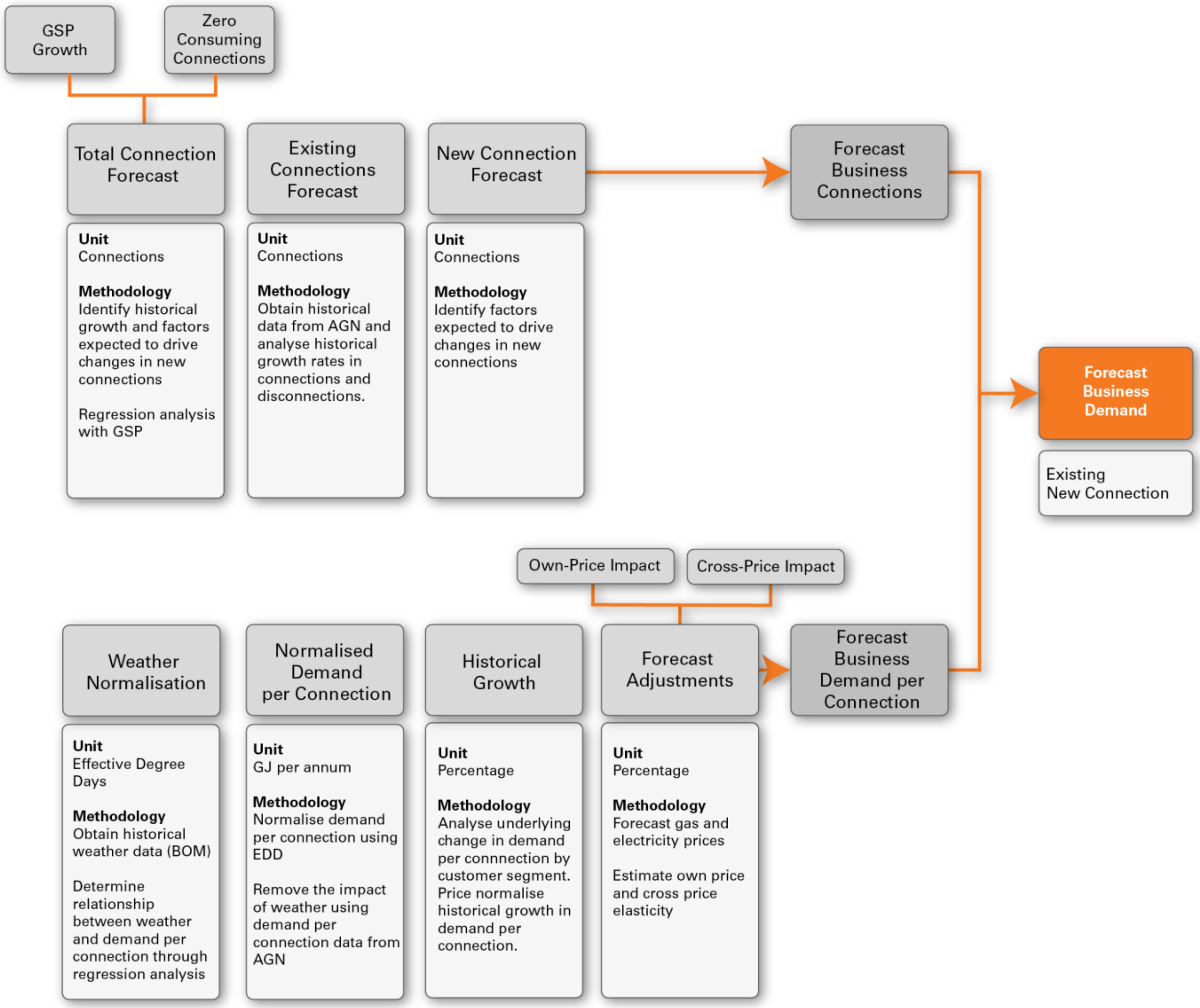
3. Adjust normalised historical annual average growth in demand per connection to remove historical impact of own and cross price elasticity effects. This is done to account for the expected future changes in prices which provide a different price situation to that experienced historically.

4. Derive a forecast of demand per connection, having regard to major factors which have the potential to influence demand per connection including economic activity, government policy, efficiency trends and energy price movements. This step aligns with the approach undertaken by AEMO to develop NGFR forecasts, which also tests whether statistically significant correlations exist between residential demand per connection and economic variables.[25]

2.2.2. Tariff V | Commercial

The methodology adopted to derive a forecast of commercial demand parallels the approach used for residential demand. Figure 2.2 outlines the elements of the connections forecast as well as the demand per connection forecast.

Figure 2.2 Commercial Demand Forecast Methodology



[25] ACIL Allen Consulting, *Report to Australian Energy Market Operator, 'Gas Consumption Forecasting: A Methodology*,' June 2014. p. 29

2.2.2.1 Connections

Total Connections

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

1. Collate connections data from the 2005 to 2014 period based on inputs provided by AGN.[26]
2. Undertake regression analysis to establish the relationship between historical GSP and growth in commercial connections.[27]
3. Adjust historical average annual growth to remove the impact of historical movements in GSP and use the resulting underlying growth rate to forecast commercial connections between 2015 and 2021.
4. Use the relationship derived from the regression analysis in the second step to forecast the additional growth in commercial connections due to anticipated movements in GSP between 2015 and 2021.
5. Apply the connections forecast in step 3 and step 4 to commercial connection numbers in 2014 to derive a forecast of total commercial connections between 2015 and 2021.

These steps were carried out before total connections were then disaggregated into existing connections and new connections. Existing connections are derived by taking the number of connections in 2014 and adjusting for the forecast in annual disconnections to 2021. The disconnections forecast is calculated using the average historical proportion of disconnections as a percentage of opening connections for a given year (0.9%). The new connections forecast is derived by subtracting the existing connections forecast from the total connections forecast.

2.2.2.2 Demand per Connection

The style of approach used in the residential demand forecast was also adopted for the commercial sector. However, the commercial sector did not require a bottom-up approach as commercial dwellings were not divided into further categories. Similarly to the residential sector, historical annual average growth rates were found to be more appropriate than statistical trends. Historical average annual growth was derived before adjusting for the impact of each material factor. Models were developed to calculate EDD, normalised demand and a forecast of demand per connection (these have been provided to AGN and form an attachment to this report). The same qualities and standards mentioned in reference to the residential sector methodology were also upheld for the commercial forecast.

1. Normalise demand per connection for the effects of weather using the methodology discussed in Section 2.1.
2. Determine the historical annual average growth in demand per connection based on demand per connection between 2011 and 2014, for both existing and new connections.
3. Normalise the historical annual average growth with respect to own and cross price to remove historical pricing impacts. This is done to account for the expected future changes in prices which provide a different price situation to that experienced historically.
4. Determine the forecast of demand per connection, having regard to the price normalised historical annual average growth and the movement in factors that are expected to impact demand per connections. These factors include own and cross price, policy change and appliance trends.

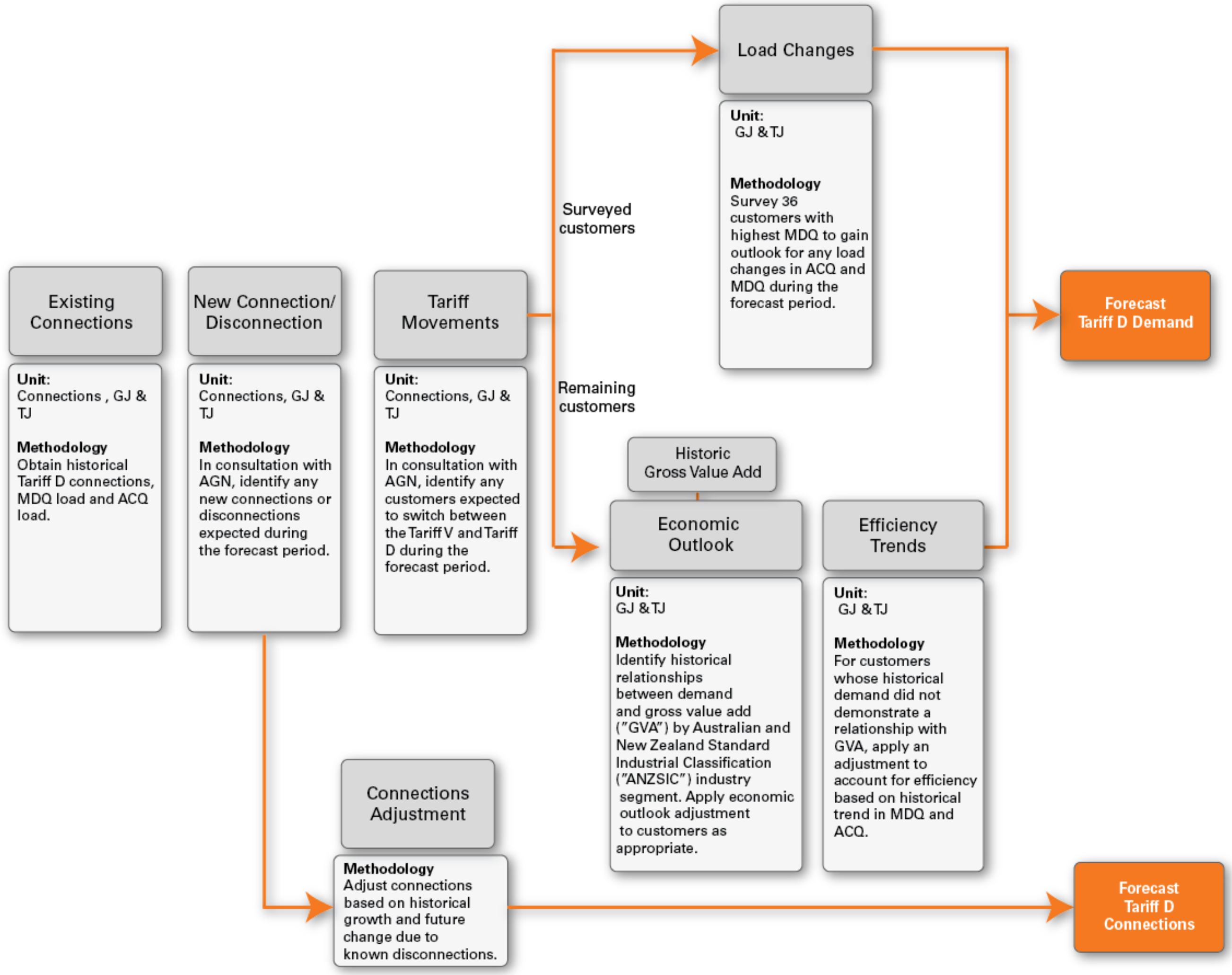
[26] AGN, *Supporting Document 5 Historic SA Annual Data (AER)*, October 2014.
[27] ABS, *5220.0 Australian National Accounts; State Accounts*, 2013-14.

2.3. Tariff D Demand

Tariff D demand was forecast using individual customer consumption data provided by AGN, and through customer consultation in the form of a survey. Figure 2.3 provides an overview of the approach adopted by Core to derive a forecast of Tariff D demand. This is consistent with the forecasting methodology developed by ACIL Allen Consulting for AEMO, which states that;

'The recommended approach to forecasting the gas consumption of large customers is to use the survey method'.[28]

Figure 2.3 Tariff D ACQ and MDQ Forecast Methodology



The specific steps taken by Core to arrive at a forecast for MDQ, is as follows:

- Review the list of Tariff D demand customers for 2014 and sort these according to ANZSIC's classification of industry sectors.
- Adjust for any known closures, new connections, tariff reallocation and expected material load changes. These adjustments were provided by AGN and a considerable amount of the data was generated by customer feedback via survey.[29] Core also undertook a review that helped to build the MDQ forecast. For instance, the Holden closure was

[28] ACIL Allen Consulting, *Report to Australian Energy Market Operator, 'Gas Consumption Forecasting: A Methodology*,' June 2014. p. 45
[29] A pro forma survey is included as Annexure 8.

public knowledge but Core also considered the effects of this news for industries and businesses who are connected to Holden's operations.

- Assess whether demand should be revised for remaining customers at an industry segment level based on the economic outlook for each material industry segment. The economic outlook is based on the GVA of individual ANSZIC industry segments. To assess whether a statistically significant relationship exists between economic activity and sector demand, sector GVA is regressed against gas demand. Sector GVA regressions were performed using GVA data from the ABS.[30] No statistically significant relationship between historical gas demand and GVA for any ANZSIC industry segment was observed.
- For industry segments which did not demonstrate a statistically significant relationship between economic activity and demand, a growth factor to account for efficiency trends was applied to demand based on an analysis of historical data. ACIL Allen's gas consumption forecasting methodology for AEMO suggests;

  'It may also be worth considering the historical data for large customers in aggregate in each forecast area over time to identify any statistically long-term growth (or decline) trend...'.[31].

  This growth has been derived using data from customers that had held a connection continuously from 2011 to 2014. Disconnections and new connections during this period would skew the growth rates so these customers were excluded from this part of the Tariff D forecast.

[30] ABS, *5220.0 – Australian National Accounts: State Accounts*, 2013-2014.
[31] ACIL Allen Consulting, *Report to Australian Energy Market Operator, 'Gas Consumption Forecasting: A Methodology*, June 2014. p.46

3. Tariff V Demand Forecast

3.1. Introduction

Core has undertaken an analysis of historical demand data, which was then normalised to remove fluctuations caused by weather factors. The trend revealed by this data was extrapolated across the forecast period. The impact of other influences (such as price elasticity) was removed to avoid including their impact twice. Each factor was analysed and then reintroduced to the forecast separately. Details of this analysis and the resultant forecasts are summarised below.

3.2. Derivation of Weather Normalised Demand

The first step in projecting Tariff V demand was to normalise historical data for the impact of weather. Core's proprietary Excel-based models were used to calculate EDD index coefficients to weather normalise demand. For greater detail, the EDD index model and weather normalised demand model should be read in conjunction with this report. These models have been submitted to AGN and form a confidential attachment to AGN's Access Arrangement Information.

The following tables and figures present the results of normalised EDD. The long term trend of EDD can be compared to the fluctuations in weather. Further clarification in the table shows that from 2011 to 2013, EDD was greater than the trend. This implies that weather during this period was colder than normal. The colder weather corresponds to higher demand per connection, as more gas is required for heating. The opposite is shown in 2014, when EDD was lower than the trend. Warmer weather in 2014 required less heating- hence demand per connection in 2014 was lower.

For the residential sector, demand per connection exhibits a declining trend, whereas demand appears to be steady. The tables below list the results of the previous 16 years. The equivalent results for the commercial sector are also presented. Normalised commercial demand has a reasonably positive trend over the 16 years while as demand per connection has fallen.

Figure 3.1 EDD Index

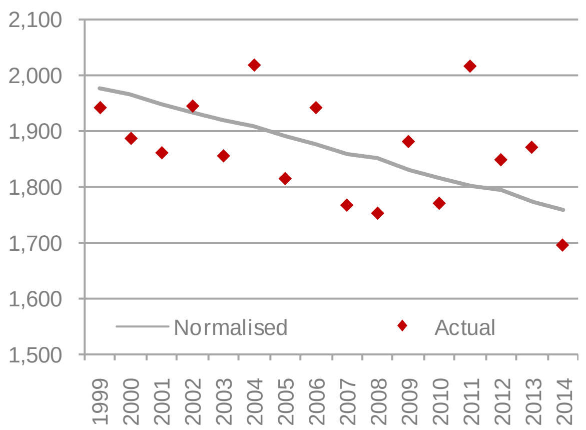


Figure 3.2 Residential Demand per Connection | GJ

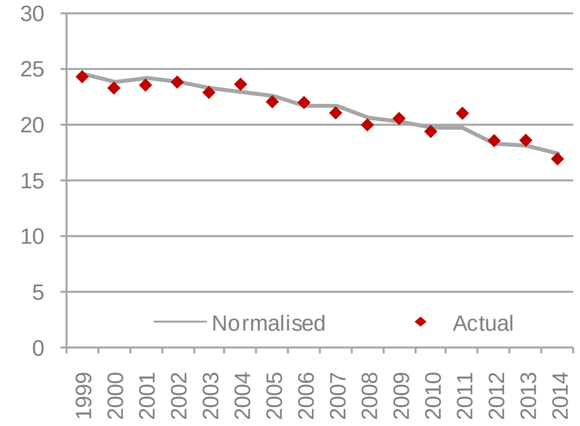


Figure 3.3 Residential Demand | GJ

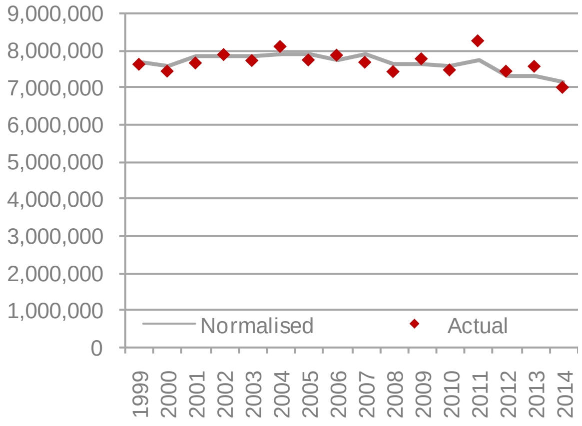


Figure 3.4 Commercial Demand per Connection | GJ

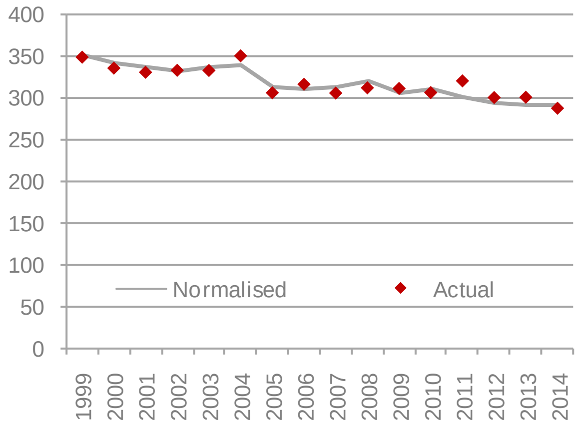


Figure 3.5 Commercial Demand | GJ

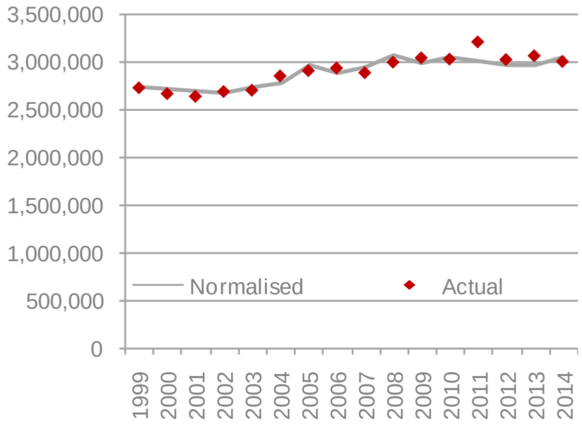


Table 3.1 EDD

Year	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Normalised EDD	1,975	1,966	1,946	1,932	1,918	1,909	1,889	1,875	1,860	1,851	1,831	1,817	1,803	1,793	1,774	1,759
Actual EDD	1,942	1,887	1,862	1,945	1,856	2,018	1,816	1,942	1,768	1,754	1,882	1,772	2,016	1,849	1,872	1,697
Difference	(33)	(79)	(85)	13	(61)	110	(73)	68	(92)	(97)	50	(45)	214	56	98	(62)

Table 3.2 Normalised Residential Demand per Connection/Demand | GJ

Year	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Normalised Demand	7,690,898	7,594,541	7,833,494	7,865,716	7,857,539	7,879,839	7,904,299	7,724,877	7,890,359	7,648,601	7,659,148	7,579,719	7,748,032	7,297,762	7,323,753	7,154,434
Actual Demand	7,626,614	7,438,192	7,662,305	7,892,525	7,728,699	8,113,616	7,744,584	7,875,405	7,682,187	7,425,021	7,777,427	7,471,069	8,269,742	7,437,268	7,570,581	6,994,307
Difference	(64,284)	(156,349)	(171,189)	26,809	(128,840)	233,777	(159,715)	150,528	(208,172)	(223,580)	118,279	(108,650)	521,710	139,506	246,828	(160,127)
Normalised D/C	24.51	23.78	24.08	23.74	23.28	22.95	22.51	21.57	21.63	20.59	20.25	19.68	19.70	18.22	18.00	17.33
Actual D/C	24.31	23.29	23.55	23.83	22.90	23.64	22.06	21.99	21.06	19.99	20.56	19.39	21.03	18.57	18.61	16.94
Difference	(0.20)	(0.49)	(0.53)	0.08	(0.38)	0.68	(0.45)	.42	(0.57)	(0.60)	0.31	(0.28)	1.33	0.35	0.61	(0.39)

Table 3.3 Normalised Commercial Demand per Connection/Demand | GJ

Year	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Normalised Demand	2,752,472	2,722,897	2,698,673	2,680,386	2,748,123	2,776,372	2,972,990	2,882,919	2,966,041	3,083,583	3,002,883	3,072,957	3,025,793	2,978,840	2,980,551	3,065,891
Actual Demand	2,729,591	2,667,376	2,638,755	2,689,714	2,703,859	2,855,567	2,911,225	2,938,666	2,889,074	3,000,956	3,046,571	3,033,097	3,215,869	3,028,984	3,068,923	3,007,967
Difference	(22,881)	(55,521)	(59,918)	9,328	(44,264)	79,195	(61,765)	55,747	(76,967)	(82,627)	43,688	(39,860)	190,076	50,144	88,372	(57,924)
Normalised D/C	352	343	339	332	339	341	313	311	314	321	307	311	302	296	293	293
Actual D/C	349	336	331	334	333	351	307	317	306	313	312	307	321	301	301	288
Difference	(2.9)	(7.0)	(7.5)	1.2	(5.5)	9.7	(6.5)	6.0	(8.2)	(8.6)	4.5	(4.0)	19.0	5.0	8.7	(5.5)

3.3. Derivation of Tariff V Connections and Demand Forecast

For the remaining sections of this report, the demand data referred to has already undergone the weather normalisation process detailed above. The weather normalisation process was a preliminary step completed prior to the demand forecasting.

3.3.1. Summary

The following sections detail the total demand forecast for Tariff V as well as the individual forecasts for each component of Tariff V demand. Forecasts for connections numbers and demand per connection are presented before relevant factors are comprehensively examined. This incorporates Core's analysis of gas appliance substitution, price effects, climate, energy efficiency, household behaviour and energy policy.

3.3.1.1 Total Demand

Tariff V demand is forecast to decrease from 9,324,026GJ to 8,326,085GJ during the Review Period. The first table divides the demand forecast according to two market sectors. As is shown below, the residential sector is a dominant component of the overall movements in the demand forecast.

