Review of Demand Forecasts for Envestra Albury

Victorian Gas Access Arrangement Review for the period 2013 – 2017

Prepared for the Australian Energy Regulator

Final Report – August 2012

ACIL Tasman

Economics Policy Strategy

Reliance and Disclaimer

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Contents

List of figures

List of tables

1 Introduction

1.1 Background

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

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

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

1.2 Scope and approach

The AER has engaged ACIL Tasman to provide independent advice through written reports on the demand forecasts contained in the access arrangement proposals submitted by the Victorian transmission and distribution businesses to assist it in its decision about whether to approve the access arrangement proposals.[1]

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

1.2.1 Requirements of the Terms of Reference

The Terms of Reference for the review of demand forecasts are set out in Appendix B. In summary, the Terms of Reference require ACIL Taman to provide advice on whether the demand forecasts for each business have been arrived at on a reasonable basis and represent the best forecasts for demand in the circumstances.

More specifically, the Terms of Reference require ACIL Tasman to:

1. undertake a desktop review of the demand forecasts
2. formulate questions on areas where further information or clarification is required

[1] Envestra Victoria, Envestra Albury, Multinet, SP AusNet and APA GasNet.

3. analyse all material provided and prepare separate reports for each service provider, including recommendations on whether the demand forecasts have been arrived at on a reasonable basis and represent the best forecasts for demand in the circumstances.
4. provide alternative forecasts if necessary (that is, if the review of the forecasts submitted by the service provider finds that they have not been arrived at on a reasonable basis and do not represent the best forecasts for demand in the circumstances).

1.2.2 Approach to the review

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

- Demand forecasts may impact the forecast capital expenditure required to meet the new demand of prospective users or the increased demand of existing users and may therefore influence forecast revenue.
- Demand forecasts influence the tariffs set to meet forecast revenue in each year of the access arrangement period, and how this revenue is to be allocated between tariff classes for different reference services.

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

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

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

1.2.3 Data sources

In preparing this review, ACIL Tasman has relied on the following data sources:

- The National Gas Rules
- The Access Arrangement Information submitted by Envestra (Envestra, 2012c)

- The demand forecast prepared by Core Energy Group (Core, 2012)
- Requests for additional information to Envestra Albury
- Various specialist reports as detailed in the Bibliography

1.2.4 Structure of the report

This remainder of this report is structured as follows:

Chapter 2 sets out the key findings of the report. To the extent that the review takes issue with particular elements of the forecast, it described the nature of those concerns and recommends action to be taken to address those concerns.

Chapter 3 described the scope of the Envestra Albury operations.

Chapter 4 describes the forecast methodology and assumptions.

In Chapter 5 we consider whether the application of the methodologies and assumptions described in Chapter 4 has produced forecast results for the Envestra Albury network that are reasonable in light of historical patterns of demand as well as current and anticipated influences on retail gas demand in the distribution area. We consider separately the forecasts for the Volume and Demand sectors of the market.

Finally, in Chapter 6, we set out our conclusions regarding the acceptability of the forecasts, and the actions that the AER should require to address identified deficiencies in the forecasts as submitted.

2 Key Findings and Recommendations

2.1 Core Energy Group forecast

In preparing the demand forecasts for the Envestra Albury network, Core has used a forecasting approach that basically assumes that the combined effect of the individual drivers of demand is largely represented in the linear trend of weather adjusted historic data, and that it is not necessary (or practical) to separately estimate each of the individual demand drivers given the limitations of the available data.

The analysis prepared by Core on behalf of Envestra assumes that three factors will drive increases in gas prices during the regulatory period: carbon price; other influences on the wholesale gas market; and network prices. The analysis accounts for the impact of the carbon price on retail gas prices (reweighted for non-residential customers) based on Commonwealth Treasury modelling of the carbon trading scheme. In our view this is reasonable.

We agree with Envestra that the price of gas is likely to increase noticeably over the regulatory period and that this is an important factor to take into account in forecasting gas demand. The analysis also takes into account anticipated increases in wholesale gas prices based on the same Australian Treasury modelling from which it drew the impact of the carbon price. In our view the assumed increases in wholesale gas price are reasonable and may be conservative in the light of growing demand for gas in the power generation sector and the potential impact of liquefied natural gas (LNG) exports on domestic gas prices in the eastern Australian market.

Core has adjusted the Envestra Albury demand forecasts to take into account the anticipated effects of the 6-star building standard for new homes in Victoria. This is a new policy the effects of which could not be expected to be reflected in the historical data on gas demand. Drawing on a Regulatory Impact Statement (RIS) prepared by the Centre for International Economics (CIE) for the Council of Australian Governments, Core has estimated that the average impact of the 6-star energy efficiency requirement across all new residential connections on the Envestra Albury network will be a reduction in demand of approximately 5.3 GJ/a per connection. We consider this assumption to be reasonable.

We accept that it is appropriate to take into account the whole of the (anticipated) network price increase in determining the expected future delivered price of gas to customers on the Envestra Albury network.

The analysis has assumed a value of -0.30 for the own-price elasticity of demand for gas, consistent with the AER's recent decision regarding access arrangement in South Australia. This is broadly supported by analysis undertaken by Core which found an estimated price elasticity of about -0.27 for all customer classes on the Envestra Albury network, and is generally consistent with the estimates used the other distribution businesses.

