Jemena Gas Networks (NSW) Ltd

2015-20 Access Arrangement Information

Appendix 5.1

Demand forecasting report

Confidential

30 June 2014

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Gas Demand and Customer Forecasts

Jemena Gas Networks | NSW Gas Access Arrangement 2015-2020

April 2014

FINAL DRAFT

Table of Contents

Section 1 | 1. Executive Summary **10**

1.1. Scope of this Report 10

1.2. Overview of JGN 10

1.3. Methodology Overview 12

1.4. Overview of Historical Tariff V Connections and Demand 13

1.5. Overview of Historical Tariff D Demand 14

1.6. Overview of Connections and Demand Forecast 14

1.7. Validation 16

1.8. Structure of Report 17

Section 1 | 2. Methodology **18**

2.1. Weather Normalisation 18

2.2. Tariff V Demand 21

2.3. Tariff D Demand 25

Section 1 | 3. Tariff V Demand Forecast **27**

3.1. Introduction 27

3.2. Derivation of Weather Normalised Demand 27

3.3. Derivation of Tariff V Demand and Connection Forecast 30

3.4. Residential Segment Forecast | Tariff V 31

3.5. Own Price and Cross Price Elasticity of Demand 36

3.6. Reduction in New Dwelling Demand 37

3.7. Tariff V Small Business and I&C Connections and Demand per Connection 38

Section 1 | 4. Tariff D Demand Forecast **41**

4.1. Introduction 41

4.2. Approach to CD Forecast 41

4.3. Tariff D | Connections 47

4.4. Tariff D | ACQ 47

Section 1 | 5. Conclusion | Demand and Customer Forecasts **49**

5.1. Tariff V 49

5.2. Tariff D CD Demand 53

Section 2 | 1. Tariff V Connection Forecast **55**

1.1. Tariff V | E-to-G 55

1.2. Tariff V | New Dwellings 56

1.3. Core Bottom-Up Approach 56

1.4. Third Party Forecast 59

Section 2 | 2. Other Tariff V Residential Gas Demand Influences **62**

2.1. Introduction 62

2.2. Summary of Supporting Information Sources 62

Section 2 | 3. Gas Price Forecast **66**

3.1. Introduction 66

3.2. Approach 66

3.3. Background 66

3.4. Gas Price Drivers 68
3.5. Third Party Analysis 70
3.6. Third Party Gas Price Analysis 72
3.7. SKM 74
3.8. Australian Industry Group 75
3.9. Oakley Greenwood 76
3.10. Credit Suisse 77
3.11. BREE/ IES – Eastern Australia Gas Market Study 78
3.12. EnergyQuest 79
3.13. AGL/Brattle Group 80

Section 2 | 4. Forecast Retail Gas and Electricity Prices 81

4.1. Increase in Wholesale and Retail Gas Prices 81
4.2. Increase in Retail Electricity Prices 82
4.3. Increase in Gas Prices Relative to Electricity Prices. 84
4.4. Supporting Information 84

Section 2 | 5. Price Elasticity of Demand Analysis 86

5.1. Introduction 86
5.2. Background 86
5.3. Approach 86
5.4. Summary 87
5.5. Derivation of Forecast 87

Section 2 | 6. NSW Manufacturing Gas Demand Forecast 92

6.1. Introduction 92
6.2. Manufacturing Sector Gas Usage 92
6.3. Core Forecast of Manufacturing Demand 93

List of Tables and Figures

List of Tables

Table 1.1. Tariff Classification. 11
Table 1.2. Historical Connections, Demand per Connection and Demand – Tariff V. 13
Table 1.3. Tariff D Demand Projection | Summary 14
Table 1.4. Tariff V Demand, Connections and Demand per Connection | Summary 14
Table 1.5. Tariff D Demand Projection | Summary 15
Table 1.6. Demand Forecasts – Tariff D. 16
Table 2.1. Core NSW EDD Index: 18 vs 21.2 Degrees. 20
Table 3.1. Weather Normalisation. 28
Table 3.2. Historical Normalised Growth Rates by Customer Class 2002-2013. 29
Table 3.3. Normalised EDD Projections. 29
Table 3.4. Forecast Demand and Historical CAGR Comparison – Tariff V. 30
Table 3.5. Forecast Connections and Historical CAGR Comparison | Tariff V. 30
Table 3.6. Forecast Demand Per Connection – Tariff V. 31
Table 3.7. Forecast Connections and Historical CAGR | Tariff V. 31
Table 3.8. Forecast Connections | Tariff V Residential Segments. 32
Table 3.9. Tariff V Disconnections. 32
Table 3.10. Forecast Demand Per Connection – Tariff V. 33
Table 3.11. Contributors to Historical Trend. 34
Table 3.12. Price Elasticity Impacts. 36
Table 3.13. Demand per Connection of New Dwellings vs. Average. 37
Table 3.14. Cumulative Weighting of New Residential Connections. 37
Table 3.15. Tariff V Connection Forecast |Small Business and I & C 38
Table 3.16. Tariff V Small Business and Tariff V I&C New Connections. 38
Table 3.17. Tariff V Disconnections. 39
Table 3.18. Tariff V Connection Forecast |Small Business and I & C 40
Table 3.19. Tariff V Connection Forecast |Small Business and I & C 40
Table 4.1. Forecast CD Demand | Tariff D. 42
Table 4.2. Forecast CD Demand | Tariff D. 42
Table 4.3. Forecast CD Demand CAGR | Tariff D. 42
Table 4.4. Known Closures | Tariff D. 43

Table 4.5. Impact of Survey Responses | Tariff D 44
Table 4.6. Forecast Movement in Underlying CD Demand | Tariff D. 44
Table 4.7. EEO Program Summary. 45
Table 4.8. General Economic Themes - Manufacturing Sector. 45
Table 4.9. Tariff D Load Factors. 47
Table 4.10. Drivers of Tariff D Connections. 47
Table 4.11. Drivers of Tariff D ACQ. 48
Table 5.1. Forecast Total Demand and Historical CAGR – Tariff V. 49
Table 5.2. Forecast Connections and Historical CAGR | Tariff V. 50
Table 5.3. Forecast Net New Connections – Tariff V. 50
Table 5.4. Forecast Demand Per Connection – Tariff V. 52
Table 5.5. Forecast Chargeable Demand – Tariff D. 53
Table 1.1. Marketing Impact. 55
Table 1.2. Change in New E-to-G Connections. 55
Table 1.3. Connections due to Increasing Population. 57
Table 1.4. Connections due to reduction of NSW dwelling stock Deficiency. 58
Table 1.5. Connections due to reduction of NSW dwelling stock Deficiency. 58
Table 2.1. Policy Influences. 62
Table 2.2. Penetration of Heating Appliances 2012. 65
Table 3.1. Summary - Wholesale Gas Cost Projections (Real AUD/GJ 2014). 66
Table 3.2. GLNG Supply Shortfall | December 2013. 69
Table 3.3. Summary - Wholesale Gas Price Projections (Real AUD/GJ 2013) ex-field - LNG linkage. 70
Table 5.6. Summary - Wholesale Gas Price Projections (Real AUD/GJ 2013) ex-field - cost push. 70
Table 3.4. Third Party Wholesale Gas Price Summary. 71
Table 3.5. Recent Gas Contract References. 71
Table 4.1. Summary - Wholesale Gas Cost Projections (Real AUD/GJ 2013). 81
Table 4.2. Summary – Retail Gas Price Changes (Real 2013; %). 81
Table 4.3. Retail Gas Price Projections – Residential (Real 2013 AUD per GJ). 81
Table 4.4. Retail Gas Price Projections – Non-Residential (2013 AUD per GJ). 82
Table 4.5. Indicative Changes in Regulated Retail Electricity Prices (Nominal). 83
Table 4.6. Electricity Price Projections – Third Party Summary (Real Percentage Change). 83
Table 4.7. NSW Electricity Distribution Network Charges Summary (Real Percentage Change from 2013-14). 84
Table 4.8. Retail Gas and Electricity Price Projections (Real Percentage Change). 84
Table 4.9. Carbon Price Projections. 85

Table 5.1. Price Elasticity of Demand Analysis Summary | % 87
Table 5.2. Price Elasticity Results Using Actual Jemena/IPART Data........ 88
Table 5.3. Price Elasticity of Gas Demand – Literature Review........ 88
Table 5.4. Price Elasticity of Gas Demand – Prior AER Submissions. 88
Table 5.5. Own Price Elasticity. 89
Table 5.6. Short-Run Price Elasticity Factors. 89
Table 5.7. Own Price Elasticity Impact on Demand. 90
Table 5.8. Retail Gas and Electricity Price Projections (Real Percentage Change). 90
Table 5.9. Price Differential Using AGL Price Proposal for IPART 2014. 91
Table 5.10. Cross Price Elasticity Impact on Demand. 91
Table 6.1. 2013 Manufacturing CD by Sub-sector. 92
Table 6.2. Manufacturing Known Movements........ 92
Table 6.3. Influences on Manufacturing Gas Use. 93

List of Figures

Figure 1.1. Core Methodology – Tariff V. 12
Figure 1.2. Core Methodology - Tariff D. 12
Figure 1.3. Total Demand and Total Connections – Tariff V – History and Forecast. 13
Figure 1.4. Demand Forecasts and Historical Comparison – Tariff D. 14
Figure 1.5. Significant Forecast Trends | GAAR submissions. 16
Figure 2.1. Core NSW EDD Index. 19
Figure 2.2. Tariff V Residential Demand Forecast Methodology 21
Figure 2.3. Tariff V Non-residential Methodology. text in box 23
Figure 2.4. Tariff D Industrial Methodology. 25
Figure 3.1. Trend in EDD. 27
Figure 3.2. Tariff V Residential – Historical Trend & Adjusted Forecast. 33
Figure 3.3. Long Term Trend in EDD. 35
Figure 3.4. Standardised energy consumption of externally installed gas water heaters by type and date of certification (Australia-wide). 36
Figure 3.5. Tariff V Small Business and I&C – Extrapolated Trend vs. Core Forecast. 39
Figure 4.1. Tariff D Industrial CD – Extrapolated Trend from 2006 vs. Core Forecast. 42
Figure 4.2. Tariff D Industrial ACQ and CD – Extrapolated Trend vs. Core Forecast. 41
Figure 4.3. Tariff D Industrial ACQ and CD – Extrapolated Trend vs. Core Forecast. 48
Figure 5.1. Forecast Total Demand | Tariff V. 49
Figure 5.2. Historical Actual and Forecast Connections | Tariff V. 50
Figure 5.3. Forecast New Connections – Tariff V. 51
Figure 5.4. Forecast Demand per Connection – Tariff V. 52
Figure 5.5. Forecast Chargeable Demand – Tariff D. 53
Figure 1.1 JGN Historical Connections 2001-2013. 56
Figure 1.2 JGN Historical Dwellings Connections 2001-2013 and Core Forecast to 2020. 59
Figure 1.3 JGN Dwelling Connections and BIS Completions. 60
Figure 1.4 JGN Dwelling Connections and BIS Completions 60
Figure 1.5 BIS vs. HIA Dwellings Projections. 61
Figure 2.1 Map of Existing Eastern Australia Gas Basins & Transmission Network. 67
Figure 2.2 NSW/ACT Peak Pipeline Flow - 2013 Calendar Year. 68
Figure 2.3 ACIL Tasman Gas Price Scenarios, April 2013. 72
Figure 2.4 ACIL Tasman Projected Prices – Sydney 73
Figure 2.5 New contract prices ($/GJ, $2013 real) 74
Figure 2.6 High contract diversion - ($/GJ, $2013 real) 74
Figure 6.1 Tariff D Industrial CD – Extrapolated Trend from 2006 vs. Core Forecast. 93
Figure 6.2 Manufacturing Sub-Sector Movement (% of GSP). 94
Figure 6.3 NSW Manufacturing Full-Time Employees. 94
Figure 6.4 Expected Employment Growth by Industry, NSW, 2011/12 to 2016/17. 95
Figure 6.5 Projected Employment Growth (‘000s) by Manufacturing Sector – Five Years to Nov-17. 95
Figure 6.6 ABS Private New Capital Expenditure and Expected Expenditure - Manufacturing. 96
Figure 7.1 Type of Heater Used Most Often in NSW 2005-2011. 64
Figure 5.6. Total Connections Summary. **Error! Bookmark not defined.**
Figure 6.1. Small Business Demand per Connection. **Error! Bookmark not defined.**
Figure 6.2. I&C Demand per Connection. **Error! Bookmark not defined.**

Glossary

AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BASIX	Building Sustainability Index
BOM	Bureau of Meteorology
CBJV	Cooper Basin Joint Venture
CD	Chargeable Demand
COAG	Council of Australian Governments
CSG	Coal Seam Gas
DD	Degree Days
EDD	Effective Degree Days
EEO	Energy Efficiency Opportunities
EGP	Eastern Gas Pipeline
E-to-G	Electricity-to-Gas
GAAR	Gas Access Arrangement Review
GBJV	Gippsland Basin Joint Venture
GEMS	Greenhouse and Energy Minimum Standards
HDD	Heating Degree Days
IPART	Independent Pricing and Regulatory Tribunal
JCC	Japanese Cleared Crude
LGA	Local Government Area
LRET	Large-scale Renewable Energy Target
LRMC	Long Run Marginal Cost
MDQ	Maximum Daily Quantity
MEPS	Minimum Energy Performance Standards
MSP	Moomba to Sydney Pipeline
NABERS	National Australian Built Environment Rating System
NSW	New South Wales
RET	Renewable Energy Target
RIN	Regulatory Information Notice
SCER	Standing Council on Energy and Resources
SRES	Small Scale Renewable Energy Scheme
STTM	Short Term Trading Market
UHI	Urban Heat Island
VIC	Victoria
VPA	Voluntary Pricing Agreement

Part 1| Summary

Section 1 | 1. Executive Summary

1.1. Scope of this Report

This report has been prepared by Core Energy Group Pty Ltd (“**Core**”) for the purpose of providing Jemena Gas Networks (“**Jemena or JGN**”) with an independent forecast of gas customers and demand for the company’s natural gas distribution network in New South Wales (“**NSW**”), for the five financial years from 1 July 2015 to 30 June 2020 (“**Review Period**”).

Core has noted that these projections (both this Report and related forecasting models[1]) will form part of Jemena’s Gas Access Arrangement Review (“**GAAR**”) submission to the Australian Energy Regulator (“**AER**”).

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

"74. Forecasts and estimates

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

(2) A forecast or estimate:

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

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

75. Inferred or derivative information

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

1.2. Overview of JGN

The JGN extends over 23,800 km and provides gas to over one million customers across Sydney, Newcastle, Wollongong and over 20 country centres. The gas distributed by the network has historically been produced mainly from the Cooper Basin and Gippsland Basin (Bass Strait) Joint Ventures. [3]

1.2.1. JGN Customer and Tariff Classifications

For the purpose of this Report, reference will be made to two Customer Types - type V and type D[4] as defined in Table 1.1 below.

1 The forecasting models are Confidential and an application will be sought for disclosure to be suppressed in accordance with NGR part 43 (2) (b).
2 NGR dated April 2014 and access from AEMC website.
3 Source: http://jemena.com.au/what-we-do/assets/jemena-gas-network/
4 These classes are consistent with the classification referenced in the JGN Schedule of Reference Tariffs and Charges

Table 1.1. Tariff Classification.

Customer Type	Description
Type V (<10TJ)	Type V customers consist of residential and business customers who are reasonably expected to consume less than 10 TJ of natural gas per year. For management accounting purposes Jemena groups Type V customers as follows: ▪ Residential (~20GJ average usage per year); ▪ Small Business (~250GJ average usage per year); and ▪ I&C (~400GJ average usage per year). New Residential customers are further segmented for management accounting purposes as follows: ▪ E-to-G – i.e. electricity only houses which connect to gas ▪ New Estates – i.e. detached houses ▪ Medium Density/High Rise – houses connected as part of a higher density apartment/ dwelling. Throughout this Report, customer type V will be referred to as Tariff V customers and the Tariff V customer segments defined above will be referred to consistently throughout the Report.
Type D (>10TJ)	Tariff D customers consist of large industrials that are reasonably expected to consume more than 10 TJ of gas per year. Note: Starting in 2011, Jemena's demand capacity measure for Tariff D changed from a maximum daily quantity ("**MDQ**") system to a Chargeable Demand ("**CD**") system, where chargeable demand refers to the quantity of gas used to determine the Demand Charge under Jemena's Reference Tariff Schedule. Throughout this Report, customer type V will be referred to as Tariff D customers and MDQ will be referred to for certain historical data and analysis and CD will be used to define capacity use in all forecast periods.

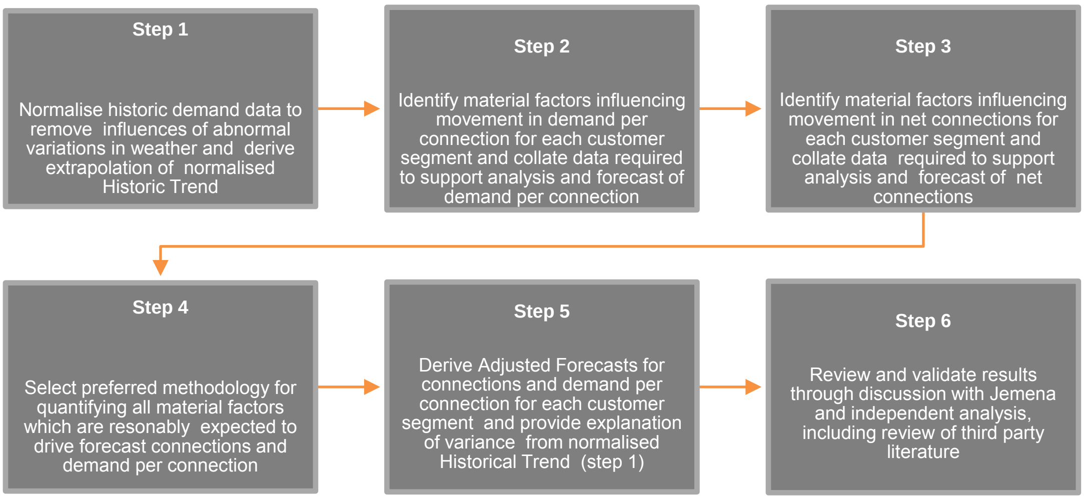
Source: Core Energy based on advice from Jemena and JGN Schedule of Reference Tariffs and Charges

1.3. Methodology Overview

An overview of the methodology adopted by Core to derive forecasts of JGN demand and customer numbers is provided below for both Tariff V and Tariff D classes. Further detail is presented in Section 2.

1.3.1. Tariff V

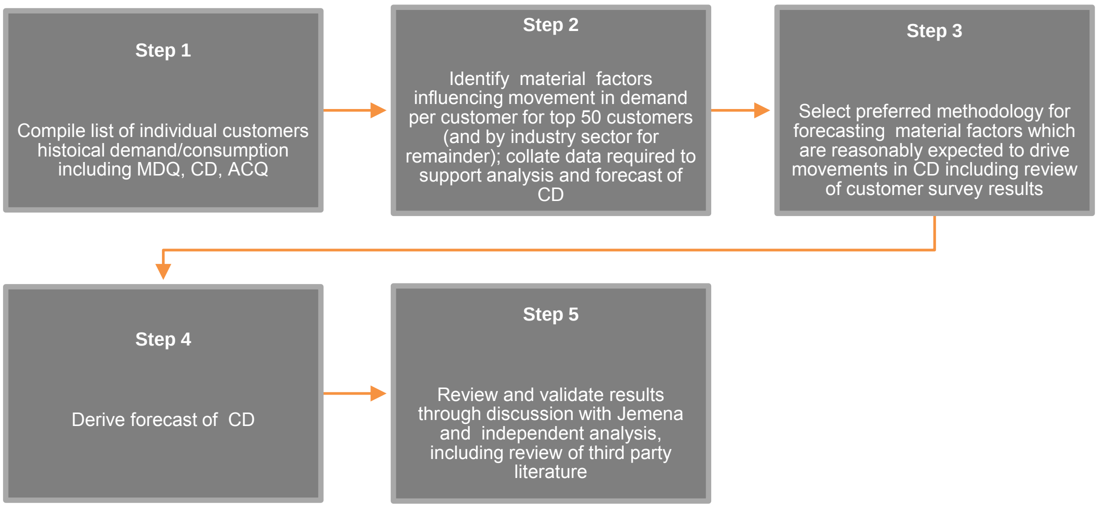
Figure 1.1. Core Methodology – Tariff V.



Source: Core Energy Group.

1.3.2. Tariff D

Figure 1.2. Core Methodology - Tariff D.



Source: Core Energy Group.

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

1.4. Overview of Historical Tariff V Connections and Demand

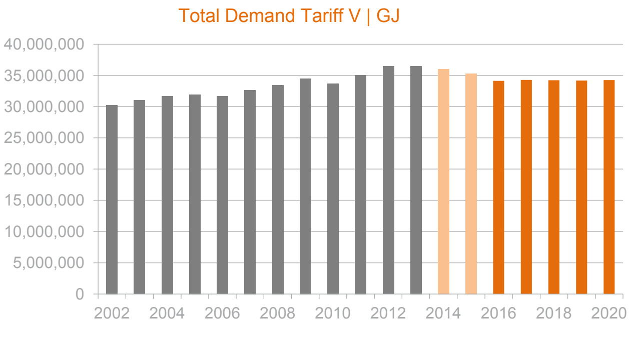
Table 1.2 and Figure 1.3 provide a summary of actual connections, demand per connection and total demand for Tariff V for the 2013 year and prior, together with a summary of compound average growth rates relating to two historical time series - 2002 to 2013 and 2008 to 2013, to illustrate any differences between shorter term and longer term trends.

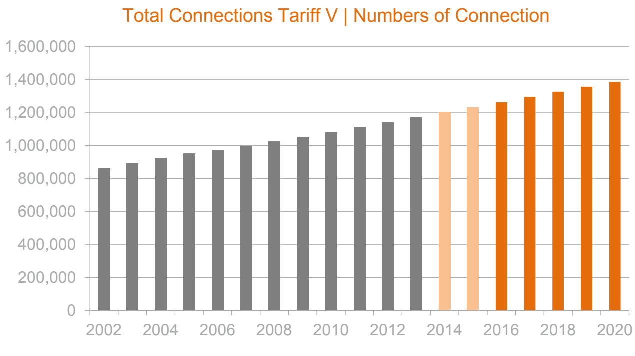
Table 1.2. Historical Connections, Demand per Connection and Demand – Tariff V.

Tariff V	2013 Actual	CAGR 02-13 A	CAGR 08-13 A
Connections			
Residential	1,136,607	2.72%	2.70%
Small Business	21,581	6.37%	3.76%
I&C	15,933	2.76%	4.28%
Total Tariff V Connections	**1,174,121**	**2.78%**	**2.73%**
Demand per Connection			
Existing Residential	20.57	-0.88%	-0.76%
New E-to-G	13.66	N/A	N/A
New Estates	17.89	N/A	N/A
New Med Density	15.71	N/A	N/A
Total Residential Demand per Connection	**20.57**	**-0.88%**	**-0.76%**
Small Business	244.22	-4.73%	-2.51%
I&C	493.42	-1.41%	-2.49%
Total Demand			
Residential	23,375,250	1.82%	1.91%
Small Business	5,270,576	1.34%	1.15%
I&C	7,861,616	1.31%	1.69%
Total Tariff V Demand	**36,507,442**	**1.64%**	**1.75%**

Source: Core Energy Group with historical data from Jemena. [1] Historical breakdowns of usage for residential segments (E-to-G etc.) was not available from Jemena.

Figure 1.3. Total Demand and Total Connections – Tariff V – History and Forecast.





Source: Core Energy Group with historical data from Jemena.

1.5. Overview of Historical Tariff D Demand

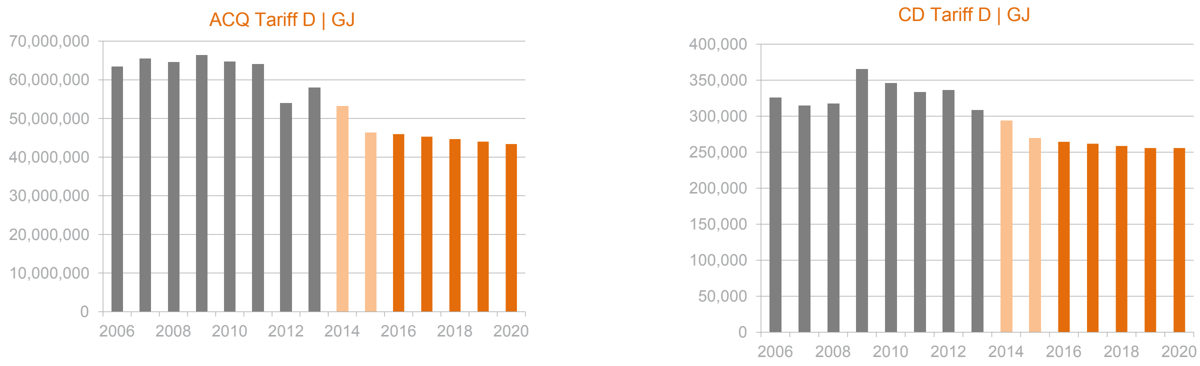
Table 1.3 and Figure 1.4 provide a summary of historical ACQ and CD demand for Tariff D for the 2013 year and prior, together with a summary of compound average growth rates relating to two historical time series - 2006 to 2013 and 2008 to 2013, to illustrate differences between the two periods, particularly in light of the impact of the GFC on industrial activity during this time period.

Table 1.3. Tariff D Demand Projection | Summary

Tariff D Demand (GJ)	2013	CAGR 2006-2013	CAGR 2008-2013
ACQ	57,949,465	-1.27%	-2.16%
CD	308,226	-0.78%	-0.61%

Source: Core Energy Group based on historical data from Jemena which commenced in 2006.

Figure 1.4. Demand Forecasts and Historical Comparison – Tariff D.



Source: Core Energy Group with historical data from Jemena.

1.6. Overview of Connections and Demand Forecast

The following paragraphs provide a summary of the forecasts derived by Core Energy for both the Tariff V and Tariff D customer classes.

1.6.1. Tariff V

Gas demand for Tariff V customers as a whole is forecast to fall by 0.61% p.a. from 2016 to 2020. This forecast is influenced by two principal forces - an increase in forecast connections of 2.38% p.a., offset by a reduction in demand per connection of 2.1% p.a. (Residential), 4.56% p.a. (Small Business) and 4.29% p.a. (I&C) as shown in the following table.

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

Tariff V	2016	2017	2018	2019	2020	CAGR 2003-2013	CAGR 2008-2013	CAGR 2016-2020
Tariff V Connections								
Total Tariff V Connections	1,261,795	1,294,162	1,325,300	1,355,224	1,384,940	2.78%	2.73%	2.38%
Tariff V Demand Per Connection								
Existing Residential	18.86	18.61	18.29	18.06	17.86	-0.88%	-0.76%	-1.54%

New E-to-G	12.53	12.36	12.15	12.00	11.86	N/A	N/A	
New Estates	16.41	16.19	15.91	15.71	15.54	N/A	N/A	
New Med Density	14.41	14.21	13.97	13.80	13.64	N/A	N/A	
Total Residential	**18.51**	**18.15**	**17.75**	**17.43**	**17.15**	**-0.88%**	**-0.76%**	**-2.10%**
Small Business	201.42	194.51	186.34	177.17	169.93	-4.73%	-2.51%	-4.56%
I&C	404.82	398.41	390.16	379.96	373.60	-1.41%	-2.49%	-4.29%
Tariff V Demand								
Residential	22,535,845	22,644,314	22,687,131	22,820,905	22,996,609	1.82%	1.91%	0.23%
Small Business	4,671,596	4,619,335	4,552,256	4,468,591	4,432,905	1.34%	1.15%	-1.80%
I&C	6,809,061	6,832,957	6,825,440	6,782,586	6,807,666	1.31%	1.69%	-2.43%
Total	**34,016,503**	**34,096,606**	**34,064,827**	**34,072,082**	**34,237,180**	**1.64%**	**1.75%**	**-0.61%**

Source: Core Energy Group. Note: historical usage statistics for residential segments (E-to-G etc.) were not available.