Table 3.4 Tariff V Demand Forecast | GJ

Total Demand	2015	2016	2017	2018	2019	2020	2021
Residential	6,720,782	6,446,907	6,258,721	6,071,982	5,897,659	5,733,964	5,583,903
Commercial	2,917,861	2,877,119	2,838,515	2,819,789	2,788,096	2,759,758	2,742,183
Total	**9,638,643**	**9,324,026**	**9,097,235**	**8,891,771**	**8,685,755**	**8,493,722**	**8,326,085**

Table 3.5 Comparison of Historical and Forecast Average Annual Growth in Demand | %

Average Growth	2011 - 2014	2015 - 2021	2017 - 2021
Residential	-1.39%	-3.47%	-2.83%
Commercial	-0.04%	-1.57%	-0.96%
Total	**-1.01%**	**-2.88%**	**-2.24%**

Total demand is the product of connection forecasts and demand per connection forecasts. The decreasing total volumes reflect that, consistent with recent history - namely the period between 2011 and 2014, falling consumption per connection is expected to more than offset the continued growth in connections.

Tariff V connections and demand per connection forecasts are summarised below, with further detail provided in Section 3.4 and 3.5 for the residential and commercial sectors respectively.

3.3.1.2 Tariff V Connections

The absolute number of Tariff V connections is forecast to increase steadily over the Review Period. However, the pace of residential and commercial connections growth is forecast to slow during the Review Period. Specific drivers for residential and commercial connections are detailed in Section 3.4, but generally the major factors include dwelling forecasts for residential connections, and GSP forecasts for commercial connections.

Table 3.6 Tariff V Connections Forecast | No.

Total Connections	2015	2016	2017	2018	2019	2020	2021
Residential	418,754	420,828	424,321	429,376	434,603	440,208	446,004
Commercial	10,587	9,983	9,781	9,913	10,086	10,261	10,439
Total	**429,341**	**430,811**	**434,102**	**439,289**	**444,689**	**450,469**	**456,443**

Table 3.7 Comparison of Historical and Forecast Average Annual Growth in Connections | %

Average Growth	2011 - 2014	2015 - 2021	2017 - 2021
Residential	1.75%	1.11%	1.17%
Commercial	1.39%	0.03%	0.91%
Total	**1.74%**	**1.08%**	**1.16%**

3.3.1.3 Tariff V Demand per Connection

As mentioned above, the falling demand per connection is the dominant component of Tariff V demand and is more than offsetting the demand impact of the increasing number of total connections. For the residential weighted average, the rate of decline of demand per connection is forecast to be faster than recent history (2011 – 2014), as summarised in the following tables. Specific drivers for each dwelling type are detailed below but generally the major factors are gas appliance trends, energy policy and price elasticity effects. Demand per connection of existing commercial connections is forecast to fall at a slightly slower rate than observed between 2011 and 2014, while demand per connection for new commercial connections is forecast to increase at a slower rate than between 2011 and 2014.

Table 3.8 Tariff V Demand per Connection Forecast | GJ/Connection

Demand/Conn.	2015	2016	2017	2018	2019	2020	2021
Residential | Existing	16.15	15.52	15.03	14.49	13.98	13.50	13.04
Residential | New Estate	9.97	9.55	9.20	8.88	8.57	8.27	8.13
Residential | MD/HR	6.23	5.97	5.75	5.55	5.35	5.17	5.08
Residential | E to G	12.53	12.00	11.57	11.16	10.77	10.40	10.21
Residential | Weighted Average	**16.05**	**15.32**	**14.75**	**14.14**	**13.57**	**13.03**	**12.52**
Commercial | Existing Connection	279.5	293.1	298.3	293.3	286.7	280.0	274.5
Commercial | New Connection	172.0	176.1	181.0	185.8	190.0	194.7	197.2
Commercial | Weighted Average	**275.2**	**287.8**	**289.8**	**283.1**	**275.1**	**267.6**	**261.4**

Table 3.9 Comparison of Historical and Forecast Average Annual Growth in Demand per Connection | %

Average Growth	2011 – 2014	2015-2021	2017- 2021
Residential | Existing	-3.08%	-3.98%	-3.43%
Residential | New Estate#	-8.84%	-4.15%	-3.16%
Residential | MD/HR#	-9.02%	-4.15%	-3.16%
Residential | E to G#	-7.31%	-4.15%	-3.16%
Residential | Weighted Average	**-3.08%**	**-4.09%**	**-3.96%**
Commercial | Existing Connection	-1.42%	-0.91%	-1.29%
Commercial | New Connection#	8.20%	2.09%	2.29%
Commercial | Weighted Average	**-1.42%**	**-0.52%**	**-1.90%**

#Note: Historical growth for residential and commercial new connections has been assessed from the 2011 to 2013 period. Due to data being unavailable, 2014 demand per connection is estimated.

Although the forecast decline in residential demand per connection is slightly below recent history (2011-2014), Core notes that the average annual decline in residential demand per connection observed since 2013 of 4.2% is faster than the 3.96% average annual decline forecast for the Review Period (on a weighted average demand per connection basis). Core believes that the forecast for residential demand per connection is conservative when compared to the previous two years.

3.4. The Composition of Residential Demand

Residential demand consists of two main elements:

- New Connections
  - New E to G
    - Dwellings that connect to the gas network within a particular year after only using electricity for their energy requirements.
  - New Estates
    - New detached dwellings.
  - New MD/HR
    - New dwellings that are not detached.
- Existing Connections
    - Dwellings that are already connected to the gas network when a given year begins.

Total residential demand is forecast to decrease from 6,446,907GJ to 5,583,903GJ, equivalent to an average annual decline of 2.83% over the Review Period. Table 3.10 divides this forecast according to connection type.

Table 3.10 Residential Demand Forecast | GJ

Total Demand	2015	2016	2017	2018	2019	2020	2021
Existing	6,647,064	6,305,205	6,057,682	5,818,749	5,594,353	5,381,241	5,176,809
New Estate | Cumulative	51,397	99,647	141,031	176,777	211,578	246,411	285,218
MD/HR | Cumulative	4,344	7,617	10,205	12,414	14,462	16,790	19,258
E to G | Cumulative	17,977	34,438	49,802	64,042	77,266	89,523	102,617
Total	**6,720,782**	**6,446,907**	**6,258,721**	**6,071,982**	**5,897,659**	**5,733,964**	**5,583,903**

3.4.2. Derivation of Residential Connections

Residential connections are expected to increase from 420,828 to 446,004 during the Review Period. The following table shows the absolute contributions made by each connection type. This section of the forecast is best captured by the annual growth rate in connections of 1.17% - a rate that is slightly lower than the average observed over the recent historical period between 2011 and 2014. This slowing growth rate can be attributed to several factors. The zero consuming meters program significantly reduces the existing connections number in 2016 and 2017. There is also a historical trend prevailing whereby the penetration rate of gas connections is reducing in households. This in turn is due to factors such as an increased preference for electricity and solar power reflected in the appliance trends towards RC air-conditioning and solar water heating. The forecast growth in E to G connections maintains the historical average growth rate.

Table 3.11 Residential Connection Forecast by Connection Type | No.

Total Connections	2015	2016	2017	2018	2019	2020	2021
Existing 2014 Connections	411,463	406,241	402,915	401,480	400,027	398,557	397,068
New Dwelling Connections | New Estates	5,158	5,282	4,886	4,592	4,781	5,093	5,306
New Dwelling Connections | MD/HR	697	579	498	464	463	547	544
New E to G Connections	1,435	1,435	1,435	1,435	1,435	1,435	1,435
Total Connections	418,754	420,828	424,321	429,376	434,603	440,208	446,004

Table 3.12 Average Annual Growth of Residential Connections | %

Average Growth	2011 - 2014	2015-2021	2017 - 2021
Residential	1.75%	1.11%	1.17%

Existing Connections

Core forecasts net existing connections by subtracting the number of disconnections from the previous year's opening connections. Forecast disconnections are based on the historical rate of disconnections as a percentage of year-opening connections between 2011 to 2014, which provided a historical annual average of 0.34%.

Existing connections are forecast to decline from 406,241 to 397,068 during the Review Period. The forecast for existing connections and disconnections is presented in Table 3.13.

Table 3.13 Existing Connections Forecast | No.

Connections	2015	2016	2017	2018	2019	2020	2021
Opening Connections	412,860	411,463	406,241	402,915	401,480	400,027	398,557
Disconnections	1,397	1,417	1,424	1,435	1,453	1,470	1,489
Disconnections | Zero Consuming Connections	-	3,805	1,903	-	-	-	-
Closing Connections	**411,463**	**406,241**	**402,915**	**401,480**	**400,027**	**398,557**	**397,068**

New Estate & MD/HR Connections

The number of New Estate & MD/HR gas connections is based on a new dwellings forecast. The new dwellings forecast used to underpin the connections forecast is obtained from BIS Shrapnel and dated as of March 2015.[32] Further detail on the methodology undertaken to forecast new dwellings is provided in Annexure 6. Core notes that BIS Shrapnel forecast fewer households to be built in the period between 2017 to 2021 (50,400 households), when compared to the period between 2010 and 2014 (51,565 households).

[32] BIS Shrapnel, *AGNL South Australia forecasts.xlsx*, as provided by AGN on 26 March 2015.

Table 3.14 BIS Shrapnel New Dwellings Forecast | No.

	2015	2016	2017	2018	2019	2020	2021
New Estates (Detached Houses)	7,850	8,100	7,550	7,150	7,500	8,050	8,450
MD/HR	2,938	2,500	2,200	2,100	2,150	2,600	2,650
Total	**10,788**	**10,600**	**9,750**	**9,250**	**9,650**	**10,650**	**11,100**

The number of new gas connections during the forecast period is based on declining proportion of New Estate and New MD/HR connections to New Estate and MD/HR dwellings (per 2013 -2014 data as reported by BIS Shrapnel) [33], consistent with historical observation. This is likely due to consumer preference to appliances that utilise solar or electricity as a fuel source, or growth in households outside of the AGN gas network.

Table 3.15 Forecast of New Residential Gas Connections within the AGN Network Reach | No.

	2015	2016	2017	2018	2019	2020	2021
New Estates	5,158	5,282	4,886	4,592	4,781	5,093	5,306
MD/HR	697	579	498	464	463	547	544
Total	**5,855**	**5,861**	**5,384**	**5,056**	**5,244**	**5,640**	**5,850**

It was assumed that there will be no changes to policy that would impact the rate of new connections, or the allocation of New Estate and MD/HR connections during the AA period.

Electricity to Gas (“E to G”) Connections

The average historical number of E to G connections between 2010 and 2014 (calculated to be 1,435), was used as a basis to forecast E to G connections beyond 2014. Due to a high level of observed volatility in the historical data, the more appropriate method was to use the average number rather than an average growth rate. The summary of the E to G connections forecast is provided in Table 3.16.

Table 3.16 Forecast of New E to G Connections | No.

	2014	2015	2016	2017	2018	2019	2020	2021
New E to G	1,342	1,435	1,435	1,435	1,435	1,435	1,435	1,435

3.4.3. Derivation of Residential Demand per Connection

Table 3.17 provides the forecast of residential demand per connection for each connection type. The weighted average of these connection types shows a forecasted decline from 15.32GJ to 12.52GJ over the Review Period. This is equivalent to an average annual growth rate of -3.96%.

[33] BIS Shrapnel, *AGNL South Australia forecasts.xlsx*, as provided by AGN on 26 March 2015.

Table 3.17 Residential Demand per Connection Forecast | GJ/connection

Demand per Connection	2015	2016	2017	2018	2019	2020	2021
Existing	16.15	15.52	15.03	14.49	13.98	13.50	13.04
New Estate	9.97	9.55	9.20	8.88	8.57	8.27	8.13
New MD/HR	6.23	5.97	5.75	5.55	5.35	5.17	5.08
New E to G	12.53	12.00	11.57	11.16	10.77	10.40	10.21
Weighted Average	**16.05**	**15.32**	**14.75**	**14.14**	**13.57**	**13.03**	**12.52**

A forecast for demand per connection was derived for the residential sector using the methodology outlined in section 2.2.1.2. The average annual growth in demand per connection was derived using historic data. This was completed separately for each connection type. Further analysis was then conducted to identify two sources of influence:

- Factors influencing the historic average annual growth rate that will not exert the same influence during the Review Period; and
- Factors that will exert an influence during the Review Period but did not contribute to the historic average growth rate.

The significant drivers for the predicted reduction in residential demand per connection are movements in gas prices and electricity prices. Additionally, the proportion of less gas intensive dwellings is increasing for all connection types and this is also contributing to lower the weighted average demand per connection forecast. These factors are described in further detail below.

3.4.3.1 Factors Continuing to Impact Demand per Connection

Core's analysis looked firstly at capturing the historical underlying growth rate of demand per connection, based on weather normalised demand. Rather than using a historical trend, the preferred approach here was to use historical average annual growth. This was the conclusion reached after several model specifications were fitted, including linear and quadratic trends, but none were a suitable fit for the data series. As part of the bottom-up approach, this process was undertaken separately for each connection type.

The growth rates were calculated using historical data from 2011 to 2014 (which, as outlined in Section1.7, was deemed to be the appropriate history, given the structural change that occurred in 2009) to which adjustments were made to remove the impacts of price fluctuations. The historical average annual growth captures other existing impacts on demand per connection such as climatic trends, appliance substitution trends and energy efficiency trends. The impact of these factors during the forthcoming Review Period is discussed below. Section 3.4.3.2 which follows, will discuss the new impacts on demand per connection such as future gas and electricity prices.

For the 2011-2014 period, demand per connection for existing connections decreased by an annual average of 2.31% (net of elasticity factors). The other residential connection types experienced a larger fall in their underlying growth rates. New Estate connections have fallen by 8.84% while as E to G connections and MD/HR connections have both fallen by 7.1% and 9.02%, respectively.

Core has adopted a conservative view and applied the historical average annual growth in existing connections to all new connections types. The following table summarises the assumed underling annual growth in demand per connection, normalised for weather and price effects for each connection type.

Table 3.18 Forecast impact of historical average annual growth by residential connection type | %

% Impact	2015	2016	2017	2018	2019	2020	2021
Existing Connections	-2.31%	-2.31%	-2.31%	-2.31%	-2.31%	-2.31%	-2.31%
New Estate Connections	-2.31%	-2.31%	-2.31%	-2.31%	-2.31%	-2.31%	-2.31%
MD/HR Connections	-2.31%	-2.31%	-2.31%	-2.31%	-2.31%	-2.31%	-2.31%
E to G Connections	-2.31%	-2.31%	-2.31%	-2.31%	-2.31%	-2.31%	-2.31%

Table 3.18 shows that these underlying growth rates for demand per connection will continue during the Review Period. The remainder of this section will examine the factors behind these rates and explain why Core believes they are appropriate to carry into the forecast.

Household Appliance Trends

Core analysis concluded that South Australian households will likely maintain the rate of substitution of gas appliances in favour of electrical or solar powered appliances. This is reflected by recent ABS data, which highlights some key trends for gas appliance substitution rates.[34] Of all the households that were using gas as their main heating source in 2011, 7.5% switched away from gas heating by 2014. Furthermore, over the same time period, electricity increased its market share by over 4% when it comes to heating homes in South Australia. In addition to the substitution of gas heating appliances, gas water heating appliances have also been under threat from solar heating systems. Over the same period, solar water heaters increased their market share by 23% to 8.1%. Data and further explanation can be found in Annexure 7.

Induced by efficiency gains and lower running costs, South Australian households are switching away from gas in favour of substitute appliances such as RC air-conditioning and solar water heaters.

Households are further incentivised by the convenience of having one RC air-conditioning system that can both heat and cool. Increased awareness has resulted in a growing number of households that are adopting solar based appliances based on the reduced environmental impact. Discussion on the incentives and behaviour of Australian households is provided below, with further analysis presented in Annexure 7.

Heating requirements consume more gas than water heating and cooking which means that the reduction in gas heating penetration will have the biggest influence on demand per connection. During the Review Period, the continued growth of RC air-conditioning will lower the average consumption of gas in households. There is significant momentum in the appliance substitution rate and this will be strengthened by the efficiency trends and policies discussed below.

The three main segments of gas usage for South Australian households are space heating, water heating and cooking appliances.

[34] ABS, *4602.0.55.001 Environmental Issues: Energy Use and Conservation*, Mar 2014.

National Energy Policy

The E3 program is a household energy efficiency program that has been implemented in Australia. The program improves the efficiency of products and appliances that are sold in Australia and incorporates several key efficiency initiatives such as the Minimum Energy Performance Standards ("**MEPS**"). The latest impact study for the E3 program shows a considerable increase in gas savings. Between 2000 and 2013, it is estimated that the E3 program saved 6.1 petajoules ("**PJ**") of gas. However, over a quarter of this was achieved in 2013 alone, the final year of the review study.

Given the implementation of new policies under E3 and the strengthening of existing policies, the study forecasted that on average, three times the 2013 gas savings will be achieved each year until 2020. This was somewhat of a conservative estimate based on a scenario with slower policy implementation. The E3 program has been strengthened at the end of 2012 with new legislation and a national framework that extends to South Australia. Increased reporting and compliance (e.g. financial penalties) will ensure that gas demand per connection will continue to fall over the Review Period.

State Energy Policy and Efficiency Trends

A multitude of policies, programs and initiatives are driving efficiency gains in South Australia. Core identified these policies for the 2011-2014 period and after a comprehensive review (as outlined in Annexure 7), has concluded that the reach and intensity of these policies will not change significantly during the Review Period. Accordingly, Core believes that the impact on underlying changes to demand per connection will continue at the annual rate seen between 2010 and 2014.

In addition to the appliance substitution discussed above, these policies will continue to reduce average gas usage by fuelling the proliferation of superior building design and energy efficient household appliances. Such appliances are becoming more widely available and affordable to residential customers. As more customers move to energy efficient appliances, less gas is required for household activities leading to a decrease in gas demand per customer.

Household Behaviour and Motivations

A recent qualitative survey conducted by the Australian Housing and Urban Research Institute also reveals that Australians assess the environmental impact of their energy use and then use this to make decisions that reduce energy.[35] In the survey, approximately half of Australian households that reduced their energy use were influenced by the environmental aspects of doing so. Over 60% of these households cited a new awareness of the potential efficiency and cost advantages. This reinforces that all the policies, campaigns and even fact sheets will continue to lower demand per connection during the Review Period through behavioural changes in consumption. Further analysis on the incentives and behaviour of Australian households can be found in Annexure 7.

Climatic Trend

Long term weather analysis indicates that a warming trend will continue across the Review Period. Core believes it is reasonable to assume that this trend captured by the historic annual average growth rate of gas demand will continue during the Review Period. Core is of the opinion that deviation from the warming trend is unlikely in the forecast

[35] Fielding, K. Et al. (Australian Housing and Urban Research Institute), *Environmental Sustainability: understanding the attitudes and behavior of Australian households,* October 2010.

period. This opinion reflects the analysis and forecasts of the CSIRO in their latest annual climate report.[36] Core accepts this warming trend.

Macroeconomic Variables and Residential Demand

The role of certain macroeconomic variables in household gas demand is a logical line of inquiry. Core's analysis showed that the relationship between certain economic variables and residential demand per connection is either unreliable or not statistically significant. Therefore, an economic variable was not included in the forecasting model. A variety of different model and variable specifications confirmed that the best approach was to exclude the following variables:

- GSP
- Gross Household Disposable Income per capita ("**GHDI**")
- State Final Demand ("**SFD**")

Annexure 5 provides further analysis of the relationship between residential demand and economic activity. Given the small sample size and high level of collinearity present in most of the models used to test the macroeconomic variables, the coefficients and statistical significance should be interpreted with caution. Despite comprehensive econometric testing, the results were not significant. Different variable specification is a powerful robustness check and in this situation it produced inconsistent results. This suggests that the precise impact of macroeconomic fluctuations cannot be accurately or reliably isolated. Furthermore, some apparently significant results departed from economic theory. Accordingly, Core took the view that a macroeconomic variable should not be included in the residential forecast.

3.4.3.2 Factors with a New Impact on Demand per Connection

Own Price Elasticity

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

The gas price movements that instigate this elasticity impact are derived using Core's proprietary model. Core has undertaken gas price forecasting within an AA context for Jemena Gas Network's New South Wales distribution network and Envestra's (now AGN) Victorian distribution network. Core has also developed gas price forecasts for each eastern Australian jurisdiction as part of its Gas Networks Sector Study, commissioned by the Energy Networks Association in August 2014.

The approach undertaken by Core to forecast retail gas prices consists of analysing each individual component of the retail gas price. A full listing and analysis of these components can be found in Annexure 2 |. The forecast is driven by an expected increase in wholesale gas costs which is more than offsetting the reduction in distribution costs.

Furthermore, the elasticity value used by Core is a product of extensive third party analysis via international literature review as well as a review of previous AA price elasticity factors that have been accepted by the AER. Accordingly, a long-run elasticity factor of -0.30 has been used for residential demand. Due to wholesale cost increases, gas prices

[36] CSIRO, *State of the Climate 2014*, February 2015.

are expected to increase during the Review Period despite a reduction in distribution costs, which are expected to fall by 11.67% in 2017. Distribution costs are then expected to increase by 5% per annum thereafter. The lagged impact of price increases in 2015 and 2016 results in an overall negative impact on demand during the forecast period. Table 3.19 provides the forecast of own price impacts on demand per connection.

Core has also assumed that reductions in gas prices will not result in a symmetric response, and customers won't increase gas demand as a response to gas price decreases. Price sensitivity is an established factor for gas demand and energy demand more generally. There is evidence to suggest that price responses tend to be asymmetric-demand responses are greater when prices rise.

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

'*Consumer response to changes in electricity prices is asymmetric. While consumers may reduce consumption in response to price rises, they do not necessarily revert to previous levels of consumption when prices later fall, due to permanent changes in behaviour, or momentum. To reflect this, AEMO applied a Maximum Price Model which assumes that rather than responding to the carbon price repeal, customers will continue to respond to the highest prices they have experienced in recent years'.*[37]

Table 3.19 Own Price Elasticity Impact on Demand | %

	2015	2016	2017	2018	2019	2020	2021
Change in Gas Bill	6.08%	2.05%	-6.41%	4.86%	3.78%	2.61%	2.66%
Price Elasticity Impact (-0.30)	-3.08%	-2.03%	-1.03%	-1.05%	-1.00%	-0.91%	-0.89%

Further detail on the gas price forecast and price elasticity impact can be found in Annexes 2 and 4.

Cross Price Elasticity

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

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

Core forecasting captures the response of consumers as they face relative price changes between gas and electricity. For example, the model would capture the degree of substitution that occurs between gas heating and heating by RC air-conditioning when there is a shift in relative prices between gas and electricity. Cross price elasticity has a more significant effect in the forthcoming Review Period in comparison to previous AAs due to the significant electricity price decreases that are anticipated. Previous AA reviews have generally faced stagnant or rising electricity prices.

Core has derived electricity retail price movements from data contained in the AER's 2014 State of the Energy Market Report, Essential Services Commission of South Australia's ("**ESCOSA**") August 2014 Ministerial Pricing Report, and the AER's SA Power Networks – Determination 2015-2020. Further detail on the electricity price forecast and price elasticity impact can be found in Annexes 3 and 4. Table 3.20 summarises the cross price elasticity impact.