Envestra and its consultant Core do not appear to have considered the impact that higher electricity prices will have on gas demand (assumed a cross-price elasticity of zero). We consider that Envestra's reliance on own-price elasticity estimates alone is not unreasonable. In its report to SP AusNet, CIE concluded that the price of electricity should not be included in its models of gas demand (CIE, 2012). This is further discussed in section 4.5.2.

Normalisation of historical weather data has been carried out using a conventional approach based on Heating Degree Day (HDD) trends and weather sensitivities estimated, for each class of customer, using regression analysis. In considering the approach to weather normalisation of historical data, the key issue arising is the assumption regarding "normal" weather between 2005 and the present. The Envestra forecasts are based on an HDD trend that is sensitive to the input period. Those projections were based on all data available when they were prepared. However, since then, another year of data has become available. If that year is included in the projection, the outlook is for significantly cooler 'normal' weather conditions and consequently higher demand for gas.

We consider that it would be more appropriate for Envestra to include the 2011 data in its weather normalisation process. We estimate that, based on HDD data from 1994 (earliest available) to 2011, this change would increase total forecast demand levels in the Envestra Albury system by between approximately 0.5 and 1.0 per cent per annum. This is further discussed in section 4.4.

There are a number of methodological issues with the forecasting approach used by Core to develop the Envestra demand forecasts (see section 4.2.3). These issues have the potential to introduce bias and distortions to the modelling results. Core has acknowledged that, ideally, the forecasting model would be more comprehensive and rigorous, containing "a variable for every factor significantly influencing gas demand". However it has opted to use a simpler approach on the basis that the limited data available does not support a more comprehensive econometric analysis.

Notwithstanding the methodological issues identified, we have concluded that a more rigorous approach would not necessarily produce a more reliable forecast. This is because of the limitations of available data and the difficulties involved in reliably estimating the coefficients associated with each of the variables in a fully specified demand function.

Accordingly, while recommending that consideration be given in future to the methodological issues identified, we consider that in the circumstances the approach used by Core to develop the Envestra Albury demand forecasts is acceptable.

2.2 Assessment of the forecasts

We have reviewed the forecasts themselves, to consider whether the application of the methodologies and assumptions used by Core have produced forecast results for the Envestra Albury network that are reasonable in light of historical patterns of demand as well as current and anticipated influences on retail gas demand in the distribution area.

Based on a comparison with historical trends and statistical confidence intervals around those trends, together with consideration of recent policy and market developments, we find that the forecasts of customer numbers, average demand per customer and total demand by customer class are not unreasonable, with the proviso that the AER should require Envestra to modify the forecasts by including the 2011 HDD data in its weather normalisation process.

3 Scope of Albury operations

The Envestra Albury gas distribution network (the network) serves the City of Albury and its environs, extending to Jindera, north of Albury.

The network comprises approximately 368 km of pipeline and supplies around 20,000 customers. The Envestra Albury distribution business comprises around 1% of Envestra's annual earnings.

The network, which was constructed over a period of more than 100 years, has been substantially upgraded. It comprises mostly polyethylene pipe, with the remainder constructed from protected steel (Envestra, 2012c).

3.1 Historical gas demand

The historical customer numbers for the Envestra Albury distribution network are shown in Table 1.

Table 1 **Envestra Albury gas networks—historical customer numbers, by class**

Calendar Year	2008	2009	2010	2011	2012
Residential	17,493	17,865	18,212	19,118	19,430
Commercial	892	890	883	890	883
Volume customer total	**18,385**	**18,755**	**19,095**	**20,008**	**20,313**
Industrial	9	9	9	9	8
Total customers	**18,394**	**18,764**	**19,104**	**20,017**	**20,321**

Data source: *(Envestra, 2012c)*

Historical gas demand, by customer class, is summarised in Table 2.

Table 2 **Envestra Albury gas networks—historical customer demand (TJ), by class**

Year ended 30 June	2008	2009	2010	2011	2012
Residential	793	837	831	842	853
Commercial	255	254	254	254	254
Volume Customer Total	**1,048**	**1,091**	**1,085**	**1,096**	**1,107**
Industrial	231	217	231	230	229
Total usage	**1,279**	**1,308**	**1,317**	**1,326**	**1,336**

Data source: *(Envestra, 2012c)*

4 Forecast methodology and assumptions

The demand forecasts contained in the Envestra Albury Access Arrangement Information document (Envestra, 2012c) are based on the forecasts developed by Core Energy Group (Core) the results of which are detailed in Attachment 13.4 of the access arrangement submission (Core, 2012). The forecasts cover a period from 1 January 2013 to 31 December 2017 and are based on a combination of assumptions and econometric regression models.

4.1 Scope of the demand modelling study

The scope of the demand study undertaken by Core for Envestra is detailed in Appendix 1 of the Core report (Core, 2012). The key points in the Terms of Reference for the study are:

- To provide forecasts over the 2013-2017 period for
  - Customer numbers
  - Energy
  - Demand
  - Average use per customer

- The forecast needs to be specific to
  - Tariff Zones
  - Tariff Class (Residential, Non-Residential and Large Industrial)
- The forecast also needs to satisfy the overarching criteria set out in the National Gas Rules, namely.-

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.

- Criteria earlier expressed by the AER in previous forecasting decisions:
  - be accurate and unbiased
  - transparent and repeatable
  - incorporate key drivers
  - address model validation and testing
  - be accurate and consistent at all forecast levels
  - use the most recent input information
  - clearly state assumptions and have backing for these
  - account for weather normalization
  - adjust for temporary transfers
  - adjust for discrete block loads.