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

- an increase in the number of new dwellings connected with lower gas usage levels, including mid-high rise dwellings (refer Part 2 Section 1);
- continued trends in gas use efficiency and energy substitution (refer Part 2, Section 2); and
- customer demand response to increased gas price rises (refer Part 2, Section 5).

1.6.2. Tariff D

Capacity demand (as measured by Chargeable Demand or "**CD**") for Tariff D customers as a whole is forecast to fall by 0.74% p.a. from 2016 to 2020. This fall is attributable to a forecast reduction in gas-intensive industrial capacity and an increase in energy efficiency measures more generally.

Table 1.5. Tariff D Demand Projection | Summary

Tariff D	2013	2014	2015	2016	2017	2018	2019	2020	CAGR 2006-2013	CAGR 2008-2013	CAGR 2016-2020
ACQ	57,949,465	53,144,476	46,296,728	45,951,999	45,290,414	44,644,746	44,014,608	43,399,622	-1.27%	-2.16%	-1.28%
CD/ MDQ	308,226	291,580	263,885	262,397	259,881	256,632	254,228	254,228	-0.78%	-0.61%	-0.74%

Source: Core Energy Group, utilising historical data from Jemena.

The projected reduction in the growth rate of CD is a function of the following:

- known and projected business closures/ capacity reductions due in large part to deteriorating domestic and international competitiveness;
- continuing trend in energy efficiency, including peak demand as a response to increased energy costs and profit pressures more broadly.

Further detail relating to Tariff D forecasts are provided in Part 1, Section 4.

Table 1.6. Demand Forecasts – Tariff D.

Tariff D	2014	2015	2016	2017	2018	2019	2020	CAGR 06-13	CAGR 08-13	CAGR 16-20
ACQ	53,144,476	46,296,728	45,951,999	45,290,414	44,644,746	44,014,608	43,399,622	-1.27%	-2.16%	-1.28%
CD	291,580	263,885	262,397	259,881	256,632	254,228	254,228	-0.78%	-0.61%	-0.74%

Source: Core Energy Group.

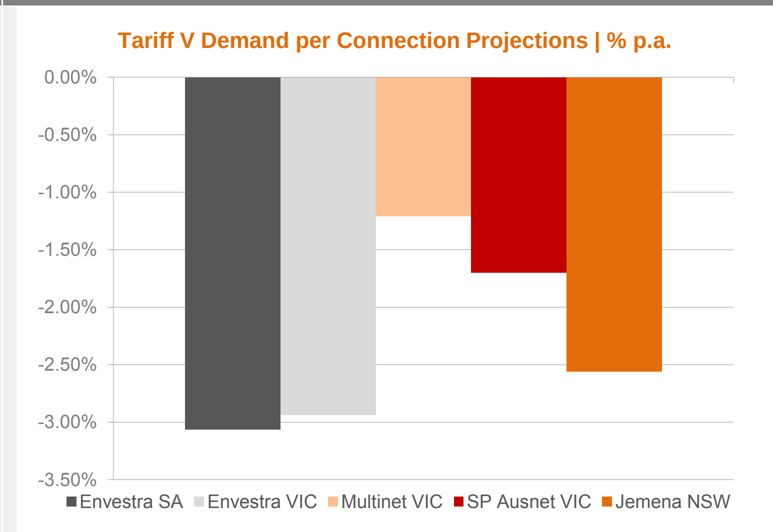
1.7. Validation

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

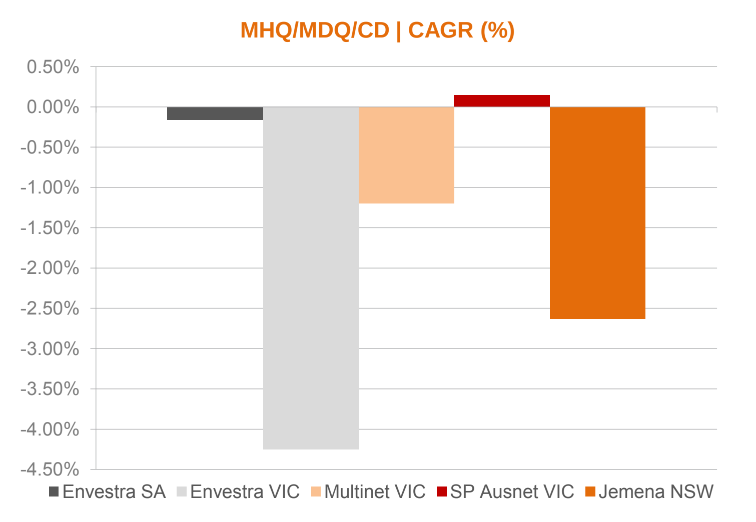
- estimates of NSW residential dwelling growth;
- projections of NSW retail gas and electricity prices;
- trends in energy efficiency at the appliance and building level; and
- trends in manufacturing activity.

In addition Core has reviewed all recent demand forecasts which have formed part of final GAAR decisions for South Australia and Victoria networks, to determine whether trends forecast by Core for the JGN were observable across other networks (Envestra's SA and VIC networks, Multinet VIC and SP Ausnet VIC). This analysis highlights two significant trends as summarised in Table 1.5 below.

Figure 1.5. Significant Forecast Trends | GAAR submissions.

Regulatory Trend	Analysis
Tariff V demand per connection is projected to fall consistently across all networks, and at levels greater than those forecast for the JGN in the case of Envestra SA and Envestra VIC networks	

Tariff D capacity demand is generally forecast to fall across all networks (with exception of low growth for SP Ausnet VIC) and in the case of Envestra VIC network it is forecast to fall at a significantly faster rate than the forecast for the JGN.



Source: Core Energy Group based on latest GAAR proposals and final AER decisions

1.8. Structure of Report

This report comprises two parts:

Part 1 – Summary

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

- Methodology
- Tariff V Forecast – connections/customer numbers and demand
  - Residential
  - Small business
  - I &C
- Tariff D Forecast - CD and ACQ Forecast
- Conclusion

Part 2 – Supporting Information and Analysis

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

- Residential Connection Forecast
- Residential Demand Forecast
- Wholesale Gas Price Forecast
- Retail Gas and Electricity Price Forecast
- Price Elasticity of Demand Forecast
- Tariff D CD Forecast
- NSW Manufacturing Sector Gas Demand Forecast

Section 1 | 2. Methodology

- The purpose of this Section of the Report is to outline the methodology adopted by Core to derive JGN forecasts, including, more specifically, the methodology adopted to:
  - > normalise demand for the impact of weather (Section 2.1)
  - > forecast Tariff V demand (Section 2.2)
  - > forecast Tariff D demand (Section 2.3)
- Prior to finalising the methodology Core completed a review of all recent GAAR proposals and decisions to ensure all constructive positive and negative feedback by the AER and other stakeholders were taken into consideration. Further Core ensured that all relevant requirements of the NGR are strictly complied with.
- The Core methodology favours a highly transparent approach and forecasting model which focuses on those factors which are expected to materially impact future normalised demand and connections, having regard to Historical Trend analysis and forecast changes in certain historical trends and demand drivers, to derive final, Adjusted Forecasts.
- Core is of the opinion that the methodology described herein, provides a basis for the best forecasts available under these specific circumstances, utilising quality data and information, including primary source data where it is reasonably available to Core.

2.1. Weather Normalisation

Gas demand is significantly influenced by weather. Accordingly these influences must be isolated to arrive at normalised demand, to provide a consistent basis for demand forecasting purposes.

The methodology adopted by Core to normalise demand data involves the calculation of Effective Degree Days ("**EDD**"), based upon the Australian Energy Market Operator's ("**AEMO**") "*2012 Weather Standards for Gas Forecasting*" guidelines.

Historical analysis of NSW gas demand indicates that the level of gas consumed during a specific period is highly dependent on the weather conditions during that period, where cooler temperature (below a given threshold) results in higher gas use for heating purposes. Core has therefore normalised gas demand for the JGN by reference to actual EDD in NSW.

Core notes that an EDD approach to weather normalisation has not been applied in prior NSW submissions to the AER. Nevertheless Core considers an EDD approach to be the preferred method for weather normalisation in Jemena's NSW gas network (as opposed to DD) as it takes additional climatic factors into consideration (i.e. sunshine, wind chill and seasonality) when determining the relationship between gas demand and weather conditions; it delivers a higher quality statistical fit than DD and is consistent with approaches applied in other jurisdictions such as Victoria.

Core's approach to weather normalising demand using EDD is outlined below:

1. Develop a model which enables the calculation of the EDD Index - this has been provided to Jemena.
2. Specify the EDD index for calculating EDD using historical temperature data at the Sydney Airport weather station, having regard to AEMO's EDD312 specification in its "2012 Weather Standards for Gas Forecasting". This involves using regression analysis to determine the coefficients of the EDD312 specification which are calibrated for the best fit in Jemena's NSW network.

3. Determine the underlying linear trend in historical EDD to derive an appropriate 'normalised' EDD figure for each year which represents normal weather conditions.
4. Compare the actual EDD each year to the normalised EDD figure for that year to obtain the variance between normalised and observed EDD.
5. Use regression analysis to determine the sensitivity of demand to EDD in each year for each customer class, multiplying this factor by the EDD variance figure to arrive at the total variation in gas demand due to weather for each year.
6. Subtract this variation in gas demand from actual demand to arrive at weather normalised demand for each customer class.

The definition for EDD is taken from the EDD_{312} model contained in AEMO's "*2012 Weather Standards for Gas Forecasting*" and its coefficients have been calibrated for NSW. The EDD outputs are summarised below.

Figure 2.1. Core NSW EDD Index.

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 = DD (temperature effect)

+ 0.0094 x DD x average wind (wind chill factor)

- 0.0624 x sunshine hours (warming effect of sunshine)

+ 5.39 * Cos $\left(\frac{2\pi(\text{day}-198)}{365}\right)$ (seasonal factor)

Where:

DD is the degree day (see below calculation);

DD = 21.2 – T if T < 21.2

0 if T > 21.2:

T is the average of 8 three-hourly Sydney temperature readings (in degrees Celsius) from 3.00am to 12.00 pm inclusive as measured at the Sydney Airport Weather Station, Cos is the cosine function and EDD will be 0 if the calculated value is negative.

21.2 degrees Celsius represents the threshold temperature for residential gas heating.

Friday, Saturday and Sunday are dummy variables for those days of the week, consistent with the AEMO EDD_{312} methodology.

Demand per connection is equal to total daily demand divided by estimated total daily customer numbers (using year-end customer numbers and interpolating for each day of the year). Given the network's historically stable rate of customer growth Core believes this to be a reasonable estimate of daily customer numbers.

Core recognises that the threshold temperature of 21.2 degrees differs from the conventionally accepted 18 degrees and has undertaken analysis of this variance.

For comparative purposes Core re-calibrated its EDD index under an 18 degree threshold to compare with its existing EDD index, with the results shown in Table 2.1 below.

Table 2.1. Core NSW EDD Index: 18 vs 21.2 Degrees.

Statistical factor	21.2 Degrees	18 Degrees
R-Squared	0.9536	0.9402
T-Statistic of EDD variable	272.32	238.15
Wind Chill coefficient	0.0094	0.0157
Insolation coefficient	-0.0624	0.0633
Seasonality factor (days)	198	196
Seasonality coefficient	5.39	7.17

Source: Core Energy Group.

It is noteworthy that the EDD t-statistic and R-squared values (measuring statistical significance and goodness of fit) are both higher under the 21.2 degree threshold, indicating a better level of fit with the actual data. More importantly however is that the use of a traditional 18 degree threshold for calculating EDD gives a positive insolation coefficient, which is contrary to what is reasonably expected (i.e. this EDD model would assume that higher levels of sunshine cause higher gas demand). This supports Core's analysis that specifying EDD under an 18 degree threshold is not appropriate for Jemena's NSW network.

In light of these findings Core considers the use of a 21.2 degree threshold for calculating EDD to provide the most appropriate basis for deriving normalised demand.

The derivation of normalised demand for the Review period is address in Part 1,Section 3.2.

Core has reviewed the use of EDD for weather normalisation in prior Access Arrangements, including responses from the AER in relation to the Envestra VIC 2013-17 Draft Decision. The methodology detailed above demonstrates that Core has applied a weather normalisation process using EDD that is consistent with AEMO's "2012 Review of Weather Standards for Gas Forecasting" method; daily EDD values have been calculated through regression of historical data rather than being based on projected figures. Core consider this process to be compliant with 74 (2) of the National Gas Rules, in that they are arrived at on a reasonable basis and represent the best forecasts possible in the circumstances.

2.1.2. Limitations of Weather Normalisation Methodology

While Core believes that its methodology gives rise the best forecasts possible in the circumstances, there are some limitations which have the potential to bias the demand forecasts. These include:

- **Non-linearities in demand** – Core's trend analysis of a number of key demand drivers rely on the assumption that the relationship with demand is linear in nature. For example, the own price elasticity effect on demand assumes a linear relationship between gas prices and gas usage, when in reality there may be some price thresholds where a larger demand response is observed (e.g. more severe declines in demand as gas prices move beyond a certain level). The analysis required to address these non-linearities is deemed to be overly complex, and have not been undertaken. Nevertheless, Core is of the opinion that the projections resulting from its current methodology to be the best estimate possible under reasonable circumstances.
- **Omitted Variable Bias** – Ideally all of Core's regression models used in this analysis would be more rigorous than is presented, containing a variable for all factors that influences demand (e.g. individual government policies, customer specific characteristics such as their income and year of connection etc) in order to obtain the 'comprehensive' model of demand for the JGN. However, due to a lack of sufficient data a more simplistic method has been employed, focusing

on the major drivers of demand. Core is of the opinion that the projections resulting from its current methodology to be the best estimate possible under reasonable circumstances.

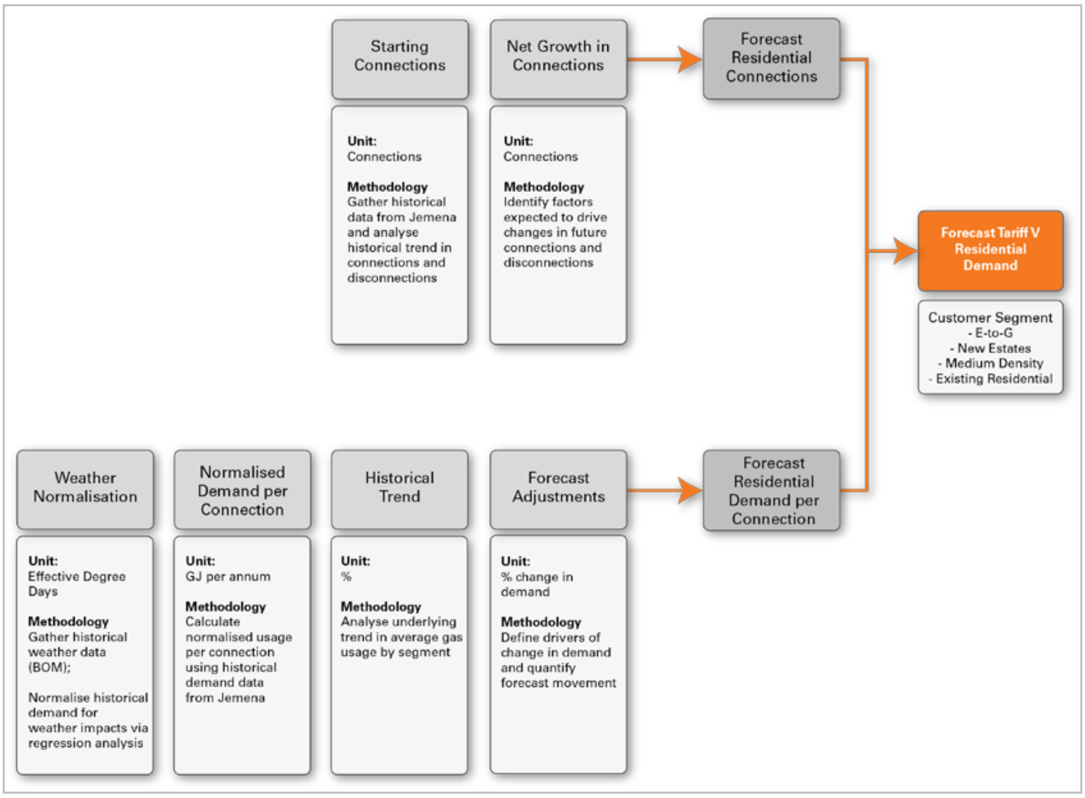
- **Degrees of Freedom** – Core's historical trend analyses of annual data uses 11 to 12 data points, meaning that the resulting regression equations contain approximately ten degrees of freedom. As this is fewer than the widely accepted range of 15-20 degrees of freedom the coefficients may not fully converge with their true population values and some forecasting error may be present. Nevertheless, Core is of the opinion that the projections resulting from its current methodology to be the best estimate possible under reasonable circumstances.

2.2. Tariff V Demand

2.2.1. Residential | Tariff V

Figure 2.2 provides a diagrammatic representation of the approach used by Core to derive a forecast of Tariff V Residential demand, including a forecast of connections and demand per connection.

Figure 2.2. Tariff V Residential Demand Forecast Methodology



Source: Core Energy Group.

2.2.1.2. Connections

Core has undertaken a qualitative assessment of the alternative methodologies which could reasonably be used to derive a forecast of Residential Connections for the JGN. Core has determined that a bottom-up approach which assesses the impact of each material factor which is reasonably expected to influence connections, to be the best approach under the Review circumstances. (appropriate rigour and data quality),

Therefore, the steps taken by Core to arrive at forecast connections are as follows:

1. Analyse historical new connection activity across major Residential segments (E-to-G, New Estates, Medium Density, Existing residential), including discussions with JGN management. Define the material factors driving new connections and the data that is available to support analysis of these factors;
2. For each Residential segment, apply a bottom-up approach to derive a forecast of new connections, using analysis of all material factors define in 1 above;
3. Deduct the forecast of Residential disconnections from the Forecast resulting from step 2 to derive a forecast of net Residential connections for each year.

The specific assumptions and analysis relied upon for these projections are outlined in Part 1 Section 3.

2.2.1.3. Demand per Connection

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

Therefore, the steps taken to arrive at forecast connections are as follows:

1. Developed models for calculation of EDD, normalised demand and forecast of Demand per Connection (these have been provided to Jemena).
2. Normalise total demand per annum for the effects of weather using the methodology discussed in Part 1, Section 3.
3. Divide total historical demand by number of connections to determine average demand per connection.
4. Determine the Historical Trend in demand per connection.
5. Derive Adjusted Forecast of demand per connection having regard to the Historical Trend and the influence of factors which are not present in the Historical Trend.

Section 3 presents a detailed description of this process.

2.2.1.4. Forecast Demand

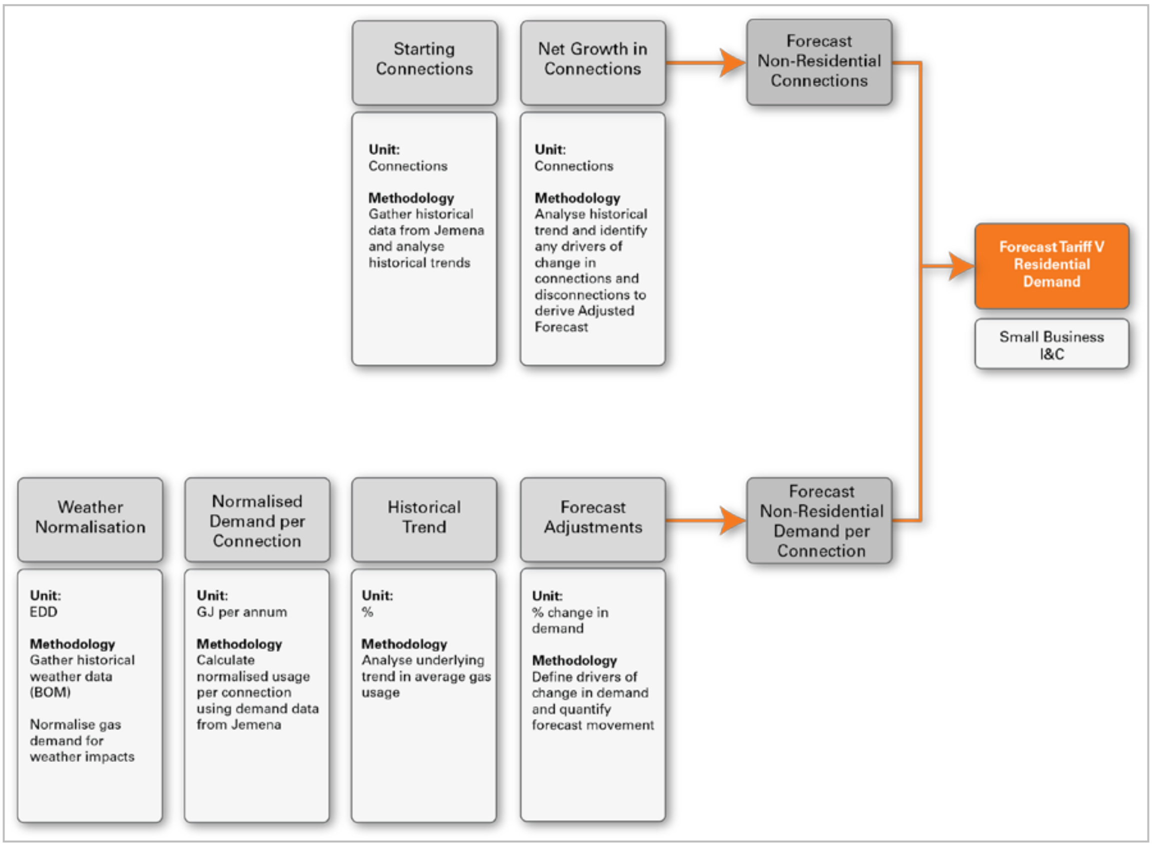
The product of forecast residential connections and forecast demand per residential connection is total forecast demand for the Tariff V residential segment.

2.2.2. Tariff V Non-Residential Demand (Small Business, I&C)

This section provides a summary of the methodology used to derive a forecast for Small Business and I&C elements of the Tariff V class.

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

Figure 2.3. Tariff V Non-residential Methodology. text in box



2.2.2.2. Connections

The methodology adopted to derive the final forecast of connections is as follows:

1. Compile a consistent list of historical connection data sourced from Jemena and use regression analysis to derive an extrapolation of the Historical Trend;
2. Analyse all factors which are reasonably expected to influence future connections and define net impact of each factor;
3. Aggregate the impact of expected movements which are not observable in the Historic Trend and apply against the Historic Trend to derive an Adjusted Forecast of connections;
4. For the I&C segment, manually adjust expected load and connections changes due to known switching (as advised by Jemena) between Tariff D and Tariff V I&C over the review period.

The specific assumptions used for these projections are outlined in Section 3 and Part 2.

2.2.2.3. Demand per Connection

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

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

1. Develop model logic to accommodate Non residential demand per connection forecasting;
2. Normalise historical actual demand for the effects of weather using the methodology discussed above;
3. Divide historical annual demand by actual annual connections to determine average demand per connection;
4. Determine the Historical Trend in demand per connection;
5. Analyse all factors which are reasonably expected to influence future connections and define net impact of each factor; and
6. Derive Adjusted Forecasts of demand per connection by adjusting for any factors which are not present in the Historical Trend.

The specific assumptions and analysis used to derive these projections are outlined in Sections 3.

2.2.2.4. Forecast Total Demand

The product of this forecast of connections and demand per connection is Total Forecast Demand for the Tariff V Small Business and I&C classes.

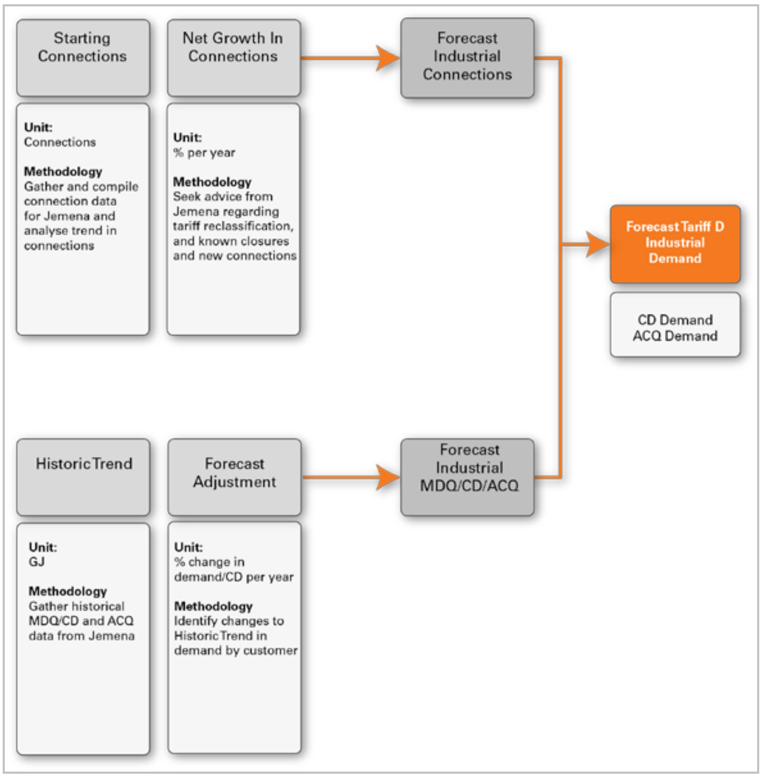
2.3. Tariff D Demand

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

[It is important to note that in 2011 Jemena moved from an MDQ-based charge to a CD-based system; references to MDQ and CD are used interchangeably in this Report as they relate to Tariff D capacity demand.]

Figure 2.4 provides an outline of the Methodology and explanations of key elements of the approach are provided below.

Figure 2.4. Tariff D Industrial Methodology.



Source: Core Energy Group.

2.3.2. Annual Quantity

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

- Review list of Tariff D customers and allocate to industry sectors;
- Identify individual customers and industry sectors which have potential to experience material change in demand;
- Adjust for any known closures, new connections, tariff reallocation and expected material load changes; and
- Adjust demand for remaining customers via analysis of the outlook/competitiveness of industry segments.

2.3.2.1. Connections

As the methodology used does not rely upon use of any form of average CD/ customer, the connection or customer number statistic for the Tariff D class is deemed, by Core, to be immaterial. Further, Core is not aware of any approach which could derive a reliable forecast of customer numbers for such a small number of customers (approximately 400) given the lack of transparency of relevant facts. Core has therefore assumed that connection numbers are constant throughout the period, with the exception of:

- known closures;
- known new connections; and
- customers reasonably expected to switch between Tariff D and Tariff V I&C over the review period.

2.3.2.2. Chargeable Demand (CD)

To derive the Adjusted Forecast Core has considered the following:

- Information provided by Jemena regarding known Tariff D customer business closures and tariff reclassifications (4.2.2.2);
- Results of a Top 20 customer survey (4.2.2.3);
- Core forecast of additional underlying movements in demand (4.2.2.4).

2.3.3. Model Outputs

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

Section 1 | 3. Tariff V Demand Forecast

3.1. Introduction

As noted in Section 2 of this Report, Core has undertaken an analysis of historical actual consumption data, which has been normalised to remove any abnormal impact of weather conditions. This data has been used to derive an extrapolated gas demand trend by tariff class for the 2016 and 2020 financial years (referred to in this Report as the **"Historical Trend"**). The Historical Trend has then been adjusted, where appropriate, to reflect those influences on demand which were not observable in the Historic Trend, to derive a revised forecast (referred to in this Report as the **"Adjusted Forecast"**).

Details of this analysis and the resultant forecast are summarised below.

3.2. Derivation of Weather Normalised Demand

The objective of this Section of the Report and accompanying model is to provide a clear explanation of the approach used to normalise historical demand and to derive a forecast of normalised EDD.