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

Table 3.20 Cross Price Elasticity Impact on Residential Demand per connection | %

	2015	2016	2017	2018	2019	2020	2021
Change in Electricity Bill	-13.91%	-4.81%	-2.44%	-2.44%	-2.00%	-2.44%	-2.44%
Price Elasticity Impact (0.10)	-1.39%	-0.48%	-0.24%	-0.24%	-0.20%	-0.24%	-0.24%

3.4.4. Combined results by connection type:

Following the analysis of each driver outlined above and in Annexes 4-6, an annual forecast of movement in gas demand per connection was derived for each connection type, as summarised in the following figures and tables. The drivers are clarified for each connection type but generally, the underlying growth contribution is a combination of the qualitative factors discussed in the previous section such as gas appliance trends, energy policy, climatic trends and potentially a macroeconomic variable impact. As previously mentioned, some of these factors have been analysed statistically and the quantitative results were not precise or robust enough to individually quantify the impacts for the forecast period. However, the combined impact of these variables is captured with the weather normalised, historical annual average growth rates which have been adjusted for historical price impacts. This average annual change appears as the first forecast component for each of the connection types. For existing connections, the zero consuming meters adjustment is also incorporated. No such adjustment is required for new connection types as the program targets meters that have been zero consuming over time.

Existing Connections

The forecast for existing connections is a combination of the drivers listed in Table 3.21 which shows the percentage impact and Table 3.22 which shows the absolute impact. The average annual change forms the base of the forecast and this component captures the continuing impact of appliance trends and energy policies. The existing connections forecast is revised upwards for 2016 and 2017 due to the zero consuming meter program and downwards due to the two price elasticity effects. The rate of decline for existing connections is an annual average of 3.43% over the Review Period.

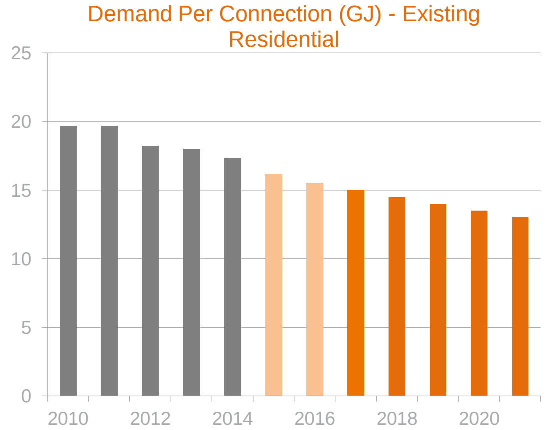
Table 3.21 Forecast Impact of Drivers on Existing Connection Demand per Connection | %

% Impact	2015	2016	2017	2018	2019	2020	2021
Average Annual Change	-2.31%	-2.31%	-2.31%	-2.31%	-2.31%	-2.31%	-2.31%
Own Price Elasticity	-3.08%	-2.03%	-1.03%	-1.05%	-1.00%	-0.91%	-0.89%
Cross Price Elasticity	-1.39%	-0.48%	-0.24%	-0.24%	-0.20%	-0.24%	-0.24%
Zero Consuming Connections Adjustment	0.00%	0.89%	0.45%	0.00%	0.00%	0.00%	0.00%
Total Impact	**-6.78%**	**-3.92%**	**-3.13%**	**-3.60%**	**-3.51%**	**-3.45%**	**-3.44%**

Table 3.22 Forecast Change of Existing Connection Demand per Connection due to Drivers | GJ

Demand per Connection	2014	2015	2016	2017	2018	2019	2020	2021
2014 Demand per Connection	17.33							
Average Annual Change		-0.40	-0.37	-0.36	-0.35	-0.33	-0.32	-0.31
Own Price Elasticity		-0.53	-0.33	-0.16	-0.16	-0.15	-0.13	-0.12
Cross Price Elasticity		-0.24	-0.08	-0.04	-0.04	-0.03	-0.03	-0.03
Zero Consuming Connections Adjustment		0.00	0.14	0.07	0.00	0.00	0.00	0.00
Forecast		**16.15**	**15.52**	**15.03**	**14.49**	**13.98**	**13.50**	**13.04**

Figure 3.6 Existing Connection Demand per Connection | GJ



New Estate Connections

The decline in demand per connection for New Estates is greater than the decline seen in existing households. In addition to the same underlying growth rate which incorporates several aspects such as appliance trends and energy policy, the same percentage impacts from price elasticity are forecast. New estates do not feature zero consuming meters so this driver is left out of the forecast. New dwellings are continually exposed to the newest technologies and the constant decline in average gas demand reflects the continual improvements in energy efficiency. The average demand per connections is used to derive total demand to account for the lagged nature of new connections coming online throughout the year. The following two tables show that the forecast decrease in demand per connection is greater than existing connections for 2016 and 2017 due to no impact from zero consuming meters. In other years, the percentage impact is the same. The average annual growth rate of demand per connection of new estate connections is forecast to decline at 3.52% during the Review Period. This is significantly slower than the decline in average annual growth rate of 8.84%, observed between 2010 and 2013 (note 2014 demand per connection for new estate connections is forecast).

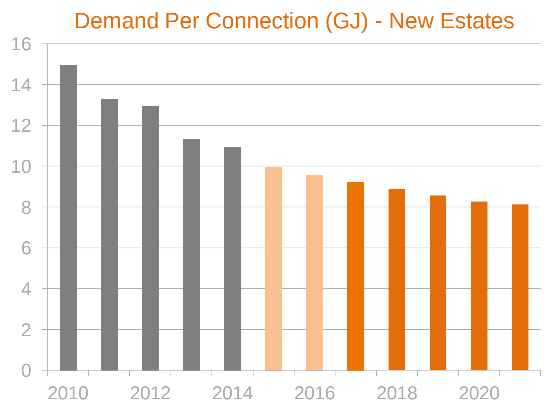
Table 3.23 Forecast Impact of Drivers on New Estate Connection Demand per Connection | %

% Impact	2015	2016	2017	2018	2019	2020	2021
Average Annual Change	-2.3%	-2.3%	-2.3%	-2.3%	-2.3%	-2.3%	-2.3%
Own Price Elasticity	-3.1%	-2.0%	-1.0%	-1.1%	-1.0%	-0.9%	-0.9%
Cross Price Elasticity	-1.4%	-0.5%	-0.2%	-0.2%	-0.2%	-0.2%	-0.2%
Total Impact	**-6.78%**	**-4.82%**	**-3.58%**	**-3.60%**	**-3.51%**	**-3.45%**	**-3.44%**

Table 3.24 Forecast Change of New Estate Connection Demand per Connection due to Drivers | GJ

Demand per Connection	2014	2015	2016	2017	2018	2019	2020	2021
2014 Demand per Connection	10.95							
Average Annual Change		-0.25	-0.24	-0.22	-0.22	-0.21	-0.20	-0.19
Own Price Elasticity		-0.34	-0.21	-0.10	-0.10	-0.09	-0.08	-0.07
Cross Price Elasticity		-0.15	-0.05	-0.02	-0.02	-0.02	-0.02	-0.02
Forecast		10.21	9.72	9.37	9.03	8.72	8.42	8.13
Adjusted Forecast | Average		**9.97**	**9.55**	**9.20**	**8.88**	**8.57**	**8.27**	**8.13**

Figure 3.7 New Estate Connection Demand per Connection | GJ



MD/HR Connections

Demand per connection for MD/HR connections declines at the same rate as new estate connections. The demand factors are the same whereby aspects such as appliance trends and energy policy continue to drive underlying growth rate and new price elasticity effects contribute to the falling demand per connection. The average demand per connection is used to derive total demand to account for the lagged nature of new connections coming online throughout the year. The average annual growth rate of demand per connection of new estate connections is forecast to decline at 3.52% during the Review Period. This is significantly slower than the decline in average annual growth rate of 9.02%, observed between 2010 and 2013 (note 2014 demand per connection for new estate connections is forecast).

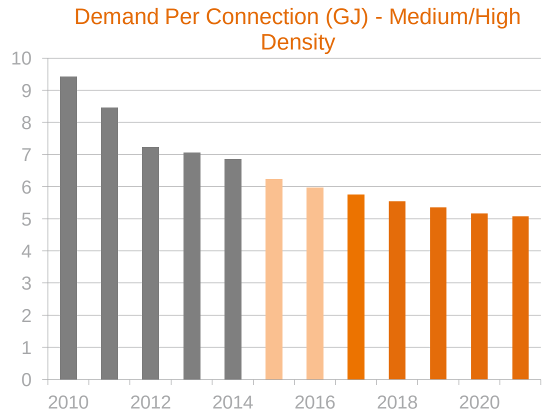
Table 3.25 Forecast Impact of Drivers on MD/HR Connections Demand per Connection | %

% Impact	2015	2016	2017	2018	2019	2020	2021
Average Annual Change	-2.3%	-2.3%	-2.3%	-2.3%	-2.3%	-2.3%	-2.3%
Own Price Elasticity	-3.1%	-2.0%	-1.0%	-1.1%	-1.0%	-0.9%	-0.9%
Cross Price Elasticity	-1.4%	-0.5%	-0.2%	-0.2%	-0.2%	-0.2%	-0.2%
Total Impact	**-6.78%**	**-4.82%**	**-3.58%**	**-3.60%**	**-3.51%**	**-3.45%**	**-3.44%**

Table 3.26 Forecast Change of MD/HR Connection Demand per Connection due to Drivers | GJ

Demand per Connection	2014	2015	2016	2017	2018	2019	2020	2021
2014 Demand per Connection	6.85							
Average Annual Change		-0.16	-0.15	-0.14	-0.14	-0.13	-0.13	-0.12
Own Price Elasticity		-0.21	-0.13	-0.06	-0.06	-0.06	-0.05	-0.05
Cross Price Elasticity		-0.10	-0.03	-0.01	-0.01	-0.01	-0.01	-0.01
Forecast		6.38	6.07	5.86	5.65	5.45	5.26	5.08
Adjusted Forecast | Average		**6.23**	**5.97**	**5.75**	**5.55**	**5.35**	**5.17**	**5.08**

Figure 3.8 MD/HR Demand per Connection | GJ



E to G Connections

The strength of the E to G decline can also be attributed to the historical underlying average which is being driven primarily by appliance trends and energy policy. Demand per connection for E to G connections declines at the same percentage rate as the other new connection types due to the same price elasticity effects and no influence from the zero consuming meters program. The average demand per connections is used to derive total demand to account for the lagged nature of new connections coming online throughout the year. The average annual growth rate of demand per connection of new estate connections is forecast to decline at 3.52% during the Review Period. This is significantly slower than the decline in average annual growth rate of 7.31%, observed between 2010 and 2013 (note 2014 demand per connection for new estate connections is forecast).

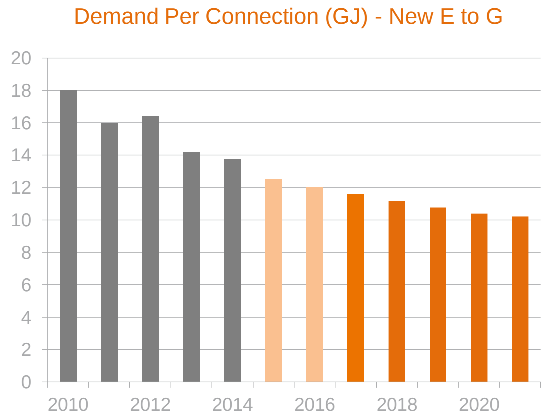
Table 3.27 Forecast Impact of Drivers on E to G Demand per Connection | %

% Impact	2015	2016	2017	2018	2019	2020	2021
Average Annual Change	-2.3%	-2.3%	-2.3%	-2.3%	-2.3%	-2.3%	-2.3%
Own Price Elasticity	-3.1%	-2.0%	-1.0%	-1.1%	-1.0%	-0.9%	-0.9%
Cross Price Elasticity	-1.4%	-0.5%	-0.24%	-0.2%	-0.2%	-0.2%	-0.2%
Total Impact	**-6.78%**	**-4.82%**	**-3.58%**	**-3.60%**	**-3.51%**	**-3.45%**	**-3.44%**

Table 3.28 Forecast Change of E to G Demand per Connection due to Drivers | GJ

Demand per Connection	2014	2015	2016	2017	2018	2019	2020	2021
2014 Demand per Connection	13.77							
Average Annual Change		-0.32	-0.30	-0.28	-0.27	-0.26	-0.25	-0.24
Own Price Elasticity		-0.42	-0.26	-0.126	-0.124	-0.114	-0.099	-0.094
Cross Price Elasticity		-0.19	-0.06	-0.030	-0.03	-0.02	-0.03	-0.03
Forecast		12.83	12.22	11.78	11.35	10.96	10.58	10.21
Adjusted Forecast | Average		**12.53**	**12.00**	**11.57**	**11.16**	**10.77**	**10.40**	**10.21**

Figure 3.9 E to G Connection Demand per Connection | GJ



3.5. Tariff V | Commercial Demand Forecast

3.5.1. Derivation of Commercial Demand

Commercial demand is divided into two segments:

- Existing commercial connections
- New commercial connections

Total annual commercial demand is forecast to decrease from 2,877,119GJ to 2,742,183GJ, equivalent to an average annual growth of -0.96%, over the 2017 to 2021 period.

Table 3.29 Commercial Demand Forecast | GJ

Total Demand	2015	2016	2017	2018	2019	2020	2021
Existing	2,893,374	2,792,775	2,705,027	2,630,401	2,542,920	2,455,110	2,378,385
New	20,191	80,048	129,192	175,092	230,880	290,352	349,502
Tariff D to Tariff Movement	4,296	4,296	4,296	14,296	14,296	14,296	14,296
Total	**2,917,861**	**2,877,119**	**2,838,515**	**2,819,789**	**2,788,096**	**2,759,758**	**2,742,183**

3.5.2. Derivation of Commercial Connections

Over the Review Period, commercial connections are forecast to increase from 9,983 to 10,439, equivalent to an annual average growth of 0.91%.

Table 3.30 Commercial Connections Forecast | No.

Total Connections	2015	2016	2017	2018	2019	2020	2021
Existing	10,351	9,528	9,067	8,968	8,869	8,768	8,665
New	235	220	259	229	272	277	281
Cumulative New	1	1	1	2	2	2	2
Tariff D to Tariff	235	455	714	943	1,215	1,492	1,773
Total	**10,587**	**9,983**	**9,781**	**9,913**	**10,086**	**10,261**	**10,439**

3.5.2.1 Total Connections

Total connections are forecast based on historical average annual growth and GSP. The historical average annual growth of 0.97% was applied to the existing number of connections in 2014 to provide a forecast. This growth rate was adjusted to remove the impact of historical GSP. The GSP component is estimated separately and then later added to this underlying historical growth.

Table 3.31 Historical Commercial Connections | No.

Connections	2010	2011	2012	2013	2014	Average Growth (2011-2014)
Total Connections	9,885	10,022	10,068	10,189	10,446	1.39%
Annual Growth	-	1.4%	0.5%	1.2%	2.5%	1.39%
Annual Growth | GSP Adjusted	-	1.1%	-0.2%	0.8%	2.3%	0.97%

Regression results support a relationship between GSP and commercial connections, with a regression coefficient of 0.285. The regression coefficient implies that for every 1% increase in GSP in the previous year, commercial connections will increase by 0.285%. GSP forecasts are obtained from BIS Shrapnel, as provided by AGN. BIS Shrapnel indicated that the GSP growth forecast assumes BHP Billiton's Olympic Dam will come online post 2018. Core deems it unlikely that an expansion of Olympic Dam will proceed within the Review Period, and as such has assumed 2.10% GSP growth per annum to 2021. ACIL Allen Consulting's best practice gas consumption methodology, as adopted by AEMO for the purpose of the NGFR forecasts, states that:

'*…there may be cases where it is appropriate to alter the GSP forecast in a particular forecast area*.' [38]

[38] ACIL Allen Consulting, *Report to Australian* Energy *Market Operator, 'Gas Consumption Forecasting: A Methodology*,' June 2014.

Table 3.32 GSP Growth Forecast | %

Impact	2015	2016	2017	2018	2019	2020	2021
GSP Growth Forecast	0.70%	1.90%	0.80%	2.10%	3.10%	4.10%	2.80%
Adjusted GSP Growth Forecast	0.70%	1.90%	0.80%	2.10%	2.10%	2.10%	2.10%

Table 3.33 Forecast Impact of Drivers on Commercial Connections | %

Impact	2015	2016	2017	2018	2019	2020	2021
Average Annual Change	0.97%	0.97%	0.97%	0.97%	0.97%	0.97%	0.97%
GSP Impact	0.37%	0.20%	0.54%	0.23%	0.60%	0.60%	0.60%
Total	**1.34%**	**1.17%**	**1.51%**	**1.20%**	**1.57%**	**1.57%**	**1.57%**

Annual average growth and GSP impacts were applied to the number of commercial connections in 2014 to derive the forecast of total commercial connections. This forecast is summarised in Table 3.34.

Table 3.34 Forecast of Total Commercial Connections | No.[39]

	2014	2015	2016	2017	2018	2019	2020	2021
Connections	**10,446**	**10,586**	**10,710**	**10,872**	**11,003**	**11,176**	**11,351**	**11,529**

An additional 1092 zero consuming connections are forecast to be disconnected between 2016 and 2017. The resulting forecast of connections is provided in Table 3.35.

Table 3.35 Forecast of Total Commercial Connections | No.[40]

	2014	2015	2016	2017	2018	2019	2020	2021
Opening Connections		10,446	10,586	9,982	9,780	9,911	10,084	10,259
Historical Growth		102	103	104	106	107	109	110
GSP Impact		39	21	58	25	66	67	68
Zero Consuming Disconnections		0	728	364	0	0	0	0
Connections Forecast	**10,446**	**10,586**	**9,982**	**9,780**	**9,911**	**10,084**	**10,259**	**10,437**

3.5.2.2 Existing Connections

Core forecasts net existing connections by extrapolating the number of disconnections and subtracting this value from the previous year's existing connections. The historical average percentage of disconnections as a proportion of connections is 1.01%. The forecast for existing connections and disconnections is provided in Table 3.36.

[39] Excluding one additional Tariff D to Tariff V connection.

[40] Excluding one additional Tariff D to Tariff V connection.

Table 3.36 Existing Connections Forecast | No.

Connections	2014	2015	2016	2017	2018	2019	2020	2021
Existing Connections	10,446							
Disconnections		95	96	97	98	100	101	103
Zero Consuming Disconnections		-	728	364	-	-	-	-
Existing Connections Forecast		**10,351**	**9,528**	**9,067**	**8,968**	**8,869**	**8,768**	**8,665**

3.5.2.3 New Connections

The forecast of new connections is derived by subtracting the existing connections forecast from the total connections forecast. The following table lists the estimated number of new commercial connections up to 2021.

Table 3.37 Forecast of New Commercial Connections | No.

New Connections	2015	2016	2017	2018	2019	2020	2021
Annual	235	220	259	229	272	277	281
Cumulative	235	455	714	943	1,215	1,492	1,773

3.5.2.4 Tariff D to Tariff V Movements

Core was informed by AGN of only one customer who planned to move from the Tariff D to Tariff V class during the Review Period. This customer was added to the forecast of commercial connections from 2015 onwards.

3.5.3. Derivation of Commercial Demand per Connection

Table 3.38 provides a summary of commercial demand per connection which has been divided into new and existing connections. Adjusting for the Tariff D to Tariff V customer movements, the weighted average of existing and new commercial demand per connection also appears in Table 3.38. The new connections apply upward pressure on the total demand per connection in each year of the forecast period. However, the overwhelming effect comes from the much higher proportion of existing connections. Apart from 2016 and 2017 when zero consuming meters provide a positive, artificial spike in demand per connection, the demand per connection forecast is falling. The weighted average demand per connection is forecast to steadily fall for most of the Review Period but the spike from the zero consuming meter program means absolute demand per connection will likely be slightly higher than at the beginning of the forecast period, from 288.19 to 261.36 GJ.

Table 3.38 Commercial Demand per Connection Forecast | GJ/connection

Demand per Connection	2015	2016	2017	2018	2019	2020	2021
Existing Connection	279.51	293.12	298.35	293.30	286.73	280.02	274.49
New Connection	171.99	176.07	181.02	185.76	190.03	194.66	197.17
Weighted Average	**275.22**	**287.79**	**289.79**	**283.07**	**275.08**	**267.61**	**261.36**
Weighted Average | Tariff movement adjusted	**275.60**	**288.19**	**290.20**	**284.46**	**276.44**	**268.95**	**262.68**

3.5.3.1 Demand per Connection Drivers

The drivers for the commercial demand per connection forecast are similar to the residential forecast outlined in the previous section. A forecast for demand per connection was derived for the commercial sector using the methodology outlined in Section 2.2.2.2. The average annual growth in demand per connection was derived using historical data and further analysis was then conducted to identify two sources of influence:

- Factors influencing the historic average annual growth rate that will not exert the same influence during the Review Period; and
- Factors that will exert an influence during the Review Period but did not contribute to the historic average growth rate.

A historical average was used as the foundation of the forecast as a linear trend model was not reliable and could not provide reliable or significant explanatory power. The major drivers for the predicted reduction in commercial demand per connection are gas prices and electricity prices. The proportion of less gas intensive dwellings is increasing for all connection types and this is also contributing to lower the weighted average demand per connection forecast.

3.5.3.2 Factors with a Continuing Impact

Historical Annual Average Growth

For commercial demand, the historical average annual growth removes the impact of gas and electricity prices. However, the impacts of climatic trend, appliance trend, energy efficiency trend, and government policy are still captured by the historical rate. Accordingly, Core research determined the likely impact of these drivers over the Review Period. Further detail and analysis can be found in Annexure 7 and there is also considerable overlap with the efficiency, policy and appliance trend analysis that was discussed in the context of residential demand. Ultimately it was determined that each one of these factors is best predicted by what was observed during recent history (2011-2014). This is already captured by the historical average annual growth rate, meaning no further revision was needed.

Economic Variables and Commercial Demand

A comprehensive analysis concluded that the relationship between economic variables and commercial demand is unreliable and not statistically significant. To derive an optimal forecast with maximum precision, the decision was made to exclude any economic variables. The methodology and results are detailed in Figure 5.3Annexure 5 |.

3.5.3.3 Factors with a New Impact

Own Price Elasticity

The analysis and logic behind price elasticity follows the description for the residential sector above. The review of key literature and previous AA decisions enabled Core to settle on a price elasticity of demand (“**PED**”) value of 0.35 which is slightly higher than the residential sector. Core has also assumed reduction in gas prices will not result in a symmetric response, and customers won’t increase gas demand as a response to gas price decreases, as previously mentioned for residential demand per connection. The resulting impact of gas prices is summarised below. Further detail on the gas price forecast and price elasticity impact can be found in Annexes 2 and 4.