The scope of the consultancy brief also includes a list of candidate inputs which may be used in generating the forecasts, including:

1. Gross State Product (GSP)
1. Inflation
2. Disposable income
3. housing approvals
4. population growth
5. alternative energy uptake
6. appliance uptake
7. price elasticity
8. policy changes
9. weather projections
10. household composition.

The Terms of Reference note that all inputs should be properly referenced to independent sources.

4.1.1 Modelling approach

The approach taken to development of the demand forecasts can be summarized as follows:

- Base Forecast – developed by Core using trend analysis of weather normalized historical data
- Minus adjustment for impact of 6-Star Building Standard Policy (residential demand only)
- Minus adjustment for impact of carbon price
- Minus adjustment for impact of changes in wholesale gas price
- Minus adjustment for (anticipated) network price increase.

4.2 Econometric modelling

In this section we review the data sources used by Core in developing the Envestra demand forecasts, as well as its econometric and forecasting approach. The section concludes with a detailed discussion of the issues that ACIL Tasman has identified with the demand forecast prepared by Core for Envestra.

4.2.1 Data sources

Table 3, Table 4 and Table 5 summarise the sources of data used by Core in developing the demand forecasts for Tariff V Residential, Tariff V Non-residential (commercial and small industrial) and Tariff D (large industrial) customers respectively.

Table 3 **Data Sources – Tariff V, Residential**

Parameter	Source
Historic – gas demand by region	Envestra
Historic – connections by region	Envestra
Historic – connections by age of connection	Envestra
Historic – GHDI - VIC	ABS 5220.0 Table 13 Series ID A2335042J
Forecast – households	ABS 32360DO001_20062031 Household and Family Projections, Australia, 2006 to 2031; August 2010
Historic – new dwelling starts	Housing Industry Association (HIA)
Normalised – Effective Degree Days ("HDD")	CSIRO
Historic – Actual HDD	AEMO
Historic – Albury Temperature	Bureau of Meteorology ("BOM"); 072160 - Albury Airport Weather Station
Forecast – GHDI	SACES
Forecast – new dwelling starts	HIA
Forecast – households	ABS 32360DO001_20062031 Household and Family Projections, Australia, 2006 to 2031; August 2010
Forecast – effect of 6-Star Building Standard	CIE; Final Regulation Impact Statement for residential buildings (class 1, 2, 4 and 10 buildings), Table 6.2 p.80 ; December 2009
Forecast – new connections Murray Valley and Bairnsdale	Envestra
Own price elasticity of gas demand	AER; Final Decision Envestra Limited Access Arrangement Proposal For The SA Gas Network 1 July 2011 – 30 June 2016
Retail gas price components	Core Energy Group
Forecast – carbon price impact on retail gas prices	Australian Treasury Strong Growth, Low Pollution - Modelling; July 2011; Table 5.19: Effects on weekly expenditure and the consumer price
Forecast – network price	Envestra
Forecast – wholesale gas prices	Australian Treasury Strong Growth, Low Pollution - Modelling a Carbon Price; July 2011; Chart B6: Domestic Australian gas prices

Source: (Envestra, 2012)

Table 4 **Data Sources – Tariff V, Non-Residential**

Parameter	Source
Historic - gas demand by region	Envestra
Historic - connections by region	Envestra
Historic – GSP	SACES
Normalised – HDD	CSIRO
Historic – HDD	AEMO
Historic – Albury Temperature	BOM; 072160 - Albury Airport Weather Station
Forecast - GSP	SACES
Forecast – new connections Murray Valley and Bairnsdale	Envestra
Price elasticity of gas demand	AER; Final Decision Envestra Limited Access Arrangement Proposal For The SA Gas Network 1 July 2011 – 30 June 2016
Retail gas price components	Core Energy Group
Forecast – carbon price impact on retail gas prices	Australian Treasury Strong Growth, Low Pollution - Modelling a Carbon Price; July 2011; Table 5.19: Effects on weekly expenditure and the consumer price
Forecast – network price	Envestra
Forecast – wholesale gas prices	Australian Treasury Strong Growth, Low Pollution - Modelling a Carbon Price; July 2011; Chart B6: Domestic Australian gas prices

Source: (Envestra, 2012)

Table 5 **Data Sources – Tariff D, Large Industrial**

Parameter	Source
Historic - gas demand by region	Envestra
Historic – MHQ by region	Envestra
Historic - connections by region	Envestra
Historic – GSP	SACES
Normalised – HDD	CSIRO
Historic – HDD	AEMO
Historic – Albury Temperature	BOM; 072160 - Albury Airport Weather Station
Forecast - GSP	SACES
Price elasticity of gas demand	AER; Final Decision Envestra Limited Access Arrangement Proposal For The SA Gas Network 1 July 2011 – 30 June 2016
Retail gas price components	Core Energy Group
Forecast – carbon price impact on retail gas prices	Australian Treasury Strong Growth, Low Pollution - Modelling a Carbon Price; July 2011; Table 5.19: Effects on weekly expenditure and the consumer price
Forecast – network price	Envestra
Forecast – wholesale gas prices	Australian Treasury Strong Growth, Low Pollution - Modelling a Carbon Price; July 2011; Chart B6: Domestic Australian gas prices