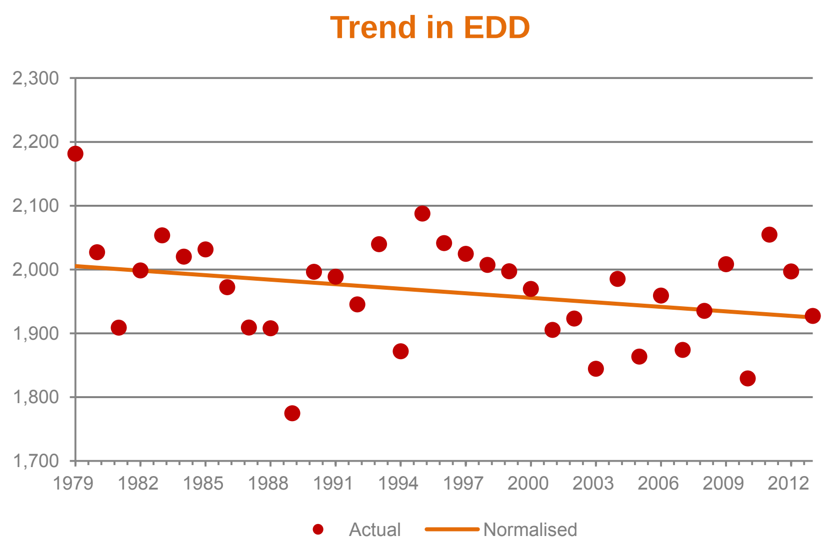
It is widely recognised that weather conditions have a significant influence on gas usage. Therefore Core has adopted the methodology described in Section 2 to derive normalised historical demand for Tariff V customers.

Core has used proprietary Excel-based models to calculate EDD and to normalise demand. These models, which include full detail of Core's analysis, have been provided to Jemena as an accompaniment to this Report.

Table 3.1 presents a summary of the weather normalised gas demand for the JGN for the 2002 to 2013 period for Tariff V customers, and Table 3.2 presents a summary of the normalised growth rates on a CAGR basis.

Core's analysis indicates a declining trend of approximately 2.5 EDD per year as shown in Figure 3.1 below. This trend has been extrapolated to derive normalised EDD forecast which is set out in Table 3.3 below.

Figure 3.1. Trend in EDD.



Source: Core Energy Group, 2013.

Table 3.1. Weather Normalisation.

Weather Normalisation	Units	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Effective Degree Days	(EDD)	1,923	1,845	1,985	1,864	1,959	1,874	1,935	2,008	1,829	2,055	1,997	1,927
Normalised Effective Degree Days	(EDD)	1,951	1,949	1,946	1,944	1,942	1,939	1,937	1,934	1,932	1,930	1,927	1,925
Abnormal Weather	(EDD)	(28)	(104)	39	(80)	18	(65)	(2)	74	(103)	125	70	2
Tariff V | Residential													
Sensitivity per connection	(GJ/EDD)	0.0027	0.0030	0.0028	0.0029	0.0026	0.0028	0.0027	0.0025	0.0027	0.0027	0.0027	0.0028
Total connections	(no.)	835,394	868,680	898,236	923,566	945,257	965,653	995,074	1,018,263	1,045,033	1,074,697	1,103,184	1,136,607
Total Sensitivity	(TJ/EDD)	2.232	2.594	2.478	2.684	2.465	2.705	2.706	2.588	2.859	2.940	2.993	3.212
Abnormal demand	(GJ)	(61,997)	(270,076)	96,861	(215,543)	43,585	(176,083)	(4,192)	191,403	(293,647)	367,503	208,593	7,483
Abnormal percentage	(%)	-0.3%	-1.4%	0.5%	-1.1%	0.2%	-0.8%	0.0%	0.9%	-1.4%	1.7%	0.9%	0.0%
Actual total demand	(GJ)	18,832,671	19,248,456	20,081,071	19,890,051	19,992,838	20,587,965	21,257,752	22,260,279	20,717,306	22,619,574	23,529,305	23,382,733
Normalised total demand	(GJ)	18,894,668	19,518,531	19,984,209	20,105,594	19,949,252	20,764,047	21,261,944	22,068,876	21,010,953	22,252,071	23,320,712	23,375,250
Actual demand per connection	(GJ)	22.54	22.16	22.36	21.54	21.15	21.32	21.36	21.86	19.82	21.05	21.33	20.57
Normalised demand per connection	(GJ)	22.62	22.47	22.25	21.77	21.10	21.50	21.37	21.67	20.11	20.71	21.14	20.57
Tariff V | Small Business													
Sensitivity per connection	(GJ/EDD)	0.0188	0.0207	0.0183	0.0181	0.0176	0.0150	0.0156	0.0119	0.0107	0.0153	0.0130	0.0109
Total connections	(no.)	12,670	11,638	13,573	15,190	17,008	18,382	17,947	20,475	20,795	21,404	20,941	21,581
Total Sensitivity	(TJ/EDD)	0.238	0.241	0.249	0.275	0.300	0.276	0.281	0.244	0.222	0.328	0.273	0.235
Abnormal demand	(GJ)	(6,600)	(25,091)	9,715	(22,080)	5,299	(17,990)	(435)	18,061	(22,759)	41,013	19,008	547
Abnormal percentage	(%)	-0.1%	-0.5%	0.2%	-0.4%	0.1%	-0.3%	0.0%	0.4%	-0.4%	0.7%	0.4%	0.0%
Actual total demand	(GJ)	4,432,714	4,586,870	4,828,318	4,923,717	5,094,381	5,351,584	4,977,332	4,826,406	5,300,359	5,607,913	5,193,328	5,271,123
Normalised total demand	(GJ)	4,439,314	4,611,961	4,818,603	4,945,797	5,089,082	5,369,573	4,977,766	4,808,345	5,323,118	5,566,900	5,174,320	5,270,576
Actual demand per connection	(GJ)	349.86	394.13	355.73	324.14	299.53	291.13	277.34	235.72	254.89	262.00	248.00	244.25
Normalised demand per connection	(GJ)	350.38	396.28	355.01	325.60	299.22	292.11	277.36	234.84	255.98	260.09	247.09	244.22

Weather Normalisation	Units	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Tariff V | I&C													
Sensitivity per connection	**(GJ/EDD)**	0.0563	0.0589	0.0669	0.0698	0.0600	0.0551	0.0418	0.0581	0.0597	0.0555	0.0509	0.0536
Total connections	**(no.)**	11,990	12,137	12,270	12,345	12,285	12,301	12,922	13,510	13,868	14,064	15,188	15,933
Total Sensitivity	**(TJ/EDD)**	0.675	0.715	0.821	0.862	0.737	0.678	0.541	0.785	0.829	0.781	0.773	0.854
Abnormal demand	**(GJ)**	(18,755)	(74,430)	32,092	(69,246)	13,032	(44,105)	(838)	58,084	(85,091)	97,605	53,891	1,990
Abnormal percentage	**(%)**	-0.3%	-1.1%	0.5%	-1.0%	0.2%	-0.7%	0.0%	0.8%	-1.2%	1.3%	0.7%	0.0%
Actual total demand	**(GJ)**	6,898,148	6,828,181	6,929,884	6,837,573	6,628,090	6,466,442	7,230,461	7,650,880	7,289,536	7,344,903	8,018,067	7,863,606
Normalised total demand	**(GJ)**	6,916,903	6,902,611	6,897,792	6,906,819	6,615,059	6,510,547	7,231,299	7,592,795	7,374,627	7,247,299	7,964,175	7,861,616
Actual demand per connection	**(GJ)**	575.33	562.59	564.78	553.87	539.53	525.68	559.55	566.31	525.64	522.25	527.92	493.54
Normalised demand per connection	**(GJ)**	576.89	568.72	562.17	559.48	538.47	529.27	559.61	562.01	531.77	515.31	524.37	493.42

Source: Core Energy Group.

The resultant growth rate of weather normalised demand during the 2002 to 2013 period, expressed in CAGR terms, is summarised in Table 3.2.

Table 3.2. Historical Normalised Growth Rates by Customer Class 2002-2013.

CAGR (% p.a.)	Residential	Small Business	I&C
Demand per connection	-0.88	-4.73	-1.41
Total Connections	2.72	6.37	2.76
Total Demand	1.82	1.34	1.31

Source: Core Energy Group.

Projections of normalised EDD as set out in the accompanying model are summarised in Table 4.3.

Table 3.3. Normalised EDD Projections.

Projected EDD	2014	2015	2016	2017	2018	2019	2020
Normalised EDD	1,923	1,920	1,918	1,916	1,913	1,911	1,908

Source: Core Energy Group.

3.3. Derivation of Tariff V Demand and Connection Forecast

The objective of this section of the report is to explain the derivation of the Core forecast of Connections and Demand per Connection for the Tariff V customer group.

This Report should be read in conjunction with the accompanying proprietary model which was utilised by Core in developing the forecast. The model sets out a comprehensive logic and transparent set of assumptions which have been relied upon by Core.

3.3.1. Summary

3.3.1.1. Total Tariff V Demand

Table 3.4 provides a summary of the Tariff V demand forecast which has been derived by Core, together with a comparison of historical and forecast demand growth rates.

Total Tariff V demand is forecast to fall by 0.61% on a CAGR basis over the 2016 to 2020 period.

Table 3.4. Forecast Demand and Historical CAGR Comparison – Tariff V.

Total Demand (GJ)	2014	2015	2016	2017	2018	2019	2020	CAGR 03-13	CAGR 08-13	CAGR 16-20
Residential	23,092,505	22,736,962	22,535,845	22,644,314	22,687,131	22,820,905	22,996,609	1.82%	1.91%	0.23%
Small Business	5,059,748	4,856,832	4,671,596	4,619,335	4,552,256	4,468,591	4,432,905	1.34%	1.15%	-1.80%
I&C	7,882,384	7,698,139	6,809,061	6,832,957	6,825,440	6,782,586	6,807,666	1.31%	1.69%	-2.43%
Total	**36,034,637**	**35,291,933**	**34,016,503**	**34,096,606**	**34,064,827**	**34,072,082**	**34,237,180**	**1.64%**	**1.75%**	**-0.61%**

Source: Core Energy Group.

The demand forecast is the product of forecast connections and forecast demand per connection. A summary of these forecasts is set out below.

3.3.1.2. Tariff V Connections

Table 3.5 provides a summary of the Tariff V connections forecast which has been derived by Core, together with a comparison of historical and forecast growth rates.

Total Tariff V connections are forecast to increase by 2.38% on a CAGR basis over the 2016 to 2020 period.

Table 3.5. Forecast Connections and Historical CAGR Comparison | Tariff V.

Total Connections	2014	2015	2016	2017	2018	2019	2020	CAGR 03-13	CAGR 08-13	CAGR 16-20
Residential	1,163,815	1,192,049	1,221,754	1,253,153	1,283,259	1,312,083	1,340,626	2.72%	2.70%	2.38%
Small Business	22,086	22,631	23,221	23,858	24,546	25,290	26,092	6.37%	3.76%	2.89%
I&C	16,244	16,551	16,820	17,151	17,494	17,851	18,222	2.76%	4.28%	1.94%
Total Tariff V	**1,202,145**	**1,231,231**	**1,261,795**	**1,294,162**	**1,325,300**	**1,355,224**	**1,384,940**	**2.78%**	**2.73%**	**2.38%**

Section 3.3.1.3 below provides further detail of the derivation of the Tariff V Connections forecast.

3.3.1.3. Tariff V Demand per Connection

Table 3.6 provides a summary of the Tariff V demand per connection forecast which has been derived by Core, together with a comparison of historical and forecast growth rates.

Tariff V Demand per Connection is forecast to fall by 2.1% in the Residential segment, 4.57% in the small business segment and 4.29% in the I&C segment.

Table 3.6. Forecast Demand Per Connection – Tariff V.

Demand Per Connection (GJ)	2014	2015	2016	2017	2018	2019	2020	CAGR 03-13	CAGR 08-13	CAGR 16-20
Existing Residential	19.97	19.31	18.79	18.52	18.22	18.02	17.86	-0.88%	-0.76%	-1.55%
New E-to-G	13.26	12.83	12.48	12.30	12.10	11.97	11.87	N/A	N/A	
New Estates	17.37	16.80	16.35	16.11	15.85	15.68	15.54	N/A	N/A	
New Med Density	15.25	14.75	14.35	14.15	13.92	13.77	13.65	N/A	N/A	
All Residential	19.84	19.07	18.45	18.07	17.68	17.39	17.15	-0.88%	-0.76%	-2.10%
Small Business	229.10	214.61	201.18	193.62	185.45	176.70	169.89	-4.73%	-2.51%	-4.57%
I&C	485.24	465.11	404.82	398.41	390.16	379.96	373.60	-1.41%	-2.49%	-4.29%

Source: Core Energy Group.

The following sections of this report address the derivation of the Core forecast for each Tariff V segment

3.4. Residential Segment Forecast | Tariff V

3.4.1. Net Connections

The Core forecast of net Residential Connections includes a calculation of connections and disconnections for two segments:

- Existing dwellings – E to G connections
- New dwellings
  - New estates
  - Mid-High rise

3.4.1.1. New Connections

New connections are forecast to increase at 2.38% p.a. on a CAGR basis as summarised in Table 3.7.

Table 3.7. Forecast Connections and Historical CAGR | Tariff V.

Connections	2014	2015	2016	2017	2018	2019	2020	CAGR 03-13	CAGR 08-13	CAGR 16-20
Total Residential	1,163,815	1,192,049	1,221,754	1,253,153	1,283,259	1,312,083	1,340,626	2.72%	2.70%	2.38%
Net Movement	27,208	28,234	29,705	31,399	30,106	28,823	28,543			

The contribution of each Residential segment to total forecast growth is set out in Table 3.8.

Table 3.8. Forecast Connections | Tariff V Residential Segments.

New Connections	2013	2014	2015	2016	2017	2018	2019	2020
E-to-G	8,649	8,217	7,395	7,025	6,885	6,747	6,612	6,480
New Estates	12,391	11,920	12,913	13,906	14,899	13,906	13,906	13,906
Med Density/High Rise	12,110	12,913	13,906	14,899	15,893	15,893	14,899	14,899
Total New Connections	**33,150**	**33,050**	**34,214**	**35,830**	**37,677**	**36,546**	**35,417**	**35,285**

The basis of these forecasts is summarised below and a detailed analysis is included in Part 2.

E-G	▪ Historical trends were observed and extrapolated to arrive at a Historical Trend based forecast. ▪ An Adjusted Forecast was derived by adjusting the Historical Trend to reflect forecast changes in the impact of E-G focused marketing programs
New estates	▪ A new dwelling forecast was derived via a bottom-up methodology which used population and household density as inputs to define a base level of new dwelling demand ▪ A shortfall in dwelling stock was identified and a formula applied to determine the level of new dwellings that would be developed and connected over the Review period to reduce the shortfall ▪ New connections were apportioned between New Estates and Medium density/ high rise segments.
Medium density/ High rise	▪ Per New Estates

3.4.1.2. Disconnections

The long-term historical average disconnection rate for the Residential segment has been reviewed by Core and determined to be the best estimate of future disconnections available. The final disconnection forecast is shown in Table 3.9.

Table 3.9. Tariff V Disconnections.

	2014	2015	2016	2017	2018	2019	2020
Residential	-5,841	-5,980	-6,125	-6,278	-6,439	-6,594	-6,742

Source: Core Energy Group.

The total of new connections less disconnections is the net movement shown in Table 3.7.

3.4.2. Demand per Connection

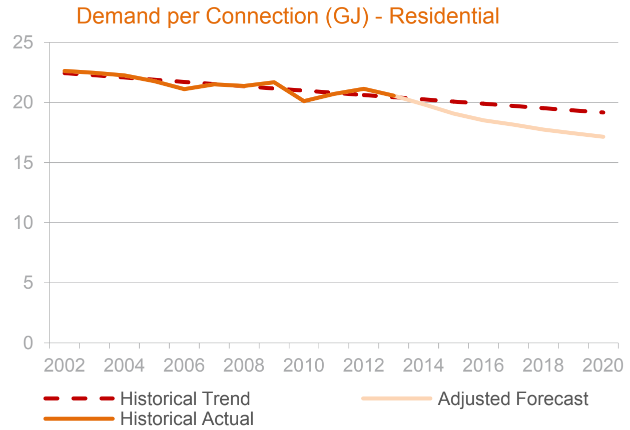
The methodology adopted to derive a forecast of Demand per Connection for Tariff V | Residential is summarised in Section 2 above.

Our approach involved the compilation of historic demand data and the use of regression analysis to extrapolate a Historical Trend in Demand per Connection for the Review Period as shown in Figure 3.2. This trend was analysed by Core to determine the influence of:

- factors present in the Historical Trend which were unlikely to exert an influence during the Review period.
- factors that are reasonably expected to influence future demand which were not observed in the Historical Trend.

The result of this analysis is an Adjusted Forecast shown in Figure 3.2.

Figure 3.2. Tariff V Residential – Historical Trend & Adjusted Forecast.



Source: Core Energy Group.

As summarised in Table 3.10, the major contributors to the forecast decline in demand per connection, relative to the Historic Trend, is the influence of future gas price rises (not evident in the Historic Trend) and the impact of growth in less gas intensive dwellings (not as significant in the Historic Trend).

Table 3.10. Forecast Demand Per Connection – Tariff V.

Residential	CAGR 16-20
Historic Trend	-0.8%
Own price elasticity	-0.5%
Cross price elasticity	-0.2%
Reduction in New Dwelling Demand	-0.6%
Total	**-2.1%**

Each of the factors listed in Table 3.10 are addressed in the following Sections.

3.4.2.2. Historic Trend

Core assumes that a Historical Trend of 0.8% p.a. decline in gas demand will continue throughout the Review period.

Core analysis concludes that the factors summarised in Table 3.11 are the major drivers of this trend.

Table 3.11. Contributors to Historical Trend.

Factor		Evidence	Likely Future Impact
Climatic Trend		Section 3.4.2.3 below sets out the basis for the Core forecast of a 0.03% reduction in demand due to a falling long term trend in EDD.	Long-term trend in weather indicates warming trend will continue over the Review Period. Core believes it is reasonable to assume that this tend observed in the Historical Trend will continue during the Review Period.
Appliance Trends	Solar Hot Water	BIS Shrapnel data shows that solar hot water penetration in NSW has risen from 4% in 2008 to 10% in 2012.[5] This has impacted the growth of gas hot water penetration which has remained relatively flat over the same period, and electric storage units which have lost market share.	This trend is supported by Government policy and an assumed response to increased gas prices, particularly if the cost of solar solutions shows a flat to declining trend.These forces are expected to be partially offset by lower feed-in tariffs and other incentive schemes - the extent of which is impractical to estimate. Core believes it is reasonable to assume that the trend observed in the Historical Trend will continue during the Review Period. While it is likely that the rate of growth will slow the impact on the total -0.8% Historical Trend will be modest and will be offset by other factors addressed below.
	Improvements in Appliance Efficiency	Introduction of Minimum Energy Performance Standards (**MEPS**) has provided household consumers with access to increasingly energy efficient appliances over time (see Figure3.4 below relating to gas water heater efficiency), which has reduced gas usage. Increased penetration of energy efficient showerheads under the Water Efficiency Labelling and Standards (**WELS**) Scheme, which reduces water usage by 40% compared to standard showerheads[6], has contributed to lower gas hot water usage. BASIX policy introduced in 2005 requires all new dwellings, alterations and additions to be designed to use up to 40% less water and emit up to 40% fewer greenhouse gas emissions than the average NSW home.	MEPS policy is ongoing and further products are being explored for efficiency compliance. Energy efficiency improvements are expected to continue over the Review Period. As the BASIX policy continues in NSW, Core expects the penetration of energy-efficient appliances to increase within JGN and reduce demand per connection.
	Reverse-Cycle Space Heating	ABS data shows increased penetration of reverse cycle air conditioning units in NSW, from 27% in 2005 to 33.7% in 2011. [7] Over that same period gas heating has declined from 27.4% to 26.8% penetration, indicating that consumers are likely to be switching towards reverse cycle units for heating rather than gas.	Core expects this trend to continue as the price of gas relative to electricity increases, with higher reverse cycle penetration to come at the expense of gas heating.

[5] BIS Shrapnel: Climate Control Report 2012.

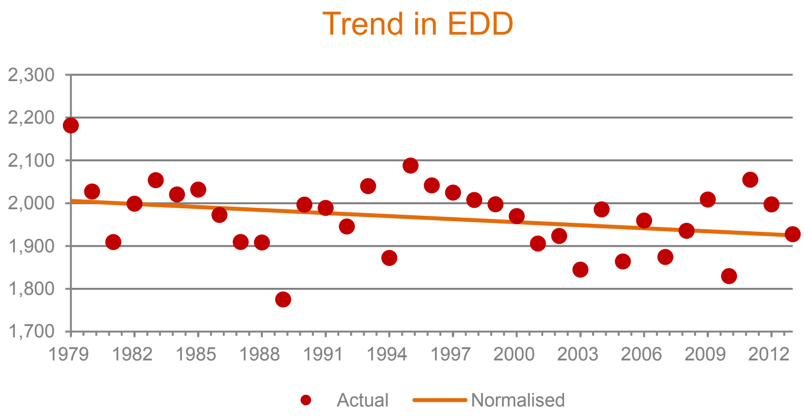
[6] Water Rating website states that "gas hot water costs for a standard showerhead are around $1,500 over ten years whereas gas hot water costs for a water-efficient shower head are only $790 over ten years or a 47 per cent reduction."

[7] ABS; 4602.0.55.001 - Environmental Issues: Energy Use and Conservation, Mar 2008 and Mar 2011 editions.

3.4.2.3. Climatic Trend

As addressed in Section 3.2, a long-term 'warming trend' can be observed through statistical analysis of EDD. This trend is presented again in Figure 3.3.

Figure 3.3. Long Term Trend in EDD.



Source: Core Energy Group.

This trend demonstrates the widely accepted presence of an Urban Heat Island ("**UHI**") impact, whereby concentrated population growth in urban areas (such as Sydney) causes a rise in average temperature over long periods.

Core estimates that if this trend will contribute to a reduction in demand of approximately 0.03% p.a. after taking account of the sensitivity of each tariff class to changes in EDD. This is broadly consistent with the warming trend found by NIEIR in Jemena's prior Access Arrangement.[8]

This 0.03% p.a. trend forms part of the -0.8%pa Historical Trend which is incorporated with the Core Adjusted Forecast noted in Table 3.10.

3.4.2.4. Appliance Trends

Core is of the opinion that changes relating to household appliance usage will to continue to have a material impact on gas consumption over the Review Period. Two types of change are noted. The first is a substitution of gas appliances in favour of non gas appliances, and the second is an improvement in efficiency of appliances and residential dwellings.

3.4.2.5. Substitution

Core notes two major substitution trends. The first relates to policy-driven growth in solar hot water heating at the expense of gas. The second is a trend toward use of reverse cycle air conditioning for heating and cooling, reducing the use of gas for heating.

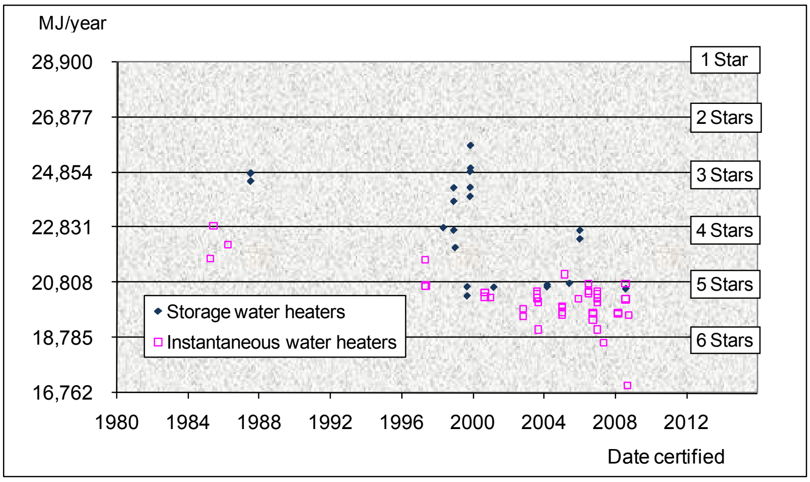
Further analysis of appliance substitution trends is presented in Supporting Information, Part 2 - Section 2.

[8] p32 of NIEIR's Revised Proposal for Jemena NSW. 17.0 TJ/HDD sensitivity x 5.56 HDD decline per year = 95TJ decline due to weather trends. As a percentage of tariff V demand at 2010 this equates to ~0.028%.

3.4.2.6. Energy efficiency

There is extensive evidence of a material improvement in the efficiency of gas appliances over recent years, and this trend is expected to continue during the Review period. The following Figure provides a useful example, illustrating the improvement in efficiency of instantaneous heaters associated with the star rating system. Further analysis of appliance efficiency trends is presented in Part 2, Section 2.

Figure 3.4. Standardised energy consumption of externally installed gas water heaters by type and date of certification (Australia-wide).



Source: Australian Gas Association; Gas Appliance Energy Efficiency Labeling Discussion paper, p56.

Whilst it is difficult to derive a specific estimate of the impact of this trend in improved efficiency on Tariff V Residential gas demand, Core believes there is adequate evidence of a sustainable trend. Accordingly Core has assumed that this trend forms part of the assumed 0.8% Historical Trend included in Table 3.10.

3.5. Own Price and Cross Price Elasticity of Demand

Core has derived a forecast of the impact on gas demand of expected changes in absolute gas prices (own price elasticity) and gas price relative to electricity prices (cross price elasticity). The results of the analysis are summarised Table 3.12 below.

It is important to note that the 2014 and 2015 results include a lagged demand response to gas price increases in prior years (mainly network costs).

Table 3.12. Price Elasticity Impacts.

Price Elasticity Impact on Demand (%)	2014	2015	2016	2017	2018	2019	2020	CAGR
Residential								
Own Price	-2.4%	-2.4%	-0.5%	-0.5%	-0.8%	-0.4%	-0.3%	-0.5%
Cross Price	0.4%	-0.1%	-1.0%	0.0%	0.0%	0.0%	0.0%	-0.2%
Total	**-2.0%**	**-2.5%**	**-1.5%**	**-0.5%**	**-0.8%**	**-0.4%**	**-0.3%**	**-0.7%**

Part 2 - Section 5 presents a detailed analysis of price elasticity of demand across the JGN.

3.6. Reduction in New Dwelling Demand

Historical data provided by Jemena shows that new dwellings/connections use significantly less gas than the existing residential average. Table 3.13 shows the most recent 2013 average usage for all residential customer types.

Table 3.13. Demand per Connection of New Dwellings vs. Average.

Customer Type	2013 Usage (GJ)
Total Residential average	20.57
New E-to-G	13.66
New Estates	17.89
New Medium Density	15.71

Source: Jemena data weather normalised by Core Energy Group.

Core believes it is reasonable to assume that the addition of new connections over the Review Period will increase the weighting of lower gas usage dwellings relative to higher gas usage dwellings and therefore progressively reduce residential demand per connection.

The cumulative weighting of new connections over the period 2014-2020 is shown in the table below.

Table 3.14. Cumulative Weighting of New Residential Connections.

Customer Type	2013	2014	2015	2016	2017	2018	2019	2020
2013 Residential	100.0%	97.8%	95.5%	93.3%	91.0%	88.8%	86.8%	84.9%
New E-to-G	-	0.5%	0.9%	1.3%	1.6%	1.9%	2.2%	2.5%
New Estates	-	0.9%	1.8%	2.8%	3.8%	4.7%	5.6%	6.4%
New Medium Density	-	0.9%	1.7%	2.7%	3.6%	4.5%	5.3%	6.1%

Source: Core Energy Group.

The increase in weighting of new, lower gas usage dwellings translates to a 0.6% p.a. reduction in residential demand per connection on a CAGR basis. This reduction is listed in Table 3.1.

3.7. Tariff V Small Business and I&C Connections and Demand per Connection

3.7.1. Connections

Net connections forecasts for Tariff V small business and I & C involves an assessment of new connections, any switching between Tariff classes and disconnections. The result is summarised in Table 3.15.