Table 3.39 Own Price Elasticity Impact on Demand | %

	2015	2016	2017	2018	2019	2020	2021
Change in Gas Bill	-5.00%	4.51%	-6.51%	6.75%	4.71%	2.58%	2.64%
Price Elasticity Impact (-0.35)	-3.0%	-1.6%	-1.1%	-0.9%	-1.5%	-1.6%	-1.2%

Cross Price Elasticity

The cross price elasticity captures the impact of electricity prices for commercial demand per connection. This measures the response of businesses to relative prices of gas and electricity prices. For instance, businesses may substitute gas heating for heating by RC air-conditioning when faced with lower electricity prices. Core uses a proprietary model to derive electricity price forecasts and the following table provides the forecast of cross price impacts on demand per connection. The fall in electricity prices will only soften gas demand in the lead up to the Review Period. Further detail on the electricity price forecast and price elasticity impact can be found in Annexure 2 and Annexure 4.

Table 3.40 Cross Price Elasticity Impact on Demand | %

	2015	2016	2017	2018	2019	2020	2021
Change in Electricity Bill	-12.0%	-4.8%	-2.4%	-2.5%	-2.0%	-2.4%	-2.4%
Price Elasticity Impact (0.10)	-1.20%	-0.48%	-0.24%	-0.25%	-0.20%	-0.24%	-0.24%

3.5.3.4 Existing Connections

The forecast for existing connections is a combination of the following three drivers:

- Historical average annual change
- Own price elasticity
- Cross price elasticity

Average annual growth in demand per connection has been -1.42% since 2010. This increases to -0.52% when the historical price elasticity effects are removed. In total, the demand per connection for existing connections is forecast to fall from 293.12GJ to 274.49GJ between 2017 and 2021. Own price and cross price impacts have a net negative impact, an average annual change of approximately -0.75%. The percentage impact and absolute impact over the forecast period is presented in the following two tables.

Table 3.41 Forecast Impact of Drivers on Existing Commercial Demand per Connection | %

Demand per Connection	2015	2016	2017	2018	2019	2020	2021
Average Annual Change	-0.52%	-0.52%	-0.52%	-0.52%	-0.52%	-0.52%	-0.52%
Own Price Elasticity	-3.04%	-1.57%	-1.10%	-0.92%	-1.52%	-1.57%	-1.21%
Cross Price Elasticity	-1.20%	-0.48%	-0.24%	-0.25%	-0.20%	-0.24%	-0.24%
Zero Consuming Connections Adjustment	0.00%	7.50%	3.67%	0.00%	0.00%	0.00%	0.00%
Total	-4.8%	4.9%	1.8%	-1.7%	-2.2%	-2.3%	-2.0%

Table 3.42 Forecast Change of Existing Commercial Connection Demand per Connection due to Drivers | GJ

Demand per Connection	2014	2015	2016	2017	2018	2019	2020	2021
2014 Demand per Connection	293.50							
Average Annual Change		-1.54	-1.46	-1.53	-1.56	-1.53	-1.50	-1.47
Own Price Elasticity		-8.92	-4.39	-3.22	-2.75	-4.45	-4.51	-3.39
Cross Price Elasticity		-3.53	-1.35	-0.72	-0.75	-0.60	-0.72	-0.71
Zero Consuming Connections Adjustment		0.00	21.05	10.88	0.00	0.00	0.00	0.00
Forecast		**279.51**	**293.12**	**298.35**	**293.30**	**286.73**	**280.02**	**274.49**

3.5.3.5 New Connections

The forecast for new connections is also a combination of the following three drivers:

- Historical average annual change
- Own price elasticity
- Cross price elasticity

The demand per connection for new commercial connections is forecast to increase from 176.07GJ to 197.17GJ during the Review Period. The combined own and cross price impacts are negative, an average annual change of -0.75%. However, the major influence driving the increase in demand per connection is the historical average annual change of 4.07%. The percentage impact and absolute impact over the forecast period is presented in the following two tables. The average demand per connection is used to derive total demand to account for the lagged nature of new connections coming online throughout the year.

Table 3.43 Forecast Impact of Drivers on Existing Commercial Demand per Connection | %

Demand per Connection	2015	2016	2017	2018	2019	2020	2021
Average Annual Change	4.07%	4.07%	4.07%	4.07%	4.07%	4.07%	4.07%
Own Price Elasticity	-3.04%	-1.57%	-1.10%	-0.92%	-1.52%	-1.57%	-1.21%
Cross Price Elasticity	-1.20%	-0.48%	-0.24%	-0.25%	-0.20%	-0.24%	-0.24%
Total	**-0.18%**	**2.01%**	**2.72%**	**2.90%**	**2.35%**	**2.25%**	**2.61%**

Table 3.44 Forecast Change of New Commercial Connection Demand per Connection due to Drivers | GJ

Demand per Connection	2014	2015	2016	2017	2018	2019	2020	2021
2014 Demand per Connection	170.58							
Average Annual Change		6.93	6.92	7.06	7.25	7.46	7.64	7.81
Own Price Elasticity		-5.18	-2.67	-1.91	-1.64	-2.79	-2.95	-2.32
Cross Price Elasticity		-2.05	-0.82	-0.43	-0.45	-0.37	-0.47	-0.49
Forecast		**170.28**	**173.71**	**178.44**	**183.61**	**187.92**	**192.15**	**197.17**
Adjusted Forecast | Average		**171.99**	**176.07**	**181.02**	**185.76**	**190.03**	**194.66**	**197.17**

3.6. Review Period Possibilities

In addition to the discussions in Section 3.4 and 3.5, Core reviewed a number of factors that could impact Tariff V demand during the Review Period but could not be sufficiently quantified or predicted for the forecast. For instance, there has been considerable development in battery storage technology which has the potential to reduce gas demand. AGL recently announced it is launching a battery storage device into the Australian market.[41] If households invest in this technology they will have a greater incentive to fully utilise the technology, switching from gas appliances to electricity appliances and there will be an associated increased preference for electricity connections relative to gas connections.

The South Australian electricity market is introducing cost-reflective electricity tariffs from 2017. SA Power Networks is currently resubmitting a proposal for cost-reflective tariffs after their initial proposal did not meet requirements.[42] There are potential cost savings for customers and the new tariff structure provides a degree of increased price transparency and further advantages for customers who can be flexible with their electricity consumption patterns. Overall this will make electricity use more attractive to small energy users and exert downward pressure on both Tariff V gas connections and demand per connection.

Another possible influence on gas demand is the media hype surrounding Australia's rapidly expanding Liquefied Natural Gas ("**LNG**") export sector and speculation surrounding future higher gas prices due to the corresponding demand shock. Conceivably, households may respond to future uncertainty in gas prices and substitute electricity appliances for gas where possible and there will be an increased preference for electricity connections over gas connections.

In January 2014 the South Australian Water Heating Standards were amended to allow for the installation of smaller and medium size electric water heaters in houses that are not connected to reticulated gas. Previously, the standards required plumbers to install high efficiency gas, solar or electric heat pump systems only. The partial reversal of this ban will potentially reduce gas demand, albeit by a minor amount. Given the timing of the policy, there is no available data to quantify the change or incorporate it into the forecast but Core notes the minor downward pressure that the policy should apply to gas demand.

[41] AGL, *ASX and Media Release: 'AGL is first major retailer to launch battery storage'*, May 2015.
[42] AER, '*Statement of Reasons: SAPN tariff proposal 2015-16*', June 2015; The proposed Social Tariff and Solar Tariff were not accepted by the AER and SAPN must resubmit their proposed tariffs by the end of June, 2015.

In light of the issues discussed above, Core acknowledges that recent developments in the energy sector, significant media coverage and ongoing technology changes will likely decrease gas demand during the Review Period. The continued decline in Tariff V gas demand may receive additional momentum from these factors and Core believes the forecast declines form a conservative estimate. This is reflected in other parts of the demand forecast such as the E3 and MEPS forecast impact study which is based on the lower of two implementation scenarios. This reinforces the somewhat conservative nature of the demand forecast and the downside potential for gas demand over the Review Period.

4. Tariff D Demand Forecast

4.1. Introduction

At the end of 2014, AGN had a total of 129 Tariff D customers that were charged on a capacity basis. The ACQ and MDQ forecast for Tariff D customers is based upon analysis of the following:

- Existing ACQ and MDQ by customer at the end of 2014;
- Tariff D to Tariff V or Tariff V to Tariff D reallocations;
- Known and forecast load changes, disconnections and new connections; and
- The impact of movements in the economic outlook and energy efficiency.

4.2. Summary of Demand Forecast

A summary of the ACQ and MDQ forecast during the Review Period is provided below.

- MDQ is forecast to drop from 59.29TJ to 56.04TJ representing an annual average growth of 1.09%. This decline rate is slightly slower than what has been observed historically, a decline rate of 1.32% between 2011 and 2014.
- ACQ is forecast to drop from 11,666,047GJ to 10,931,438GJ, representing an annual average growth of -1.28%.This decline rate is slower than what has been observed historically, a decline rate of 2.30% between 2011 and 2014.
- Forecast of Tariff D MDQ & ACQ | TJ and GJ

Demand	2015	2016	2017	2018	2019	2020	2021
MDQ | TJ	56.09	59.29	60.57	56.96	56.59	56.27	56.04
ACQ | GJ	11,551,525	11,666,047	11,801,188	11,352,437	11,190,175	11,052,034	10,931,438

Table 4.1 Comparison of Historical and Forecast Average Annual Growth in Tariff D Demand | %

Average Growth	2011 - 2014	2015 - 2021	2017- 2021
MDQ	-1.32%	-0.83%	-1.09%
ACQ	-2.30%	-2.09%	-1.28%

The components of MDQ and ACQ load changes during the Review Period are outlined in Table 4.2 and Table 4.3, respectively. A significant proportion of the load reduction stems from known load changes of existing customers, which are detailed in Section 4.4. The forecast declines are primarily due to the continual competitive pressures in the industrial sector due to reduced competitiveness internationally and the efficiency trends that are expected to continue during the Review Period due mostly to the persistent advances in technology. There is also momentum towards reduction of gas consumption or partial fuel switching induced partly by forecast increases in gas price as a result of the LNG export sector expansion.

Table 4.2 Forecast Change in MDQ | TJ

Demand	2015	2016	2017	2018	2019	2020	2021
Existing Connections	59.74	56.09	59.29	60.57	56.96	56.59	56.27
Existing Connections | Load Changes	-1.17	2.88	-	-0.02	-0.16	-0.13	-0.03
New Connections	-	0.52	2.00	-	-	-	-
Disconnections	-2.25	-	-0.51	-3.23	-	-	-
Efficiency Trend	-0.20	-0.20	-0.20	-0.20	-0.20	-0.20	-0.20
Tariff D to Tariff Movements	-0.02	-	-	-0.17	-	-	-
Tariff to Tariff D Movements	-	-	-	-	-	-	-
Total	**56.1**	**59.3**	**60.6**	**57.0**	**56.6**	**56.3**	**56.0**

Table 4.3 Forecast Change in ACQ | GJ

Connections	2015	2016	2017	2018	2019	2020	2021
Existing Connections	12,727,141	11,551,525	11,666,047	11,801,188	11,352,437	11,190,175	11,052,034
Existing Connections | Load Changes	-568,470	218,155	329,164	14,839	-42,496	-20,501	-5,044
New Connections	-	80,000	250,000	-	-	-	-
Disconnections	-473,002	-56,681	-319,325	-331,105	-	-	-
Efficiency Trend	-129,848	-126,952	-124,698	-122,485	-119,766	-117,640	-115,552
Tariff D to Tariff V Movements	-4,296	-	-	-10,000	-	-	-
Tariff V to Tariff D Movements	-	-	-	-	-	-	-
Total	**11,551,525**	**11,666,047**	**11,801,188**	**11,352,437**	**11,190,175**	**11,052,034**	**10,931,438**

The primary forecasting approach was to rely on customer surveys and known closures (as publically reported by the company or media). This approach is unlikely to capture any closures after approximately three to four years. Consequently, the historical rate of disconnections was incorporated into the forecast to ensure that the forecast remained accurate for the entire Review Period. Tariff D connections are expected to fall from 125 to 110 during the Review Period.

Historically, connections between 2011 and 2014 have fallen at an average rate of 4.5% per annum. As such, Core's forecast predicts that connections will fall below 118. The forecast decline in connections should fall to 110 by the end of the Review Period. Core has adjusted the forecast decline in connections numbers to be equivalent to 2.2% per annum post 2018. This is based on the forecast decline in Tariff D connections between 2015 and 2018, as indicated by customer survey results.

Table 4.4 Forecast Change in Customers Based on Customer Surveys and Known Connection Movements | No.

Connections	2015	2016	2017	2018	2019	2020	2021
Existing Connections	125	125	124	118	118	118	118
New Connections	0	0	1	0	0	0	0
Disconnections	-3	0	-1	-6	0	0	0
Tariff D to Tariff Movements	-1	0	0	-1	0	0	0
Tariff V to Tariff D Movements	0	0	0	0	0	0	0
Total	**125**	**125**	**125**	**118**	**118**	**118**	**118**
% change	-3.1%	0.0%	0.0%	-5.6%	0.0%	0.0%	0.0%
Adjusted Total	**125**	**125**	**125**	**118**	**115**	**113**	**110**
% change	-3.1%	0.0%	0.0%	-1.4%	-2.2%	-2.2%	-2.2%

4.3. Disconnections & New Connections

AGN has advised Core of one definite closure for the Review Period. Core has undertaken a review of all publicly available information and reasonably assumed that there is likely to be seven disconnections, with one occurring in 2017 and an additional six customer disconnecting in 2018. Three disconnections have been identified for 2015. The forecast change in load due to disconnections and new connections is summarised in Table 4.5.

Table 4.5 Forecast Load Changes Due to Disconnections and New Connections

	2015	2016	2017	2018	2019	2020	2021
New Connections | No.	-	-	1	-	-	-	-
Disconnections | No.	3	0	1	6	0	0	0
New Connections							
ACQ Change | GJ	-	80,000	250,000	-	-	-	-
MDQ Change | TJ	0.00	0.52	2.00	0.00	0.00	0.00	0.00
Disconnections							
ACQ Change | GJ	-473,002	-56,681	-319,325	-331,105	-	-	-
MDQ Change | TJ	-2.25	0.00	-0.51	-3.23	0.00	0.00	0.00

The three recorded disconnections in 2015 are as follows:

- [redacted], which closed in October 2014
- [redacted], which was reported as closed in December 2014; and
- [redacted], reported as closed as of February 2014.

The existing Royal Adelaide Hospital has been marked for closure in 2017. The commissioning of the new Royal Adelaide Hospital is forecast for 2017, and it is assumed to require an ACQ similar to the old hospital. However, MDQ load for the new hospital is forecast to be slightly higher.

The remaining six disconnections in 2018 are due to the following:

- closure of Holden Ltd, and [redacted]
- closure of both the Repatriation Hospital and Hampstead Rehabilitation Centre.

These closures are expected to result in a reduction in ACQ and MDQ load. It should be noted that Holden is forecast to ramp down load prior to actual disconnection.

4.4. Known Load Changes

Following consultation with Core, AGN issued a survey to the top 30 Tariff D customers (36 separate consuming sites). This provided information on the outlook for demand over the Review Period. 78% of total recorded MDQ in 2014 is accounted for by the top 36 Tariff D customer sites. The form of survey that was issued is included as Annexure 8. Of the 36 surveys issued, AGN received 17 responses, with two customers indicating the survey would not be completed. For the two customers that did not complete the survey, it was assumed that their existing 2014 MDQ and ACQ would remain constant during the Review Period. The demand adjustments due to known load changes is summarised in Table 4.6.

Table 4.6 Known ACQ and MDQ Load Changes

Existing Customers	2015	2016	2017	2018	2019	2020	2021
ACQ | GJ	-568,470	218,155	329,164	14,839	-42,496	-20,501	-5,044
MDQ | TJ	-1.17	2.88	0.00	-0.02	-0.16	-0.13	-0.03

A significant proportion of the movement in existing customer load is attributed to planned changes in consumption by [redacted] and [redacted]. [redacted] has indicated via survey response that it plans to reduce ACQ and MDQ in 2015 and further in 2016. In contrast, [redacted] is planned for a major technology transformation which will see an increased use of natural gas at the site from 2016 onwards.

4.5. Economic Activity and Efficiency Trends

The change in MDQ and ACQ load due to forecast efficiency trends is summarised in Table 4.7. Across the Review Period, efficiency trends are forecast to decrease ACQ and MDQ by 600,142GJ and 0.99TJ, respectively. MDQ and ACQ have been observed to decline at an annual average growth rate of 0.6% and 1.8%, respectively. This excludes any new connections or disconnections that occurred during the historic 2010 to 2014 period. As such, it can be assumed that these declines can be attributed to reduced load due to efficiency gains.

Core expects the efficiency trends to continue during the Review Period due mostly to the continued advances in technology. There is also momentum towards reduction of gas consumption or partial fuel switching induced partly by forecast increases in gas price as a result of the LNG export sector expansion.

With respect to economic activity, the regression analysis determined that historic GVA growth and gas demand showed no statistically significant correlation by industry segment. Extensive detail and results from this process is provided in Annexure 9. The statistical results for each ANZSIC sector were either insignificant or not robust but there are additional sources of economic influence captured by the underlying growth rate rather than the regression analysis. The industrial sector is continually losing competitiveness relative to the export sectors in neighbouring countries. The annual decline in industrial demand is due partially to the reduced competitiveness of this sector in the face of these international competitive pressures.

Table 4.7 Change in ACQ and MDQ load due to Efficiency Trends

Existing Customers	2015	2016	2017	2018	2019	2020	2021
ACQ | GJ	-129,848	-126,952	-124,698	-122,485	-119,766	-117,640	-115,552
MDQ | TJ	-0.201	-0.203	-0.202	-0.201	-0.199	-0.197	-0.196

4.6. Movements Between Tariff D and Tariff V

One Tariff D to Tariff V movement was identified for the Review Period, [redacted]. AGN is currently processing a Tariff D closure request, effective 1 January 2015. [redacted] is also forecast to move to Tariff V due to reduced demand from the closure of Holden Ltd. Furthermore, there are a number of customers that moved from Tariff D to Tariff V during 2014. As a result, this registers as residual Tariff D consumption in 2014. Historically, this residual amount averages 15,788GJ per annum. In 2014, the residual consumption of connections that have moved from Tariff D to Tariff V is 17,013GJ. The balance between the 2014 and historical average residual Tariff D to Tariff V consumption (1,225GJ) has been allocated to the Tariff V Commercial demand forecast. No Tariff V to Tariff D movements are expected during the Review Period.

5. Conclusion

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

5.1. Tariff V

5.1.1. Total Demand

Tariff V demand is forecast to fall by an annual average rate of 2.24% over the Review Period, due primarily to a lower rate of forecast residential connections and continuation of a decline in residential demand per connection. This is a faster decline than the average annual rate seen over the 2011 to 2014 period. The outlook for each demand component, connections and demand per connections, is described in further detail below.

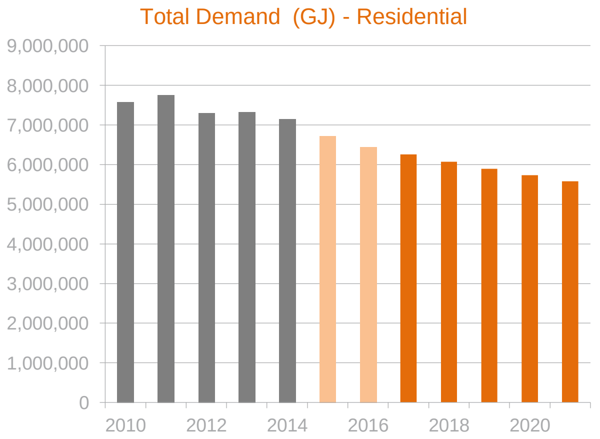
Table 5.1 Forecast Total Tariff V Demand | GJ

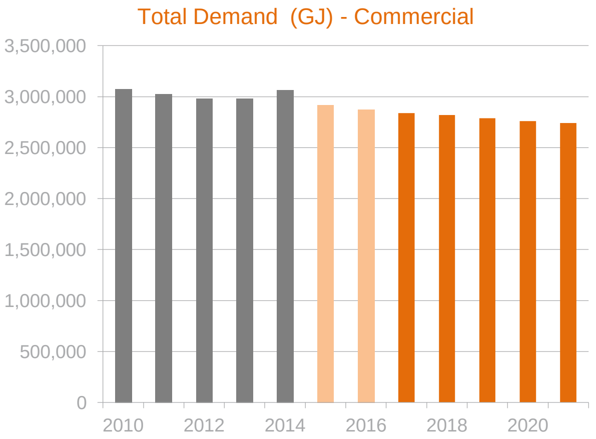
Total Demand	2015	2016	2017	2018	2019	2020	2021
Residential	6,720,782	6,446,907	6,258,721	6,071,982	5,897,659	5,733,964	5,583,903
Commercial	2,917,861	2,877,119	2,838,515	2,819,789	2,788,096	2,759,758	2,742,183
Total	**9,638,643**	**9,324,026**	**9,097,235**	**8,891,771**	**8,685,755**	**8,493,722**	**8,326,085**

Table 5.2 Comparison of Historical and Forecast Average Annual Growth in Demand | %

Average Growth	2011 - 2014	2015 - 2021	2017 - 2021
Residential	-1.39%	-3.47%	-2.83%
Commercial	-0.04%	-1.57%	-0.96%
Total	**-1.01%**	**-2.88%**	**-2.24%**

Figure 5.1 Forecast Total Tariff V Demand | GJ





5.1.2. Connections

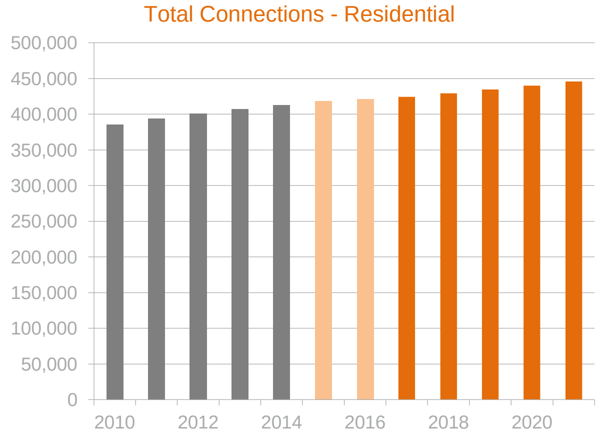
The connections growth can be attributed to a continuation of the historical trends of the past few years. The majority of Tariff V connections are in the residential sector meaning the key result from this section is a predicted 1.17% increase over the Review Period. The residential disconnections rate is predicted to retain its historical average. The new residential connections growth rate is forecast to be slower than the period between 2011 and 2014, primarily due to the continuing decline in the proportion of new dwellings adopting a gas connection. The declining proportion is a consequence of increasing household preference for other competitive energy sources.