Source: Envestra (2012)

4.2.2 Modelling approach

Core describes its modelling approach as follows:

> "Ideally, a model would contain a variable for every factor significantly influencing gas demand, however, due to the limited availability of information on appliance usage and penetration in VIC, as well as only 6 years of actual gas demand observations, alternative methods were required. Given the constraints on available data, Core considers its methodology to be appropriate.
>
> The precise effect of individual factors such as government policy, changing consumer attitudes and increases in efficiency are difficult to identify on a stand-alone basis, as such, Core has opted to represent the combined effect of all factors through a linear trend of weather adjusted historic data. This type of model contains the implicit assumption that all factors which have affected gas demand historically, will continue to affect gas demand in the future. Core believes this to be a reasonable assumption

> with the exception of four additional factors that have not been present historically but will become present over the forecast period, namely the demand response to:
>
> - the Clean Energy Bill 2011 – the introduction of a price on carbon in July 2012
> - distribution network price increases
> - wholesale gas price increases – as a result of the introduction of a price on carbon (July 2012), the start up of an export industry (2014) and increases in the underlying extraction costs
> - 6-Star Building Standards – introduced in May 2011, but not accounted for in the historic trend.
>
> In addition to the linear trend, Core combined an income component for households and an economic growth component for commercial / industrial customers. This was done in the form of GHDI for households and GSP for commercial / industrial customers. These measures are appropriate as they are both publicly available from the ABS and geographically relevant to Envestra's Albury network. The following figure displays the model specification used for demand per connection."

The approach taken by Core to develop the demand forecasts involved estimation of a number of regression equations and identification of key drivers of the variable to be forecast. The resulting regression equations were then used to generate forecasts by feeding projections of independently generated inputs. More specifically, the forecasts were arrived at through a sequence of steps, as follows:

1) Account for weather abnormalities and rebase historical demand.
2) Forecast the number of customers by using
    a) the relationship between dwellings starts and the net change in connections (for Tariff V Residential customers)
    b) a time trend and Gross State Product, GSP (for Tariff V Non-residential (commercial and industrial) and Tariff D customers).
3) Forecast demand per customer using a regression relating usage per customer to:
    a) a time trend
    b) Gross Household Disposable Income, GHDI (for Tariff V Residential customers)
    c) GSP (for Tariff V Non-residential and Tariff D customers).
4) Adjust the demand per customer forecast to account for other impacts, specifically:
    a) Clean Energy Bill, introduced in 2011
    b) distribution network tariff increases
    c) wholesale gas price increases
    d) 6-Star Building Standards (only for Tariff V Residential customers).

5) Multiply the number of customers by the (policy adjusted) demand per customer to obtain the total demand forecast.
6) For large industrial (Tariff D) customers, apply historical load factors to obtain Maximum Hourly Quantity (MHQ) forecasts

The key regression equations proposed by Core to establish average demand per customer connection are of the following form:

$$Log\left(\frac{Demand}{Customer}_t\right) = \beta_0 + \beta_1 \, Log(Trend_t) + \beta_2 Log(Income_t) \qquad (1)$$

Where:

- t represents the time period for the corresponding variable
- q represents the number of time lags on a variable
- $Demand/Customer_t$ is the gas demand per connection in year t
- $Trend_t$ is a time trend corresponding to year t
- $Income_t$ is GHDI for Residential or GSP for Commercial/Industrial in year t
- β_0 is the intercept term
- β_1 is the coefficient on the time trend
- β_2 is the coefficient on the income factor

Since variables are in logarithms, the coefficients can be interpreted as the per cent change in the dependent variable associated with a one per cent change in the corresponding explanatory variable. In other words, the coefficients represent elasticities.

Equation (1) looks like the typical regression used to estimate demand functions, except for the fact that it excludes price information (own price and the prices of substitutes). The implications of excluding price information are discussed in the following section of this report dealing with the main issues ACIL Tasman has identified in relation to the forecasting methodology (see equation (2) below and related discussion).

4.2.3 Methodological Issues

This section presents the main issues identified by ACIL Tasman as related to the forecasting methodology.

Issue 1 – Simultaneity Problem

When generating the forecast, a two-step approach has been taken. The first step was to generate demand forecasts without regard for price. This assumes (implicitly) that price remains unchanged through the forecast period (refer to Steps 1-3 in section 4.2.2). The second step is to subtract a demand adjustment component from the above forecast (Step 4(b) in section 4.2.2). This is achieved by applying the own price elasticity of demand to a given network price increase.

This approach suffers from what can be described as a 'Simultaneity Problem'. The problem arises because the proposed network price increase is calculated by feeding the unadjusted demand forecast through a tariff model, which will then calculate the tariff level necessary for the distributor to achieve a given rate of return. Own demand price elasticity is then applied to these preliminary tariffs, and the resulting fall in quantity demanded is subtracted from the initial forecasts. The problem with this approach is that the revised forecasts then need to be fed again through the tariff model and a new set of tariffs need to be calculated. This will lead to higher tariffs, which will lead to lower demand forecasts. The process needs to be iterated until the system converges to equilibrium.

There are two ways in which the simultaneity problem could be resolved. The first would be to integrate the forecast model and the tariff model, so that the two models can be solved as a simultaneous system of equations. The second would be to iterate the process between the two models until convergence is achieved. The first option is time consuming due to the modelling efforts required to integrate the models. The second option may also be time consuming due to the iterative nature of the process.