Table 3.15. Tariff V Connection Forecast |Small Business and I & C

Small Business	CAGR % 2015-2020
New Connections	3.1%
Disconnections	-0.2%
Total	**2.9%**
I & C	
New Connections	2.2%
Disconnections	-0.2%
Net Tariff V - Tariff D switching	-0.1%
Total	**1.9%**

Source: Core Energy Group.

The derivation of the above forecasts are explained in the following paragraphs.

3.7.1.2. New Connections and Tariff Switching

Core's approach to forecasting new connections was to:

- estimate new connections based on the Historical Trend;
- identify the Tariff V customers expected to move into the Tariff D Industrial class due to their load specifications (and vice versa) based on advice from Jemena.

The resulting forecast of new connections for these customer classes is summarised in Table 3.16 below.

Table 3.16. Tariff V Small Business and Tariff V I&C New Connections.

	2013	2014	2015	2016	2017	2018	2019	2020
Small Business	510	549	591	636	685	737	794	855
I&C – New Connections	315	327	339	352	365	378	393	407
I&C – Net Tariff Switching	-	17	1	-49	-	-	-	-

Source: Core Energy Group.

3.7.1.3. Disconnections

Historical disconnections for the Small Business and I&C classes were reviewed over the 2006 – 2013 period and were found to be significantly negatively skewed in earlier years and thus were determined to be an unreliable estimate of future connections. After due enquiry Core believes this bias to be due to the disconnection of a large number of dormant meters/supply points which translated to a high disconnection rate prior to 2010. Acknowledging that it is a shorter timeframe than preferred, Core determined that the use of the 2010-13 average disconnection rates was the best primary data available to derive a forecast of disconnections for the Review period.

The final disconnection forecasts are shown in Table 3.17.

Table 3.17. Tariff V Disconnections.

	2014	2015	2016	2017	2018	2019	2020
Small Business	-44	-45	-47	-48	-49	-51	-52
I&C	-32	-33	-34	-34	-35	-36	-36

Source: Core Energy Group.

3.7.2. Demand per Connection

Figure 3.5 below shows the Historical Trend and Adjusted Forecast for Tariff V Small Business and Tariff V I&C Demand per Connection.

The Adjusted Forecasts have been derived by assuming the Historical Trend will continue and adjusted to include the impact of the forecast increase in gas prices which was not observed in the Historic Trend. Table 3.17 and the paragraphs below summarise the factors influencing the Core forecast.

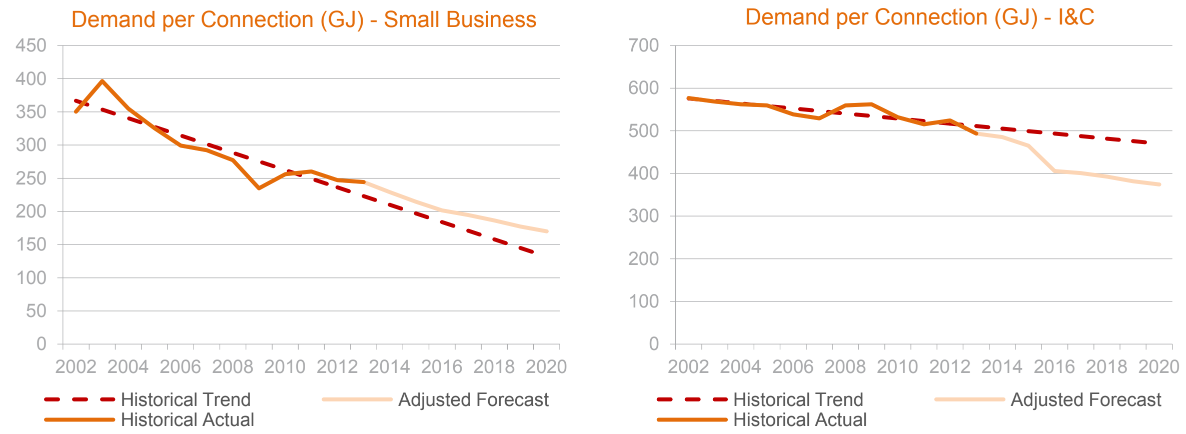
3.7.2.1. Historical Trend

Core has considered the range of economic and other factors which influence small business and I & C demand and has determined that the Historical Tend is the best guide to future demand available under the circumstances. This trend has been adjusted to reflect only one factor - price increases - which were not observable in the Historic Trend.

3.7.2.2. Adjustment Due to Price Increases

The Adjusted Forecast includes Core's estimate of the own price and cross price elasticity of demand for the small business and I & C segment. The detailed analysis of these factors in include in Part 2, Section 5.

Figure 3.5. Tariff V Small Business and I&C – Extrapolated Trend vs. Core Forecast.



Source: Core Energy Group.

Table 3.18. Tariff V Connection Forecast |Small Business and I & C

Small Business	
Change due to Historic Trend	-3.2%
Change due to own price elasticity	-1.1%
Change due to cross price elasticity	-0.2%
Total	**-4.6%**
I & C	
Change due to Historic Trend	-1.1%
Change due to own price elasticity	-1.1%
Change due to cross price elasticity	-0.2%
Total	**-2.4%**

Source: Core Energy Group.

The annual percentage movements in demand due to price elasticity are summarised in Table 3.17

Table 3.19. Tariff V Connection Forecast |Small Business and I & C

Price Elasticity Impact on Demand (%)	2014	2015	2016	2017	2018	2019	2020	CAGR
Small Business								
Own Price	-3.3%	-3.0%	-1.9%	-0.2%	-1.0%	-1.7%	-0.9%	-1.1%
Cross Price	0.4%	-0.1%	-1.0%	0.0%	0.0%	0.0%	0.0%	-0.2%
Total	**-3.0%**	**-3.1%**	**-2.9%**	**-0.2%**	**-1.0%**	**-1.7%**	**-0.9%**	**-1.3%**
I&C								
Own Price	-3.3%	-3.0%	-1.9%	-0.2%	-1.0%	-1.7%	-0.9%	-1.1%
Cross Price	0.4%	-0.1%	-1.0%	0.0%	0.0%	0.0%	0.0%	-0.2%
Total	**-3.0%**	**-3.1%**	**-2.9%**	**-0.2%**	**-1.0%**	**-1.7%**	**-0.9%**	**-1.3%**

Source: Core Energy Group.

Part 2 - Section 5 presents a detailed analysis of price elasticity of demand across the JGN.

Section 1 | 4. Tariff D Demand Forecast

4.1. Introduction

The objective of this Section of the Report is to present the Core forecast of Tariff D demand, focusing primarily on CD, but also including a forecast of ACQ.

4.2. Approach to CD Forecast

Core has derived the forecast of CD via analysis of the following:

- Net known new customer connections and closures and associated demand estimates as advised by Jemena;
- Net known movements/ reallocations between Tariff D and V as advised by Jemena; and
- A forecast of net movement in CD, starting with an actual December 2013 position based on data provided by Jemena.

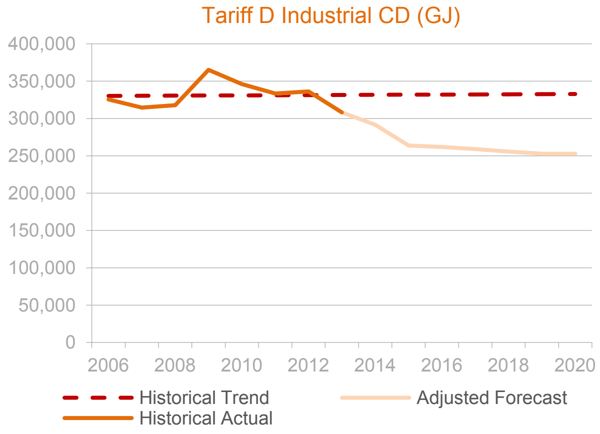
The known movements based on Jemena advice and include closures of large users such as Caltex and Shell refineries, HC Extractions, Pilkington Ingleburn and Alcoa Yennora.

The forecast movements are based on an analysis of historical actual movements and Core analysis of potential movements in ACQ and CD due to projected economic and energy efficiency trends.

4.2.1. Summary of CD Forecast

Figure 4.1 below shows the Historical Trend and Core Adjusted Forecast derived for Tariff D CD demand.

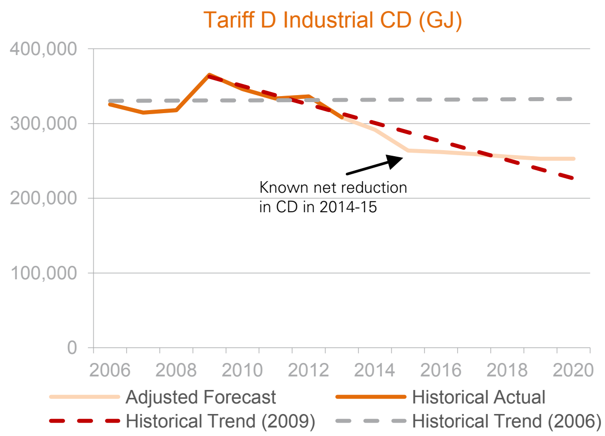
Figure 4.1. Tariff D Industrial CD – Extrapolated Trend vs. Core Forecast.



Source: Core Energy Group.

Figure 4.2 presents the Adjusted Forecast against a trend line based on a historical demand line for the 2009 to 2013 timeframe rather than 2006 to 2013. As noted below Core believes that this comparison is more representative of the expected future trend in CD demand.

Figure 4.2. Tariff D Industrial CD – Extrapolated Trend from 2006 vs. Core Forecast.



Source: Core Energy Group.

Tables 4.1, 4.2 and 4.3 below present the results in numerical terms.

The Core forecast of total CD demand is summarised in Table 4.1.

Table 4.1. Forecast CD Demand | Tariff D.

CD (GJ)	2013	2014	2015	2016	2017	2018	2019	2020
Total	308,226	291,580	263,885	262,397	259,881	256,632	254,228	254,228

Source: Core Energy Group.

The makeup of the reduction from the 2013 level of 308,226 to the 2020 level of 254,228 is summarised in Table 4.2.

Table 4.2. Forecast CD Demand | Tariff D.

CD (GJ)	2014	2015	2016	2017	2018	2019	2020	Total Change
Opening	308,226	291,580	263,885	262,397	259,881	256,632	254,228	
New Connections	2,358							2,358
Known closures	-1,029	-23,589						-10,300
Survey results	-10,300							-24,618
Tariff reclassifications	-2,645	-84	2,846					117
Core Forecast of Additional reductions	-7,388	-1,664	-4,334	-2,516	-3,249	-2,404		-21,555
Adjusted Forecast	291,580	263,885	262,397	259,881	256,632	254,228	254,228	-53,998

Source: Core Energy Group.

Table 4.3. Forecast CD Demand CAGR | Tariff D.

Tariff D	CAGR 14-20
Net Known Movements (Formally advised to Jemena + Survey Results)	-1.9%
Forecast Movement	-0.8%
Total	-2.7%

Source: Core Energy Group.

4.2.2. Derivation of Core Forecast

To derive the Adjusted Forecast Core has considered the following:

- Information provided by Jemena regarding known Tariff D customer business closures and tariff reclassifications (4.2.2.2);
- Results of a Top 20 customer survey (4.2.2.3);
- Core forecast of additional underlying movements in demand (4.2.2.4).

These factors are addressed below.

4.2.2.1. Historical vs. Forecast Comparison | Tariff D

Figure 4.1 above illustrates that the historical trend in CD between 2006 and 2013 has been relatively flat over the period. Further analysis of this historical trend highlights two sub trends - growth prior to 2009 and a fall thereafter.

Given that the growth environment before the 2009 period is substantially different to that of recent years, Core considers that it is more representative to consider the post-GFC trend since 2009. This is presented in Figure 4.2 and represents a reduction of 4.2% on a compound average annual basis.

Core's Adjusted Forecast which reflects a compound annual reduction of 2.7% (1.9% due to known customer movements and 0.8% due to forecast economic and other factors) is notably lower than this Historical Trend.

4.2.2.2. Known Closures and Tariff Reclassifications | Tariff D

Jemena has advised Core that it has received formal notification from a number of customers of intentions to close or curtail demand beyond 2013, with consequences for the Review period.

Table 4.4 below summarises these movements.

Table 4.4. Known Closures | Tariff D.

Customer	2013	2014
Shell Refining	2,065,235	1,032,618
Caltex Refineries	2,649,515	2,649,515
HC Extractions	1,941,918	1,941,918
Pilkington Ingleburn	1,009,643	100,000
Tyco Water	75,147	-
Pacific Beverages (Bluetongue Brewery)	34,182	19,939
Standard Knitting Mills	54,859	9,143
Bessemer Pty Ltd	22,045	7,348
South West Metal Fabrications	11,333	3,166
Senior Engineering Australia	13,717	9,144
Austral Masonry Port Kembla	15,503	-
Darrell Lea Chocolate Shops	12,467	7,914
Total Demand from closing customers	**7,905,563**	**5,780,706**
Net Change in Demand		**-2,124,857**

Source: Core Energy Group.

In addition Jemena has advised Core of its estimate of likely reclassification between Tariff V and Tariff D based on estimates of change in usage. Following review of this estimates Core has determined it to provide a best estimate of likely tariff reclassifications.

4.2.2.3. Top 20 Customer Survey | Tariff D

Following consultation with Core, Jemena issued a survey to each of its top 20 Tariff D customers to gain information on the outlook for demand over the review period. The survey form used is included as Attachment 3, and the results are summarised in Table 4.5 below.

Table 4.5. Impact of Survey Responses | Tariff D

Customer	2013	2014	2015
BHP Port Kembla	2,628,542	1,500,000	1,500,000
ACI Glass Packaging	1,796,712	1,200,000	1,200,000
Endeavour Coal	301,081	75,270	75,270
Delta Electricity	229,142	300,000	300,000
Caltex Port Botany	95,548	120,000	120,000
Chris OBrien Lifehouse	37	49,000	49,000
Renegade Gas Pty Ltd	20,407	30,000	30,000
GPT Castlereagh St	2,104	13,000	13,000
Total Demand	**5,073,573**	**3,287,270**	**3,287,270**
Net Movement		**-1,78,6303**	**0**

Source: Core Energy Group.

4.2.2.4. Core Forecast of 2014 to 2020 net Reductions | Tariff D

In addition to known changes and tariff reclassifications, Core has derived an forecast of the underlying trend in demand over the Review period. The results are summarised in Table 4.6.

Table 4.6. Forecast Movement in Underlying CD Demand | Tariff D.

CD (GJ)	2014	2015	2016	2017	2018	2019	2020	CAGR %
Adjustment | GJ	-7,388	-1,664	-4,334	-2,516	-3,249	-2,404		
Adjustment | %								**-0.8%**

Source: Core Energy Group.

Core's forecast has been developed having regard to a range of factors including:

- Analysis of the Historical Trend as a basis for extrapolation (4.2.2.1);
- Information disclosed under the Energy Efficiency Opportunities (EEO) Program (4.2.2.5);
- Information relating to the economic outlook of specific manufacturing sectors (4.2.2.6); and
- A review of the sustainability of 2013 Tariff D customer ACQ/CD relationships (4.2.2.7).

4.2.2.5. EEO Program

Core has highlighted some of the initiatives which have recently been undertaken or planned by a number Jemena's larger industrial customers in Table 4.3 Core believes that an increase in wholesale gas prices, which cause a large percentage increase in total industrial gas costs, will place continuing pressure on energy efficiency measures.

Table 4.7. EEO Program Summary.

Tariff D Customer	EEO Statements/ Efficiency Initiatives
Tomago - Aluminium Smelter	"A number of processes at Tomago Aluminium use natural gas for heating. A series of opportunities were identified to improve and optimise natural gas consumption. An upgraded control system was installed on anode bake furnace No1 which improved natural gas combustion in this area. The other natural gas opportunity involved optimizing the burner efficiency in the cast products furnaces through regular tuning of burners."[9]
Amcor - Fibre Packaging, Botany	"In February 2013, the $500 million 'B9' paper machine was officially opened at our existing site in Botany, Australia. B9 is custom built and replaces three older paper machines to deliver significant environmental benefits. The combination of de-commissioning the old machines and efficiencies offered by B9 is projected to: reduce water use by 26%; reduce energy usage by 34%; and reduce waste to landfill by 75%."[10]
CSR - Gyprock, Wetherill Park	2012 Sustainability Report states upgraded dryer end seals and installed gas metering equipment in plaster board dryer - expected to reduce gas consumption by 2%.
Orica – Kooragang Island, Botany	Orica have commenced implementation of opportunities that will save 137,000GJ/year of energy, equating to roughly 0.8% of the 17PJ of energy used in FY2013[11].
Qenos – Botany	Identified 3 opportunities with a payback period of less than 4 years with potential energy savings of 62,220 GJ of natural gas – mainly furnace improvements and major maintenance activities.[12]

Source: Company EEO Reports and Sustainability Reports.

4.2.2.6. Economic & Manufacturing Sector Outlook

To arrive at a projection of CD, Core has considered general economic trends and specific analysis of major industry segments of significance to CD customers. As noted below, the vast majority of CD customers are grouped within the Manufacturing sector, a sector which is experiencing a sustained period of change in NSW and Australia more broadly. Table 4.4 lists three major themes which are weighing on the Manufacturing sector.

Table 4.8. General Economic Themes - Manufacturing Sector.

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

Source: Core Energy Group.

Core analysis showed that two industry classes accounted for 87% of CD service across the JGN network in 2013 - Electricity/gas/water services and Manufacturing. Accordingly these sectors were the focus of Core's analysis.

[9] Rio Tinto Energy Efficiency Report 2012 – Pechiney Consolidated Australia.
[10] Amcor Sustainability Review 2013.
[11] Orica 2013 EEO Public Report.
[12] Qenos; Energy Efficiency Opportunities, Public Report 2012 to 2013.

One customer dominates the Electricity/gas/water services class, namely Delta Electricity. Core confirmed through analysis and customer survey that Delta was likely to maintain its CD at 2013 levels.

For the Manufacturing sector Core developed a listing of customers for the 2013 year by sub-sector as a basis for analysing economic influences which relate to major manufacturing classes. This is covered in Section 6.

The results of Core's CD projections are presented in Table 4.1.

4.2.2.7. Review of CD/ACQ Relationship

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

LF = CD/ (ACQ/365)

where:

- LF = load factor; and
- ACQ/ 365 = average daily average gas demand.

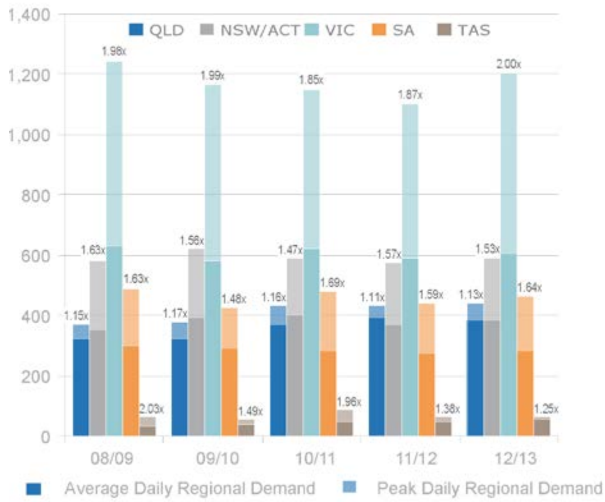
The load factor indicates the extent to which CD exceeds average daily ACQ.

The CD is expected to be higher than average daily ACQ due to variability of activity throughout a year. However, as the cost of maintaining that CD rises Core believes that there will be an increased incentive for customers to reduce their CD levels to a minimum acceptable level.

As noted in Figure 4.6, the JGN Tariff D sector as a whole has a load factor of 1.94 in 2013. This would increase to 2.59 by 2020 if CD remained constant against the forecast fall in ACQ.

Core analysis indicates that this load factor is high when measured against the total load factor of the NSW and eastern Australia markets. Figure 4.3 below indicates that the load factor for NSW as a whole in 2013 was 1.53. Given that industrial load is generally found to be materially lower that gas generation and residential and commercial segment loads, the existing load is assessed to be high.

Figure 4.3. Comparison of Average and Peak Gas Demand | PJ and Load Factor



Source: Core Energy and AER

Core believes it is reasonable to expect Tariff D customers to respond to a weak manufacturing environment and increasing gas prices by reducing both ACQ and CD.

Table 4.6 summarises Core's forecast reduction in both CD and ACQ. Whilst CD is forecast to fall materially, it is expected to fall at a lower rate than ACQ, giving rise to a load factor which increases rather than falls. This result suggests to Core that there is additional scope for CD reduction, for example through demand management in peak demand periods). However without further detailed information and analysis of the potential for major customers to reduce CD levels further, Core believes it is prudent to maintain this forecast, but notes there is evidence of conservatism.

Table 4.9. Tariff D Load Factors.

Load Factor	2013	2014	2015	2016	2017	2018	2019	2020
ACQ (GJ)	57,949,465	53,144,476	46,296,728	45,951,999	45,290,414	44,644,746	44,014,608	43,399,622
CD (GJ)	308,226	291,580	263,885	262,397	259,881	256,632	254,228	254,228
Load Factor	1.94	2.00	2.08	2.08	2.09	2.09	2.10	2.13

Source: Core Energy Group.

4.3. Tariff D | Connections

The number of connections in the 2015 to 2020 period is not a material factor for the purposes of this Review. Therefore Core has not attempted to develop a detailed forecast of connection movements. Core has simply identified the change in connections associated with movements which are known to Jemena, resulting in 427 customers at the beginning of the Review Period. The percentage change from an opening position of 401 connections is summarised below.

Table 4.10. Drivers of Tariff D Connections.

Tariff D	CAGR 16-20
Net Tariff V ←→ Tariff D switching*	2.5%
Total	**2.5%**

Source: Core Energy Group.
*At the commencement of the Review Period, a number of Tariff V customers are expected to be revised up to Tariff D billing, causing a one-off step change in connections at the beginning of 2016 which results in the above increase.

4.4. Tariff D | ACQ

Core has derived a forecast of ACQ by analysing three factors:

- Net known new customer connections and closures;
- Net known movements/ reallocations between Tariff D and V;
- Forecast trend in demand between 2014 and 2020 (to arrive at 2015-2020 forecasts from a 2013 year end position).

The results are summarised below.

Table 4.11. Drivers of Tariff D ACQ.

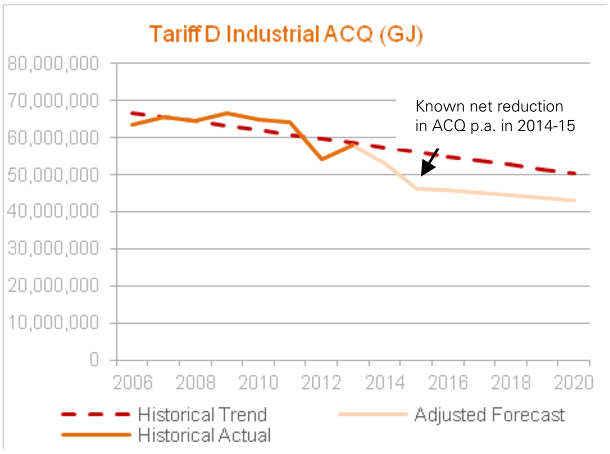
Tariff D	CAGR 14-20
Net Known Movements[13]	-2.6%
Net Forecast Movements	-1.4%
Total	**-4.0%**

Source: Core Energy Group.

The forecast movements are based on an analysis of historical actual movements and Core analysis of potential movements in ACQ due to projected economic and energy efficiency trends, known closures, reclassifications and survey results..

Figure 4.4 illustrates that the historical trend between 2006 and 2013 which represents a fall of 2% p.a. on a CAGR basis, in large part due to customers falling from 483 in 2006 to 401 as at the end of 2013. It is noteworthy that this downward trend in ACQ has been generally steeper in more recent years.

Figure 4.4. Tariff D Industrial ACQ and CD – Extrapolated Trend vs. Core Forecast.



Source: Core Energy Group.

Based on Core's analysis of the outlook for industry sectors represented by JGN Tariff D customers, and an assessment of trends in energy efficiency, Core has derived a future average annual reduction of 1.4% on a CAGR basis after accounting for known closures/new connections and tariff movements. In general terms, the Adjusted Forecast is consistent with the Historical Trend if the adjustment for known closures is excluded.

[13] Includes known closures, connections and reallocation between Tariff V and D.

Section 1 | 5. Conclusion | Demand and Customer Forecasts

The purpose of this Section of the Report is to summarise Core's forecast of demand and connections for Tariff V customer class and CD for the Tariff D customer class, based on data and analysis addressed in this Report.

Core is of the opinion that the following forecasts represent the best estimate of demand and customer numbers for the JGN for the 2016 to 2020 period, that can reasonably be developed, based on the specific circumstances of this Review and therefore comply with the requirements of the NGR.

5.1. Tariff V

The forecast highlights a 0.61% decline in total demand for Tariff V over the 2016 to 2020 period, with variations between customer segments as shown in Table 5.1.

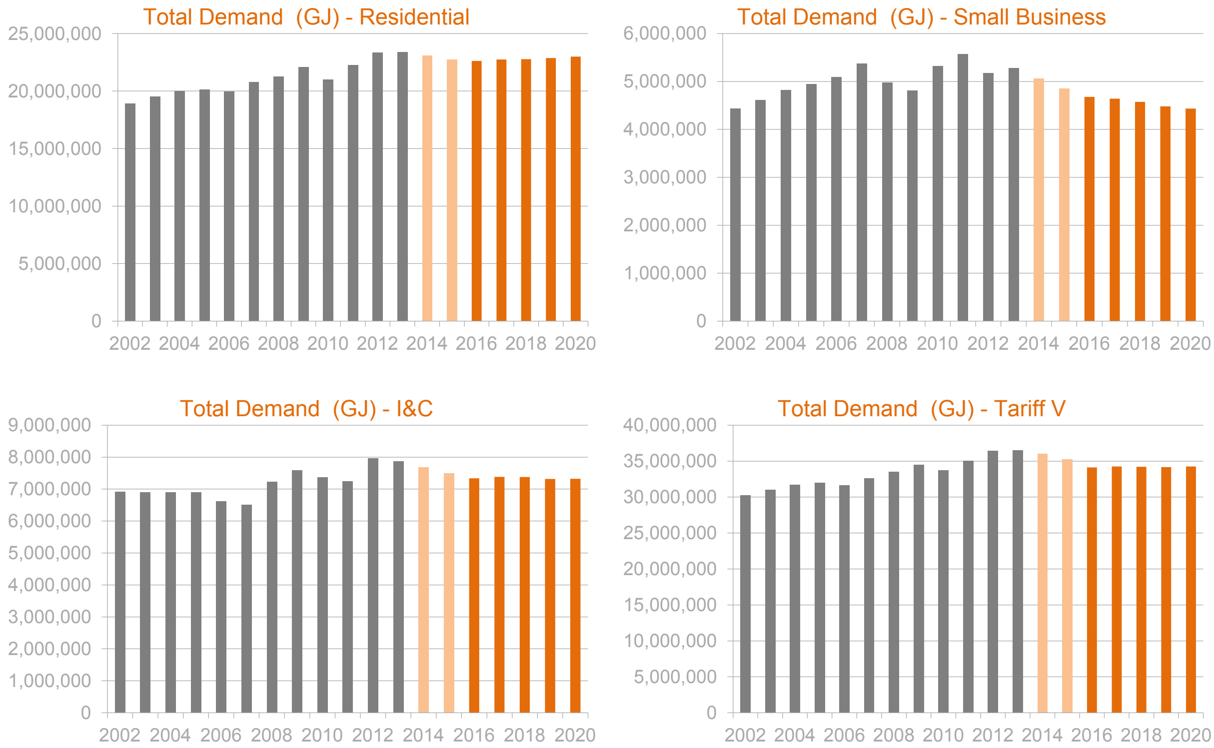
5.1.1. Total Demand | Tariff V

Table 5.1. Forecast Total Demand and Historical CAGR – Tariff V.