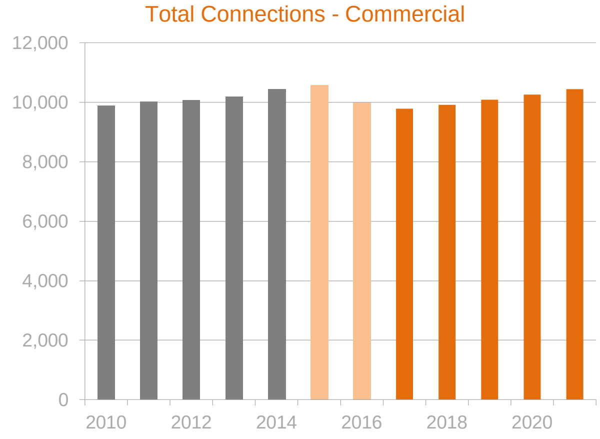
The growth rate of new commercial connections is also forecast to be slower than historically observed between 2011 and 2014. This is largely due to the removal of zero consuming connection in 2016 and 2017. If zero consuming connection were not taken into consideration, average annual growth in commercial connections would be 1.48%, predominately driven by a stronger forecast in GSP compared to historical.

Table 5.3 Average Annual Growth of Connections | %

Average Growth	2011 - 2014	2015 - 2021	2017 - 2021
Residential	1.75%	1.11%	1.17%
Commercial	1.39%	0.03%	0.91%
Total	1.74%	1.08%	1.16%

Figure 5.2 Forecast of Total Connections | No.





5.1.3. Demand per Connection

The results seen for demand per connection are a combination of many aspects. Core's bottom up approach has accounted for price effects (own and cross price), weather effects, appliance trends and efficiency trends to arrive at the following growth rates. The resounding theme across the various connection types is that demand per connection will continue to fall albeit at a slightly slower rate than the previous few years. Generally, the appliance and efficiency trends have the largest impact on demand per connection growth rates. These results employed methodology that remained consistent across both the residential and commercial sector as well as across the several connection types.

Although the forecast decline in residential demand per connection is below recent history (2011-2014), Core notes that the average annual decline in residential demand per connection observed since 2013 of 4.2% is faster than the 3.98% average annual decline forecast for the Review Period (on a weighted average demand per connection basis). Core believes that the forecast for residential demand per connection is conservative when compared to the previous two years.

Further average annual growth rate of demand per connection across all new residential connection types is forecast to decline at 3.16% during the Review Period. This is significantly slower than the decline in average annual growth rates observed between 2010 and 2013 (note 2014 demand per connection for new estate connections is forecast).

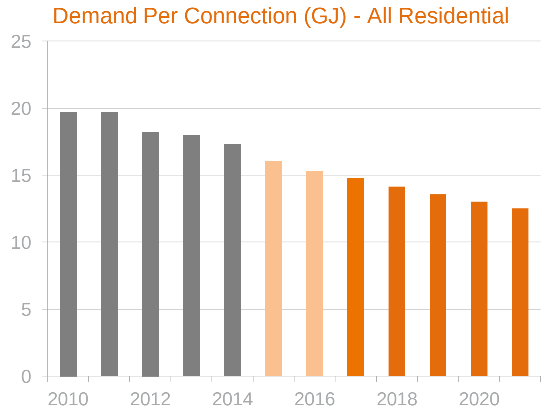
Table 5.4 Tariff V Demand per Connection Forecast | GJ/Connection

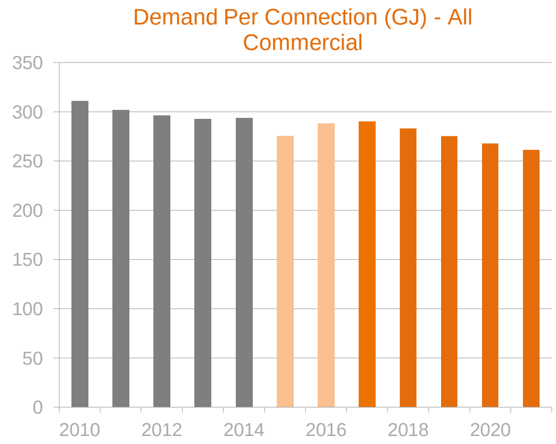
Demand/Conn.	2015	2016	2017	2018	2019	2020	2021
Residential | Existing	16.15	15.52	15.03	14.49	13.98	13.50	13.04
Residential | New Estate	9.97	9.55	9.20	8.88	8.57	8.27	8.13
Residential | MD/HR	6.23	5.97	5.75	5.55	5.35	5.17	5.08
Residential | E to G	12.53	12.00	11.57	11.16	10.77	10.40	10.21
Residential | Weighted Average	**16.05**	**15.32**	**14.75**	**14.14**	**13.57**	**13.03**	**12.52**
Commercial | Existing Connection	279.5	293.1	298.3	293.3	286.7	280.0	274.5
Commercial | New Connection	172.0	176.1	181.0	185.8	190.0	194.7	197.2
Commercial | Weighted Average	**275.2**	**287.8**	**289.8**	**283.1**	**275.1**	**267.6**	**261.4**

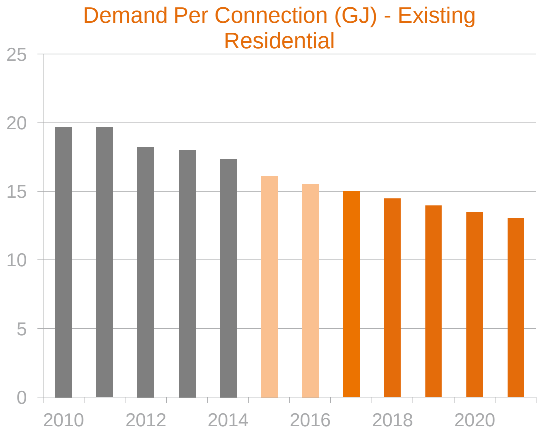
Table 5.5 Comparison of Historical and Forecast Average Annual Growth in Demand per Connection | %

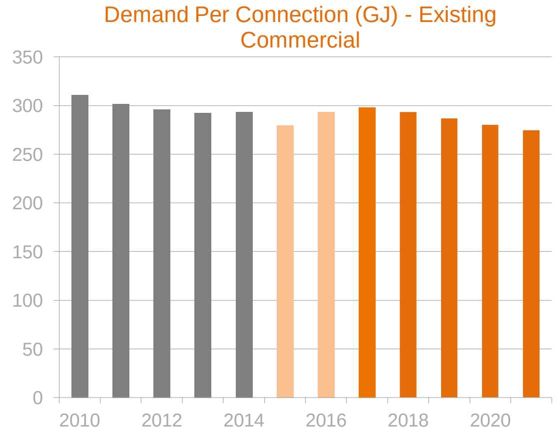
Average Growth	2011 - 2014	2015-2021	2017- 2021
Residential | Existing	-3.08%	-3.98%	-3.43%
Residential | New Estate#	-8.84%	-4.15%	-3.16%
Residential | MD/HR#	-9.02%	-4.15%	-3.16%
Residential | E to G#	-7.31%	-4.15%	-3.16%
Residential | Weighted Average	**-3.08%**	**-4.09%**	**-3.96%**
Commercial | Existing Connection	-1.42%	-0.91%	-1.29%
Commercial | New Connection#	8.20%	2.09%	2.29%
Commercial | Weighted Average	**-1.42%**	**-0.52%**	**-1.90%**

#Note: Historical growth for residential and commercial new connections has been assessed from the 2011 to 2013 period. Due to data being unavailable, 2014 demand per connection is estimated.









5.2. Tariff D

Core forecasts that Tariff D MDQ will fall by 1.09% per annum on average throughout the Review Period. The results shown below have been influenced by known load changes due to customer surveys and an extrapolation of historical load requirements (for non-survey customers). The demand forecast also incorporates the independent forecasts of GVA across the industrial sectors that exist in the AGN distribution network. This result is driven by continued efficiency trends which are expected to continue during the Review Period and the momentum towards reduction of gas consumption or partial fuel switching which is likely occurring due to expectations of future higher prices caused by LNG exports. There is an ongoing economic challenge to industrials in the network arising from competitive pressures in the Asia pacific region and elsewhere. The predicted fall in Tariff D MDQ demand can also be attributed to these competitive pressures, particularly in the manufacturing sector.

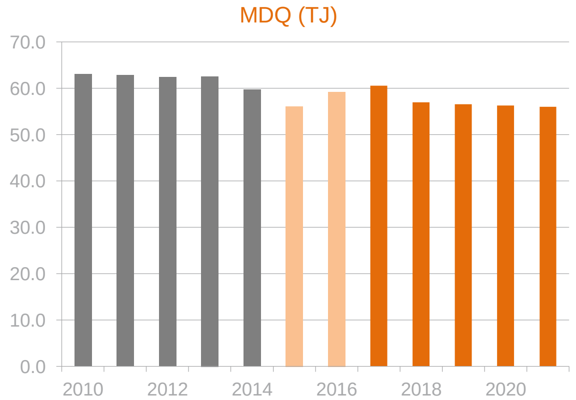
Table 5.6 Forecast of Tariff D MDQ & ACQ | TJ and GJ

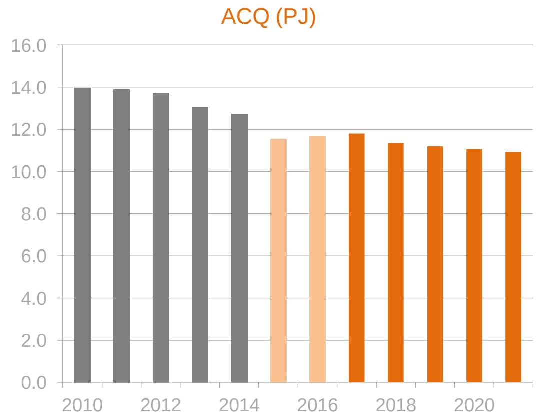
Demand	2015	2016	2017	2018	2019	2020	2021
MDQ | TJ	56.09	59.29	60.57	56.96	56.59	56.27	56.04
ACQ | GJ	11,551,525	11,666,047	11,801,188	11,352,437	11,190,175	11,052,034	10,931,438

Table 5.7 Comparison of Historical and Forecast Average Annual Growth in Tariff D Demand | %

Average Growth	2011 - 2014	2015 - 2021	2017- 2021
MDQ	-1.32%	-0.83%	-1.09%
ACQ	-2.30%	-2.09%	-1.28%

Figure 5.3 Forecast of Tariff D Actual MDQ | TJ and ACQ | PJ





Compliance with Federal Court Practice Note CM7

In keeping with my instructions, I confirm that I have read, understood and complied with the Guidelines for Expert Witnesses in Proceedings in the Federal Court of Australia, as set out in Practice Note CM7. I can also confirm that the options set out in this report are wholly or substantially based upon my expertise. A statement of my compliance with Practice Note CM7 is set out in Annexure 10. I have been assisted in the preparation of this report by Jessica Neong and Zhi Oh at Core Energy Group. Notwithstanding this assistance, the opinions in this report are my own. A list of the material that I have relied upon in the preparation of this report is contained in References.

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Annexure 1 | Terms of Reference

Scope and Context

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

Relevant Considerations

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

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

Output

Core provides the following output in different stages:

- Demand Model Framework
- Demand Forecast, EDD Index and Scenario Modelling
    - Preliminary and Final
- AER Report
    - Draft and Final

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

Annexure 2 | Retail Gas Price Forecast

The retail gas price is assumed by Core to consist of the cost components outlined in Table A 2.1. The price forecast was developed by analysing each of these components- a process in which Core has significant experience. Gas price forecasting has been completed by Core for several previous AA reports and in countless other engagements. The bottom-up approach to price forecasting is a comprehensive way to capture all factors that influence final gas prices.

Table A 2.1 Components of Retail Gas Price

Cost Component	Units	Description
Variable Cost		
Wholesale	AUD/GJ	The market price of gas realised by the supplier to produce and deliver gas into the transmission pipeline. This is the price for flat load gas production.
MDQ	AUD/GJ	The cost of production to deliver maximum daily supply capacity to meet peak customer demand during the winter heating season.
Transmission	AUD/GJ	Cost of transporting gas along the transmission pipeline from the supply source to the distribution network. This includes base load and an additional load factor for maximum daily quantity MDQ capacity allowance.
Distribution	AUD/GJ	Cost of transporting gas though the distribution network to the customer.
Carbon	AUD/GJ	Additional cost due to carbon emissions tax or other environment program costs.
Retail Margin	AUD/GJ	Retailer costs and profit margin.
Market Charges	AUD/GJ	Cost to cover AEMO market participant fees.
Fixed Cost		
Fixed Retail Supply Charge	AUD p.a.	Annual fixed charge per customer per annum to cover certain fixed costs.

Summary of Retail Gas Price Forecast

Table A 2.2 Summary of Residential Retail Gas Price Forecast

Cost Component	Unit	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Wholesale	AUD/GJ					5.00	6.25	6.25	7.38	8.00	8.00	8.00
MDQ	AUD/GJ					1.25	1.25	1.25	1.25	1.25	1.25	1.25
Transmission	AUD/GJ					1.19	1.19	1.19	1.19	1.19	1.19	1.19
Distribution	AUD/GJ					22.41	22.41	19.78	20.77	21.80	22.89	24.04
Carbon	AUD/GJ					0.00	0.00	0.00	0.00	0.00	0.00	0.00
Retail	AUD/GJ					8.86	8.86	8.86	8.86	8.86	8.86	8.86
Market Charges	AUD/GJ					0.03	0.03	0.02	0.02	0.02	0.02	0.02
Other Costs	AUD/GJ					0.07	0.07	0.07	0.07	0.07	0.07	0.07
GST	AUD/GJ					4.06	4.00	3.89	4.01	4.07	4.07	4.07
Total Variable Cost | Real 2014 AUD excl tax	**AUD/GJ**					**38.81**	**40.05**	**37.41**	**39.53**	**41.19**	**42.28**	**43.42**
Total Variable Cost | Real 2014 AUD inc tax	**AUD/GJ**	**24.25**	**27.97**	**33.56**	**39.26**	**42.87**	**44.05**	**41.15**	**43.48**	**45.31**	**46.51**	**47.77**
Fixed Supply Charge | Real 2014 AUD	**AUD**	**222.32**	**232.77**	**251.55**	**265.38**	**260.12**	**260.12**	**244.94**	**251.07**	**257.34**	**263.78**	**270.37**
Average Gas Usage	GJ	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40	17.40
Retail Bill | Real 2014 AUD	**AUD**	**644.24**	**719.41**	**835.45**	**948.45**	**1006.07**	**1026.67**	**960.88**	**1007.59**	**1045.68**	**1073.00**	**1101.51**
Change in Retail Bill | Real 2014 AUD	AUD		75.17	116.04	113.00	**57.62**	**20.60**	**-65.79**	**46.72**	**38.09**	**27.32**	**28.50**
Change in Retail Price | Real 2014 AUD	%		**11.67%**	**16.13%**	**13.53%**	**6.08%**	**2.05%**	**-6.41%**	**4.86%**	**3.78%**	**2.61%**	**2.66%**

Table A 2.3 Summary of Commercial Retail Gas Price Forecast

Cost Component	Unit	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Wholesale	AUD/GJ	5.00	5.00	5.00	5.00	5.00	6.25	6.25	7.38	8.00	8.00	8.00
MDQ	AUD/GJ	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82
Transmission	AUD/GJ	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19	1.19
Distribution	AUD/GJ	9.48	10.66	12.41	14.61	14.68	14.68	12.96	13.60	14.28	15.00	15.75
Carbon	AUD/GJ	-	-	1.53	1.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Retail	AUD/GJ	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21	3.21
Market Charges	AUD/GJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Costs	AUD/GJ	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
GST	AUD/GJ	1.98	2.10	2.42	2.64	2.48	2.62	2.55	2.66	2.72	2.72	2.72
Total Variable Cost | Real 2014 AUD excl tax	**AUD/GJ**	**19.77**	**20.96**	**24.24**	**26.43**	**24.98**	**26.22**	**24.50**	**26.27**	**27.58**	**28.29**	**29.04**
Total Variable Cost | Real 2014 AUD inc tax	**AUD/GJ**	21.7	23.1	26.7	29.1	27.5	28.8	26.9	28.9	30.3	31.1	31.9
Fixed Supply Charge | Real 2014 AUD	**AUD**	**453.91**	**453.91**	**453.91**	**453.91**	**453.91**	**453.91**	**427.42**	**438.11**	**449.06**	**460.29**	**471.79**
Average Gas Usage	GJ	131.00	131.00	131.00	131.00	131.00	131.00	131.00	131.00	131.00	131.00	131.00
Retail Bill | Real 2014 AUD	**AUD**	**3,303**	**3,474**	**3,947**	**4,263**	**4050**	**4232.71**	**3957.24**	**4224.27**	**4423.04**	**4537.20**	**4656.77**
Change in Retail Bill | Real 2014 AUD	AUD	171.08	472.49	316.62	-212.95	-212.95	182.48	-275.47	267.03	198.76	114.16	119.57
Change in Retail Price | Real 2014 AUD	%	**5.2%**	**13.6%**	**8.0%**	**-5.00%**	**-5.00%**	**4.5%**	**-6.5%**	**6.7%**	**4.7%**	**2.6%**	**2.6%**

Residential

Table A 2.4 Gas Price Forecast Key Assumptions | Residential

Cost Component	Key Assumptions
Wholesale	▪ The wholesale gas costs are projected based on a weighted average of estimated AGL and Origin contract gas prices from the Cooper and Otway Basins.
MDQ	▪ The MDQ cost is assumed to be constant throughout the projection period. ▪ The cost is estimated based on an MDQ cost of AUD 240/GJ/MDQ per annum and a residential load factor of 1.90 in SA.
Transmission	▪ The transmission cost is estimated based on a weighted average of Moomba Adelaide Pipeline ("**MAP**") and South East Australia Gas Pipeline ("**SEAGas**") transmission tariffs, obtained from the 2012 GSOO and adjusted to real 2014 terms. Lateral tariff charges are also included under this cost component. ▪ Based on the AGN reticulation map and AGN demand data, MAP is assumed to provide 97% of mass market demand, whereas gas flows from SEAGas supplies the remaining 3%. ▪ The Riverland lateral tariff was provided by AGN on a per annum basis. The AUD/GJ charge was estimated using AGN provided demand data by region. It has been assumed that there is no additional tariff for the load factor. ▪ Whyalla/Port Pirie and Mt Gambier lateral tariffs are assumed to be AUD0.70/GJ based on Core estimates.
Distribution	▪ The distribution cost was provided by AGN and estimated based on an average consumption of 21 GJ p.a. per connection, as reported by ESCOSA/Origin. It is assumed that distribution costs will fall by 11.67% in 2017, and increase by 5% per annum thereafter.
Carbon	▪ The carbon charge is estimated based on ESCOSA's Final Decision report on Origin Carbon Price Cost pass-through application as influenced by the repeal of the Carbon Tax.
Retail Margin	▪ The retail margin is estimated to be 19% of total variable cost, using ESCOSA's Gas Price Determination Final Decision 2012 as a benchmark.
Market Charges	▪ Market charges is estimated using SA Full Retail Contestability ("**FRC**") Gas Final Budget and Fees: 2014-2015 as the source.

Historical Retail Price

Retail residential gas prices for the 2003 to 2011 period were obtained from the SA Government's Energy Consumer Council 2011-2012 release.[43] The historical gas prices for 2013 and 2014 were obtained from the ESCOSA's 2014 South Australian Energy Retail Prices Ministerial Pricing Report.[44]

Wholesale Gas Cost

- Three main gas retailers operate in SA- AGL, Origin Energy, and EnergyAustralia.
- Origin Energy and AGL hold approximately 77% of market share. For the purpose of this analysis, it is assumed that Origin Energy has 62% market share, while AGL has the remaining 38% market share.
- AGL are known to have a contract with the Cooper Basin Joint Venture ("**CBJV**") that will expire in 2016, assumed to be priced at AUD5.00 /GJ. It is assumed that post 2016, AGL will source gas priced at AUD8.00 /GJ.
- Origin Energy have an existing contract with Santos that expired at the end of 2014, assumed to be priced at AUD5.00 /GJ. Another contract has been signed with Beach Energy, assumed to be priced at AUD7.00 /GJ from 2015 to 2017, and then re-priced in 2018 to AUD 8.00 /GJ to the end of the Review Period.
- The blended wholesale cost of gas was calculated based on the market shares for each retailer, and is shown in Table A 2.5.

[43] SA Government, Energy Consumer Council, *Energy Consumer Council Annual Report 2011-12,* September 2012.
[44] ESCOSA, *South Australian Energy Retail Prices Ministerial Pricing Report 2014*, August 2014.

Table A 2.5 Blended Wholesale Gas Cost Forecast | AUD/GJ

	2015	2016	2017	2018	2019	2020	2021
Blended Wholesale Cost	5.00	6.25	6.25	7.38	8.00	8.00	8.00

Generally this forecast is consistent with other forecasts that have entered the public domain as revealed by the following list;

- ~ 7.00-8.00 AUD/GJ by 2019
  - ACIL Allen Consulting-medium supply scenario[45]
- ~ AUD 6.50 AUD/GJ for 2014-2016
  - MDQ Consulting for Longford and Gippsland gas supply[46]
- ~AUD 6.00-8.00 AUD/GJ for 2015-2016
  - Jacobs SKM in regards to Gippsland (6.00) , Surat and Cooper (8.00)[47]

MDQ

Core uses the following formula to derive cost of MDQ:

- Cost _MDQ = MDQC/365 x LF where:
  - Cost_MDQ is the cost of MDQ
  - MDQC (MDQ cost) is assumed to be 240 per GJ/MDQ/year
  - LF is load factor expressed as % AQ; and
  - AQ is annual quantity.
  - MDQC/365 = 240/365 = AUD0.66

For a load factor of 1.9 for residential supply this equates to 1.9 x AUD0.66 = AUD1.25/GJ.

The following table provides information from an ACIL Tasman report which was used by Core to support the estimate of the price of peak supply (MDQ).[48]

Table A 2.6 Extracts from ACIL Tasman (pp. 30-33)

Topic	Commentary
MDQ Cost Benchmarks	*We consider a number of MDQ cost benchmarks based on gas storage, and then develop additional non-storage benchmarks based on the prospects of interrupting and alternatively providing excess gas at a discounted price to gas-fired power generation. For comparative purposes, we also estimate an MDQ cost based on daily gas spot prices at the Sydney Hub observed during 2012.*

[45] ACIL Allen Consulting (East Coast Gas Outlook Conference), *Gas Supply & Demand Outlook for Eastern Australia*, October 2013.
[46] MDQ Consulting, *NSW Wholesale Gas Market Report*, February 2014.
[47] Jacobs SKM, *New Contract Gas Price Projections*, April 2014.
[48] ACIL Tasman, *Cost of gas for the 2013 to 2016 regulatory period*, June 2013.