The impact of this problem will be that the current forecasts tend to over-estimate demand, leading to upward bias in the demand forecasts. It is difficult to ascertain the size of the impact this issue might have, but it is clear that it will tend to lead to relatively high demand forecasts and under-estimated tariffs, which, holding everything else constant, will cause realised revenue to be less than forecast revenue for Envestra.

Issue 2 – Non-linearities in Demand

The regression equations specified in equation (1) do not capture non-linear aspects of demand. In particular, as income rises or falls, it does not necessarily follow that demand per customer will track income by a constant per cent change. At high/low income levels, a given per cent change in income will not necessarily lead to the same per cent change in gas demand per customer. For example, businesses or households will not necessarily continue to increase heating their environments as their incomes grow: There are upper thresholds in demand, above which the intensity of demand tapers off. Likewise, there are also lower thresholds. For example, consumers are likely to maintain consumption for heating at a minimum level to keep environmental conditions liveable, notwithstanding falling income levels.

The non-linearities discussed above exist not just in relation to income: they can also be present in prices of gas as well as substitutes. There may be thresholds in gas and electricity prices above or below which a larger or smaller customer response is triggered. For example, if electricity prices rise beyond a certain level, then it may become optimal for customers to switch to gas heating, and given that the electricity price thresholds may be common to many customers, this could have an 'avalanche effect', which should be reflected in larger cross-substitution coefficients for high electricity price levels. The same logic applies to lower thresholds, as well as own price.

This issue could be ameliorated by introducing non-linear terms into the regression equations. In particular, introducing higher powers of the relevant variables would capture non-linearities present in the data.

As income continues to grow, not accounting for non-linearities in demand (particularly not accounting for the presence of upper thresholds) may result in demand being overstated, tariffs under-estimated, realised revenue for Envestra being lower than forecast. The analysis for price thresholds is more complex and it is difficult to ascertain *ex-ante* the magnitude or direction of any impact.

Accounting for non-linearities in demand becomes particularly important when there are large impacts to the explanatory variables. Whilst policy changes are on-going, ACIL Tasman does not envisage substantial and unaccounted for shocks to the drivers of demand. Hence not accounting for non-linearities in demand is not expected to be a fundamental cause for error in the forecast.

Issue 3 – Absence of Dynamics and Price Elasticities in Estimation

The regressions in equation (1) omit a treatment of dynamic aspects of demand and exclude price information. In the presence of dynamic behaviour, it is often the case that the dependent variable (for the case under consideration, gas demand) is a function of past values of itself[2]. This can arise because the dependent variable may exhibit a sluggish adjustment process; hence past values will continue to affect values in the present.

To account for this, it is customary to introduce a lagged dependent variable among explanatory variables. In a demand function that takes dynamic aspects of demand into account, the regression equation would take the following form:

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2 In econometric terms, the time series for the dependent variable exhibits a certain degree of autocorrelation.

$$Log\left(\frac{Demand}{Customer}{}_{t}\right) = \beta_0 + \beta_1 Log(Trend_{t}) + \beta_2 Log(Income_{t}) + \beta_3 Log(OwnPrice_{t}) + \beta_4 Log(SubsPrice_{t}) + \beta_5 Log\left(\frac{Demand}{Customer}{}_{t-q}\right) \quad (2)$$

Where:

- t represents the time period for the corresponding variable
- q represents the number of time lags on a variable
- $Demand/Customer_t$ is the gas demand per connection in year t
- $Demand/Customer_{t-q}$ is the gas demand per connection in year t-q
- $Trend_t$ is a time trend corresponding to year t
- $Income_t$ is GHDI for Residential or GSP for Commercial/Industrial in year t
- $OwnPrice_t$ is the gas price in year t
- $SubsPrice_t$ is the price of a key substitute in year t (for example, electricity)
- β_0 is the intercept term
- β_1 is the coefficient on the time trend
- β_2 is the coefficient on the income factor
- β_3 is the coefficient on own price ('own-price short-run elasticity')
- β_4 is the coefficient on the price of a substitute ('cross-price elasticity')
- β_5 is the coefficient on the lagged dependent variable

Estimation of a regression such as equation (2) would allow the definition of short-run and long-run elasticities of demand. In particular, the coefficient β_3 represents the short-run own-price elasticity of demand. The long-run elasticity is calculated as $\beta_3/(1-\beta_5)$.

However, the regression used by Core in the Envestra forecasts, namely equation (1), omits price information and dynamic aspects of demand. As a result, it does not allow the estimation of price or demand elasticities either as static (linear) estimates or as short and long run elasticities that take dynamics into account.

Ideally this problem would be resolved by specifying a demand function which contains prices of gas as well as substitutes (in particular, electricity) as explanatory variables, alongside other explanatory variables such as income. Incorporating a lagged dependent variable into the demand function would allow estimation of short and long run demand elasticities. Note, however, that the inclusion of prices as explanatory variables would mean that endogenous variables are being treated as exogenous variables, leading to further econometric estimation problems. Nonetheless, standard econometric techniques are available to address these[3].

In practice—and as alluded to by Core in the previously-quoted explanation of its methodology— limited availability of detailed (connection level) information on consumer behaviour, together with the short time series of available gas demand observations (in this case six years) are likely to make it difficult if not impossible to establish a fully-specified demand function supported by reliable data.