Total Demand (GJ)	2014	2015	2016	2017	2018	2019	2020	CAGR 03-13	CAGR 08-13	CAGR 16-20
Residential	23,092,505	22,736,962	22,535,845	22,644,314	22,687,131	22,820,905	22,996,609	1.82%	1.91%	0.23%
Small Business	5,059,748	4,856,832	4,671,596	4,619,335	4,552,256	4,468,591	4,432,905	1.34%	1.15%	-1.81%
I&C	7,882,384	7,698,139	6,809,061	6,832,957	6,825,440	6,782,586	6,807,666	1.31%	1.69%	-2.43%
Total	**36,034,637**	**35,291,933**	**34,016,503**	**34,096,606**	**34,064,827**	**34,072,082**	**34,237,180**	**1.64%**	**1.75%**	**-0.61%**

Source: Core Energy Group.

Figure 5.1. Forecast Total Demand | Tariff V.



Source: Core Energy Group.

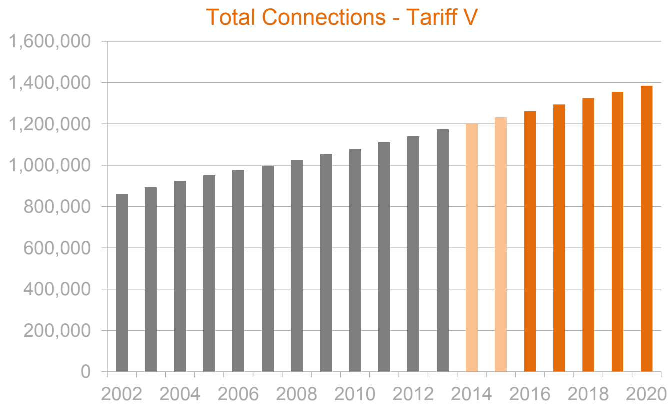
5.1.2. Connections| Tariff V

Table 5.2 and Figure 5.2 present a forecast of continuing growth in Tariff V connections during the 2016 to 2020 period at a CAGR of 2.38% which is 0.35% below the average actual growth over the 2008 – 2013 period.

Table 5.2. Forecast Connections and Historical CAGR | Tariff V.

Total Connections	2014	2015	2016	2017	2018	2019	2020	CAGR 03-13	CAGR 08-13	CAGR 16-20
Residential	1,163,815	1,192,049	1,221,754	1,253,153	1,283,259	1,312,083	1,340,626	2.72%	2.70%	2.38%
Small Business	22,086	22,631	23,221	23,858	24,546	25,290	26,092	6.37%	3.76%	2.89%
I&C	16,244	16,551	16,820	17,151	17,494	17,851	18,222	2.76%	4.28%	1.94%
Total Tariff V	**1,202,145**	**1,231,231**	**1,261,795**	**1,294,162**	**1,325,300**	**1,355,224**	**1,384,940**	**2.78%**	**2.73%**	**2.38%**

Figure 5.2. Historical Actual and Forecast Connections | Tariff V.



Source: Core Energy Group.

Table 5.3 and Figure 5.3 present projections for new connections and disconnections for Tariff V.

Table 5.3. Forecast Net New Connections – Tariff V.

New Connections	2014	2015	2016	2017	2018	2019	2020
E-to-G	8,217	7,395	7,025	6,885	6,747	6,612	6,480
New Estates	11,920	12,913	13,906	14,899	13,906	13,906	13,906
Med Density/High Rise	12,913	13,906	14,899	15,893	15,893	14,899	14,899
Small Business	549	591	636	685	737	794	855
I&C	327	339	352	365	378	393	407
I&C Tariff Reallocation	17	1	-49				
Disconnections	-5,917	-6,059	-6,206	-6,360	-6,524	-6,680	-6,831
Total Tariff V	**28,024**	**29,086**	**30,564**	**32,366**	**31,138**	**29,924**	**29,716**

Source: Core Energy Group.

Figure 5.3. Forecast New Connections – Tariff V.

Source: Core Energy Group. Note that 2002 new connections data for Small Business and I&C classes was not available.

5.1.3. Demand per Connection | Tariff V

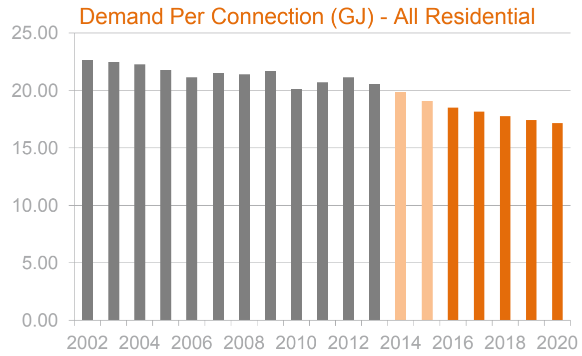
Table 5.4 and Figure 5.4 present projections for demand per connection for Tariff V.

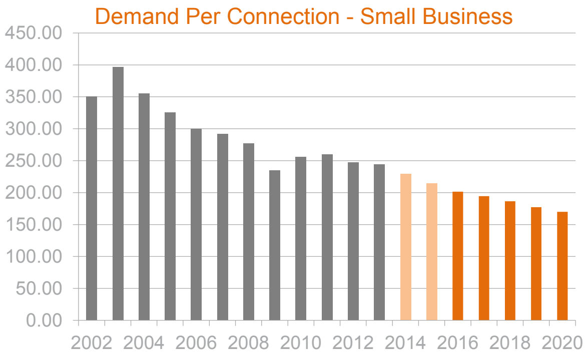
Table 5.4. Forecast Demand Per Connection – Tariff V.

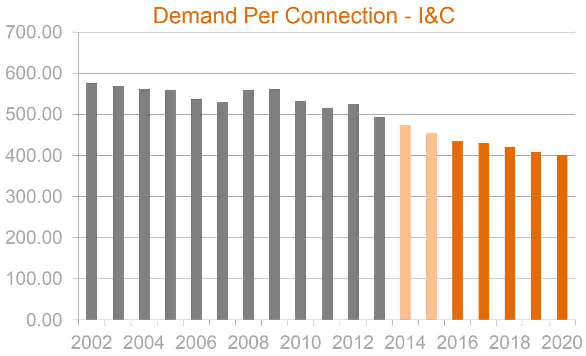
Demand Per Connection (GJ)	2014	2015	2016	2017	2018	2019	2020	CAGR 03-13	CAGR 08-13	CAGR 16-20
Existing Residential	19.97	19.31	18.79	18.52	18.22	18.02	17.86	-0.88%	-0.76%	-1.55%
New E-to-G	13.26	12.83	12.48	12.30	12.10	11.97	11.87	N/A	N/A	
New Estates	17.37	16.80	16.35	16.11	15.85	15.68	15.54	N/A	N/A	
New Med Density	15.25	14.75	14.35	14.15	13.92	13.77	13.65	N/A	N/A	
All Residential	19.84	19.07	18.45	18.07	17.68	17.39	17.15	-0.88%	-0.76%	-2.10%
Small Business	229.10	214.61	201.18	193.62	185.45	176.70	169.89	-4.73%	-2.51%	-4.57%
I&C	485.24	465.11	404.82	398.41	390.16	379.96	373.60	-1.41%	-2.49%	-4.29%

Source: Core Energy Group.

Figure 5.4. Forecast Demand per Connection – Tariff V.







Source: Core Energy Group.

5.2. Tariff D CD Demand

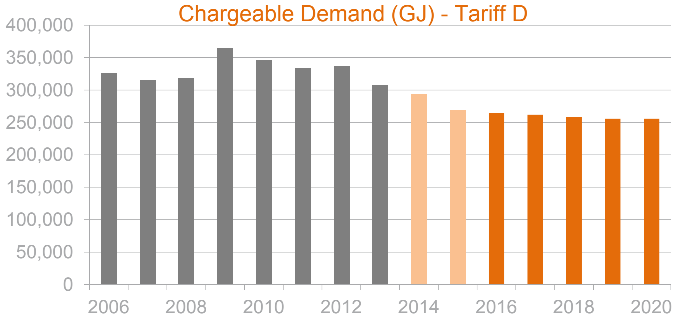
Chargeable Demand capacity is forecast to continue the trend observed over recent years. During the period 2006 to 2013 CD fell by 0.78%pa on a CAGR basis and this fall is forecast to continue at 0.74%pa between 2016 and 2020 as shown in Table 5.5.

Table 5.5. Forecast Chargeable Demand – Tariff D.

CD (GJ)	2014	2015	2016	2017	2018	2019	2020	CAGR 06-13	CAGR 08-13	CAGR 16-20
CD	291,580	263,885	262,397	259,881	256,632	254,228	254,228	-0.78%	-0.61%	-0.74%

Source: Core Energy Group.

Figure 5.5. Forecast Chargeable Demand – Tariff D.



Source: Core Energy Group.

Part 2 | Supporting Information and Analysis

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Section 2 | 1. Tariff V Connection Forecast

1.1. Tariff V | E-to-G

E-to-G customers are defined as those who move from a pure electricity household to one which is also connected to gas.

While there are a range of factors which contribute to the customer's decision to connect to reticulated gas, Core considers a major influence of new E-to-G connections to be Jemena's marketing initiatives.

The impact of marketing on E-to-G connections is a function of:

- Changes in marketing expenditure to target E-to-G's; and
- Changes in the impact of marketing efforts on a constant dollar basis.

Core was asked by Jemena to derive a 'base forecast' of new E-to-G connections which assumes no change in the level of marketing expenditure. Therefore, the only driver of E-to-G connections for the purposes of this forecast is assumed to be any change in the impact of Jemena's marketing activities.

Core expects new E-to-G connections to an assumption of lower assumed marketing impact during the Review period. This assumption is based on the following:

E-to-G marketing will become increasingly difficult as the relative price outlook of gas vs. electricity moves in favour of electricity; and

The propensity for the influence of media (newspapers, electricity distributors etc) to impact consumer behaviour in anticipation of major price changes taking place will cause these declines in marketing impact to occur prior to actual price increases.

Core's view of marketing impact, giving consideration to the factors outlined above, is captured in the table below.

Table 1.1. Marketing Impact.

	2014	2015	2016	2017	2018	2019	2020
Change in Marketing Impact	-5%	-10%	-5%	-2%	-2%	-2%	-2%

Source: Core Energy Group.

This factor gives rise to the expected change in new E-to-G connections as shown below. This contributes approximately 0.6%pa to the increase in total Residential connections over the Review Period.

Table 1.2. Change in New E-to-G Connections.

	2013	2014	2015	2016	2017	2018	2019	2020
Marketing Impact		-5.0%	-10.0%	-5.0%	-2.0%	-2.0%	-2.0%	-2.0%
New E-to-G Connections	**8,649**	**8,217**	**7,395**	**7,025**	**6,885**	**6,747**	**6,612**	**6,480**

Source: Core Energy Group.

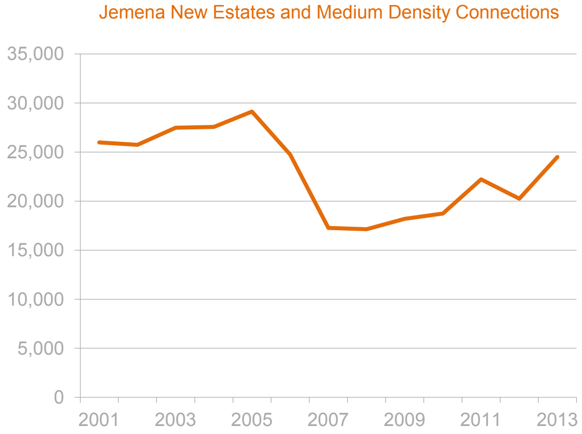
1.2. Tariff V | New Dwellings

Core has assessed the major driver of new dwelling connections to be:

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

Consistent with the approach adopted throughout this Report, Core commenced its analysis by observing the trend in historical completions within the JGN network as summarised in Figure 1.1.

Figure 1.1 JGN Historical Connections 2001-2013.



Source: Core Energy Group based on JGN data.

Based on the high degree of variability over this period, Core concluded that it was unable to derive a meaningful historical trend as a basis for forecasting future connections. Accordingly Core pursued two alternative approaches:

- Development of a bottom-up forecast of residential dwelling completions and connections within the JGN network;
- Use of third party forecasts as a cross-check of the bottom-up analysis.

1.3. Core Bottom-Up Approach

Core's methodology assumes that new dwelling connections (New Estates and Medium Density/High Rise customer classes) are driven by two separate forces:

- Connections due to demand side factors – primarily population and household density;
- Connections due to supply-side factors – owner and investor preferences to provide supply including a reduction in any housing stock 'deficiency'.

1.3.1. Demand side Factors

To derive a forecast of new dwelling connections Core adopted the following approach:

- **Derive Population Forecast** - using NSW Government projections of population by local government area (“**LGA**”), Core calculated the annual increase in NSW population within the LGAs serviced by Jemena.
- **Dwelling Demand Forecast** - using NSW Government’s projections of NSW household density to derive number of new households due to an increasing population.
- **Forecast of JGN Penetration/ Connections** - Based on discussion with Jemena’s marketing executives and analysis of historical data, Core determined a penetration rate of 80% of new dwellings to be a reasonable assumption. This assumption is underpinned, to a large extent, by the assumed continuation of the BASIX program, which continues to encourage gas connections in new homes and historically has resulted in penetration rates of up to 90%. This rate is expected to fall due to higher gas prices and use of substitute energy sources.
- **Forecast JGN New Dwelling Connections** – the product of the Penetration rate and the Forecast of new dwellings is the Forecast of JGN new dwelling connections.

The results of this analysis are summarised in Table 1.3, with the sum of Forecast new connections being 175,059.

Table 1.3. Connections due to Increasing Population.

Connections due to Increasing Population	2013	2014	2015	2016	2017	2018	2019	2020	Sum
Population in Jemena LGAs	6,042,640	6,120,460	6,198,280	6,276,100	6,351,860	6,427,620	6,503,380	6,579,140	
Population Growth	-	77,820	77,820	77,820	75,760	75,760	75,760	75,760	
Average NSW dwelling density	2.48	2.47	2.46	2.45	2.45	2.45	2.44	2.44	
New Dwellings	-	31,512	31,606	31,701	30,917	30,973	31,029	31,085	
Penetration/ Connection Rate		80%	80%	80%	80%	80%	80%	80%	
New Connections		**25,210**	**25,285**	**25,361**	**24,734**	**24,778**	**24,823**	**24,868**	**175,059**

Source: NSW Government 2010 LGA Population Projections, NSW Government 2010 Household and Dwelling Projections. Original data was presented in 5 year intervals and has been interpolated to arrive at annual figures.

1.3.2. Supply-side Response

As with many goods and services, the demand for new dwellings and the supply of new dwellings will rarely be in equilibrium. The response of supply to emerging demand pressures will depend on a wide range of factors including:

- Investor and prospective owner/ occupier confidence;
- Availability and cost of finance; and
- Projected investment yields and capital gains relative to alternative investments with similar risk characteristics.

At the end of the 2013 financial year, a significant housing shortfall (demand > supply) of dwellings existed in NSW. In order to determine the impact of this imbalance on forecast dwelling connections, Core adopted the following approach:

- **Confirm Dwelling Shortfall** – review third party analysis to derive a best estimate of the existing shortfall. In its ‘Building in Australia: 2013-2028’ study, BIS Shrapnel estimates the current dwelling stock deficiency at approximately 46,000 homes as at June 2013. Core considers this 2013 estimate to be reasonable, as it is broadly consistent with the range of other estimates by specialist property sector analysts and commentators.

- **Estimate the Reduction of Shortfall Over Review Period** - Core has assumed that some portion of this excess demand will be matched with new supply over the regulatory period, which will deplete this shortfall and contribute further to new JGN connections. Based on analysis of NSW housing demand and construction activity, Core has assumed 80% of this shortfall (36,800 dwellings) will be satisfied by supply of new houses over the regulatory period.
- **Estimate Shortfall within JGN LGA's** - To express this figure in terms of Jemena's LGA-servicing region, these 36,800 households were multiplied by the current ratio of Jemena LGA households to total NSW households, which is also 80%. This leaves 29,440 homes from which Jemena will source additional connections over the regulatory period.
- **Forecast JGN Connections -** The penetration rate of these homes is assumed to be equal to 80%, in line with the calculation in Table 1.3. This results in 23,600 connections within Jemena's network over the period to 2020.

The results of this analysis are summarised in Table 1.4.

Table 1.4. Connections due to reduction of NSW dwelling stock Deficiency.

Connections due to NSW Dwelling Stock Deficiency	
BIS – Current Dwelling Stock Deficiency	46,000
Expected Depletion of Dwelling Deficiency	80%
Dwellings built in NSW due to depletion of deficiency	36,800
Jemena's LGA to total NSW population ratio	80%
Jemena penetration rate	80%
New connections	**23,600**

Source: Core Energy Group; BIS Shrapnel - Building in Australia 2013-2028.

1.3.3. Allocation of New Dwellings – New Estates vs. Medium/High Density

The combination of forecasts associated with Demand and Supply-side factors above gives rise to 198,659 connections from 2014 to 2020, in the form of either New Estates or Medium Density dwellings.

To allocate total connections between these two segments (to enable calculation of demand per connection), Core has given consideration to a range of third party analysis regarding the outlook for higher density dwellings in NSW relative to houses. This analysis indicates a clear trend towards inner-city living and a higher density dwelling mix.

Core has concluded that a reasonable allocation is 52% Medium Density dwellings and 48% New Estates, with the allocation over the forecast period as summarised in Table 1.5.

These two classes contribute approximately 2.4% growth in Residential connections on a CAGR basis over the Review Period.

Table 1.5. Connections due to reduction of NSW dwelling stock Deficiency.

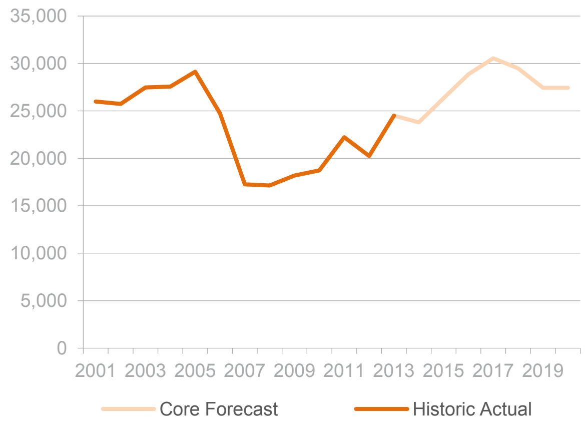
	2013	2014	2015	2016	2017	2018	2019	2020	Total
Apportionment									
New Estates		6.0%	6.5%	7.0%	7.5%	7.0%	7.0%	7.0%	48%
Medium Density/High Rise		6.5%	7.0%	7.5%	8.0%	8.0%	7.5%	7.5%	52%
Connections									
New Estates		11,920	12,913	13,906	14,899	13,906	13,906	13,906	
Medium Density/High Rise		12,913	13,906	14,899	15,893	15,893	14,899	14,899	

Total Dwellings		**24,833**	**26,819**	**28,805**	**30,792**	**29,799**	**28,805**	**28,805**	**198,658**

Source: Core Energy Group.

A comparison of the Core Forecast and historical actual connections is presented in Figure 1.2.

Figure 1.2 JGN Historical Dwellings Connections 2001-2013 and Core Forecast to 2020.



Source: Core Energy Group.

1.4. Third Party Forecast

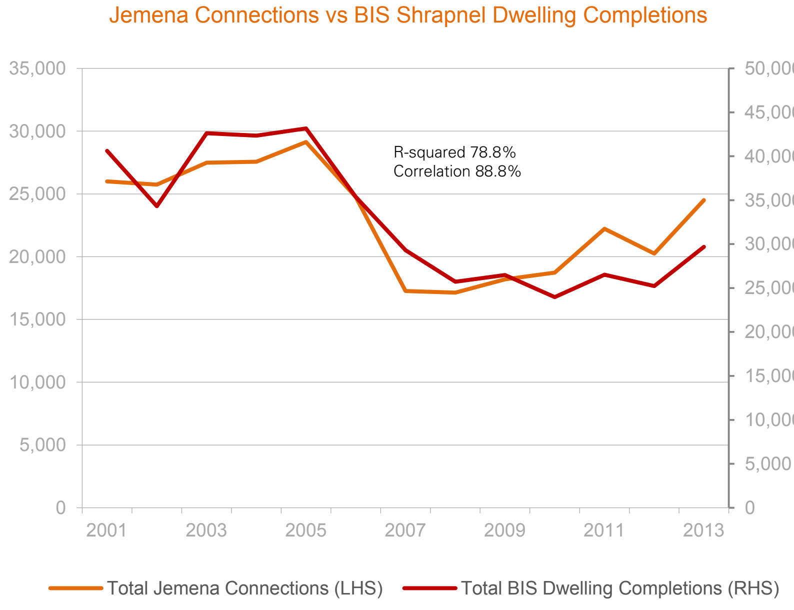
As a cross-check to the Bottom-up forecast outlined in section 1.3.1 above, Core undertaken an analysis of BIS Shrapnel data regarding historical and forecast dwelling completions. The following approach was adopted:

- Undertake a statistical analysis of the relationship between actual historical connections provided by Jemena for its network and historical dwelling completions data available via BIS Shrapnel's 'Building in Australia 2013-2028' report for NSW as a whole.
- Apply the relationship derived from the step above to the NSW forecasts developed by BIS, for the period to 2020, as a proxy for a BIS forecast for the JGN network.
- Compare the results with those developed via the bottom-up approach addressed above.

1.4.1. Historical Analysis – JGN vs. BIS

Figure 1.3 summarises the historical data series for JGN actual connections and BIS reported NSW connections. Whilst the statistical relationship (closeness of fit) is by not 'ideal' Core believes it is reasonable to use this for cross-check purposes.

Figure 1.3 JGN Dwelling Connections and BIS Completions.

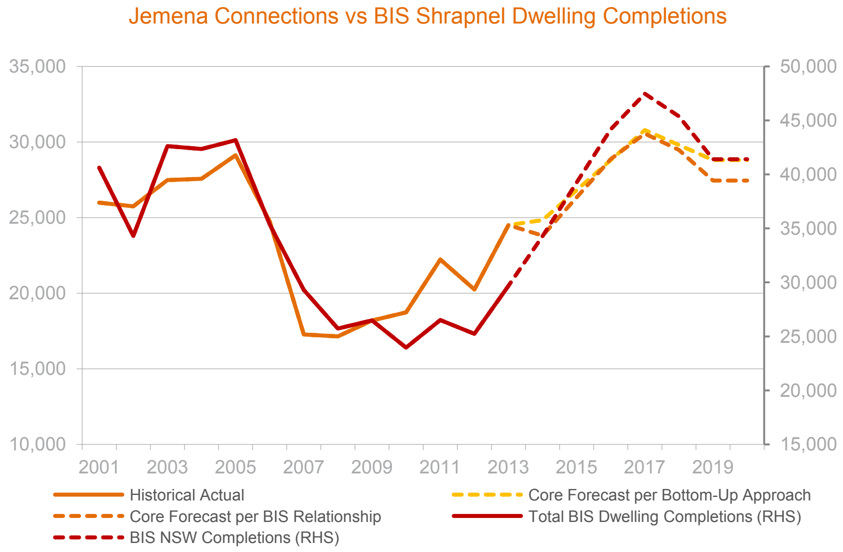


Source: Core Energy Group based on JGN and BIS Shrapnel data.

1.4.2. Forecast Analysis – JGN vs. BIS

Figure 1.4 summarises the results of the forecasting process using the results of the step above. This analysis indicates that the bottom-up approach generally results in forecast JGN connections which are above the BIS based projection. However, the cumulative new connections are quite similar.

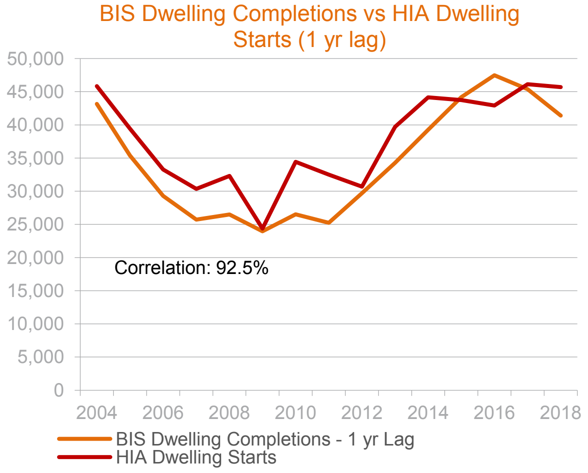
Figure 1.4 JGN Dwelling Connections and BIS Completions



Source: Core Energy Group, BIS Shrapnel.

Finally, Core compared the BIS projections of completions against the HIA projections of housing starts, assuming a one year lag between dwelling starts and dwelling completions. The result shown in Figure 1.5 below indicates that the BIS data is reasonably consistent with other third party sources (i.e. HIA).

Figure 1.5 BIS vs. HIA Dwellings Projections.



Source: Core Energy Group, HIA Housing Forecasts – November 2013.

1.4.3. Conclusion

Core is of the opinion that the bottom-up approach outlined in Section 1.3.1 and the cross check against BIS and HIA projections provides a best estimate under the circumstances of new dwelling connections for Jemena over the Review Period.

Section 2 | 2. Other Tariff V Residential Gas Demand Influences

2.1. Introduction

Throughout this forecasting process Core has considered a wide range of information, views and data regarding the outlook for residential gas demand in eastern Australia generally and NSW specifically. Information which can be reasonably applied in a quantifiable way to derive Core's Adjusted Forecast is set out in the Sections above. In addition there is a range of data, information and views which is generally supportive of Core's forecast but cannot be directly used in quantifiable terms. This Section of the Report presents a summary of information which has not been directly incorporated in Core's forecast but do provide additional qualitative support of Core's forecast.

2.2. Summary of Supporting Information Sources

Two types of supporting information are addressed in this Section:

- Information relating to energy policy influences - see Section 9.3;
- Statistics relating to residential gas appliance use - see Section 9.4.

2.2.1. Policy Influences

Table 2.1. Policy Influences.

Policy	Description	Likely Impact
BASIX	Targets efficiency in energy use (including gas) to reduce greenhouse gas emissions.	▪ Likely to maintain a high penetration of gas for new connections due to benefits of hot water system installation. ▪ Likely to contribute to progressive marginal reductions in gas use per connection, through a range of efficiency measures.
MEPS	Targets standardisation of reporting relating to efficiency of energy appliances, including gas.	▪ Likely to reduce marginal gas use per connection over time by encouraging improved appliance efficiency - in particular space heating and hot water appliances and continued trends in conservation e.g. use of efficient showerheads.
RET	Targets 20% use of renewable energy by 2020.	▪ Likely to favour renewable energy over gas at the commercial and residential level - particularly hot water and space heating.
NABERS	Targets energy efficiency.	▪ Likely to stabilise or reduce gas and broader energy use over time.

Source: Core Energy Group.

These programs are described in further detail below.

2.2.1.2. Building Sustainability Index (BASIX)

The Building Sustainability Index (BASIX) aims to deliver effective water and greenhouse gas reductions across the State of NSW by setting sustainability targets for water and energy use by NSW households.

BASIX applies to all residential dwelling types and is part of the development application process in NSW and is implemented under the Environmental Planning and Assessment Act.

The benchmarks are determined from NSW average residential water, electricity and gas consumption data collected from state-wide energy utilities by government departments.

- Water: the NSW benchmark is expressed in terms of potable water consumption and is equal to 90,340 litres of water per person per year.
- Energy: the NSW benchmark is expressed in terms of greenhouse gas emissions and is equal to 3,292 kg of CO2 per person per year.

BASIX targets:

- up to a 40% reduction in potable water consumption;
- up to a 40% reduction in greenhouse gas emissions.

BASIX is assessed online using the BASIX assessment tool. The tool checks elements of a proposed design against sustainability targets to arrive at a score for the proposed development. A BASIX certificate is obtained after completing the sustainability assessment.