Topic	Commentary
Underground Gas Storage (Iona)	*This storage facility was previously referred to as Western Underground Storage (WUGS). According to EnergyAustralia (EnergyAustralia), "the Iona site is located above a depleted gas field that was originally used to supply the Western System. Gas is stored in three underground storage reservoirs – Iona and the remote reservoirs of North Paaratte and Wallaby Creek. The plant includes two gas processing trains and compression equipment to process gas from the storage reservoirs and the offshore Casino development. Compressed gas can be injected into the South West Pipeline to supply Melbourne, the SEA Gas Pipeline to supply Adelaide, or into the storage reservoirs for later withdrawal."* *EnergyAustralia explains further that "Iona provides energy retailers and wholesalers the ability to shape supply contracts to meet peak requirements and provides a hedge against spikes in the spot market price. Storage might also appeal to gas producers because it allows production to remain flat whilst allowing deliverability to match demand."* *According to EnergyAustralia, "gas storage fees consist of a fixed capacity charge for MHQ and storage volume, and variable charges per gigajoule of plant throughput. Storage contracts are available until 30 September for the following reservoir year (1 October to 30 September). The minimum contracting level is typically 10TJ per day of storage withdrawal capacity."* *Previously, when operated by TXU, WUGS rates were published and constituted a publicly available source of information on the market cost of MDQ. We understand that EnergyAustralia, the current owners and operators of the gas storage, no longer publish rates publicly but invite commercial enquiries. Origin Energy (submission 2002) refers to a rate of $150 per GJ/MDQ from October 2003. For the previous review a range of MDQ costs based on WUGS published rates was $160 to $240 per GJ MDQ /year. In the previous review MMA expressed its view that the cost of MDQ for retailers was at the lower end of this range.*
Newcastle Gas Storage Facility	*According to an AGL media release of 11 May 2012, AGL is constructing the Newcastle Gas Storage Facility at Tomago. The total project investment cost is cited by AGL to be around $310 million. It is expected to be completed in 2015 and will incorporate a processing plant to treat and liquefy natural gas, LNG storage tank capable of 1.5PJ capacity and a re-gasification unit to convert the LNG back into natural gas. According to AGL it will have peaking capacity of 120 TJ/day (AGL, 27 February 2013). Ignoring any operating costs, estimates for the cost of providing MDQ at this facility can be made on the basis of its cited project development cost and peaking capacity. Assuming a thirty year asset life, annual capital recovery factors corresponding to post-tax real weighted average costs of capital of 6% and 8% are 7.26% and 8.88% respectively. Multiplying the project development cost by the annual capital recovery factor and dividing by the peak capacity expressed in GJ, gives an MDQ cost in the range of $188 to $229 GJ MDQ/year.*
Dandenong LNG Storage Facility	*According to APA Group, with a fully contracted capacity of approximately 12,000 tonnes (or 0.7 PJ), the Dandenong LNG storage facility provides peak shaving and security of supply services for the Victorian Principal Transmission System (PTS). This facility injects gas into the PTS to meet peak winter demands as well as providing a truck loading station for LNG tankers. The Dandenong LNG Facility is not subject to regulation under the National Gas Code. We understand that APA Group makes the associated peak shaving services available through a tender process, the details of which, including outcomes are not generally disclosed.*
Mondarra Gas Storage Facility	*In a media release of 26 May 2011, APA Group cited a cost of $140M to expand its Mondarra gas storage facility located on the Parmelia Gas Pipeline near Dongara in Western Australia. According to the Australian Pipeliner, October 2011, "a significant increase in the daily injection and withdrawal rates into and out of the facility will be another result of the expansion, with the current 15 TJ/d injection and withdrawal rates to increase to rates of 70 TJ/d for injection and 150 TJ/d for withdrawal." This information suggests that an additional 135TJ/day withdrawal capacity is achieved at a cost of $140M. Amortising the project development cost at 10% provides an MDQ cost estimate for this facility of $104 per GJ MDQ per year.*
Non Storage Benchmarks	*Electricity spot prices are typically more volatile is summer than in winter. This suggests that there might be a case for sourcing MDQ by interrupting gas-fired power generators in the winter season (quarters 2 and 3) when retail gas* *demand is higher. Assuming a heat rate of 11 GJ/MWh, and valuing the MDQ at the cost of an electricity cap contract, the equivalent value would be $200 per GJ MDQ/year for a $1/MWh cap premium. Winter season caps are currently traded at around $3/MWh, implying a potentially very high MDQ cost of $600 per GJ MDQ/year. This assumes that the generator is unable to produce electricity if its gas supply is interrupted.* *If the gas-fired power generator has the ability to switch from gas to liquid fuel it will retain its ability to generate against potentially high electricity prices. SKM MMA has estimated recently for Western Australia's Independent Market Operator (IMO), the capital cost of providing a 160MW open cycle gas turbine installation with liquid fuel capability (SKM MMA, January 2013). The cost is around $6.5M or $650,000 annually if amortised at 10%. Assuming that the use of liquid fuel results in a variable generation cost of $300/MWh (SKM MMA cites an estimated cost of diesel fuel of $23.62 per GJ), and that the generator is interrupted 1% of the time, the annual cost of interruption (in fuel terms) will be 0.01 x 8760 x 160 x $300 = $4.2M. The total cost of the interrupt service would be $4.85M. If the interruption is for 12 hours and the heat rate of the OCGT is assumed to be 11 GJ/MWh, the available MDQ is 12 x 160 x 11 = 21,120GJ. The cost is then $230 per GJ MDQ/year. It will be noted that this estimate is highly sensitive to assumptions, particularly the assumption regarding the time the generator is to be interrupted. As a result the cost estimate has a potentially wide range.* *Another approach is for the retailer to contract additional annual quantity and to sell excess gas at a discount to gas-fired power generators. For example if a retailer has a customer load factor of 33% and contracts for an annual quantity three times its demand, and it is assumed that it sells excess gas at a $1 per GJ discount, it will make a loss of $2 per GJ for every GJ sold to its customers. This "additional deliverability" cost of $2 per GJ corresponds to an MDQ cost of $360 per GJ MDQ/year. In this approach it is assumed that there is*

Topic	Commentary
	adequate spare gas-fired generation capacity to make use of the retailer's excess gas. This is likely to be problematic for a retailer with a relatively large customer demand. *Finally, it possible to arrive at an estimate of MDQ cost from gas spot price and system withdrawal data published by AEMO. We base our estimate on daily data published for 2012 for the Sydney hub. This estimate can be regarded as an implied MDQ cost.* *Analysis of daily system withdrawals gives an average withdrawal of 236TJ and a maximum withdrawal of 334TJ – a load factor of 71%. The difference between the system withdrawal weighted spot price and the time-weighted spot price ($5.06 - $4.77 = $0.29 per GJ) represents the cost of additional deliverability. This is the additional cost of supplying a 71% load factor demand over a 100% load factor demand. Rearranging the formula used previously to calculate the additional cost of MDQ, we have MDQC = 365 x AC_MDQ x CLF = $75.15 per GJ MDQ/year.* *The cited range of MDQ costs of $160 to $240 per GJ MDQ/year represents a multiple of 2 to 3 of this value. However this is not dissimilar to the electricity market where cap contracts trade at similar or even higher multiples to value based on spot prices.*
Conclusion	*There are a number of approaches to estimating the cost of MDQ. The application of these gives rise to a large range in estimated value from less than $100 per GJ/MDQ/year based on analysis of daily gas spot prices to possibly in excess of $300 per GJ/MDQ based on opportunities to interrupt gas-fired power generators or provide them with additional gas at a discounted price. We consider the most relevant benchmark cost to be that based on AGL's Newcastle gas storage facility. Our reasoning is that this is a facility currently under construction in New South Wales which is well suited to providing the additional deliverability service and for which the estimated cost and delivery capacity are known.* *We note further that our estimate of the MDQ cost at this facility ($188 to $229/ GJ MDQ/year) is within the range previously quoted for the underground storage facility in Victoria ($160 to $240 GJ MDQ /year). Finally we note that our estimate of MDQ cost of $230 per GJ MDQ/year based on interrupting a gas-fired power generator fitted with the capability to switch to liquid fuel is also within this range. However we note that this particular estimate depends on a number of assumptions.*

Transmission

- Pipeline transportation tariffs form the basis of the transmission cost component of total variable cost. SA is supplied gas by two main gas pipelines; the MAP and the SEAGas. Three laterals supply gas to Mt Gambier, Whyalla and the Riverland region. These pipelines are not covered by regulation and, as such, are not required to publicly disclose tariff structures.
- For the purpose of this analysis, it is assumed that the tariff to transport base load via the MAP is AUD0.65/GJ. Adjusting for a load factor of 1.69 (SA peak demand of 432TJ/d divided by the SA average demand of 256PJ) to account for peak load capacity reservation, increases the tariff to AUD1.10/GJ. A similar approach was undertaken for the SEAGas tariff, assumed to be AUD0.79/GJ, based on the 2012 AEMO GSOO, which reported the tariff to be AUD0.75/GJ. Accounting for peak load capacity reservation, increases the tariff to AUD1.34/GJ.
- The proportion of distributed demand supplied to SA via the MAP and SEAGas was determined based on Gas Bulletin Board ("**GBB**") flows, and Core's intelligence of GPG and large industrial demand. Approximately 97% of distributed demand is sourced from the MAP, while the remaining 3% is sourced from SEAGas. These ratios were used to determine a blended average tariff for the transportation of gas through major transmission pipelines of AUD1.19/GJ.
- Based on Core research and Epic Energy's MAP Application for Revocation, the lateral pipeline to Whyalla is assumed to be AUD0.70/GJ for the baseload and AUD1.18/GJ inclusive of MDQ. The tariff for the Mt Gambier lateral is assumed to be the same as the Whyalla lateral for baseload and inclusive of MDQ. The Riverland tariff charge is estimated based on an annual charge provided by AGN, assumed to be inclusive of MDQ. The Tariff is estimated to be AUD1.50/GJ, based on the profile of demand flowing through the pipeline.
- Approximately 0.5 PJ of residential and commercial supply is delivered via the three laterals. This was determined from AGN data for annual residential and commercial demand by postcode.
- The total transmission pipeline tariff cost for 2014 is provided in Table A 2.7.

Table A 2.7 Transmission Pipeline Tariff | AUD/GJ

	2014
Major Transmission Pipelines	1.10
Lateral Transmission Pipelines	0.09
Total	**1.19**

Distribution

- Consists of a variable and fixed component.
- Calculated using tariffs provided by AGN.
- The variable cost component was calculated based on an assumed average household demand of 17.4GJ p.a. This was blended with the fixed cost component on an AUD/GJ basis.
- Based on AGN analysis, it has been assumed that the distribution cost will decrease in 2017 by 11.7% and increase by 5% per annum thereafter.

Carbon

- The cost of carbon is removed from 2015 onwards, due to the repeal of the carbon tax on 1 July 2014.

Retail Margin

- The South Australian energy market was deregulated on 19 December 2012.
- In 2011, prior to deregulation, ESCOSA set Origin Energy's retail margin at approximately 19% of total variable cost.
  - This involved the Retail Operating Costs (ROC) and Retail Operating Margin (ROM).
- It is assumed that the retail cost component of the total variable cost has remained at approximately 19 to 20%. This has been calculated as the balance of total variable cost minus all other known costs.
- This is equivalent to AUD8.86/GJ.

AEMO Market Charge

AEMO charges participants in the SA FRC gas markets, with fees published in "*SA FRC Gas Final Budget and Fees: 2014-2015*". AEMO fees consist of two elements; Consumer Advocacy Panel Requirements Fees and Gas Statement of Opportunities Fees. Forecasts for Consumer Advocacy Panel Requirements Fees are provided for 2014 and 2015. Meanwhile, forecasts for Gas Statement of Opportunities Fees are provided until 2019. It is assumed that there is no change in the fees between 2019 and 2021. A summary of the AEMO markets fees are provided in Table A 2.8 and 0.

Table A 2.8 AEMO Consumer Advocacy Panel Requirements[49]

CAP Fees	2014	2014
Gas (AUD per customer supply point per month)	0.01	0.01
Gas (AUD per customer supply point per annum)	0.17	0.13

[49] AEMO, *SA FRC Gas Final Budget and Fees: 2014-2015*, May 2014.

Table A 2.9 AEMO Gas Statement of Opportunities Projected Fees | Real 2014 AUD[50]

Fees	2014	2015	2016	2017	2018	2019	2020	2021
Gas (AUD per customer supply point per month)	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Gas (AUD per customer supply point per annum)	0.36	0.34	0.32	0.34	0.36	0.37	0.37	0.37

Based on an average annual consumption of 18GJ per annum for residential customers and 131GJ/per annum for commercial customers, fees were calculated on a per GJ basis for each demand segment.

Table A 2.10 AEMO Market Fees | Real 2014 AUD

Fees	2014	2015	2016	2017	2018	2019	2020	2021
Residential | AUD/GJ	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.02
Commercial | AUD/GJ	0.0040	0.0036	0.0025	0.0026	0.0027	0.0029	0.0029	0.0029

Other Costs

Other costs are assumed to be AUD0.065/GJ, based on ESCOSA's Gas Price Determination Final Decision (page 66).

Total Variable Cost

Standing offer throughput charges are published in Origin Energy and AGL gas price fact sheets for 2015. Based on an average residential household load of 17.4GJ p.a. the blended per GJ charge for Origin Energy was calculated to be AUD43.850/GJ, while the charge for AGL was calculated to be AUD44.10/GJ. Based on the market share of each retailer (assumed market share of Origin Energy 62%, AGL 38%), the weighted average throughput was calculated to be AUD42.87/GJ (real 2014).

Fixed Retail Supply Charge

Standing offer fixed retail supply charges are published in Origin Energy and AGL gas price fact sheets for 2015. Based on the market share of each retailer (assumed market share of Origin Energy 62%, AGL 38%), the weighted average supply charge was calculated to be AUD260.12/GJ.

Commercial

Table A 2.11 Gas Price Forecast Key Assumptions | Commercial

Cost Component	Key Assumptions
Wholesale	▪ The wholesale gas costs are projected based on a weighted average of estimated AGL and Origin gas price contracts from the Cooper and Otway Basin.
MDQ	▪ The MDQ cost is assumed to be constant in the projection period. ▪ The cost is estimated based on an MDQ cost of AUD 240/GJ/MDQ per annum and a commercial load factor of 1.25 in SA.
Transmission	▪ The transmission cost is estimated based on a weighted average of MAP and SEAGas transmission tariffs, obtained from the 2012 GSOO and adjusted to real 2014 terms. Lateral tariff charges are also included under this cost component. ▪ Based on an AGN reticulation map and AGN demand data, MAP is assumed to provide 97% of mass market demand, whereas gas flows from SEAGas supply the remaining 3%. ▪ The Riverland lateral tariff was provided by AGN on an AUD per annum basis. The AUD/GJ charge was estimated using AGN demand data by region. It has been assumed

[50] Ibid.

Cost Component	Key Assumptions
	that there is no additional tariff for the load factor. ▪ Whyalla/Port Pirie and Mt Gambier lateral tariffs are not publicly available and have been assumed to be the same as the Riverland lateral.
Distribution	▪ The distribution cost was provided by AGN and estimated based on an average consumption of 131 GJ p.a. per connection, as provided by AGN. It is assumed that distribution costs will fall by 11.7% in 2017, and increase by 5% per annum thereafter.
Carbon	▪ The carbon charge is estimated based on ESCOSA Final Decision Report on Origin carbon price cost pass-through application.
Retail Margin	▪ The retail margin is estimated as the balance of the total variable cost based on AGL/Origin price fact sheets.
Market Charges	▪ Market charges are estimated using SA FRC Gas Final Budget and Fees: 2014-2015.

A similar approach as residential gas price was used to determine the cost components of commercial gas price. It was assumed that there would be no difference in wholesale costs, transmission costs and carbon charges, between the residential and commercial segments. The main cost component differences between the two segments is the distribution cost and retail margin cost, which drives the difference between the total variable cost, as well as the fixed supply charge. These cost components are further discussed in sections thereafter.

Historical Retail Price

Refer residential section of this Annexure.

Wholesale Cost

Refer residential section of this Annexure.

MDQ

Core uses the following formula to derive cost of MDQ:

- Cost _MDQ = MDQC/365 x LF where:
  - Cost_MDQ is cost of MDQ
  - MDQC (MDQ cost) is assumed to be AUD 240 per GJ/MDQ/year
  - LF is load factor expressed as % AQ; and
  - AQ is annual quantity.

MDQC/365 = 240/365 = AUD0.66.

For a load factor of 1.25 for commercial supply, this would equate to 1.25 x AUD0.66 = AUD0.82/GJ.

Transmission

Refer residential section of this Annexure.

Distribution

- Consists of a variable and fixed component.
- Calculated using tariffs provided by AGN.

- The variable cost component was calculated based on an assumed average commercial enterprise demand of 131GJ p.a. This was blended with the AUD/GJ basis of the fixed cost component.
- The distribution cost was calculated to be AUD14.68/GJ.
- Based on AGN analysis, it has been assumed that the distribution cost will decrease in 2017 by 11.67% and increase by 5% per annum thereafter.

Carbon

Refer residential section of this Annexure.

Retail Margin

The retail margin component of the total variable cost was calculated as the balance of the total variable cost minus the wholesale, transmission, distribution, carbon costs and AEMO market charges. The retail margin component for commercial customers was calculated to be AUD3.21/GJ.

AEMO Market Charges

Refer residential section of this Annexure.

Total Variable Cost

Standing offer throughput charges are published in Origin Energy and AGL gas price fact sheets for 2015. Based on an average commercial enterprise load of 131GJ p.a. the blended per GJ charge for Origin Energy was calculated to be AUD28.97/GJ, while the charge for AGL was calculated to be AUD26.77/GJ. Based on the market share of each retailer (assumed market share of Origin Energy 62%, AGL 38%), the weighted average throughput was calculated to be 27.50AUD/GJ (real 2014).

Fixed Retail Supply Charge

Standing offer fixed retail supply charges are published in Origin Energy and AGL gas price fact sheets for 2014. Based on the market share of each retailer (assumed market share of Origin Energy 62%, AGL 38%), the weighted average supply charge was calculated to be AUD453.91/GJ.

Annexure 3 | Retail Electricity Price Forecast

Historical

Historical retail electricity bills for residential households were derived from the nominal percentage change, as reported in the AER's State of the Energy Market, summarised in Table A 3.1 The percentage change is applied to a 2013 electricity bill, obtained from the ESCOSA Ministerial Pricing Report 2014. The retail bill is adjusted to real 2014 values to capture the real change in residential electricity bills.

Table A 3.1 Summary of Historical Residential Retail Electricity Price

	Unit	2009	2010	2011	2012	2013	2014
Retail Bill | Nominal	AUD p.a.	1,243	1,282	1,516	1,780	2,006	2,050
Real Price Change | Nominal	%		3.1%	18.3%	17.4%	12.7%	2.2%
Retail Bill | Real 2014	AUD p.a.	1,407	1,415	1,633	1,870	2,056	2,050
Real Price Change | Real 2014	%		0.6%	15.4%	14.5%	10.0%	-0.3%

The historical percentage change in retail electricity bills for commercial connections was assumed to be the same as residential electricity bill. Similar to the historical residential electricity bill, the commercial electricity bills were derived by applying the percentage to a 2013 retail bill, obtained from the ESCOSA Ministerial Pricing Report 2014. It should be noted that the 2013 retail bill is adjusted to real 2014 values.

Table A 3.2 Summary of Historical Non-residential Retail Electricity Price

	Unit	2009	2010	2011	2012	2013	2014
Retail Bill | Real 2014	AUD p.a.	2,674	2,690	3,104	3,556	3,909	3,867
Real Price Change | Real 2014	%		0.6%	15.4%	14.5%	10.0%	-1.1%

Forecast

The forecast electricity bill for residential and commercial households is derived based on the AER Preliminary Decision on SAPN 2015/16 to 2019/20 determination. Table A 3.3 and Table A 3.4 summarises the forecasts for residential and commercial electricity bills in nominal terms and adjusted to real 2014 values.

Table A 3.3 Summary of Forecast Residential Retail Electricity Price

	Unit	2014	2015	2016	2017	2018	2019	2020
Retail Bill | Nominal	AUD p.a.	2,050	1,809	1,765	1,765	1,765	1,773	1,773
Real Price Change | Nominal	%		-11.8%	-2.4%	0.0%	0.0%	0.5%	0.0%
Retail Bill | Real 2014	AUD p.a.	2,050	1,765	1,680	1,639	1,599	1,567	1,529
Real Price Change | Real 2014	%		-13.9%	-4.8%	-2.4%	-2.4%	-2.0%	-2.4%

Table A 3.4 Summary of Forecast Commercial Retail Electricity Price

	Unit	2014	2015	2016	2017	2018	2019	2020
Retail Bill | Nominal	AUD p.a.	3,867	3,487	3,402	3,402	3,401	3,417	3,417
Real Price Change | Nominal	%		-9.8%	-2.4%	0.0%	0.0%	0.5%	0.0%
Retail Bill | Real 2014	AUD p.a.	3,867	3,402	3,238	3,159	3,081	3,020	2,946
Real Price Change | Real 2014	%		-12.0%	-4.8%	-2.4%	-2.5%	-2.0%	-2.4%

Annexure 4 | Price Elasticity of Demand Analysis

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

Approach

Core has undertaken an assessment of the alternative approaches available to derive an estimate of the price elasticity of gas demand within the AGN network, including research of approaches adopted nationally and internationally. Core is of the opinion that the preferred approach would involve an observation of actual demand response to actual price movements over a statistically relevant period. However, the circumstances of this review involve a situation where particular material price movement in both gas and electricity prices are expected. There is not an acceptable dataset that corresponds to the circumstances of the Review Period meaning it is not possible to apply such an approach. Core is of the opinion that the best estimate, under the circumstances, will be derived by applying a rigorously determined elasticity factor against a detailed assessment of future gas and electricity prices in SA during the Review Period. Core has undertaken an extensive review of historical AA's and empirical studies relating to price elasticity of demand generally, and in relation to gas and electricity more specifically.

The two price elasticity factors Core has quantified are:

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

Core's analysis has considered:

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

Core is of the opinion that the listing of own-price and cross-price elasticity factors, which are summarised in Table A 4.1and Table A 4.2 provide a reasonable basis for deriving an estimate of the price elasticity of demand for gas in the AGN.

Table A 4.1 Price Elasticity of Gas Demand – Literature Review.

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

Source: Third party expert reports and analysis

Table A 4.2 Price Elasticity of Gas Demand – Prior AER Submissions.

Period	Network	Source	Own Price Elasticity of Demand	Cross Price Elasticity of Demand
2013-17	Multinet (VIC)	NIEIR	-0.28 (all customer segments)	N/A
2011-16	Envestra (SA)	NIEIR	-0.30 (residential, long-run) -0.35 (industrial, long-run)	N/A
2013-17	SP Ausnet (VIC)	CIE	-0.17 (residential, long-run) -0.77 (commercial, long-run)	N/A
2013-17	Envestra (VIC, Albury)	Core	-0.30 (residential, long-run) -0.35 (non-residential, long-run)	N/A

Source: Access arrangement demand forecast submissions.

Own Price Elasticity

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

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

As NIEIR's estimate is broadly in line with the range of the estimates obtained in other studies and the AER's own indicative estimate, the AER considers that the assumed long run residential price elasticity of -0.30 is reasonable and Core believes this represents the best estimate possible in the circumstances.[51] Given the price elasticity factors used for Envestra's SA network, reference values of -0.30 (residential) and -0.35 (non-residential) as long-run elasticity factors were used for the final demand forecast model as shown in Table A 4.3.