Not having price information in equation (1) means that Core, in developing the Envestra Albury forecasts, had to rely on estimates of demand elasticities from other sources. This in turn leads to potential problems arising from heterogeneous sources for inputs assumptions: the sources may not be consistent amongst themselves. Core did in fact attempt to calculate own price elasticity, with a resulting estimate of -0.27 for short-run elasticity (Core 2012, section 5.4.2). However, the regression equation used in this analysis only contains an intercept and own price as explanatory variables for gas demand per customer. This approach suffers from the well-known "identification problem": the regression equation cannot be ascribed to either a demand or a supply function, both of which constitute a relationship between markets prices and quantities. The demand function is downward sloping, leading to a negative coefficient for own price. The supply function is upward sloping, with a positive coefficient on own price. The coefficient estimated in Core (2012, section 5.4.2) is neither a demand nor supply elasticity. Furthermore, the absence of dynamics means that it cannot be ascertained whether it is a long or short run coefficient. Having undertaken this analysis, Envestra instead adopted an estimate from a prior AER determination (AER, 2012), which is higher than its own estimate (the estimates in AER (2012) are -0.30 for Residential and -0.35 for Commercial/Industrial demands).

To some extent, the assumption of a high elasticity estimate will ameliorate the impact of Issue (1), the Simultaneity Problem, since it will lead to a greater reduction in forecast demand, thereby mitigating the upward bias of the forecast. Whether the effects will cancel out or one will tend to dominate is difficult to determine *ex-ante*.

3 The problem being referred to is Endogeneity Bias. The solution is to use Instrument Variables estimation procedures.

Issue 4 – Potential for Spurious Correlation and Stationarity Testing

When conducting estimation using time series, it is desirable to test whether the time series being used are stationary or not. Intuitively, a time series is stationary if its fundamental statistical properties do not change over time. A non-stationary time series typically exhibits exponential growth, and its behaviour is dominated by its non-stationary component[4]. Running regressions using non-stationary time series may lead to problems due to spurious correlation, since the regression may be capturing the relationship between the underlying non-stationary components of the variables, as opposed to the variation in the dependent variable explained by the explanatory variables.

Because the demand forecasts in Envestra (2012c) are dealing with time series econometrics, it would be appropriate to conduct stationarity tests to establish whether the regressions can be run in levels or whether it is necessary to shift to "differences-on-differences" estimation[5]. No such tests are reported. If the time series prove to be non-stationary, then any correlation found between the variables might be spurious.

In the case of non-stationary variables, the next step would be to seek a cointegrating relationship between the variables. If such a relationship can be found, then an Error Correction Model (ECM) can be estimated. Alternatively, "differences-on-differences" estimation could be an acceptable option. However, since differencing the variables reduces the degrees of freedom, it would be preferable to find a cointegrating relationship and conduct the estimation in this manner.

Spurious correlation is a very common problem in time series analysis. The consequence would be that little reliability could be ascribed to the estimated regressions.

Issue 5 – Omitted Variable Bias

The regression models used in the Envestra analysis are highly simplistic. The only explanatory variables used are a time trend and proxies for income.

[4] In intuitive terms, the non-stationary component of a time series is akin to the underlying trend of the time series, although the comparison is not a precise definition.

[5] Difference-on-differences estimation refers to running the regression using the differenced variables instead of the variables in levels. To obtain the differenced variables, the procedure is to subtract the previous period's value of the variable from the current period's value. This is a means to remove some of the non-stationary components present in the levels of the variable. Depending on the degree of non-stationarity, it may be necessary to difference the variable once or twice.

In selecting variables Core sought to identify the potential drivers of residential gas connection numbers. They tested a number of potential variables (population, households, government policy, trend, retail gas prices, income, historic disconnections and dwelling starts (both detached and other) but ended up using only dwelling starts on the basis that:

> "Dwelling starts was found to be the best driver of new connections. This is explained by the observation that other tested variables such as population and income are in fact drivers themselves of the level of dwelling starts. Dwelling starts are further defined through two distinct building types, these are; Detached (Houses) and Other (Apartments/Units). Since there is marked difference in the proportion of Detached and Other dwellings that have a gas connection, it was necessary to include both variables separately. This is considered to provide significant explanatory power to the results determined by the model.).[6]

It would be reasonable to expect a demand function to include a number of other explanatory variables which would account for customer characteristics and pricing of substitutes. Such explanatory variables might include customer-specific characteristics, year of connection (customer cohort), price of substitutes (in particular, electricity), proxies for policy changes, etc.

Omitting explanatory variables may lead to bias in the estimated coefficients. *Ex-ante*, it is unclear whether the coefficients might be upward or downward biased.

Issue 6 – Degrees of Freedom

The statistical analysis is conducted using annual data for the period from 2005 to 2011. At best, this yields six data points, leaving most of the regression equations with four degrees of freedom at best. It is widely accepted that for Ordinary Least Squares (OLS) regression coefficients to exhibit convergence to their true population values, at least 15-20 degrees of freedom are necessary. Any regression analysis using fewer degrees of freedom is likely to yield coefficients that are distant from the true population values.