It is important to note that a range of features of the development which contribute to achieving the required score have an influence on gas consumption:

- ceiling fans and highly efficient air-conditioning;
- solar and highly efficient gas hot water systems;
- efficient showerheads;
- alternative energy systems such as PV;
- insulation, performance glazing, solar orientation and shading.

The above factors are likely to result in a compounding reduction in gas use.

2.2.1.3. Minimum Energy Performance Standards (MEPS)

On 1 October 2012, the Greenhouse and Energy Minimum Standards (**GEMS**) legislation came into effect, creating a national framework for appliances and equipment energy efficiency in Australia.

The specific requirements for regulated products—including Minimum Energy Performance Standards (**MEPS**) and energy rating labelling requirements—are set out in a legislative instrument called a GEMS Determination.

The gas labelling program is currently an industry voluntary scheme that was once managed by the Australian Gas Association (**AGA**).

These programs directly target reduced energy use and are likely to have a continuing impact on gas use.

2.2.1.4. RET

The Renewable Energy Target is a program administered by the Clean Energy Regulator and includes the Large-scale Renewable Energy Target (“**LRET”**) and the Small-scale Renewable Energy Scheme (“**SRES”**).

These schemes create a financial incentive for investment in renewable energy sources through the creation and sale of certificates.

The schemes actively target use of solar power and solar water heaters which are substitutes for gas and therefore are likely to continue to have a reducing influence on gas use.

2.2.1.5. NABERS

National Australian Built Environment Rating System ("**NABERS**") is a national rating system that measures the environmental performance of Australian buildings, tenancies and homes and is managed nationally by the NSW Office of Environment and Heritage, on behalf of Commonwealth, state and territory governments.

NABERS measures the energy efficiency, water usage, waste management and indoor environment quality of a building or tenancy and its impact on the environment.

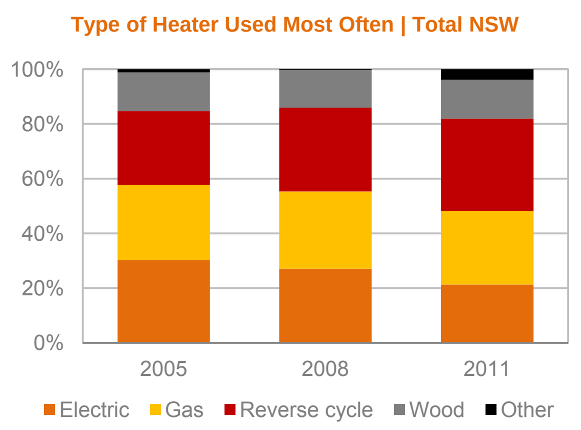
NABERS is likely to have a continued reducing impact on energy usage within commercial and residential buildings and thus reduce gas usage.

2.2.2. Appliance Trends

2.2.2.1. Increased Reverse Cycle Penetration for Space Heating

ABS data indicates that reverse cycle penetration of NSW space heating has increased significantly from 26.9% in 2005 to 33.7% in 2011, at the expense of electric heaters (and marginally from gas heating).

Figure 2.1 Type of Heater Used Most Often in NSW 2005-2011.



Source: ABS; 4602.0.55.001 - Environmental Issues: Energy Use and Conservation, Mar 2008 and Mar 2011 editions.

Additionally, the climate in NSW brings about a higher penetration of reverse cycle heating than in cooler states such as Victoria, where residential homes require more effective heating provided by gas.

Data from BIS Shrapnel shows that roughly three quarters of Victorian households use gas for space heating compared to 31% in NSW. SA penetration rates are similar to those found in NSW where average temperatures are more comparable.

Table 2.2. Penetration of Heating Appliances 2012.

Penetration of Heating Appliances 2012 (%)	NSW	VIC	QLD	SA	WA	Total
Gas – non-ducted	24	23	4	23	42	21
Gas – ducted	7	51	1	16	7	18
Total gas heating	**31**	**74**	**5**	**39**	**49**	**39**
Reverse Cycle	**44**	**19**	**46**	**46**	**38**	**38**
Portable Electric Heater	32	13	25	20	19	24
Wood	10	13	8	10	9	10
Other	4	6	4	6	3	5
None of the above	10	3	28	7	7	11

Source: BIS Shrapnel Climate Control Report 2012.

Core believes these observations demonstrate that:

- while gas heating is generally preferred in cooler climate, NSW households may have a higher propensity to substitute gas heating appliances for electricity (i.e. reverse cycle).
- reverse cycle penetration has risen when relative gas and electricity prices were a minor consideration in recent years – as gas prices cause reverse cycle to become more favourable Core expects this trend of substitution to continue. The impact on demand is expected to be substantial enough to warrant the inclusion/application of a cross price elasticity factor.

Section 2 | 3. Gas Price Forecast

3.1. Introduction

The NSW gas sector forms part of an integrated eastern Australia gas system comprising the States of NSW, VIC, QLD, SA, TAS and the ACT.

In 2016 and 2017, several large, long standing gas contracts associated with gas supply from the Cooper Basin and Gippsland Basin respectively, come to an end. This is an important milestone as they are the main supply sources for NSW customers and also represent a significant proportion of total gas supply into eastern Australia more broadly.

It is widely reported that this period of recontracting will witness a significant change in ex-field prices[14]. Core's forecast of ex-field gas prices is set out in Table 3.1.

Table 3.1. Summary - Wholesale Gas Cost Projections (Real AUD/GJ 2014).

Retail Price Component	2014	2015	2016	2017	2018	2019	2020
Wholesale Cost (ex-field)	4.00	5.00	5.00	6.00	8.00	8.00	8.00

Source: Core Energy Group.

This Section of the Report sets out the basis for the Core forecast.

3.2. Approach

Core Energy and its CEO Mr. Paul Taliangis have almost 20 years of experience in the eastern Australia gas sector including a period as an executive with Santos Limited, a leading gas producer. In Core's opinion, this experience provides a strong background for developing a forecast of future gas prices. Further Credentials are presented in Attachment 2.

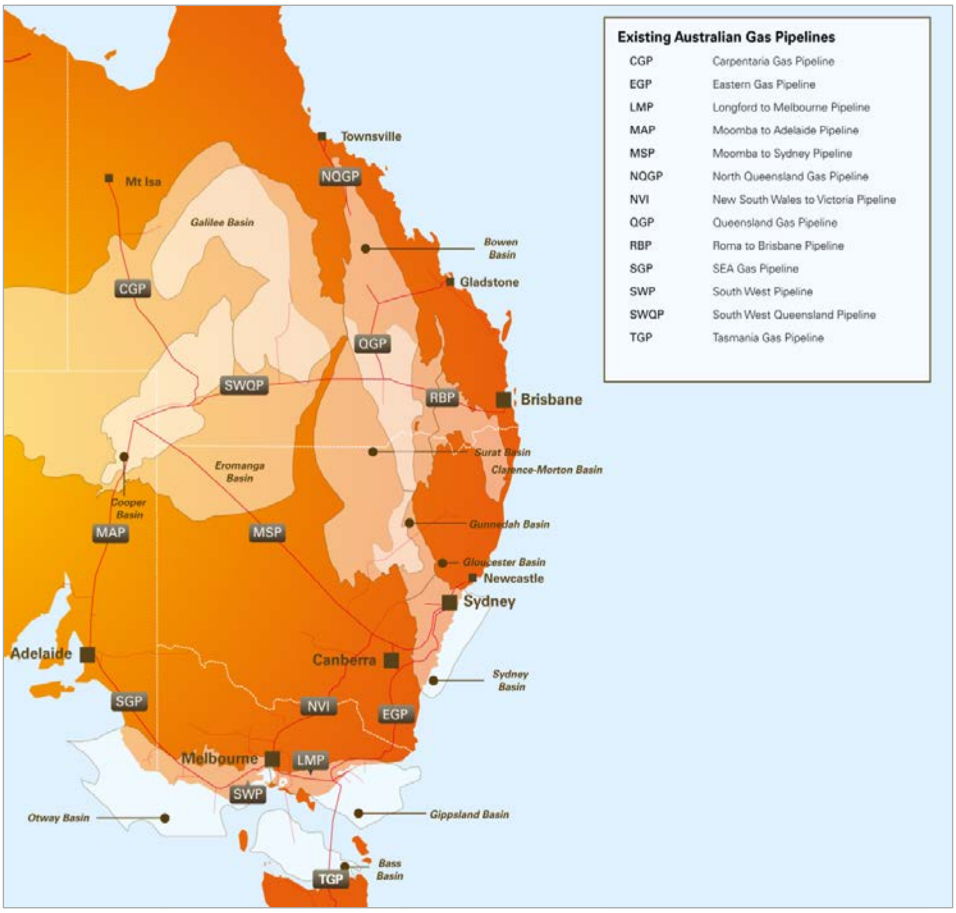
Core has utilised its extensive databases and analytical systems to derive a projection of demand, supply, cost and price of gas over the Review period. This analysis develops scenarios of the lowest cost supply available to meet forecast uncontracted demand in each State, for all individual wholesale customers. This methodology has been applied consistently by Core for over a decade and has provided the basis for independent expert advice to the majority of large gas producers, customers and transport companies in eastern Australia.

3.3. Background

The following map illustrates NSW's position within the integrated eastern Australia gas system, which comprises gas demand centres, gas hubs and pipeline networks which link demand centres to and supply hubs.

[14] Refer Attachment 3 to this Report.

Figure 3.1 Map of Existing Eastern Australia Gas Basins & Transmission Network.

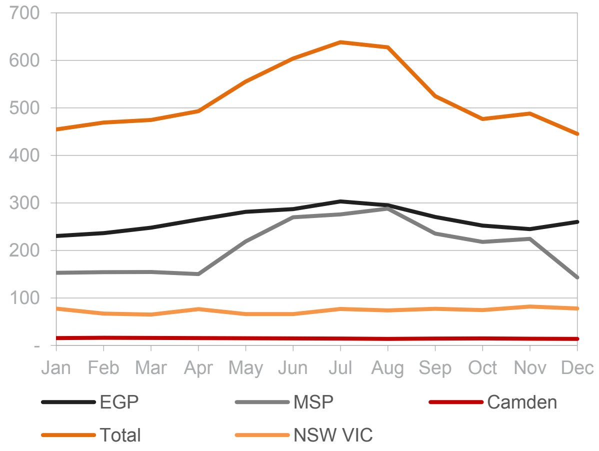


Source: Core Energy Group; 2013.

A point of importance to note is the role of the Eastern Gas Pipeline ("**EGP"**) and Moomba Sydney Pipeline ("**MSP"**) in serving the NSW market. The EGP sources gas under contract from the Gippsland Basin Joint Venture ("**GBJV"**) and the MSP sources the majority of gas under a contract with the Cooper Basin Joint Venture ("**CBJV"**).

The following figure shows the dominant role of these pipelines in delivering gas to the linked NSW/ACT market during the 2013 calendar year. The only other pipelines delivering gas include a minor volume from the Camden CSG field and modest volumes via the NSW-Vic interconnect.

Figure 3.2 NSW/ACT Peak Pipeline Flow - 2013 Calendar Year.



Source: Core Energy Group.

Over 80% of the ~140 PJ of gas consumption in NSW in 2013 was via three main retailers - AGL, EnergyAustralia and Origin[15], with the remainder involving direct sales by producers to larger industrial and electricity generation customers and small retailers.

These Retailers and customers source gas primarily from the GBJV and CBJV under long term contracts with fixed prices. In 2016 CBJV contracts with AGL will end[16] and in 2017 GBJV contracts with AGL[17] and Energy Australia[18] will end.

Importantly Santos, the operator and major equity interest holder in the CBJV, has signalled its clear intention to favour supply of gas to the GLNG venture in Gladstone[19] which has introduced linkage to LNG prices. In addition, GBJV has signalled its intention to reduce the flexibility of gas offered under new contracts by reducing the take-or-pay and MDQ provisions. The GBJV has also recently announced an oil price linked contract[20].

3.4. Gas Price Drivers

Of particular importance for this Review is the forecast wholesale price - ex-field (basis of contracts in eastern Australia) for delivery into NSW between 2014 (transition year) and 2020, with a particular focus on the 2016 to 2020 Review period.

In developing the price forecast to 2020 Core Energy has considered two primary pricing forces:

- Demand pull from LNG export projects, which introduces a linkage of domestic and export prices; and
- Cost push - increasing cost of existing and new supply sources which will also drive price increases to provide project owners with cost recovery plus a return on capital invested.

[15] Estimate based on Core Energy data and analysis and validated via reference to third party analysis.
[16] AGL, 2005, 'AGL Amends Gas Portfolio Arrangements', Media Release
[17] BHP Billiton, 2003, 'BHP Billiton Signs Gas Sale and Purchase Agreement with AGL', News Release,
[18] TRUEnergy, 2003, TXU signs contract for Gippsland Basin Gas, News Release
[19] Santos Announcement 25 October 2010 'Santos to supply 750PJ of portfolio gas to GLNG'
[20] Origin ASX Release 19 September 2013 - "Origin secures 432 PJ of natural gas from ESSO/BHPB to boost its portfolio to meet customer demand"

3.4.1. Demand Pull

It is widely recognised, within the eastern Australian gas market, that at least one LNG project, GLNG, is actively seeking reserves and production to meet the supply LNG export contract commitments relating to the two-train GLNG project[21]. This is placing an upward pressure on the price of gas resources and is also introducing a linkage to LNG prices. LNG prices are in turn linked to oil prices via a Japanese Cleared Crude (“**JCC”**) price benchmark. LNG prices at Gladstone are up to USD14.85/ GJ (F.O.B).

Core's analysis in Table 3.2 illustrates the Core’s estimate of the GLNG shortfall in reserves required to meet contracts only and the gas required to meet maximum plant capacity. Whilst Core acknowledges that this shortfall could be met through a variety of ways, it is presented as evidence that an LNG "pull" influence is a genuine force influencing market prices.

Table 3.2. GLNG Supply Shortfall | December 2013.

GLNG Gas Requirement	Max Capacity	Contracted Capacity
Capacity of trains/ Contracts (Mt p.a. LNG)	3.9	3.5
Gas required per Mt p.a. LNG (PJ p.a.)	55.5	55.5
Gas required per train (PJ p.a.)	216	194
Estimated pipeline and plant gas use	10%	10%
Gross gas required per train (PJ p.a.)	241	216
LNG contract period (years)	20	20
Gas required to meet LNG contracts per train (PJ)	4,810	4,317
Gas required to meet GLNG capacity/ contracts (PJ)	**9,620**	**8,634**
GLNG Supply Coverage (PJ)		
2012 gross GLNG reserves (2P)	5,376	5,376
Less volumes dedicated to domestic contracts:		
Fairview	151	151
Scotia	61	61
Total reserves dedicated to domestic contracts	212	212
Add volumes purchased from third parties:		
Santos ‘Horizon’ contract	750	750
Origin contract announced May 2012	365	365
Origin contract announced December 2013 (including 96PJ option)	196	196
Reserves purchased from third parties	1,311	1,311
Net reserves/ resources for GLNG (2P + contracted basis)	6,475	6,475
Estimated shortfall	**3,145**	**2,159**

Source: Core Energy Group.

A number of analysts/ commentators have assessed the resultant domestic prices to be in the range $7.00 to $8.00/ GJ ex-Moomba which is closer to $8.00 to $10.00 delivered at Sydney gate (refer to Section 3.6 below).

Core believes that the rise in prices will be approximately $1.00/GJ in 2015 to 2016 to reflect the outcome on price of some smaller contract renegotiations at higher prices, price reviews under contracts, MDQ service fees and related costs. The expiration of the Cooper Basin contract in 2016 is likely to translate to a further increase of $1.00/GJ in 2017, followed by a $2.00/GJ increase in 2018 following the expiration of the GBJV contracts.

[21] Santos Announcement 19 December 2013 ‘GLNG signs gas purchase agreement with Origin Energy’

Clearly there is uncertainty regarding timing of these increases but Core believes this path is a reasonable representation of the way prices will evolve in practice.

Table 3.3. Summary - Wholesale Gas Price Projections (Real AUD/GJ 2013) ex-field - LNG linkage.

Retail Price Component	2014	2015	2016	2017	2018	2019	2020
Wholesale Price	4.00	5.00	5.00	6.00	8.00	8.00	8.00

Source: Core Energy Group.

3.4.2. Cost Push

Core has also considered the price path that may result if LNG projects become fulfilled and prices are then set by competitive forces between suppliers with suitable reserves and production.

Core's analysis of existing and proposed resource projects, other than GBJV, indicates that there is unlikely to be material new gas reserves and production available to the domestic market prior to 2017. This opinion is based on the status of all existing and proposed projects and knowledge of the time it will take to complete any new development. Further, there is likely to be continued demand for gas by LNG producers which will withdraw gas from the domestic market. For these reasons Core is of the opinion that demand pull influences are likely to outweigh cost push influences through to 2018.

In 2015-16 (ahead of contract expiry in 2017) it is likely that EnergyAustralia and AGL will seek new contracts with GBJV to meet post 2018 requirements. This being the case, there is unlikely to be material supplier competition during this period - particularly if NSW CSG projects (Gloucester and Gunnedah) continue to be delayed. Therefore Demand Pull forces are likely to remain a major force until at least 2019.

From 2019 to 2020 if new resources are developed they will be competing for a smaller residual uncontracted market as retailers should have met substantial elements of their portfolio requirements by that time. Nevertheless there is scope for prices to stabilise or fall if resource owners are prepared to sell at lower prices. However, Core Energy and third party analysis suggests that costs of gas extraction are likely to increase materially, leaving limited scope if any for price falls. These cost increases are attributable to lower well performance, higher labour costs and increasing compliance costs.

Based on the above analysis, Core Energy believes that the following price path is reasonable having regard to both cost push and demand pull factors.

Table 5.6. Summary - Wholesale Gas Price Projections (Real AUD/GJ 2013) ex-field - cost push.

Retail Price Component	2014	2015	2016	2017	2018	2019	2020
Wholesale Price	4.00	5.00	5.00	6.00	8.00	8.00	8.00

Source: Core Energy Group.

3.5. Third Party Analysis

A summary of third party analysis/commentary relating to matters of relevance to wholesale gas price projections in eastern Australia is outlined below.

3.5.1. General Price References

Table 3.4. Third Party Wholesale Gas Price Summary.

Party	Publication	Reference
Core Energy	**Jemena NSW 2016-20 Demand Forecast**	**Wholesale costs rising from $4.00/ GJ in 2013 to $8/ GJ by 2018.**
AGL/Brattle Group, February 2014	Proposed Price Path for NSW Regulated Gas Prices	Wholesale costs of $7.12/GJ in 2015 and $8.12/GJ in 2016.
ACIL Tasman, April 2013	Cost of Gas for the 2013 to 2016 Regulatory Period	Delivered prices into Sydney of approximately $10/ GJ.
SKM, October 2013	Gas Market Modelling	Upstream contract prices of $7-8.50/ GJ 2015-2020.
Australian Industry Group, July 2013	Energy Shock: the Gas Crunch is Here	Contract price quotes of $8.72 /GJ for customers seeking long term contracts beyond 2015.
Oakley Greenwood, September 2013	Gas and Electricity Forecasts for NSW	Delivered prices rise above $9/GJ by 2018
AGL	Michael Fraser, CEO	Deals are being done at $9-$10 [per GJ] and who knows where it will go when [LNG] starts up.
Santos	David Knox, CEO	Stated that Santos was signing gas contracts at the high end of a $6 to $9 per gigajoule range that Santos had been predicting prices would rise to once the LNG plants started.
Credit Suisse	Credit Suisse Securities Research & Analytics, May 2013, Beach Energy,	Post 2015 prices to reach $8-10/GJ

3.5.2. Recent Specific Gas Contract References

Table 3.5. Recent Gas Contract References.

Party	Publication	Reference
AGL&APA/Diamantina Power Project	APA ASX Release 2011	AGL to supply gas for 6 years as part of a JV to develop a CCGT power station in Mt Isa Third party view (e.g. The Australian) that it may reach $9/GJ
Origin/MMG	ASX Announcement, December 2012	Origin Energy signed a gas deal with Chinese-controlled, Melbourne-based miner MMG. Third party view (e.g. The Australian) that it may reach $9/GJ
Origin/ QGC	Origin Media Release 28 November 2013	Origin will supply QGC with up to a total of 30 petajoules (PJ) of gas at Wallumbilla in calendar year 2014 and 2015 at oil-linked pricing. Third party opinion that price was $8/GJ
GLNG/Origin	Origin Media Release 19 December 2013	Origin will supply GLNG with at least 100 PJ of gas at Wallumbilla over a period of five years, commencing on 1 January 2016. - Oil-linked pricing. Third party opinion that price was $8/GJ
Origin/ Beach	Beach Energy ASX Release 10 April 2013	Beach signs major gas sales agreement with Origin Energy for up to ~139 PJ over eight years, with the potential for a two year extension. Commencement date window for supply under the agreement is from July 2014 to June 2015 The supply of gas will be delivered ex-Moomba, with the price incorporating a combination of an oil linked curve and other parameters.

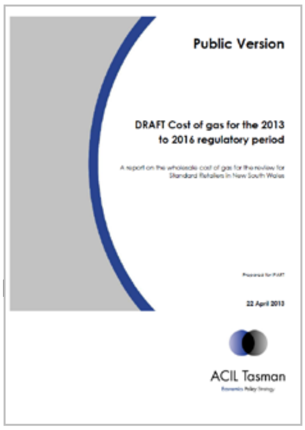
Further detail relating to third party opinions is included below.

3.6. Third Party Gas Price Analysis

3.6.1. ACIL Tasman

3.6.1.1. Study Description

ACIL Tasman released a report dated 22 April 2013 addressing the cost of gas for the 2013 to 2016 regulatory period for IPART.



3.6.1.2. Study Approach

In its report ACIL presented three scenarios which are summarised in the following table (extract).

Figure 3.3 ACIL Tasman Gas Price Scenarios, April 2013.

Table 3 Scenarios

	High price scenario	Medium price scenario	Low price scenario
Scenario title	"LNG feedstock scramble"	"All goes to plan"	"LNG price collapse"
International oil prices	IEA Current Policies assumption (~US$130/bbl by 2020)	IEA Current Policies assumption (~US$130/bbl by 2020)	ACIL Tasman low price assumption of US$80/bbl by 2020
Asia Pacific LNG prices	As per Japan import prices within IEA World Energy Outlook 2012 Current Policies scenario (US$15-16/mmbtu in 2020)	As per Japan import prices within IEA World Energy Outlook 2012 Current Policies scenario (US$15-16/mmbtu in 2020)	ACIL Tasman low price assumption declining to ~US$10/mmbtu by 2020
LNG East Coast Production	6 LNG trains by 2020 (no further commitments due to poor CSG performance)	8 LNG trains by 2020 (i.e. Shell/Arrow project proceeds with 2 train project either independently or in conjunction with existing projects)	6 LNG trains by 2020 (no further commitments due to low international price outlook)
Conventional gas outlook	As per ACIL Tasman Base case	As per ACIL Tasman Base case	As per ACIL Tasman Base case
QLD CSG assumptions	Well performance is below expectations and completion costs are significantly higher	As per ACIL Tasman Base case	As per ACIL Tasman Base case
Unconventional tight gas/shale assumptions	As per ACIL Tasman Base case	As per ACIL Tasman Base case	As per ACIL Tasman Base case

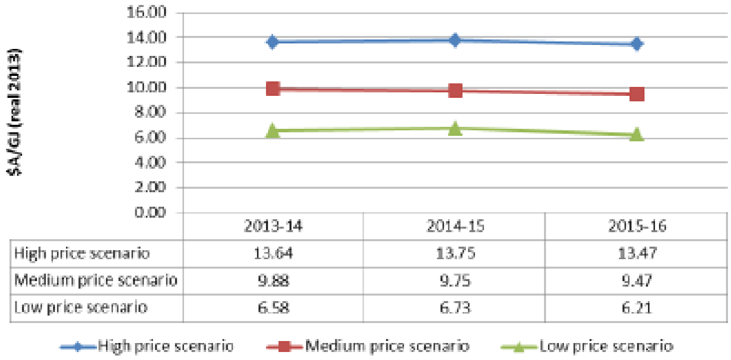
Data source: ACIL Tasman

3.6.1.3. Study Findings

ACIL's forecast of the delivered cost of gas (i.e. including transmission charges) into Sydney and Newcastle are reproduced below.

Figure 3.4 ACIL Tasman Projected Prices – Sydney

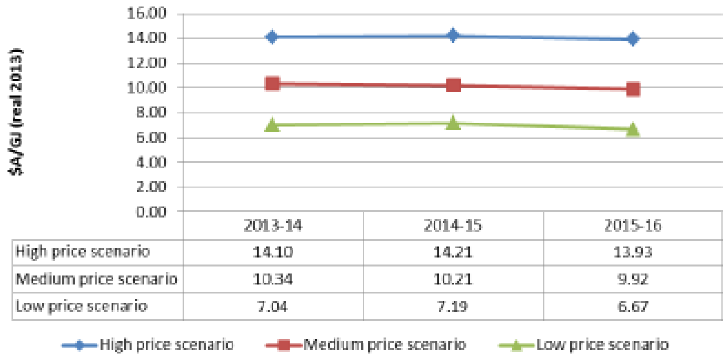
Chart 10 GasMark Projected prices - Sydney (Wilton)



	2013-14	2014-15	2015-16
High price scenario	13.64	13.75	13.47
Medium price scenario	9.88	9.75	9.47
Low price scenario	6.58	6.73	6.21

Note: Prices include transmission charges
Source: ACIL Tasman GMG Australia modelling

Chart 11 GasMark Projected prices - Newcastle



	2013-14	2014-15	2015-16
High price scenario	14.10	14.21	13.93
Medium price scenario	10.34	10.21	9.92
Low price scenario	7.04	7.19	6.67

Note: Prices include transmission charges
Source: ACIL Tasman GMG modelling

3.6.2. Consistency with Core Forecast

ACIL's forecast of Sydney prices provides broad support for the Core forecast.

3.7. SKM

3.7.1. Study Description

SKM released a report dated 15 October 2013 for the Standing Council on Energy and Resources ("**SCER**") and the Gas Market Study Task Force assessing the supply, demand and gas price dynamics of the eastern Australian gas market.

3.7.2. Study Approach

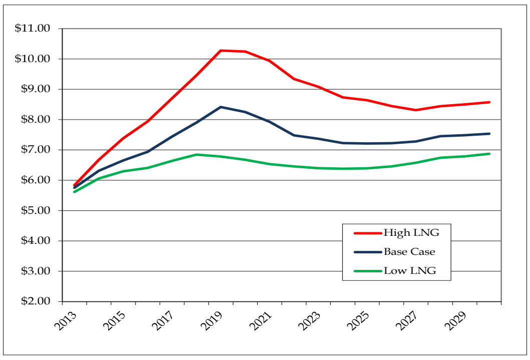
SKM notes the following - SKM projected the price of new upstream gas contracts in each of three demand-supply scenarios based on the alternative LNG demand projections. Prices have been determined using two alternative assumptions regarding existing contracts: 1) that all existing contracts remain dedicated to the domestic market; and 2) that all gas not contracted directly and indirectly to end users is available for diversion to exports and further new upstream contracts are required for the domestic market.

3.7.3. Study Findings

The Study findings are summarised in the Figures below.

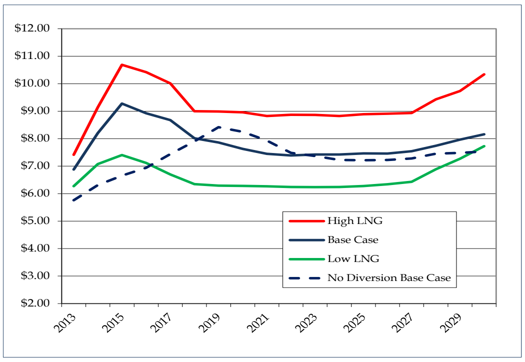
3.7.3.1. Scenario 1:

Figure 3.5 New contract prices ($/GJ, $2013 real)



3.7.3.2. Scenario 2:

Figure 3.6 High contract diversion - ($/GJ, $2013 real)



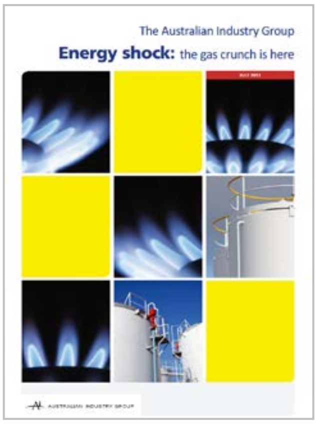
3.7.4. Consistency with Core Forecast

Core is of the opinion that the market is tending more toward Scenario 2 than Scenario 1 and between the Base and High case due to continued diversion of gas supply to LNG projects (GLNG in particular) and this range represents the most appropriate comparator for the purpose of this Review. On this basis the analysis is broadly consistent with the Core forecast with the exception that SKM presents a downward trend from 2015-16 which Core does not believe is a likely scenario based on Core's more recent direct experience in this market.