[51] AER, *Final Decision*: *Envestra Limited Access arrangement Proposal For The SA Gas Network 1 July 2011 – 30 June 2016*, June 2011, p103.

Table A 4.3 Own Price Elasticity.

Market Type	Reference
Residential	-0.30
Non Residential	-0.35

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

The interpretation of these elasticity factors is that for every percentage increase in retail gas price, gas demand will decrease by 0.3 percent (0.35 percent for non-residential customers). These long-run elasticity factors are a summation of the individual price elasticity factors, which are applied as shown in Table A 4.4 below. Demand impacts are highest in the year of the price change for residential demand and the year after the price change for non-residential demand. These price elasticity factors originate from Envestra's (now AGN) gas demand forecasts for the 2013 -2017 Victorian AA submission, and further perpetuated in the development of gas demand forecasts for Jemena's 2015-2020 New South Wales AA submission.

Core has also assumed that reductions in gas prices will not result in a symmetric response, and customers won't increase gas demand as a response to gas price decreases. Price sensitivity is an established factor for gas demand and energy demand more generally. There is evidence to suggest that price responses tend to be asymmetric- demand responses are greater when prices rise.

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

'*Consumer response to changes in electricity prices is asymmetric. While consumers may reduce consumption in response to price rises, they do not necessarily revert to previous levels of consumption when prices later fall, due to permanent changes in behaviour, or momentum. To reflect this, AEMO applied a Maximum Price Model which assumes that rather than responding to the carbon price repeal, customers will continue to respond to the highest prices they have experienced in recent years'.*[52]

Table A 4.4 Price Elasticity Factors.

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

Source: Core Energy Group.

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

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

Table A 4.5 Own Price Elasticity Impact on Demand.

Own Price Elasticity Impact on Demand (%)	2015	2016	2017	2018	2019	2020	2021
Residential							
Change in Gas Prices	6.08%	2.05%	-6.41%	4.86%	3.78%	2.61%	2.66%
Price Elasticity Impact (-0.30)	-3.08%	-2.03%	-1.03%	-1.05%	-1.00%	-0.91%	-0.89%
Non-Residential							
Change in Gas Prices	-5.00%	4.51%	-6.51%	6.75%	4.71%	2.58%	2.64%
Price Elasticity Impact (-0.35)	-3.0%	-1.6%	-1.1%	-0.9%	-1.5%	-1.6%	-1.2%

Source: Core Energy Group.

Cross Price Elasticity

Core acknowledges that cross price elasticity has not been addressed widely in prior AA reviews. Core believes this is due to the relative historical prices of gas and electricity not being sufficiently different to cause changes in demand over the regulatory time frame under consideration. However, Core is of the opinion that material changes in gas prices relative to electricity price are likely to occur during the Review Period and that it is reasonable to expect a cross-price demand response.

Based on Core’s analysis, an assumed long run elasticity of 0.10 for both residential and non-residential customers is deemed reasonable, and the impact is shown in Table A 4.6 below. The interpretation of the elasticity factor is that for every percentage increase in retail gas price in a given year, demand for electricity will increase by 0.1 percent in that year. Alternatively, for every percentage increase in electricity price, gas demand will increase by 0.1 per cent. These price elasticity factors are applied to the forecast annual real increase in electricity prices to arrive at the cross price response for each customer segment as summarised below.

Table A 4.6 Cross Price Elasticity Impact on Demand.

Cross Price Elasticity Impact on Demand (%)	2015	2016	2017	2018	2019	2020	2021
Residential							
Change in Electricity Prices	-13.9%	-4.8%	-2.4%	-2.4%	-2.0%	-2.4%	-2.4%
Price Elasticity Impact (0.10)	-1.39%	-0.48%	-0.24%	-0.24%	-0.20%	-0.24%	-0.24%
Non-Residential							
Change in Electricity Prices	-12.0%	-4.8%	-2.4%	-2.5%	-2.0%	-2.4%	-2.4%
Price Elasticity Impact (0.10)	-1.20%	-0.48%	-0.24%	-0.25%	-0.20%	-0.24%	-0.24%

Source: Core Energy Group.

There has been an elevated level of discussion as to the level of cross price elasticity that occurs in the market for gas. Deloitte’s opinion was expressed to Core during the Jemena Gas Networks process, that 0.05 was a more accurate elasticity factor as opposed to the 0.10 used by Core. Core’s decision to use 0.10 was a result of comprehensive literature review and a careful assessment of energy market price trends. The overwhelming consensus centres on values between 0.1 and 0.2. Some approaches arrived at a factor below 0.10 but this was generally for only one sector of the economy or where historical price movements are too small to capture the elasticity effect that will affect the AGN network. The literature also favours the 0.10 factor when it comes to datasets that have a comparable historical context. This context extends to relative prices and climate. Regardless of dataset context, Core is of the firm opinion that 0.1 is a conservative figure or lower bound.

Annexure 5 | Macroeconomic Variables

Demand per Connection – Residential and Commercial

The following economic variables have been selected to measure the relationship between demand per connection and the macro-economy.

- Gross State Product ("**GSP**")
- Gross Household Disposable Income per capita ("**GHDI**")
- State Final Demand ("**SFD**")

The available sample size is somewhat constrained by a limited number of observations, given that price data is only available from 2004 and an additional data point is lost when lagged variables are used. Different model and variable specifications were used to confirm, or provide further general intuition, about the relationship. The level and log transformation of the macroeconomic variables were initially regressed univariate with demand. Then a series of multivariate regressions including gas price and electricity variables were generated. The one period lags were also included in the analysis due to the potential delay in the demand response. The multivariate models were also tested for statistical problems such as collinearity, heteroskedasticity and omitted variable bias.

Results

The univariate regression analysis provided the following key findings.

- All the economic variables have a statistically significant, but negative impact on demand per connection. This is contrary to theory, where a positive relationship should exist.
- The R-Squared values for residential demand per connection are much higher than those for commercial demand per connection. This is an unexpected result as the commercial sector should have a stronger relationship with economic changes.
- Of the three economic variables, GSP appears to have the strongest correlation (R-Squared). Although this is expected for commercial demand, theory would suggest that GHDI should have the highest correlation with residential demand.
- The lag economic variables generally have higher correlations with demand per connection. This indicates that the previous period of economic growth has a greater effect on current demand, although the relationship is negative.
- The economic variables have a positive and significant relationship with total connections. The lag economic variables have a smaller impact and lower R-Squared values compared to the same period variables.
- Both gas and electricity prices, including the lags, have high correlations with demand per connection. The lag variables appear to have larger coefficients and a greater impact on demand. One unexpected result is that electricity prices have a negative impact on demand per connection.

The multivariate regression analysis provides the following key findings.

- For residential demand per connection the economic variables generally have a significant but negative effect.
- For commercial demand per connection the economic variables have a positive but insignificant impact at the 5% level.

- Although the R-Squared value for both demand and commercial demand regressions are high, residential demand is slightly higher.
- The price of gas and the lag price of gas have a statistically significant impact when included separately in the model. When both the variables are included there appears to be a high degree of correlation which renders them both insignificant. This pattern holds for both residential and commercial demand per connection.
- The impact of changes in the price of gas is greater for residential demand than commercial demand. This suggests that residential consumers are more price sensitive than businesses.
- When the price of electricity is added to the model it has a negative coefficient which is contrary to theory. Including a cross price term reduces the statistical significance of both the gas price and the economic variable. When gas price is dropped from the model the coefficient remains negative.
- Most models appear to suffer from a high degree of collinearity which makes the estimates and standard errors difficult to rely upon.

There is some recent literature that reflects the varied results produced here.[53] The International Monetary Fund ("**IMF**") found that high-income Organisation for Economic Co-operation and Development ("**OECD**") nations can sustain GDP growth with no apparent increase in per capita energy consumption. It is well established that energy demand has a positive correlation with per capita income in low and middle income countries. However, this relationship does not feature in economies with higher per capita income.[54]

Given the small sample size and high level of collinearity present in most of the models used to test the macroeconomic variables, the coefficients and statistical significance should be interpreted with caution. Despite comprehensive econometric testing, the results were not consistently significant. Different variable specification is a powerful robustness check and in this situation it produced inconsistent results. This suggests that the precise impact of macroeconomic fluctuations cannot be accurately or reliably isolated. Furthermore, some apparently significant results departed from economic theory. For the reasons discussed above, Core did not include any economic variables in the demand per connection forecasts. AEMO's methodology also supported this conclusion in so far as a macroeconomic income variable was not found to have a significant and intuitive relationship with gas demand.[55]

Residential Connections

Residential connections were not included in the statistical analysis as macroeconomic effects are captured indirectly in the demand forecast. Connections were derived using a bottom-up approach based on the SA dwellings forecast. This forecast would be influenced by a number of macroeconomic variables such as population growth and there is a risk of collinearity if additional macroeconomic variables were included.

Commercial Connections

The following economic variables were selected to measure the relationship between commercial connections and the macro-economy.

- Gross State Product ("**GSP"**)
- State Final Demand ("**SFD**")

[53] IMF website, https://www.imf.org/external/pubs/ft/weo/2011/01/c3/fig3_3.pdf.
[33] Ibid.
[55] AEMO, *Forecasting Methodology Information Paper, National Electricity Forecasting Report 2014,* July 2014.

Given the small sample size of 10 observations, different model and variable specifications were used to confirm, or provide further general intuition, about the relationship. The log transformations of the macroeconomic variables were initially regressed univariate with commercial connections. The one period lag of the macroeconomic variable was included in the analysis due to potential delay in responses. Then a series of multivariate regressions incorporating gas prices and electricity prices were generated.

The most suitable regression to model the relationship between GSP and commercial connections was:

$$Connections = \beta_0 + \beta_1 (LogGSP)_{t-1} + \beta_2 (Gas\_Price)_{t-1}$$

Table A 5.1 summarises the statistical regression.

Table A 5.1 Regression Output

	Connections
$Log(GSP)_{t-1}$	0.285*
$Log(Gas\_Price)_{t-1}$	0.0685*
Constant	0.515*
N	10
R^2	0.94
Adjusted R^2	0.93
RMSE	0.01

Note:* represents 5% significance level.

Conclusion

This regression supports a statistically significant relationship between commercial connections and a one period lag of GSP. For every 1% increase in GSP, commercial connections grow by 0.285%.

Annexure 6 | Tariff V Residential Connections Forecast

BIS Shrapnel Dwellings Based Forecast

The forecast of new connections is based on BIS Shrapnel's forecast of new dwellings in South Australia, reported as of March 2015.[56] This forecast is provided in Table A 6.1.

Table A 6.1 BIS Shrapnel Forecast of New Dwellings March 2015 | No.

Dwelling Type	2015	2016	2017	2018	2019	2020	2021
Detached Houses (New Estates)	7,850	8,100	7,550	7,150	7,500	8,050	8,450
Medium Density	1,727	2,000	1,900	1,900	1,900	2,200	2,250
High Rise	1,211	500	300	200	250	400	400
MD/HR Combined	2,938	2,500	2,200	2,100	2,150	2,600	2,650
Total	**10,788**	**10,600**	**9,750**	**9,250**	**9,650**	**10,650**	**11,100**

To determine the number of connections forecast based on this new dwellings forecast, Core analysed historical new connections by type as a proportion of historical new dwellings (as reported by BIS Shrapnel).[57] This analysis is provided in Table A 6.2, Table A 6.3 and Table A 6.4.

Table A 6.2 BIS Shrapnel Historical New Dwellings March 2015 | No.

Dwelling Type	2010	2011	2012	2013	2014
New Estate	9,691	8,266	6,941	6,406	7,926
MD/HR	2,598	2,639	2,188	2,176	2,734
Total	**12,289**	**10,905**	**9,129**	**8,582**	**10,660**

Table A 6.3 AGN Historical New Connections by Type | No.

Connection Type	2010	2011	2012	2013	2014
New Estate	6,707	7,345	5,875	4,978	5,247
MD/HR	881	977	763	612	665
Total	**7,588**	**8,322**	**6,638**	**5,590**	**5,912**

Table A 6.4 Historical Proportion of New Connections to New Dwellings | %

Connection Type	2010	2011	2012	2013	2014
Proportion of New Estate Connections	69%	89%	85%	78%	66%
Proportion of MD/HR Connections	34%	37%	35%	28%	24%

The forecast proportion of new connections to new dwellings was derived based on the historical annual average change in proportions. This was -0.8% for new estate connections and -2.4% for MD/HR connections. The resultant forecast is provided in Table A 6.5.

Table A 6.5 Forecast Proportion of New Connections to New Dwellings | %

Dwelling Type	2015	2016	2017	2018	2019	2020	2021
Proportion of New Estate Connections	65.70%	65.21%	64.72%	64.23%	63.75%	63.27%	62.79%
Proportion of MD/HR Connections	23.74%	23.17%	22.62%	22.07%	21.54%	21.03%	20.52%

Applying these percentages to the BIS Shrapnel forecast of new dwellings, as provided in Table A 6.6, derives the following forecast of new connections by type.

[56] BIS Shrapnel, *AGNL South Australia forecasts.xlsx*, as provided by AGN on 26 March 2015.
[57] Ibid.

Table A 6.6 Forecast of New AGN Connections by Type | No.

Connections Type	2015	2016	2017	2018	2019	2020	2021	Total
New Estates	5,158	5,282	4,886	4,592	4,781	5,093	5,306	35,098
MD/HR	697	579	498	464	463	547	544	3,792
Total	5,855	5,861	5,384	5,056	5,244	5,640	5,850	38,890

Population Based Forecast

In addition to the above, Core has derived a bottom-up forecast of new dwellings based on population and historical demand categorised by postcode. This analysis was used to validate the connections forecast which was derived by adopting the new dwellings forecast as reported by BIS Shrapnel in March 2015.[58] Core has assessed the major drivers of new dwelling connections to be:

- Population growth and household density which influences demand for dwellings; and
- Rate of dwelling investment to meet demand.

Core developed a bottom-up forecast of residential dwelling completions and connections within the AGN network, before adjusting the forecast based on third party data and analysis.

Bottom-up Forecast

Core compiled two data sets:

- Population projections, categorised by LGA, sourced from the ABS.[59]
- Historical demand categorised by postcode, sourced from AGN. These postcodes were assigned to South Australian LGAs to determine AGN's network reach.

Using this data Core observed the population growth of LGAs within the AGN network. When compared to the total population of South Australia, approximately 80% of the population reside in a LGA that has access to the AGN network. The compound annual average growth rate of the population within AGN's network reach, for the period 2015-2021, is estimated to be 1.07%.

[58] Ibid.
[59] ABS, *3222.0 Population Projections, Australia, 2006 to 2101*.

Table A 6.7 Population Growth of LGA within AGN Network Reach | No.

LGA	2015	2016	2017	2018	2019	2020	2021
Adelaide	21,661	21,895	22,140	22,389	22,644	22,901	23,165
Barossa, Light Regional	37,799	38,163	38,522	38,872	39,212	39,552	39,884
Berri and Barmera	11,171	11,269	11,365	11,456	11,547	11,634	11,720
Campbelltown , Charles Sturt, Gawler, Playford, Port Adelaide Enfield, Prospect, Salisbury, Tea Tree Gully, Walkerville	644,124	652,448	660,573	668,484	676,163	683,621	690,975
Grant, Mount Gambier	35,160	35,549	35,930	36,309	36,677	37,040	37,397
Burnside, Holdfast Bay, Marion, Mitcham, Norwood Payneham St Peters, Unley, West Torrens	373,188	376,480	379,735	382,951	386,132	389,238	392,362
Murray Bridge	21,032	21,250	21,468	21,686	21,901	22,113	22,320
Onkaparinga	172,015	174,285	176,506	178,681	180,801	182,861	184,913
Peterborough	1,799	1,807	1,817	1,827	1,835	1,844	1,857
Port Pirie City and Dists	18,277	18,459	18,640	18,814	18,984	19,155	19,326
Whyalla	23,840	24,165	24,481	24,786	25,093	25,381	25,660
TOTAL	**1,360,066**	**1,375,770**	**1,391,177**	**1,406,255**	**1,420,989**	**1,435,340**	**1,449,579**

Table A 6.8 Population Growth of SA | No.

South Australia Population	1,710,420	1,729,554	1,748,323	1,766,701	1,784,657	1,802,151	1,819,489

The number of occupied dwellings in 2011, categorised by LGA, was obtained from the ABS 2011 Census of Population and Housing via the ABS Table Builder. This was divided by LGA population in 2011 to derive 2011 housing density by LGA. Housing density was also derived for 2006. To forecast the housing density to 2021, it was assumed that the compound annual growth rate (“**CAGR**”) of housing density would be half of the CAGR observed between 2006 and 2011.

Table A 6.9 Forecast Housing Density by LGA | No.

LGA	2015	2016	2017	2018	2019	2020	2021
Adelaide (C)	1.96	1.95	1.94	1.93	1.93	1.92	1.91
Barossa (DC), Light Regional (C)	2.42	2.41	2.40	2.39	2.38	2.37	2.36
Berri and Barmera (DC)	2.15	2.14	2.13	2.12	2.11	2.11	2.10
Campbelltown (C), Charles Sturt,	2.32	2.31	2.30	2.29	2.28	2.28	2.27
Grant (DC), Mount Gambier (C)	2.19	2.18	2.17	2.16	2.16	2.15	2.14
Burnside (C), Holdfast Bay (C), Marion	2.25	2.24	2.23	2.22	2.21	2.21	2.20
Murray Bridge (RC)	2.29	2.28	2.27	2.26	2.26	2.25	2.24
Onkaparinga (C)	2.40	2.39	2.38	2.37	2.36	2.35	2.34
Peterborough (DC)	1.67	1.67	1.66	1.65	1.65	1.64	1.63
Port Pirie City and Dists (M)	2.16	2.15	2.14	2.13	2.12	2.12	2.11
Whyalla (C)	2.11	2.10	2.10	2.09	2.08	2.07	2.07

The forecast change in population by LGA and housing density to 2021 were used to derive the new dwellings forecast.

Table A 6.10 Forecast New Dwellings by LGA | No.

LGA	2015	2016	2017	2018	2019	2020	2021
Adelaide (C)	151	162	169	172	176	178	183
Barossa (DC), Light Regional (C)	210	210	209	207	204	205	203
Berri and Barmera (DC)	65	65	65	63	63	62	62
Campbelltown (C), Charles Sturt, Gawler (T), Playford (C), Port Adelaide Enfield (C), Prospect (C), Salisbury (C), Tea Tree Gully (C), Walkerville (C)	4,560	4,653	4,597	4,535	4,463	4,396	4,379
Grant (DC), Mount Gambier (C)	236	239	237	238	234	233	232
Burnside (C), Holdfast Bay (C), Marion (C), Mitcham (C), Norwood Payneham St Peters (C), Unley (C), West Torrens (C)	2,003	2,097	2,093	2,089	2,087	2,066	2,087
Murray Bridge (RC)	129	130	131	132	132	131	130
Onkaparinga (C)	1,199	1,221	1,209	1,198	1,182	1,165	1,169
Peterborough (DC)	9	9	10	10	9	10	12
Port Pirie City and Dists (M)	115	117	117	114	113	115	115
Whyalla (C)	197	197	194	190	192	184	181
TOTAL	**8,874**	**9,100**	**9,032**	**8,948**	**8,857**	**8,745**	**8,754**

AGN network penetration of the new dwellings to be built between 2015 and 2021 was derived based on historical connections and new dwelling starts from BIS Shrapnel.[60]

The historical penetration of the AGN network was derived by dividing the number of new dwelling starts within the AGN network by the number of historical new connections.

Table A 6.11 Historical New Dwelling Starts and Network Penetration

	2011	2012	2013	2014
New Dwelling Starts | Within AGN Network	8,454	7,492	7,129	8,095
New Connections	8,322	6,638	5,590	5,912
Penetration of Dwelling Starts	98%	89%	78%	73%

It was assumed that the penetration of the AGN network would decline at a rate consistent with the historical average annual growth, 1.6%. The penetration of the AGN network was forecast to fall to 65% by 2021.

Table A 6.12 Forecast New Connections | No.

	2015	2016	2017	2018	2019	2020	2021
New Dwellings Forecast	8,874	9,100	9,032	8,948	8,857	8,745	8,754
AGN Network Penetration	72%	71%	70%	69%	67%	66%	65%
New Connections Forecast	**6,379**	**6,439**	**6,290**	**6,134**	**5,975**	**5,808**	**5,722**

Core reviewed the historical apportionment of new estate and multi-unit dwellings as reported by HIA[61]. However, this split was observed to be inconsistent with the actual historical split. Therefore, the apportionment of New Estate versus MD/HR connections was determined based on the average split between the historical numbers of New Estate and MD/HR connections between 2011 and 2014.

[60] BIS Shrapnel, *Australian Housing Outlook 2014 – 2017*, October 2014.
[61] HIA Housing Forecasts, February 2015.

Table A 6.13 Historical Number of New Estate and MD/HR Connections and Corresponding Proportions | No. & %

	2011	2012	2013	2014
New Estate Connections	7,345	5,875	4,978	5,247
MD/HR Connections	977	763	612	665
% Proportion New Estate Connections	88%	89%	89%	89%
% Proportion MD/HR Connections	12%	11%	11%	11%

During the forecast period, 88% of total new connections are classified as New Estates, while the remaining 12% are classified as MD/HR. The resultant forecast of new dwelling connections by New Estate or MD/HR categorisation is provided in Table A 6.14 below.

Table A 6.14 New Connections AGN Forecast by Type | No.

New Connections	2015	2016	2017	2018	2019	2020	2021	Total
New Estate	5,655	5,707	5,576	5,437	5,297	5,148	5,072	37,891
MD/HR	725	731	714	697	679	660	650	4,855
Total	**6,380**	**6,438**	**6,290**	**6,134**	**5,976**	**5,808**	**5,722**	**42,746**

Forecast Approach Comparison

When comparing the forecasts from the two approaches, the forecast based on population is approximately 3,400 connections lower than the forecast based on BIS Shrapnel's dwellings forecasts. This discrepancy is considered immaterial. As such, Core believes that the forecast derived from the BIS Shrapnel dwellings forecasts is most reflective of the actual dwellings to be completed during the forecast period. BIS Shrapnel, as an independent expert on forecasting building trends, is more likely to consider additional influences that impact housing trends outside of population growth and housing density. As such, Core believes it prudent to rely on the BIS Shrapnel forecasts of new dwellings to forecast new connections.

Table A 6.15 Comparison of New Connections Forecast by Approach | No.

Connections Type	2015	2016	2017	2018	2019	2020	2021	Total
BIS Shrapnel Dwellings Based Forecast	6,419	6,398	5,851	5,470	5,645	6,047	6,238	42,068
Population Based Forecast	6,379	6,439	6,290	6,134	5,975	5,808	5,722	42,746
Difference	**-40**	**41**	**439**	**664**	**330**	**-239**	**-516**	**678**

Annexure 7 | Continued Demand per Connection Drivers

The following paragraphs provide additional details for the various factors that continue to drive demand per connection. Data available for these factors is not robust or suitable enough to quantify individually. However, the combined effect is captured by the historical annual average growth rates. The qualitative and quantitative evidence for these factors is presented below and justifies why Core considers it likely for the combined effect of these factors to maintain the trends experienced since 2011.