Issue 7 – Discrete Dependent Variable: Tariff D Customers

When estimating the number of connections for Tariff D Customers (industrial), no attempt is made to account for the fact that these are discrete decisions which have a significant impact on the demand forecast. The econometrics methods used are the same as for the other customer types (residential and commercial), which are better suited to problems with a

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[6] Core Energy Group, *AER Question Responses, Envestra Limited – Gas Access Arrangement Review, Victorian Network (2013 to 2017)*, May 2012, pp. 4-5.

continuous dependent variable. However, there are better methods for problems with discrete dependent variables. In particular, a model designed for count data may be more appropriate[7]. Attempting estimation using a standard Ordinary Least Squares linear regression approach will lead to a variety of statistical problems, including biased coefficients.

4.3 Conclusions arising from the methodology review

As discussed in Section 4.1.1 there are a number of methodological issues with the forecasting approach used by Core to develop the Envestra demand forecasts. Issues that have the potential to introduce bias and distortions to the modelling results include:

- the Simultaneity Problem which may introduce an upward bias in the demand forecast
- no accounting for non-linearities
- reliance on external estimates of elasticity
- potential for spurious correlation and the absence of statistical testing for non-stationarity in the variables
- omission of variables potentially affecting demand
- regressions on short time series data.

Core has acknowledged that, ideally, the forecasting model would be more comprehensive and rigorous, containing "a variable for every factor significantly influencing gas demand". However it has opted to use a simpler approach on the basis that the limited data available does not support a more comprehensive econometric analysis. In effect, Core assumes that the combined effect of the individual drivers of demand is largely represented in the linear trend of weather adjusted historic data, and that it is not necessary (or practical) to separately estimate each of the individual demand drivers given the limitations of the available data.

The key question is whether a more elaborate and more theoretically rigorous approach addressing the issues identified would be likely to produce a better or more reliable forecast. Given the short time series of available data and the difficulties involved in reliably estimating the coefficients associated with each of the variables in a fully specified demand function, it is not clear that a more rigorous approach would necessarily produce a more reliable forecast.

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[7] As an example, the Poisson regression model is typically used for estimation when the dependent variable takes the form of count data (0,1,2,…). There are various estimation methods which are applicable, with Maximum Likelihood being the most common.

Accordingly, while recommending that consideration be given in future to the methodological issues identified, we consider that in the current circumstances the approach used by Core to develop the Envestra Albury demand forecasts is acceptable.

4.4 Weather normalization of historical data

Weather has a significant impact on gas demand. The need to adjust historical data on gas consumption to take account of variations in weather has been noted, for example, by the Australian Energy Market Operator (AEMO) who in commenting on the Victorian gas distribution system observed that:

> "Understanding the factors that affect the consumption of gas is central in evaluating future energy demands. When temperatures are lower than normal, energy demand for residential heating increases. This strong relationship between gas demand and climate highlights the need to identify the weather conditions assumed when calculating forecast demand. In gas forecasts, the actual demand needs to be adjusted for weather before the underlying growth can be calculated. These weather adjustments can be simplified through the use of Effective Degree Day (EDD) variable." (AEMO, 2009, p. 55)

There are two measures of weather commonly used in forecasting gas demand, HDD and EDD.

HDD is calculated by taking the average of eight temperature observations each day and, where the observed temperature is less than 18, subtracting it from 18. Therefore, HDD takes account not only of how low the minimum temperature was on a given day, but also for how long it was cold and, therefore, for how long gas heating may have been used. The lower the average temperature, the higher the HDD value.

The EDD approach is a multifactor method that includes HDD and also takes account of wind velocity, sunshine hours and seasonal variations in demand. EDDs can be calculated on various different bases by incorporating weather conditions at different times of day.

In its review of the weather standards for gas forecasting AEMO considered a variety of different approaches to measuring temperature for gas demand forecasting purposes. It concluded that the EDD_{312} approach was superior to the others it considered, including HDD.