3.8. Australian Industry Group

3.8.1. Study Description

The Australian Industry Group's business survey conducted in April and May 2103 as part of its report titled "Energy Shock: the Gas Crunch is Here" aimed to assess the state of the gas market in eastern Australia.



3.8.2. Study Approach

The executive summary of its findings is quoted below, highlighting the difficulty for businesses to source gas near historic prices.

"In April and May 2013 the Australian Industry Group surveyed business gas users in eastern Australia to establish the state of the gas market. Questions related to current gas use, contracts sought and investment impact. 61 businesses responded to the survey.

About half the businesses we surveyed were looking for a new gas contract at the time. Of those businesses nearly 10% could not get an offer at all; a third could not get a serious offer; and a quarter could get an offer from only one supplier.

Only a third faced a genuinely competitive market with multiple offers available. These results confirm that the gas market is very tight at present, as the LNG exporters lock up any supply they can find in order to meet their commitments and make up for slower production growth than anticipated.

Wholesale gas prices have been widely expected to rise from their historic average of $3-4 per gigajoule and converge with the LNG netback price – that is, the price paid by gas importers in Japan and elsewhere in Asia, minus the costs of liquefaction and transport. There have been different views about how fast and far this transformation would go. The survey results suggest that price rises will be at the top end of projection.

3.8.3. Study Findings

"Of those businesses being offered prices at all, businesses seeking relatively short term contracts to commence in 2013 were seeing offers of $5.12 a gigajoule – a moderate uplift. But for everyone else, seeking later or longer contracts, the average offer was $8.72 a gigajoule – more than double the historic price. "

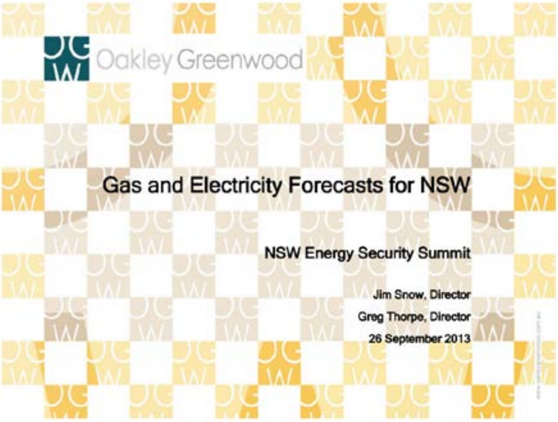
3.8.4. Consistency with Core Forecast

The AIG study findings are consistent with the Core projection that prices are increasing significantly and close to double historic levels.

3.9. Oakley Greenwood

3.9.1. Study Description

In September 2013 Oakley Greenwood made a public presentation which incorporated a forecast of eastern Australia gas prices.



3.9.2. Study Approach

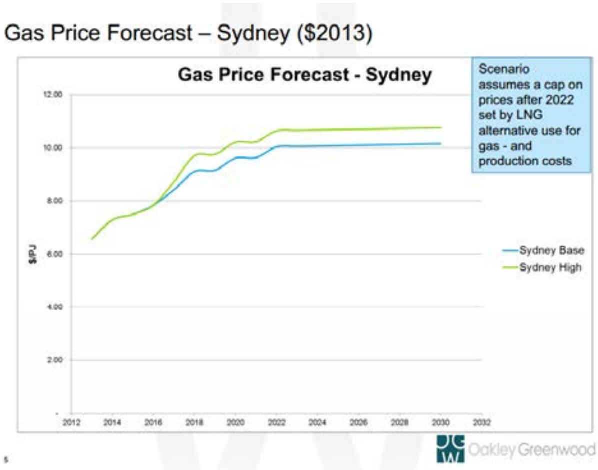
The study considered two plausible gas price scenarios - high and base (or more business as usual) and includes transmission costs to get to the Sydney hub:

• The high price scenario is reflective of more rapid impacts of LNG export values on the wholesale gas prices

• The base price scenario is more reflective of past underlying trends and assumes there is sufficient competition to mitigate price rises.

3.9.3. Study Findings

The study concluded that there would be an upward trend in Sydney gas prices to 2020



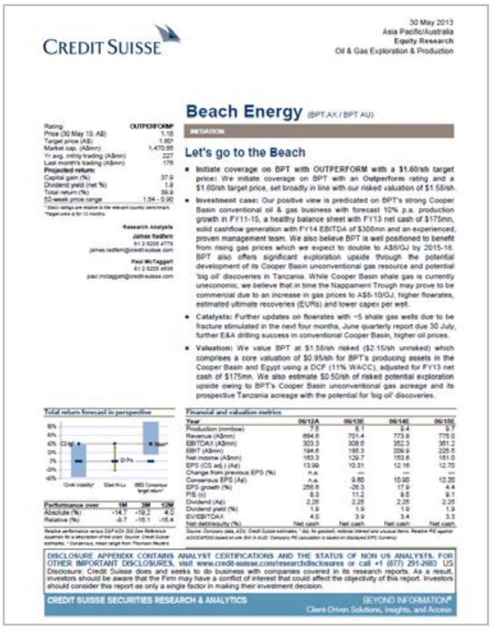
3.9.4. Consistency with Core Forecast

The analysis undertaken by Oakley Greenwood is broadly supportive of the Core forecast, albeit with some difference in the slope of the trend line.

3.10. Credit Suisse

3.10.1. Study Description

In May 2013 Credit Suisse issued a company research report relating to Beach Energy. The report made numerous comments regarding future gas prices.



CREDIT SUISSE

30 May 2013
Asia Pacific/Australia
Equity Research
Oil & Gas Exploration & Production

Beach Energy (BPT.AX / BPT AU)

INITIATION

Let's go to the Beach

Rating	OUTPERFORM
Price (30 May 13, A$)	1.16
Target price (A$)	1.60
Market cap. (A$mn)	1,470.65
Yr avg. mthly trading (A$mn)	227
Last month's trading (A$mn)	176
Projected return:	
Capital gain (%)	37.9
Dividend yield (net %)	1.9
Total return (%)	39.9
52-week price range	1.54 - 0.90

Research Analysts
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- **Initiate coverage on BPT with OUTPERFORM with a $1.60/sh target price:** We initiate coverage on BPT with an Outperform rating and a $1.60/sh target price, set broadly in line with our risked valuation of $1.58/sh.
- **Investment case:** Our positive view is predicated on BPT's strong Cooper Basin conventional oil & gas business with forecast 10% p.a. production growth in FY11-15, a healthy balance sheet with FY13 net cash of $175mn, solid cashflow generation with FY14 EBITDA of $306mn and an experienced, proven management team. We also believe BPT is well positioned to benefit from rising gas prices which we expect to double to A$8/GJ by 2015-16. BPT also offers significant exploration upside through the potential development of its Cooper Basin unconventional gas resource and potential 'big oil' discoveries in Tanzania. While Cooper Basin shale gas is currently uneconomic, we believe that in time the Nappamerri Trough may prove to be commercial due to an increase in gas prices to A$8-10/GJ, higher flowrates, estimated ultimate recoveries (EURs) and lower capex per well.
- **Catalysts:** Further updates on flowrates with ~5 shale gas wells due to be fracture stimulated in the next four months, June quarterly report due 30 July, further E&A drilling success in conventional Cooper Basin, higher oil prices.
- **Valuation:** We value BPT at $1.58/sh risked ($2.15/sh unrisked) which comprises a core valuation of $0.95/sh for BPT's producing assets in the Cooper Basin and Egypt using a DCF (11% WACC), adjusted for FY13 net cash of $175mn. We also estimate $0.50/sh of risked potential exploration upside owing to BPT's Cooper Basin unconventional gas acreage and its prospective Tanzania acreage with the potential for 'big oil' discoveries.

Total return forecast in perspective

Performance over	1M	3M	12M
Absolute (%)	-14.7	-19.2	4.0
Relative (%)	-9.7	-16.1	-16.4

Financial and valuation metrics

Year	06/12A	06/13E	06/14E	06/15E
Production (mmboe)	7.8	8.1	9.4	9.7
Revenue (A$mn)	664.6	701.4	773.8	775.0
EBITDAX (A$mn)	303.3	308.6	352.3	361.2
EBIT (A$mn)	194.6	185.3	209.9	226.6
Net income (A$mn)	163.3	129.7	153.6	161.0
EPS (CS adj.) (A¢)	13.99	10.31	12.16	12.70
Change from previous EPS (%)	n.a.	—	—	—
Consensus EPS (A¢)	n.a.	9.60	10.90	12.30
EPS growth (%)	256.6	-26.3	17.9	4.4
P/E (x)	8.3	11.2	9.5	9.1
Dividend (A¢)	2.25	2.25	2.25	2.25
Dividend yield (%)	1.9	1.9	1.9	1.9
EV/EBITDAX	4.0	3.9	3.4	3.3
Net debt/equity (%)	Net cash	Net cash	Net cash	Net cash

DISCLOSURE APPENDIX CONTAINS ANALYST CERTIFICATIONS AND THE STATUS OF NON US ANALYSTS. FOR OTHER IMPORTANT DISCLOSURES, visit www.credit-suisse.com/researchdisclosures or call +1 (877) 291-2683. US Disclosure: Credit Suisse does and seeks to do business with companies covered in its research reports. As a result, investors should be aware that the Firm may have a conflict of interest that could affect the objectivity of this report. Investors should consider this report as only a single factor in making their investment decision.

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3.10.2. Study Findings

The Australian east coast gas market is expected to experience a dramatic change in the coming years due to the ramp up of three LNG projects (GLNG, APLNG, QCLNG) in Gladstone around 2015. We forecast east coast gas consumption to triple to 2,200 PJ p.a. leading to a projected doubling of domestic east coast gas prices to A$8-10/GJ post 2015, up from ~A$3-4/GJ currently."

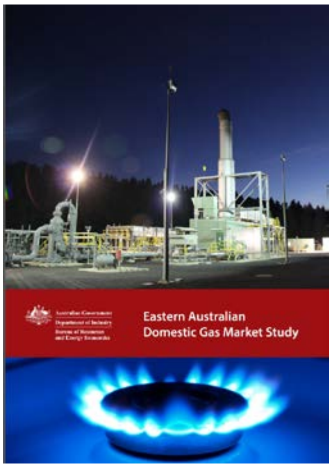
3.10.3. Consistency with Core Forecast

The analysis undertaken by Credit Suisse is broadly supportive of the Core forecast.

3.11. BREE/ IES – Eastern Australia Gas Market Study

3.11.1. Study Description

A study of the Eastern Australia Domestic Gas Market was released in January 2014 by BREE. The report included projections undertaken by IES.

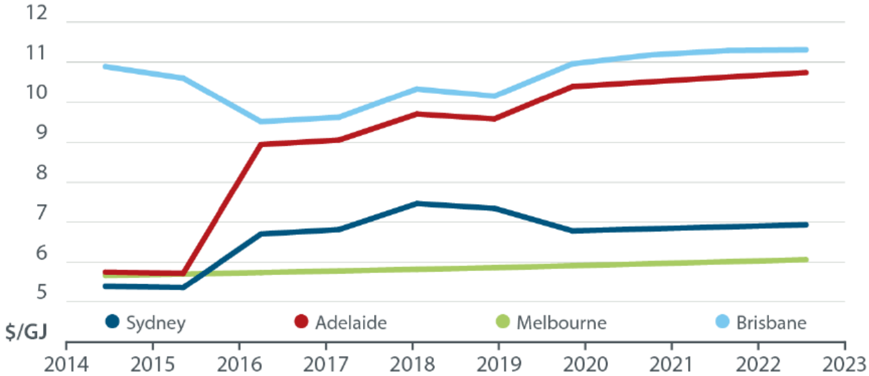


3.11.2. Study Findings

The study concludes that gas prices in Sydney would increase materially from 2015 to 2018 before falling in 2019 and 2020.

Eastern Australian Domestic Gas Market Study

Figure 6.2: Projected market gas prices, reference scenario, LNG netback run ($/GJ)



Source: IES (2013).

"Under all the scenarios modelled for this report, future gas prices remain high relative to historical levels due to higher production costs and linking to the LNG netback price."

3.11.3. Consistency with Core Forecast

IES forecasts indicate a substantial increase in prices but to a lower extent than forecast by Core. Further IES projects a fall in 2019 and 2020. In Core's opinion IES does not provide adequate evidence to support the forecast fall from 2018 to 2020.

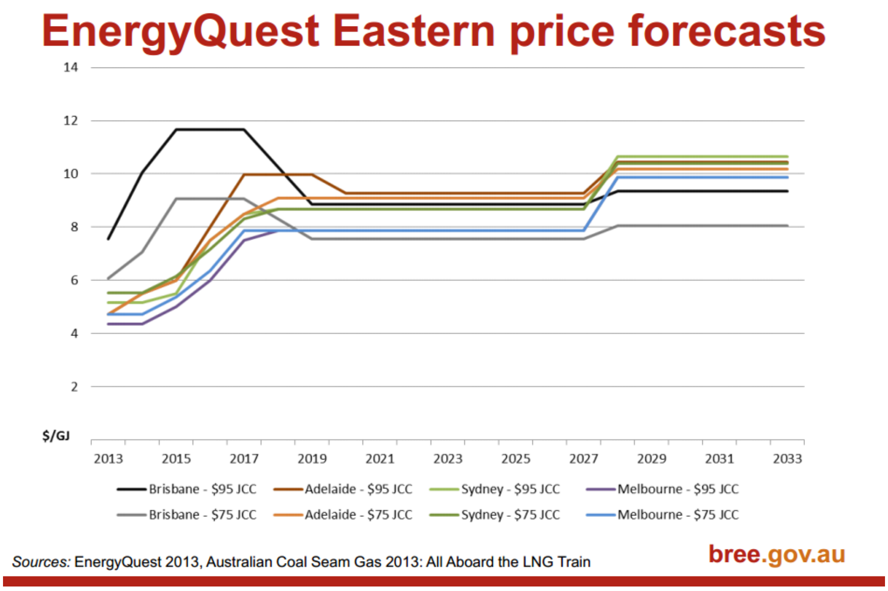
3.12. EnergyQuest

3.12.1. Study Description

A public presentation by BREE included a price projection developed by EnergyQuest in 2013.

3.12.2. Study Findings

EnergyQuest presents a profile of consistently increasing Sydney prices from 2014 to 2019, and trending flat thereafter to 2026 before increasing further.



3.12.3. Consistency with Core Forecast

The EnergyQuest forecast is broadly supportive of the Core forecast, noting that the outlook for JCC pricing is presently closer to $95 than $75 as referred to in the graph legend.

3.13. AGL/Brattle Group

3.13.1. Study Description

As part of AGL's Voluntary Price Agreement proposal, submitted to IPART, in February 2014, Brattle Group conducted analysis of forecast wholesale gas prices in NSW over the 2015 and 2016 periods.

3.13.2. Study Findings

AGL assumes an average of the Moomba and Longford price for its network, resulting in costs of **$7.12/GJ in 2015 rising to $8.12/GJ in 2016**. AGL's notes/assumptions are quoted below:

"In considering the benchmark gas commodity cost for NSW, AGL has noted the following:

- Moomba gas prices are already reflecting LNG netback prices,
- There is currently a shortage of gas for long term supply in the east coast such that Moomba prices are at risk exceeding long run netback prices,
- There is limited incremental gas supply from Longford due to pipeline constraints,
- Longford prices are expected to transition to LNG netback prices in the long run, and
- Beyond mid 2016, wholesale gas prices at Moomba and Longford will continue to remain high.

In preparing this pricing proposal for 2014 to 2016, AGL has adopted the market prices which Brattle has assessed for Moomba and Longford for the period to 30 June 2016, applying these prices to 2015/16."

3.13.3. Consistency with Core Forecast

While the AGL forecast of gas costs over the 2015 and 2016 period is higher than Core's projections, AGL's proposal is considered to be broadly supportive of the Core forecast.

Section 2 | 4. Forecast Retail Gas and Electricity Prices

The following paragraphs describe the approach adopted by Core to forecast future retail gas and electricity prices during the Review Period. This analysis is used to define both absolute movement in gas prices and relative movement in gas and electricity prices over the Review Period.

4.1. Increase in Wholesale and Retail Gas Prices

Core has conducted an independent analysis of the outlook for wholesale gas prices during the 2014 to 2020 timeframe. This analysis is summarised in Section 2 | 4 and the results are presented in Table 4.1 below.

Table 4.1. Summary - Wholesale Gas Cost Projections (Real AUD/GJ 2013).

Retail Price Component	2014	2015	2016	2017	2018	2019	2020
Wholesale Cost	4.00	5.00	5.00	6.00	8.00	8.00	8.00

Source: Core Energy Group.

Core has used the above projections of wholesale prices to derive projections of retail gas price as this is the price which is most relevant to Tariff V customers. The result of this analysis is presented in Table 4.2 below and a breakdown of key elements underlying the projections is presented in Table 4.3 and 4.4.

The Core analysis assumes that only two factors which are likely to impact future retail gas prices in a material way – the wholesale cost of gas and the cost of carbon.

Table 4.2. Summary – Retail Gas Price Changes (Real 2013; %).

Retail Price Component	2015	2016	2017	2018	2019	2020
Residential	7.06%	-6.56%	2.63%	5.12%	0.00%	0.00%
Non-Residential	8.38%	-7.34%	4.62%	8.84%	0.00%	0.00%

Source: Core Energy Group.

Table 4.3. Retail Gas Price Projections – Residential (Real 2013 AUD per GJ).

Retail Price Component	2014	2015	2016	2017	2018	2019	2020
Gas Production	4.00	5.00	5.00	6.00	8.00	8.00	8.00
MDQ	0.88	0.88	0.88	0.88	0.88	0.88	0.88
Transmission	1.90	1.90	1.90	1.90	1.90	1.90	1.90
Distribution Network	18.25	19.79	19.29	18.90	18.52	18.15	17.79
Carbon	1.72	1.76	0.88	0.88	0.88	0.88	0.88
Retail Margin	2.58	2.58	2.58	2.58	2.58	2.58	2.58
Market Charges	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Total Variable Cost (AUD per GJ)	**29.43**	**32.01**	**30.63**	**31.24**	**32.86**	**32.49**	**32.13**
Fixed Cost (Total AUD)	171.88	171.88	171.88	171.88	171.88	171.88	171.88
Customer Bill @ 20 GJ/year (Total AUD)	**760**	**812**	**784**	**797**	**829**	**822**	**814**
Change (%)	**6.91%**	**6.78%**	**-3.40%**	**1.57%**	**4.07%**	**-0.89%**	**-0.88%**

Source: Core Energy Group. All prices exclude GST.

Table 4.4. Retail Gas Price Projections – Non-Residential (2013 AUD per GJ).

Retail Price Component	2014	2015	2016	2017	2018	2019	2020
Gas Production	4.00	5.00	5.00	6.00	8.00	8.00	8.00
MDQ	0.88	0.88	0.88	0.88	0.88	0.88	0.88
Transmission	1.90	1.90	1.90	1.90	1.90	1.90	1.90
Distribution Network	8.47	9.19	8.95	8.77	8.60	8.43	8.26
Carbon	1.72	1.76	0.88	0.88	0.88	0.88	0.88
Retail Margin	3.98	3.98	3.98	3.98	3.98	3.98	3.98
Market Charges	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Total Variable Cost (AUD per GJ)	**21.05**	**22.81**	**21.69**	**22.51**	**24.34**	**24.17**	**24.00**
Fixed Cost (Total AUD)	197.72	197.72	197.72	197.72	197.72	197.72	197.72
Customer Bill @ 400 GJ/year (Total AUD)	**8,618**	**9,320**	**8,874**	**9,203**	**9,933**	**9,864**	**9,796**
Change (%)	**6.91%**	**8.15%**	**-4.78%**	**3.70%**	**7.93%**	**-0.69%**	**-0.68%**

Source: Core Energy Group. All prices exclude GST.

4.2. Increase in Retail Electricity Prices

Core has relied upon a combination of studies to develop a forecast of future retail electricity prices. Primary reliance has been placed on the Independent Pricing and Regulatory Tribunal's ("**IPART**") Review of Regulated Retail Prices for Electricity

4.2.1. IPART Review of Regulated Electricity Retail Prices for 2013-2016

In its determination of retail electricity prices in NSW, IPART published an estimate of indicative changes in regulated NSW retail electricity prices for the 2015 and 2016 financial years as shown in the table below.

Table 4.5. Indicative Changes in Regulated Retail Electricity Prices (Nominal).

Indicative Price Changes (%)	2015	2016
EnergyAustralia	1.80%	-6.60%
Origin (Endeavour Energy)	1.60%	-7.90%
Origin (Essential Energy)	1.80%	-6.20%
Weighted Average of JGN Region (EA 65%, Endeavour 35%) – Nominal	1.73%	-7.06%
Weighted Average – Real	**-0.77%**	**-9.56%**

Source: Core Energy Group with data from IPART's Review of Regulated Electricity Retail Prices for 2013-2016, p3. Core has assumed CPI of 2.5% to arrive at real price changes.

IPART stated:

"As the table shows, we expect regulated electricity prices to increase by less than inflation in 2014/15, and to fall in 2015/16. This expected fall in prices reflects the reduced costs of the carbon price as the mechanism moves from a fixed price to a market price linked to international carbon markets. The current cost of European carbon permits is significantly lower than the current fixed carbon price. Further, this cost has fallen since our draft report, resulting in a larger indicative price decrease in 2015/16 – we now expect prices to fall by around 6.9%, which is 1% more than our draft estimates. However, there is significant uncertainty in relation to the future costs of supply and we will update our indicative price change for 2015/16 in early 2014."

Core has relied upon IPART's indicative regulated retail electricity prices for the 2015 and 2016 financial years, shown in Table 4.5 above. These price changes were translated to real terms using an assumed CPI of 2.5%, and then weighted according to the estimated penetration of electricity retailers in the JGN region (assumed EnergyAustralia 65%, Endeavour Energy 35%) to arrive at a weighted average real price change as shown in Table 4.5 below.

Core has assumed no changes to retail electricity prices beyond 2016 in real terms.

4.2.2. Electricity Price Validation

Core has reviewed certain third party forecasts of NSW electricity prices as shown in Table 4.6. This analysis shows that third party forecasts are broadly consistent Core forecasts.

Table 4.6. Electricity Price Projections – Third Party Summary (Real Percentage Change).

Third Party	2014	2015	2016	2017	2018	2019	2020
Core NSW Price – Reference (based on IPART)	3.73%	-0.77%	-9.56%	0.00%	0.00%	0.00%	0.00%
AEMC – NSW[22]	Decrease of -0.7% nominally per year from FY13 to FY16, (i.e. a real fall of ~3.2% p.a. at an assumed 2.5% inflation).						
Simshauser, Nelson – NSW (Real 2012 AUD)[23]	Projection of $270/MWh in FY14 to $240/MWh in FY20, a real decrease of 11.2%.						

In addition to the table above, electricity distributors in NSW have submitted their 2014-15 Transitional Regulatory Proposal, containing their initial projections of changes to distribution network charges shown in Table 5.12. As network

[22] AEMC, 2013 Residential Electricity Price Trends, p iv.
[23] CEDA, Economic and Political Overview 2013, p46.

costs comprise approximately half of a typical residential electricity bill in NSW[24], these forecast declining charges support Core's projections of a lower electricity price over the regulatory period.

Table 4.7. NSW Electricity Distribution Network Charges Summary (Real Percentage Change from 2013-14).

Distributor	2015	2016	2017	2018	2019
Ausgrid	-2.13%	-0.40%	-0.07%	-1.43%	-1.22%
Endeavour Energy	-2.68%	-1.25%	-1.25%	-1.25%	-1.25%
Essential Energy	-0.01%	-0.01%	-0.01%	-0.01%	-0.01%

Source: Ausgrid, Essential Energy and Endeavour Energy Transitional Regulatory Proposal, all submitted to the AER on 31 January 2014.

4.3. Increase in Gas Prices Relative to Electricity Prices.

A comparison of Core's forecast of retail gas and retail electricity prices shows a price divergence of over 20 percent by 2020 from end of 2013 levels (in favour of electricity).

Table 4.8. Retail Gas and Electricity Price Projections (Real Percentage Change).

Change in Retail Bill	2014	2015	2016	2017	2018	2019	2020
Residential							
Gas	6.91%	6.78%	-3.40%	1.57%	4.07%	-0.89%	-0.88%
Electricity	3.73%	-0.77%	-9.56%	0.00%	0.00%	0.00%	0.00%
Differential	3.18%	7.55%	6.15%	1.57%	4.07%	-0.89%	-0.88%
Cumulative Differential	**3.18%**	**10.73%**	**16.88%**	**18.45%**	**22.52%**	**21.63%**	**20.74%**
Non-Residential							
Gas	6.91%	8.15%	-4.78%	3.70%	7.93%	-0.69%	-0.68%
Electricity	3.73%	-0.77%	-9.56%	0.00%	0.00%	0.00%	0.00%
Differential	3.18%	8.92%	4.77%	3.70%	7.93%	-0.69%	-0.68%
Cumulative Differential	**3.18%**	**12.10%**	**16.87%**	**20.57%**	**28.50%**	**27.81%**	**27.13%**

Source: Core Energy Group.

4.4. Supporting Information

4.4.1. Carbon Price

At the date of submission of this report there is a high degree of uncertainty regarding the future cost of carbon in Australia. This uncertainty relates to both the timing (FY2015 vs. 2016) and the magnitude of possible carbon price changes (internationally-linked prices vs. zero price).

Core notes that AGL's proposal submitted to IPART for its 2014 Voluntary Pricing Agreement ("**VPA**") assumed two possible carbon price paths, both of which deviate from current policy (zero carbon price as of 1 July 2015 and zero carbon price as of 1 July 2014).

Core has assumed a current carbon cost of $1.72 per GJ consistent with IPART in its 2013 review. Future price projections are consistent with current carbon policy, i.e. further increases in FY2015 followed by a move to

[24] IPART, Final Decision - Review of Regulated Retail Prices and Charges for Electricity, Figure 2.1, p18.

internationally-linked carbon prices in the 2016 financial year. Given the current contract prices for European carbon permits are substantially lower than current carbon prices in Australia, Core has assumed a 50% reduction in 2016 is reasonable to reflect the change in carbon price as shown in Table 4.9.

Table 4.9. Carbon Price Projections.

Retail Price Component	2014	2015	2016	2017	2018	2019	2020
Carbon Price	1.72	1.76	0.88	0.88	0.88	0.88	0.88

Source: Core Energy Group.

Core notes that these projections are consistent with current carbon policy and that any changes to Australian carbon prices would alter the outcome for gas prices shown above.

Section 2 | 5. Price Elasticity of Demand Analysis

5.1. Introduction

This Section of the Report describes the approach adopted by Core to derive a forecast of the impact that a projected material movement in NSW retail gas and electricity prices is likely to have on JGN gas demand.

5.2. Background

Based on the widely recognised principle of price elasticity of demand, Core has derived a forecast of the elasticity of JGN gas demand to a projected increase in gas prices in NSW, in conjunction with a forecast increase in the price of gas relative to a substitute energy source, electricity.

Core is of the opinion, supported by broad-based expert third party analysis, that NSW wholesale and retail gas prices, measured in real 2014 terms, will increase materially during the Review period (refer Section 2 | 4). Further, Core is of the opinion, supported by third party expert analysis, that NSW wholesale and retail electricity prices, measured in 2014 real terms, will fall materially during the Review period.