South Australian Energy Use Trends (March 2014)

The most significant uses of gas for Australian households are room heating, water heating and cooking. Recent data released by the ABS shows that gas appliances are being substituted for electricity and solar energy when it comes to space heating and water heating.[62]

Table A 7.1 below illustrates the significant increase in the number of South Australian households that now use electricity for their heating purposes. In the last three years, the market share of electricity for space heating increased by 4.3%. To reinforce this substitution effect, the market share for gas heating appliances fell by 7.5% over the same period. This is likely due to the increase in RC air-conditioning penetration. Consumers are likely to favour the convenience of a single appliance that has two functions, cooling and heating.

The data also shows that solar appliances have increasing market share in water heating. Many of these are gas boosted, meaning that the household will retain gas as a water heating source, but gas will only be used when the solar system cannot provide all the hot water demanded by a household. Therefore, the 1.0% increase in the number of households that list gas as a water heating energy source is not a true reflection of the change to gas water heating demand. More houses can list gas as a water heating source but realistically each household will likely consume less gas on average.

The market share for solar water heating rose by 22.7% to 8.1% between 2011 and 2014 and this is expected to continue during the Review Period, resulting in lower gas consumption.

Table A 7.1 South Australian Energy Use | % of Households

	2011	2014
Electricity main source for heating	50.8	53
Gas main source for heating	26.7	24.7
Gas energy for hot water (includes gas boosting)	48.6	49.6
Solar used for hot water system	6.6	8.1

A widely sourced study entitled *Are We Still Cooking with Gas?* conducted by the Alternative Technology Association (ATA), and supported by the energy market's Consumer Advocacy Panel found that houses already connected to the gas network could steadily withdraw from using gas for space heating in favour of using reverse cycle air conditioners, on economic grounds.

[62] ABS, *4602.0.55.001 - Environmental Issues: Energy Use and Conservation*, Mar 2014.

Core analysis concludes that solar power will continue to erode the market share of gas via both a use of solar water heating and change out of appliances to utilise solar PV based power. The Small-scale Renewable Energy Scheme ("**SRES**") grants households small-scale technology certificates ("**STCs**") which can be sold back to an energy provider or traded. This gives a financial incentive for the installation of solar power systems. 30% of eligible households in South Australia are fitted with solar PV and recent years have seen persistent growth in solar PV capacity. Less than 4 megawatts ("**MW**") were installed at the end of 2007 but almost 600MW is installed as of 2014. The substantial growth since 2010 is expected to continue during the Review Period.

Updated E3 program and MEPS

Under the E3 program, MEPS specify the minimum level of energy performance that appliances, lighting and electrical equipment must meet or exceed before they can be offered for sale or used for commercial purposes. MEPS and labelling was implemented for gas appliances in 2009 and 2010 as part of the "Switch on Gas" ten year strategic plan.[63] The aim of the energy rating labelling program is to:

- Encourage consumers to select the appliance that uses the least energy and which meets their energy service needs.
- Enable consumers to understand the approximate running costs of an appliance before buying and to minimise the total life cycle cost of the appliance where possible[64].
- Provide incentives for manufacturers and importers to improve the energy efficiency of the products they supply to the market.

The latest impact study of the E3 program illustrates the underlying fall in demand per connection. Between 2000 and 2013, all E3 programs have saved total 6.1PJ of gas, and 1.6PJ or 26.2% of those savings came in 2013 alone.[65] Furthermore, the impact study says that another 0.8PJ could be saved with faster implementation than the current rate. In this way it treats the initial estimate as somewhat of a conservative figure. The E3 program was strengthened in 2012 when the *Greenhouse and Energy Minimum Standards (GEMS) Act 2012* replaced seven separate state and territory energy efficiency regulations. The legislation put into place a national framework for E3. The program now incorporates increased data reporting and compliance measures such as fines. This program is therefore expected to be a continued driver of household efficiency gains. In addition, the Department of Industry's forecast in March of last year indicates that gas savings are expected to total 27.8PJ between 2014 and 2020. This is an annual average saving of 4.5PJ, almost three times the 2013 figure.

Behaviour and Attitudes of Australian households

This section seeks to clarify the incentives and decision making involved with household energy use decisions. A useful way to predict the behavioural patterns of households is to ascertain the motives for their energy usage decisions. A qualitative survey conducted by the Australian Housing and Urban Research Institute, was carried out in two cities of Australia, Brisbane and Melbourne.[66] The table below reports some relevant findings and gives a cross section of households who reduced their energy use over the study period. It shows what reasons were behind decisions that ultimately reduced energy. Note that households could hold multiple reasons for changing their energy usage. 47.1% of Brisbane respondents reduced their energy use due to an appliance or fitting replacement. 38.1% in

[63] George Wilkenfeld and Associates, *Prevention is Cheaper than Cure- Avoiding Carbon Emissions through Energy Efficiency*, January 2009.
[64] Department of Environment, Water, Heritage and the Arts (DEWHA), *Energy Use in the Australian Residential Sector 1986 – 2021*, 2008.
[65] Department of Industry, Impacts of the E3 program: Projected energy, cost and emission savings, March 2014
[66] Fielding, K. Et al. (Australian Housing and Urban Research Institute), *Environmental Sustainability: understanding the attitudes and behavior of Australian households,* October 2010.

Melbourne cited the same reason. This is a strong reflection of continuing appliance trends which have also been discussed in this report. Across two cities, almost half of energy use reductions are being driven by new appliances.

Just over 60% of respondents in both cities changed their energy use due to a new awareness of just how to achieve reduced energy use. This suggests that public campaigns and awareness measures do influence household energy use decisions. Public awareness campaigns and climate change discussions have been prominent over the last few years, suggesting that such decisions will only increase. The reduced gas demand from increased awareness will be partially captured by the appliance and efficiency trend.

There are further reasons cited which suggest a potential switch-off effect. In addition to growing awareness of energy efficiency, the proportion of households reducing their energy use due to environmental protection centres on 50%. It is reasonable to expect that climate change and public awareness will remain a live issue in Australia over the Review Period. If households are motivated by environmental protection it suggests that it isn't just energy cost savings that drive these decisions. It suggests that households may even switch off or assign a higher threshold of discomfort before using gas. In addition to more efficient appliances, it is feasible that many households will make conscientious efforts to take shorter showers or perhaps wear a jumper rather than heat their house for prolonged periods. This switch-off effect would be in addition to the impact of appliance substitution and efficiency trends.

Table A 7.2 Respondents who Cited the Following Reasons as Responsible for a Change in their Energy Use Behaviour

Reason	Brisbane respondents	Melbourne respondents
Commitment to protecting the environment	45.1%	52.1%
Awareness of ways to save energy	61.5%	62.3%
Changes in fittings and appliances	47.1%	38.1%

Policies and Programs Contributing to Appliance Substitution and Efficiency Trends

Policy	Impact on Review Period Demand
Renewable Energy Target ▪ The Renewable Energy Target (RET) scheme is designed to ensure that a certain percentage of Australia's electricity comes from renewable sources by 2020. ▪ Since January 2011 the RET scheme has operated in two parts—the Small-scale Renewable Energy Scheme (SRES) and the Large-scale Renewable Energy Target (LRET). ▪ The SRES creates a financial incentive for households, small businesses and community groups to install eligible small-scale renewable energy systems such as solar water heaters, and solar PV systems.	▪ Core has assumed that the RET will continue to impact gas consumption to a similar extent that has existed over the historical period. ▪ In May 2015, the Australian Parliament has reached a bipartisan deal for the RET, which has been set at 33,000GWh. The slight reduction from the original target is likely to have a lesser effect than the political certainty of having the deal passed. Core believes this certainty will encourage installation of solar PV systems and solar water heaters in the short to medium term. ▪ Household appliances account for 41% of residential GHG emissions. This makes them an obvious target for future policy. This suggests current efficiency trends and appliance trends should pick up their pace and at the very least, hold their current rate of growth. The resulting fall in gas demand will continue at the very least. If the target is to be achieved, average gas usage will have to fall at faster rate over the Review Period.
NABERS, NATHERS and the Building Code of Australia ▪ National Australian Built Environment Rating System is a performance-based rating system for buildings and uses a star system to rate a building on the basis of its measured operational impacts on the environment. The NABERS system now extends to 6 stars and is a simple indication of how well a commercial building manages the environmental impact of the resources used, compared with similar buildings. ▪ In 2006, the Building Code of Australia ("BCA") set a new residential building energy efficiency standard of 5 stars, as rated by software tools accredited under the Nationwide House Energy Rating Scheme ("NatHERS"). To reach the 5-star energy efficiency standard, architects and builders could choose from a large variety of options, such as increasing insulation in ceilings, walls and floors; using double glazing; and redesigning house layout and orientation. The assessment has now been extended to a 6 star rating system. ▪ Under NABERS, actual performance is measured. NatHERS predicts building performance	▪ Core knows of no reason to assume that future impact of the NaTHERS policy during the Review Period will vary materially from the impact observed during the 2011 to 2014 period. Therefore, Core assumes that energy efficiency gains from this program to continue over the Review Period.
Water Efficiency Labelling and Standards ("WELS") ▪ Increased penetration of energy efficient showerheads under the Water Efficiency Labelling and Standards Scheme, which reduces water usage by 40% compared to standard showerheads, has contributed to lower gas hot water usage. ▪ Over a third of the water savings from WELS is associated with showering, which leads to a significant reduction in hot water heating requirements.	▪ Core knows of no reason to assume that future impact of the WELS policy during the Review Period will vary materially from the impact observed during the 2011 to 2014 period. Therefore, Core assumes that energy efficiency gains from this program to continue over the Review Period.

Policy	Impact on Review Period Demand
Restriction on High Emission Water Heaters ▪ Since 31 January 2010, domestic water heaters in houses and townhouses have had to comply with minimum greenhouse intensity and/or energy efficiency standards. Only certain solar, heat pump and gas storage and gas instantaneous water heaters could be installed in a hot water system. Electric resistance water heaters were banned; however, an electric-boosted heat pump or solar water heater could be installed if it meets the minimum standard. ▪ In January 2014 the South Australian Water Heating Standards were amended to allow for the installation of smaller and medium size electric water heaters in houses that are not connected to reticulated gas. Previously, the standards required plumbers to install high efficiency gas, solar or electric heat pump systems only.	▪ Prior to January 2014, Core was not expecting the reduced use of electrical resistance systems to have a material impact on demand per connection during the Review Period due to the low penetration rate of this appliance type. ▪ However, the partial reversal of this ban will potentially reduce gas demand, albeit by a minor amount. Given the timing of the policy, there is no available data to quantify the change or incorporate it into the forecast but Core notes the minor downward pressure that the policy should apply to gas demand. This reinforces the somewhat conservative nature of the demand forecast. ▪ These requirements do not apply to: > Homes which had building approval for plans before 31 January 2010 > Water heaters installed in new apartments and units > Replacement water heaters in houses built before 31 January 2010 > Hot water systems being replaced under warranty, and > Hot-water systems containing solid fuel-burning equipment being installed in homes in non-urban land areas.

Annexure 8 | Tariff D Customer Survey

Core and AGN agreed a process to survey major Tariff D customers. The following letter and survey template were used for this purpose.

[Date]

[Name]
[Job Title]
[Customer Name]
[Address]

Dear [Name],

Regulatory Review of Gas Usage

Connection Site: [Site address]
Connection Number (ID): [ID]

Australian Gas Networks Ltd. ("**AGN**") is the owner of the gas distribution network, to which your business is connected. Your gas retailer contract for capacity on the gas distribution network.

AGN is required by the Australian Energy Regulator to forecast industrial demand for gas over coming years. AGN wishes to survey key gas users to gain more accurate data for its forecasts. This information will also assist with AGN's forward planning.

Accordingly, we request you provide us with your best estimate of likely future gas usage. You can respond to the survey by either:

> **Completing the attached sheet and returning it in the reply paid envelope;**
> **Or email the information set out on the next page to [email address].**

Your response will be kept confidential, and only aggregated forecasts will be provided to the Australian Energy Regulator.

We appreciate your timely assistance. For further information, please contact
[XXX] on [XX-XXX].

Yours sincerely

[XXXX]

Survey Response – Gas Usage Forecast

Customer Name: [Customer Name]
Connection Site: [Site address]
Connection Number (ID): [ID]
Gas Supplier: [Retailer]

Historic Usage

We include for your convenience a table of your past annual consumption from 30 June 2010.

Year ended	Annual Contract Quantity | GJ	Change on Previous yr | %	Maximum Daily Quantity | TJ/d	Change on Previous yr | %
30 June 2010				
30 June 2011				
30 June 2012				
30 June 2013				
30 June 2014				
2010 to 2014 (Average)				

Forecast Usage

Taking into account historic gas usage, and planned future activity, please make an estimate of the rate of change (if any) to future gas usage in the table below. For example, if there is no expected material change in gas usage in the period below, input "0%" in each row. Alternatively, if gas usage is expected to increase by 1% per annum for the relevant years, input "+1%" in the row of the relevant years; or for a fall in gas usage by 2% per annum, input "-2%" for the relevant years.

Year ended	Gas Usage Forecast – Estimated % change compared to prior year	
	ACQ | %	MDQ | %
30 June 2015		
30 June 2016		
30 June 2017		
30 June 2018		
30 June 2019		
30 June 2020		
30 June 2021		

If there are any foreseeable significant changes to forecast gas usage, please provide a brief description (for example, significant plant expansion/contraction in commercial activity, forecast/ possible closure, new equipment etc.)

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....

....

Historical Gas Price

1) Has your gas bill changed by more than 10% in the past 12 months?
   Please circle most applicable answer.

   a) Yes, it increased
   b) Yes, it decreased
   c) It hasn't changed significantly

2) If yes, what was the reason for the change:
   Please circle most applicable answer.

   a) Commodity charges
   b) Distribution charges (DuOs charge)
   c) Transmission charges (TuOs charge)
   d) Increase/Decrease in consumption
   e) Other, please comment

3) If you selected option a) to c) above, were you informed of the change in Tariff prior to receiving your gas bill?
   Please circle most applicable answer.

   a) Yes
   b) No

4) And were you happy with the level of information provided?
   Please comment.

....

....

....

5) How important are gas costs to your business?
   Please circle most applicable answer.

   a) Very important
   b) Important
   c) Somewhat important
   d) Not very important

Annexure 9 | Tariff D Economic Outlook and Efficiency Trends

Economic Outlook

Tariff D customers were classified by ANZSIC 2006 divisional structure, with manufacturing further divided into 12 separate categories. Historical demand for each industry segment was regressed against historical GVA using four different models. The four models are listed below followed by the regression output table:

1. $Demand = \beta_0 + \beta_1\ GVA$

2. $log\ Demand = \beta_0 + \beta_1\ log\ GVA$

3. $log\ Demand = \beta_0 + \beta_1\ log\ GVA_{t-1}$

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

Table A 9.1 Economic Outlook | Historical GVA and Gas Demand Regression Results

Industry Sectors	Model Selected	R-Square	B1	P-Value	B2	P-Value
Manufacturing | Chemicals	BIS Shrapnel GVA forecasts were unavailable. However, the only Tariff D customer in this category disconnected in 2014.	0.2401	1.809*	0.018	-	-
Manufacturing | Construction						
Manufacturing | Food						
Manufacturing | Health						
Manufacturing | Metals						
Manufacturing | Minerals						
Manufacturing | Other						
Manufacturing | Packaging	Negative coefficient - assume no economic impact on gas demand in this sector.	0.65	-72.083*	0.002	-	-
Manufacturing | Pharmaceuticals						
Manufacturing | Printing						
Manufacturing | Refining						
Manufacturing | Textiles						
Accommodation and Food Services	Unexpected result, positive b1 coefficient but negative b2 coefficient - assume no economic impact on gas demand in this sector.	0.596	5.744*	0.036	-3.85*	0.034
Administrative/ Support Services						
Agriculture, Forestry and Fishing	Negative coefficient - assume no economic impact on gas demand in this sector.	0.819	-17.9*	0.00	-	-
Arts and Recreation Services	Negative coefficient - assume no economic impact on gas demand in this sector.	0.3676	-829.2*	0.044	-	-
Construction						
Education and Training	Negative coefficient - assume no economic impact on gas demand in this sector.	0.7589	-10.311*	0.001	-	-

Electricity, Gas, Water and Waste Services	Unexpected result, positive b1 coefficient but negative b2 coefficient - assume no economic impact on gas demand in this sector					
Financial and Insurance Services						
Health Care and Social Assistance						
Information Media and Telecommunications						
Mining						
Other Services						
Ownership of Dwellings						
Professional, Scientific and Technical Services						
Public Administration and Safety	Negative coefficient - assume no economic impact on gas demand in this sector.	0.6587	-1.385*	0.001	-	-
Rental, Hiring and Real Estate Services						
Retail Trade						
Transport, Postal and Warehousing	Negative coefficient - assume no economic impact on gas demand in this sector.	0.67	-44.106*	0.00	-	-
Wholesale Trade						
* Significant at the 5% level						

Although a significant relationship was identified for a number of industry segments with GVA growth, the coefficients of the regressions were negative implying an inverse relationship between GVA growth and gas demand. This is an unexpected result, and as such it was assumed that economic outlook would have no impact on gas demand for these sectors.

Efficiency Trends

The historical average annual change in MDQ and ACQ for Tariff D was derived for the period between 2011 and 2014. This analysis was undertaken with the exclusion of any new connections or disconnections during this period. As such, the resultant historical change in MDQ and ACQ is likely to be attributed to reduced load due to efficiency gains or a proportion of fuel substitution.

Table A 9.2 Historical MDQ and ACQ | Excluding New Connections and Disconnections

	2010	2011	2012	2013	2014
MDQ | TJ	32.02	32.02	32.48	31.47	31.29
ACQ | GJ	7,468,551.90	7,338,938.01	7,500,160.38	7,433,405.65	6,937,513.60

Table A 9.3 Historical % change MDQ and ACQ | Excluding New Connections and Disconnections

% change	2011	2012	2013	2014	Average
MDQ | %	0.0%	1.4%	-3.1%	-0.6%	-0.6%
ACQ | %	-1.7%	2.2%	-0.9%	-6.7%	-1.8%

Historical average annual change in MDQ and ACQ was calculated to be -0.6% and -1.8%, respectively. These percentages were applied to Tariff D customers whose forecast was not based on customer survey or economic outlook.

Annexure 10 | Independent Expert Witness

I have read the Guidelines for Expert Witnesses in Proceedings of the Federal Court of Australia as set out in Practice Note 7 and confirm that I have made all inquiries that I believe are desirable and appropriate and that no matters of significance that I regard as relevant have, to my knowledge, been withheld from the court.

In accordance with Practice Note CM7 – Expert Witness in Proceedings in the Federal Court of Australia at 2.1(c), the following is a summary of the relevant training, study or experience by which Paul Taliangis has gained specialised knowledge.

Tertiary Qualifications

- Bachelor of Economics
- Post graduate Diploma in Accounting
- Member Institute of Chartered Accountants in Australia
- Various national and international intensive management development courses

General Professional Experience

In excess of 30 years of commercial/ business experience focused primarily in the areas of Corporate Finance and Energy, at a national and international level.

- Chartered Accounting – 6 years experience with Price Waterhouse – Australia and New Zealand
- Banking – 3 years experience with State Bank Group
- Management Consulting – 3 years experience with Ernst and Young Consulting
- Gas Industry – 8 years experience with Santos Limited – Australia, UK and USA
- Energy Advisory – 11 years as CEO and owner of Core Energy Group

Core Competencies

Core competencies include:

- Research and analysis across all major segments of the Australian energy value chain
- Strategic analysis of Australian gas markets - Western, Northern and Eastern Australia and LNG
- Corporate strategy formulation and execution
- Demand forecasting and scenario analysis – at macro and micro levels
- Valuation of assets and companies
- Mergers, Acquisitions and Divestitures
- Investment decisions
- Portfolio Management

Overview of Gas Sector Experience

Introduction

In excess of 20 years' experience in the Australian and international gas sector:

- Manager of Corporate Development, Santos Limited – responsibility for decision-making support relating to large scale investment projects including gas assets, gas companies, joint venture interests – covering Australia (west north and east), PNG, Asia, USA, UK.
- Manager Corporate Planning, Santos Limited – responsibility for group-wide planning including industry analysis (full value chain), strategy, competitor analysis, portfolio management and valuation.

Founder and Chief Executive of Core Energy Group – a niche energy advisory firm with a particular focus on the Australian and international gas and LNG sectors. Service areas include strategic analysis, corporate finance and transactions.

Relevant Specific Experience

Focus Area	Experience
Independent Expert/Witness	▪ A variety of independent expert roles covering: > Gas contract disputes > Gas price reviews – east and western Australia > Gas demand – electricity, industrial, distribution, transmission > Drilling activity (LNG) > Gas processing plants > Gas transmission pipelines > Gas storage > International LNG
Demand forecasting, modelling and scenario analysis	▪ Development of models and analytical tools, forecasts and demand scenarios along the gas sector value chain: > Exploration and production; > Transmission; > Distribution; > Electricity generation; > Retailing; and > Liquefaction (LNG) ▪ The following paragraphs address these areas in further detail
Gas Distribution	Access Arrangements > WA – ATCO > NSW – Jemena > VIC – Envestra > SA – Envestra > ACT – Actew General > Demand forecasting, modeling and scenario analysis covering all Australian networks > Valuation of the majority of gas distribution companies and assets in Australia for a variety of purposes including acquisition evaluation, equity investment and takeover defence > Acquisition of Wagga Gas Network from NSW Government

Focus Area	Experience
Gas Transmission	▪ Development of gas demand scenarios for major transmission systems: > South West Queensland > Roma Brisbane > Moomba Sydney > EGP > Moomba Adelaide > SEAGas > Tasmania > QCLNG transmission line
Gas Exploration and Production	▪ Development of contracted and potential demand and supply scenarios: > Cooper Basin: SA and SWQ JV; unconventional gas (shale, coal seam, tight gas) > Gippsland Basin: Gippsland Basin JV > Otway Basin: Minerva, Thylacine-Geographe, Casino > Surat/Bowen Basins: all major Queensland coal seam gas fields > WA Basins: NWS Domgas, John Brookes, Gorgon, Wheatstone, Pluto > LNG – NWS JV, Gorgon, Pluto, Ichthys, Wheatstone, GLNG, APLNG, QCLNG, Darwin LNG

Terms of Use

This Report has been prepared by Core Energy Group Pty Limited, A.C.N. 110 347 085, for Australian Gas Networks (AGN) in accordance with the strict terms of an agreed Engagement Letter, for the sole purpose of providing AGN with a forecast of gas demand and customer numbers relating to its SA network for submission to the AER in relation to the 2017 to 2021 Access Arrangement.

No other party should rely on any information contained within this report or associated documents.

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