Core notes that it is well recognised, nationally and internationally, that a material movement in the price of a good or service, including gas and electricity, 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 one substitute 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).

For the above reasons, Core has derived a forecast of both own price and cross price elasticity of demand for gas in the JGN over the Review period.

5.3. Approach

Core has undertaken an assessment of the alternative approaches available to derive an estimate of the price elasticity of gas demand within the JGN, including broad-based 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 specific circumstances of this Review involve a likely price material movement in both gas and electricity prices in the future (from 2016). Therefore 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 rigorous assessment of future gas and electricity prices in NSW during the Review period. This is the approach adopted for this Review.

Core has undertaken an extensive review of historical GAAR'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).

5.4. Summary

The results of Core's analysis are summarised in Table 5.1 below.

Table 5.1. Price Elasticity of Demand Analysis Summary | %

	2014	2015	2016	2017	2018	2019	2020	CAGR
Residential								
Own Price	-2.4%	-2.4%	-0.9%	-0.6%	-0.8%	-0.3%	0.0%	-0.5%
Cross Price	0.4%	-0.1%	-1.0%	0.0%	0.0%	0.0%	0.0%	-0.2%
Total	**-2.0%**	**-2.5%**	**-1.9%**	**-0.5%**	**-0.8%**	**-0.3%**	**0.0%**	**-0.7%**
Small Business								
Own Price	-3.3%	-3.0%	-2.1%	-0.5%	-1.0%	-1.5%	-0.6%	-1.1%
Cross Price	0.4%	-0.1%	-1.0%	0.0%	0.0%	0.0%	0.0%	-0.2%
Total	**-3.0%**	**-3.1%**	**-3.1%**	**-0.5%**	**-1.0%**	**-1.5%**	**-0.6%**	**-1.3%**
I&C								
Own Price	-3.3%	-3.0%	-2.1%	-0.5%	-1.0%	-1.5%	-0.6%	-1.1%
Cross Price	0.4%	-0.1%	-1.0%	0.0%	0.0%	0.0%	0.0%	-0.2%
Total	**-3.0%**	**-3.1%**	**-3.1%**	**-0.2%**	**-1.0%**	**-1.5%**	**-0.6%**	**-1.3%**

Source: Core Energy Group.

5.5. Derivation of Forecast

Core initially used historical actual data sourced from Jemena and gas/electricity price data from IPART to determine whether a reasonable estimate of own price and cross price elasticity could be determined.

The equation applied is as follows:

Log (JGN Demand per connection) = a_0 + B_1*log(Real Gas Price) + B_2*log(Real Electricity Price)+ B_3*Trend

Where:

- JGN demand per connection refers to total Tariff V demand per connection;
- Real Gas Price and Real Electricity Price refer to NSW gas and electricity prices from IPART's website adjusted for real prices;
- A_0 is the constant term;
- B_1 is the own price elasticity coefficient;
- B_2 is the cross price elasticity coefficient.

As there were relatively few data points available to perform this regression, Core did not consider the results to be sufficiently accurate to use as the demand response to price changes.

Nevertheless Core presents the results of its analysis in Table 5.2 below, using 11 years of Jemena/IPART data. Core performed a number of regressions separately, first using Real Prices in the same year as demand, then one year prior and two years prior to determine if any lagged price impacts would provide stronger relationships.

Table 5.2. Price Elasticity Results Using Actual Jemena/IPART Data.

Gas/Electricity Prices	Own Price Elasticity Estimate	Cross Price Elasticity Estimate	R^2 of Model	Own Price T-Statistic	Cross Price T-Statistic
Same year	0.05	0.03	84.75%	0.33	0.50
One year prior	**-0.25**	**0.11**	**85.61%**	**-1.60**	**1.74**
Two years prior	-0.33	0.07	80.61%	-1.56	0.87

Source: Core Energy Group.

While the low t-statistic values across each result indicate the information available is not adequate to accurately identify price elasticity, it is at interesting to note these estimates are consistent with the price elasticity values used by Core in Sections 5.5.2 and 5.5.3.

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 GAAR's.

Core's is of the opinion that the listing of own-price and cross-price elasticity factors which is summarised in Tables 5.3 and 5.4 provide a reasonable basis for deriving an estimate of the price elasticity of demand for gas in the JGN.

Table 5.3. 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 5.4. 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 classes)	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.

5.5.2. Own Price Elasticity

Core's 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 represents the best estimate possible in the circumstances.[25]."

Given the price elasticity factors used for Envestra's SA network, Core has used reference values of -0.30 (residential) and -0.35 (non-residential) as long-run elasticity factors in its final demand forecast model as shown in Table 5.5.

Table 5.5. 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 short-run elasticity factors which are applied as shown in Table 5.6 below. Demand impacts are highest in the year of the price change (for residential) and the year after the price change (non-residential).

Table 5.6. Short-Run Price Elasticity Factors.

Elasticity	Residential	Non-Residential
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 in Table 5.7 to arrive at the own price elasticity impact in each year, for each tariff class, as summarised below.

[25] AER; Final Decision, Envestra Limited Access Arrangement Proposal For The SA Gas Network 1 July 2011 – 30 June 2016, June 2011, p103.

Table 5.7. Own Price Elasticity Impact on Demand.

Own Price Elasticity Impact on Demand (%)	2014	2015	2016	2017	2018	2019	2020	CAGR (as per Table 1.24)
Residential								
Change in Gas Prices	6.9%	6.8%	-3.4%	1.6%	4.1%	-0.9%	-0.9%	2.1%
Price Elasticity Impact (-0.30)	-2.4%	-2.4%	-0.9%	-0.6%	-0.8%	-0.3%	0.0%	-0.5%
Non-Residential (Small Business and I&C)								
Change in Gas Prices	6.9%	8.1%	-4.8%	3.7%	7.9%	-0.7%	-0.7%	2.9%
Price Elasticity Impact (-0.35)	-3.3%	-3.0%	-2.1%	-0.5%	-1.0%	-1.5%	-0.6%	-0.5%

Source: Core Energy Group.

5.5.3. Cross Price Elasticity

Core acknowledges that cross price elasticity has not been addressed widely in prior access arrangement reviews. Core believes that this is attributed to the relative prices of gas and electricity historically 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 upon Core's analysis, which is set out in further detail in Section 2 | 4, the forecast price movement between gas and electricity prices (from current levels) is expected to exceed 20% for Residential customers and 27% for Non-Residential customers by 2020 (from end 2013 levels), in favour of electricity, as shown in Table 5.8.

Table 5.8. Retail Gas and Electricity Price Projections (Real Percentage Change).

Change in Retail Bill	2014	2015	2016	2017	2018	2019	2020
Residential							
Gas	6.91%	6.78%	-3.40%	1.57%	4.07%	-0.89%	-0.88%
Electricity	3.73%	-0.77%	-9.56%	0.00%	0.00%	0.00%	0.00%
Differential	3.18%	7.55%	6.15%	1.57%	4.07%	-0.89%	-0.88%
Cumulative Differential	**3.18%**	**10.73%**	**16.88%**	**18.45%**	**22.52%**	**21.63%**	**20.74%**
Non-Residential							
Gas	6.91%	8.15%	-4.78%	3.70%	7.93%	-0.69%	-0.68%
Electricity	3.73%	-0.77%	-9.56%	0.00%	0.00%	0.00%	0.00%
Differential	3.18%	8.92%	4.77%	3.70%	7.93%	-0.69%	-0.68%
Cumulative Differential	**3.18%**	**12.10%**	**16.87%**	**20.57%**	**28.50%**	**27.81%**	**27.13%**

Source: Core Energy Group.

By way of support of Core's analysis, it is noted that the recent submissions of NSW gas retailers' Voluntary Pricing Agreements to IPART (as part of its 2014 Review of Regulated Gas Prices) propose a substantial increase in retail gas prices over the 2015 and 2016 period. A comparison of AGL's proposed gas price increases and IPART's 2013 estimates of retail electricity prices, indicates a real price movement of over 30% by 2016 as summarised in Table 5.9 below. This is generally supportive of Core's estimate.

Table 5.9. Price Differential Using AGL Price Proposal for IPART 2014.

Change in Retail Prices	2014	2015	2016
Gas (AGL, for IPART 2014)	6.91%	17.70%	2.70%
Electricity (IPART 2013)	3.73%	-0.77%	-9.56%
Differential	3.18%	18.47%	12.26%
Cumulative Differential	**3.18%**	**21.65%**	**33.91%**

Source: IPART – Updating Regulated Gas Prices for 1 July 2014, IPART Review of Regulated Electricity Prices 2013-2016.

Based on Core's analysis, an assumed long run elasticity of 0.10 for both residential and non-residential customers is deemed reasonable as shown in Table 5.10 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 tariff class as summarised below.

Table 5.10. Cross Price Elasticity Impact on Demand.

Cross Price Elasticity Impact on Demand (%)	2014	2015	2016	2017	2018	2019	2020	CAGR)
Residential								
Change in Electricity Prices	3.7%	-0.8%	-9.6%	0.0%	0.0%	0.0%	0.0%	
Price Elasticity Impact (-0.10)	0.4%	-0.1%	-1.0%	0.0%	0.0%	0.0%	0.0%	-0.2%
Non-Residential (Small Business and I&C)								
Change in Electricity Prices	3.7%	-0.8%	-9.6%	0.0%	0.0%	0.0%	0.0%	
Price Elasticity Impact (-0.10)	0.4%	-0.1%	-1.0%	0.0%	0.0%	0.0%	0.0%	-0.2%

Source: Core Energy Group.

Section 2 | 6. NSW Manufacturing Gas Demand Forecast

6.1. Introduction

The objective of this Section of the Report is to provide a concise overview of the outlook for the NSW Manufacturing sector as an input to the derivation of forecast CD for the JGN Tariff D customer group.

6.2. Manufacturing Sector Gas Usage

The Manufacturing sector accounted for 221,190 GJ (or 72%) of gas demand on a CD basis in 2013, made up as follows:

Table 6.1. 2013 Manufacturing CD by Sub-sector.

Tariff D Manufacturing	2013 CD (GJ)
Chemicals	54,803
Construction	51,428
Food	29,170
Metals	36,400
Minerals	287
Other	10,814
Packaging	14,869
Pharmaceuticals	535
Printing	1,793
Refining	19,390
Textiles	1,701
Total	**221,190**

Source: Core Energy Group, based on Jemena data.

By 2020 CD is expected to fall by 51,688 GJ to 169,502 GJ, comprising:

- Known movements (-28,864) – refer Table x below, as advised by Jemena.
- Additional movement forecast by Core (-22,824) representing a CAGR of -1.7%

Table 6.2. Manufacturing Known Movements.

Tariff D Manufacturing	Net Movement – Known/ Base
Chemicals	48
Construction	- 3,000
Food	- 344
Health	98
Metals	- 4,839
Other	- 1,628
Packaging	91
Refining	- 18,766
Textiles	- 524
Total	**- 28,864**

Source: Core Energy Group.

The following factors have been considered by Core in arriving at these forecasts:

6.3. Core Forecast of Manufacturing Demand

The Core forecast of an 2.8 % fall in Tariff D CD demand (known plus forecast reductions) is due primarily to a forecast reduction in demand from the NSW manufacturing sector

The derivation of the Core forecast is based on the factors summarised in the following table:

Table 6.3. Influences on Manufacturing Gas Use.

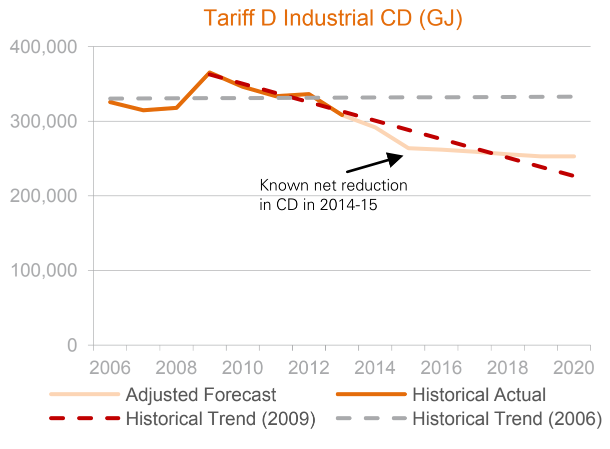
Manufacturing Gas Use Factors	Influence on Forecast
Historical Trend/ Long Term Outlook for NSW Manufacturing	An expectation that a long term trend in falling CD demand will continue during the Review Period given a relatively weak outlook for the sector.
Trends in Energy Efficiency	Recent trends in energy efficiency by the industrial sector and continued pressures in the sector indicate that further efficiency measures are likely.
Gas Price Trend	The material upward trend in gas prices is expected to have a material adverse impact on Tariff D gas consumption.

Source: Core Energy Group.

6.3.2. Historical Trend and Manufacturing Outlook

The following Figure illustrates the extrapolated Historical Trend in CD demand for the post GFC period relative to the Core forecast. This Historical trend equates to a reduction of over 4% p.a. on a CAGR basis. Excluding known reductions, the Core forecast equates to a fall of 1.7% p.a.

Figure 6.1 Tariff D Industrial CD – Extrapolated Trend from 2006 vs. Core Forecast.



Source: Core Energy Group.

The Core forecast is based on an assumed long term reduction in manufacturing activity as it relates to CD demand.

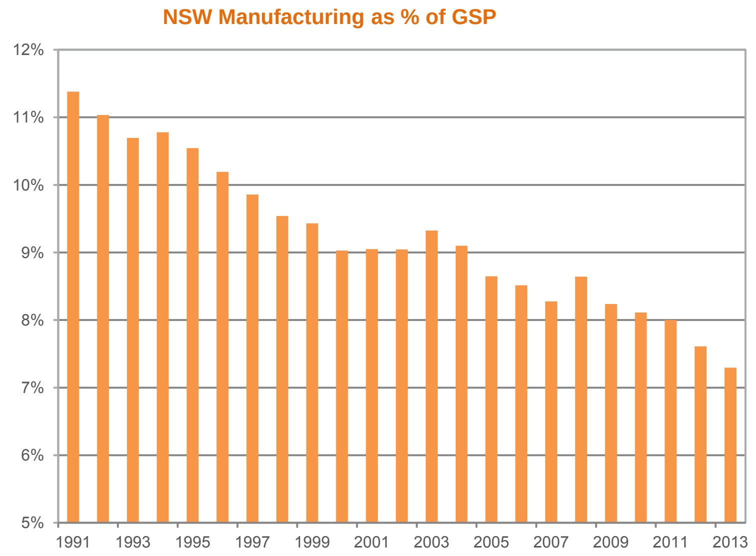
Trends in manufacturing output, employment and capital expenditure provide clear evidence of the historical trend.

6.3.2.2. Declining Manufacturing Output

NSW Manufacturing output as a proportion of NSW GSP has declined from over 11% in the early 1990s to roughly 7.5% in 2013 (a reduction of 1.9%pa on a CAGR basis) as illustrated by Figure 6.1 below.

Analysis by Core Energy and third party analysts indicates that this trend is likely to continue during the 2016-2020 period.

Figure 6.2 Manufacturing Sub-Sector Movement (% of GSP).

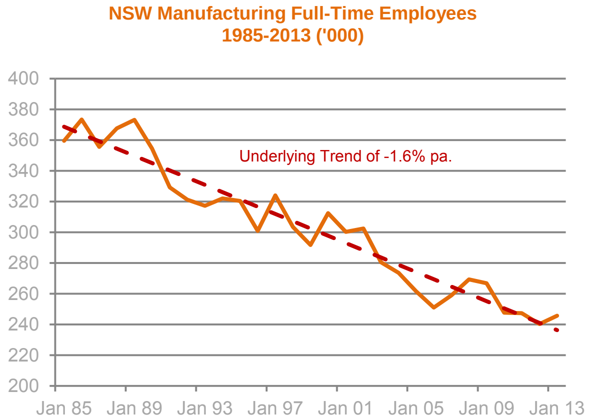


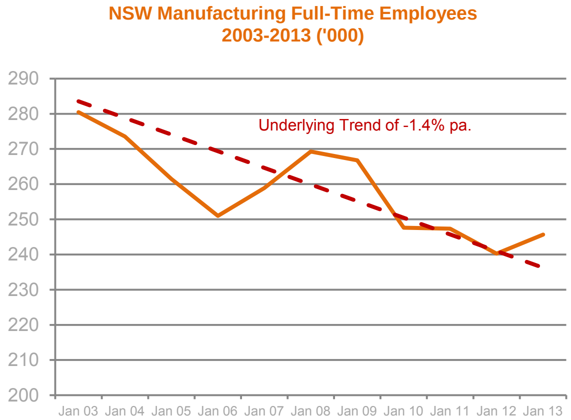
Source: Core Energy Group with data from ABS: 5220.0 - Australian National Accounts: State Accounts, 2012-13.

6.3.2.3. Declining Manufacturing Employment

ABS employment data shows that full-time employment in the NSW manufacturing industry has declined at a rate of 1.4% to 1.6% pa, evident in both recent and long-term trends.

Figure 6.3 NSW Manufacturing Full-Time Employees.

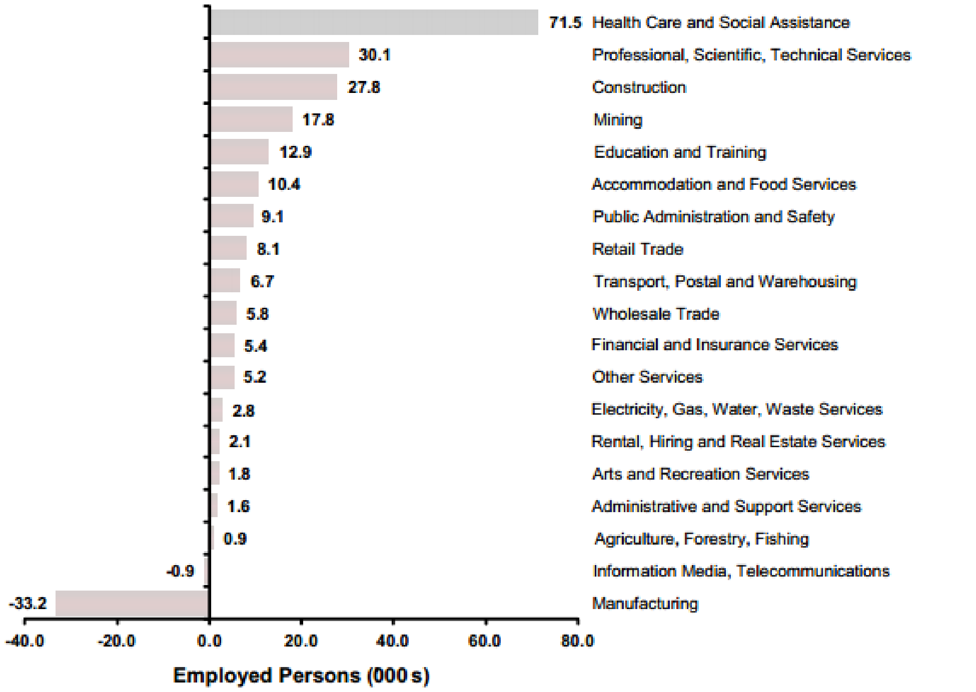




Source: Core Energy Group with data from 6291.0.55.003 - Labour Force, Australia, Detailed, Quarterly, Nov 2013.

This trend is expected to continue during the Review Period. It is noteworthy that Department of Education, Employment and Workplace Relations ("**DEEWR**") forecasts over 33,000 job losses in NSW manufacturing over the five years to FY2017 as illustrated in Figure 6.3.

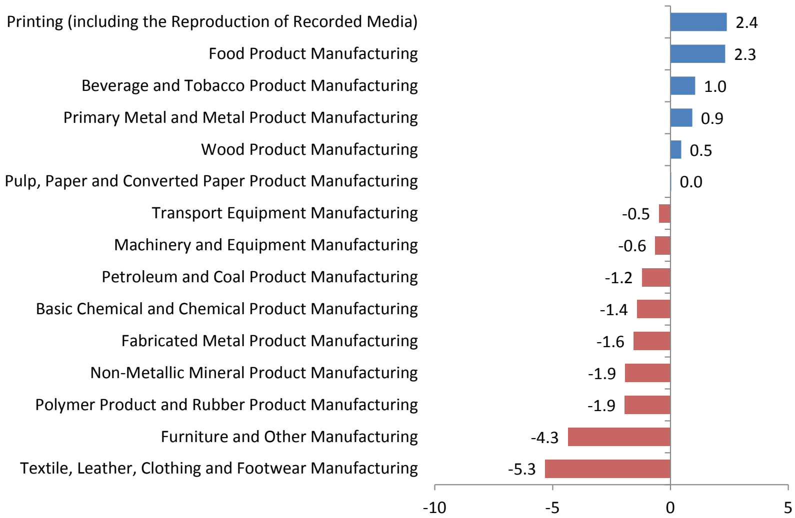
Figure 6.4 Expected Employment Growth by Industry, NSW, 2011/12 to 2016/17.



Source: Department of Education, Employment and Workplace Relations, The Industry Employment Projections - 2012 Report

On a national level, falls in manufacturing employment are expected to be led by textiles, minerals and petroleum-related manufacturing, as illustrated in Figure 6.4 below. These are industries which generally perform gas-intensive processes.

Figure 6.5 Projected Employment Growth ('000s) by Manufacturing Sector – Five Years to Nov-17.

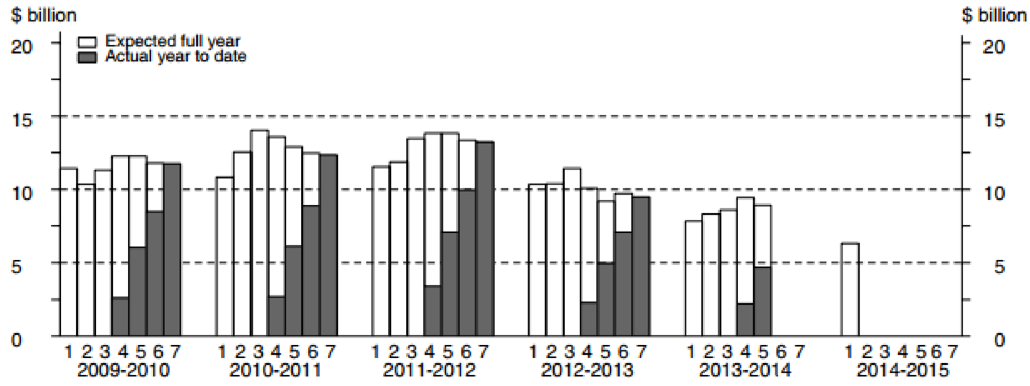


Source: Australian Department of Employment, Industry Employment Outlook for Manufacturing, p10.

6.3.2.4. Declining New Manufacturing Capital Expenditure

The most recent ABS release of Private New Capital Expenditure and Expected Expenditure shows an initial estimate of FY2015 manufacturing capital expenditure that is 20% lower than its corresponding estimate of 2014 capital expenditure at the same time last year.

Figure 6.6 ABS Private New Capital Expenditure and Expected Expenditure - Manufacturing.



Source: 5625.0 - Private New Capital Expenditure and Expected Expenditure, Australia, Dec 2013.

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1.1 Attachment 1: Terms of Reference

CORE ENERGY GROUP

1.1 Terms of Reference

- Core was engaged by Jemena to provide the following service:
- Develop independent forecasts of energy demand and customer number forecasts for Jemena's NSW gas network for the 2014 to 2020 financial year periods, for each of the following:
  - Tariff V – forecast connections and demand per connection
- Residential
- Small Business
- I&C
  - Tariff D – forecast CD;
- Provide a report in a form which is suitable for submission to the AER which describes, in a suitably transparent fashion, Core's methodology and all significant assumptions and analysis used to derive Core's projections.
- Provide an Excel-based spreadsheet model which clearly sets out the relationship between assumptions/ input and the logic applied to derive all projections, in a suitably transparent manner.
- All deliverables to comply with the National Gas Rules issued by AEMC.

2.1 Attachment 2 | Credentials

CORE ENERGY GROUP

2.1 About Core Energy Group

Core is a private, boutique advisory firm established ten years ago by Chief Executive Officer (“CEO”), Paul Taliangis. Core specialises in providing advisory services to the energy industry, with a particular focus on the Australian gas, electricity and LNG sectors.

Of specific relevance to this Report is Core’s extensive experience in assisting listed companies, private organisations and Government agencies in the area of energy demand forecasting, including extensive modeling of demand scenarios.

3.1 Core Team Leader

Work on this project has been directed by Mr. Paul Taliangis with support from Core team members.

Paul is CEO and founder of Core Energy Group. Paul has formal economics, commerce and accounting qualifications and attended an extensive range of international executive development courses including at the Chicago Business School.

Paul’s 30 years of experience, including almost 20 in the energy industry, has extended across Asia, New Zealand, Papua New Guinea, the United Kingdom and the United States of America. His areas of specialisation include strategic analysis, corporate advice, mergers and acquisitions, corporate finance and equity capital markets. During this time Paul has led a long list of projects and transactions on behalf of smaller organisations through to large multinational corporations, involving all critical elements of the energy value chain - LNG, conventional and unconventional gas, oil / liquids, gas transmission and distribution, coal, energy services, electricity, renewable energy and retail.

Paul’s experience in the gas sector has included an eight year period with Santos in Australia and USA as an executive in Corporate Development and Corporate Planning and over ten years as an independent adviser.

Paul's advisory experience includes complex market and industry analysis, including demand, supply, cost and price projections/ forecasting.

4.1 Relevant Work Experience

Specific experience and capabilities relating to this project include:

- Gas and energy market studies:
  - 2033 Energy Outlook Study (eastern Australia gas, electricity and LNG) 2013;
  - 2025 Energy Outlook Study (eastern Australia gas, electricity and LNG) 2011/12;
  - 2025 Unconventional Gas Outlook Study – The Next Wave? (2010);
  - 2020 East Coast Gas and Electricity Outlook Study (2010, 2009);
  - Asian LNG Outlook Study (2009);
- Advisory and consultancy services:
  - AEMO GSOO Distributed Gas Forecasts (2010, 2009);
  - AEMO GSOO Gas reserves, production outlook, other (2012, 2013);
  - Strategic adviser to AGL;
  - Advisor on Envestra defense against APA takeover approach;

    - Advisor on a range of asset divestitures involving gas assets, pipelines for a range of leading energy companies.
    - Advisor to a range of organisations in relation to acquisitions involving gas interests including AGL, Santos, Toyota Tsusho, Envestra;
    - Review of pipeline capacity utilisation and scope for expansion for a major gas transmission company;
    - Gas market advisory work for a South Australian Government department - DMITRE;
    - Strategic consulting projects with over 20 other companies on a confidential basis involving gas demand, supply, pricing, competition and market analysis.
- Expert reports:
    - Independent expert advice to a range of parties in relation to major gas contract negotiations which involved analysis of east coast demand, contracts, transportation tariffs and other related matters;
    - Expert advisor to major energy retailer in relation to takeover attempt by an international company;
    - Independent expert report for major infrastructure company with a particular focus on the outlook for their coal seam gas assets;
- Modeling and valuation services:
    - Valuation of APA for defense purposes;
    - Valuation of Country Energy NSW gas network;
    - Development of financial forecasting model for Envestra;
    - Valuation of wide range of energy companies for leading Australian fund managers, including APA, Envestra, Spark, SP Ausnet, DUET, Woodside, Santos, Origin, AGL;
    - Modeling gas transmission system capacity utilisation for major pipeline owner;
    - Demand modeling for gas, wind, electricity sectors;

3.1 Attachment 3 | Customer Survey Template

Survey Response – Tariff D 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	Chargeable Demand (GJ)	% Change on Previous yr
30 June 2010		
30 June 2011		
30 June 2012		
30 June 2013		
2010 to 2013 (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 percentage change compared to prior year
30 June 2014	
30 June 2015	
30 June 2016	
30 June 2017	
30 June 2018	
30 June 2019	
30 June 2020	

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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