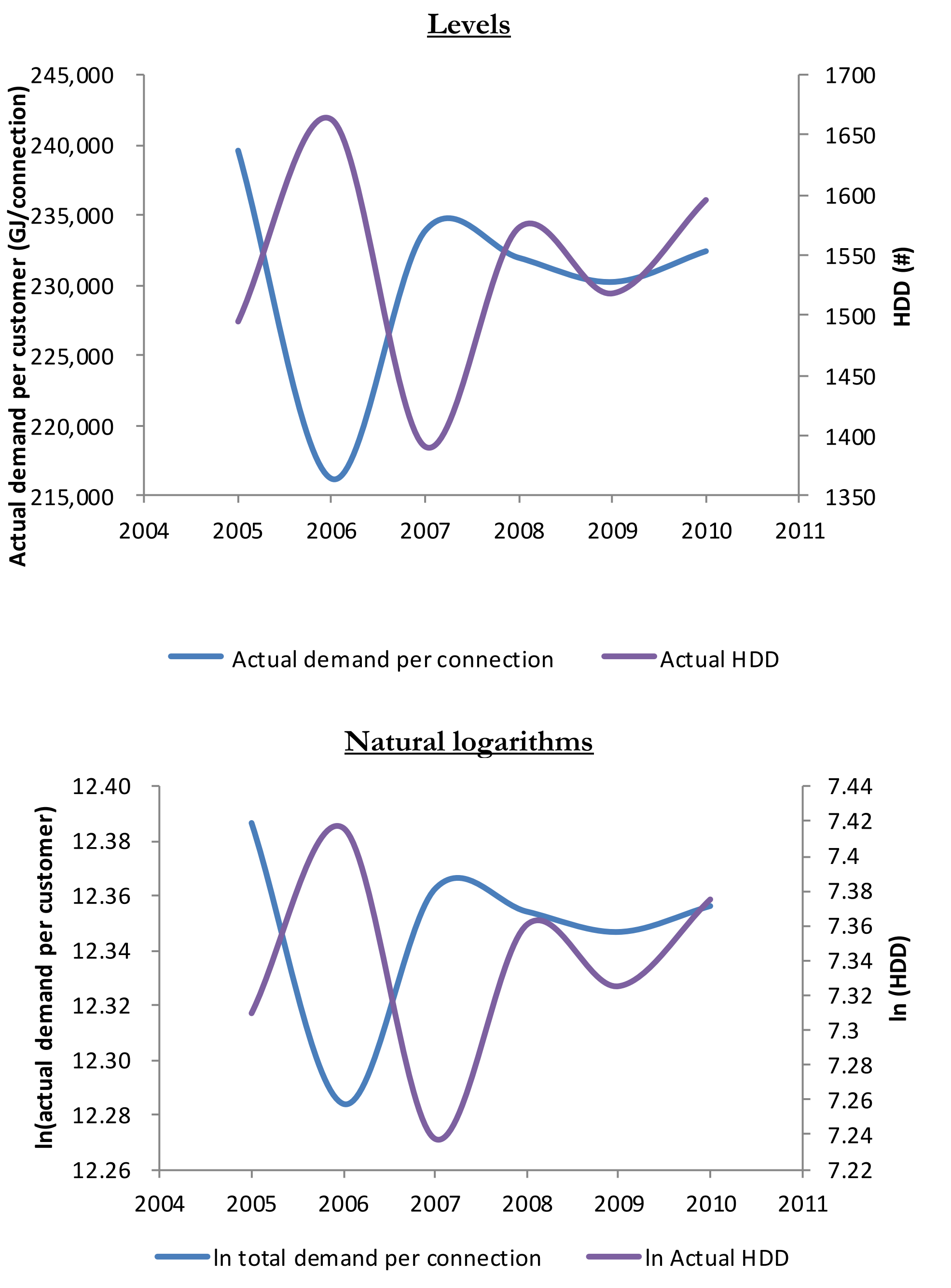
However, due to a lack of weather data for Albury, Core used HDD for weather normalisation, based on the temperature recorded at Albury Airport. In doing this, Envestra has implicitly assumed that, it is preferable to use HDD for Albury rather than EDD for Melbourne, notwithstanding AEMO's conclusion that HDD is an inferior measure. Given that we cannot calculate

EDD for Albury, we cannot test this assumption, though it does not seem unreasonable.

Generally speaking, an inverse relationship between gas demand and temperature is to be expected, with demand increasing as temperatures decrease because gas is commonly used for space heating.

Figure 1 shows the annual volume of gas supplied to Envestra's Tariff D industrial customers on a per customer basis from 2005 to 2011 along with the number of HDDs observed in each of those years. The lower pane shows the natural logarithms of the same data.

Figure 1 **HDD and gas demand per connection - Tariff D industrial customers**



Data source: (Core, 2012)

Figure 1 appears contradictory regarding the relationship between temperature and gas demand by industrial customers. For the five years pictured here these two items tended to move in opposite directions.

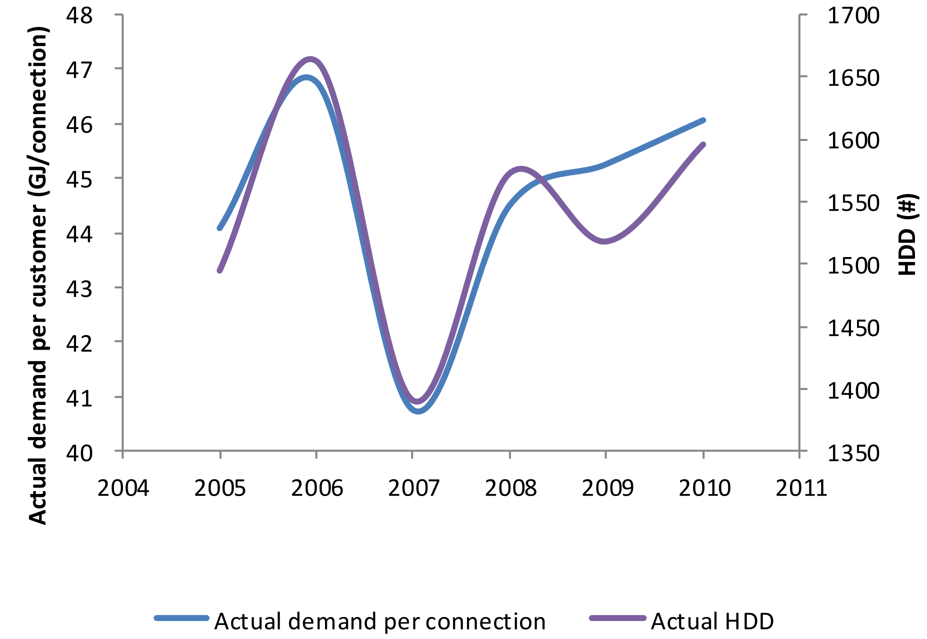
It must be noted, however, that the data plotted here relate to only 9 customers. With so few customers, average usage is subject to change as a result of a range of individual effects, making this comparison relatively unhelpful.

Figure 2 shows the corresponding data for residential customers.

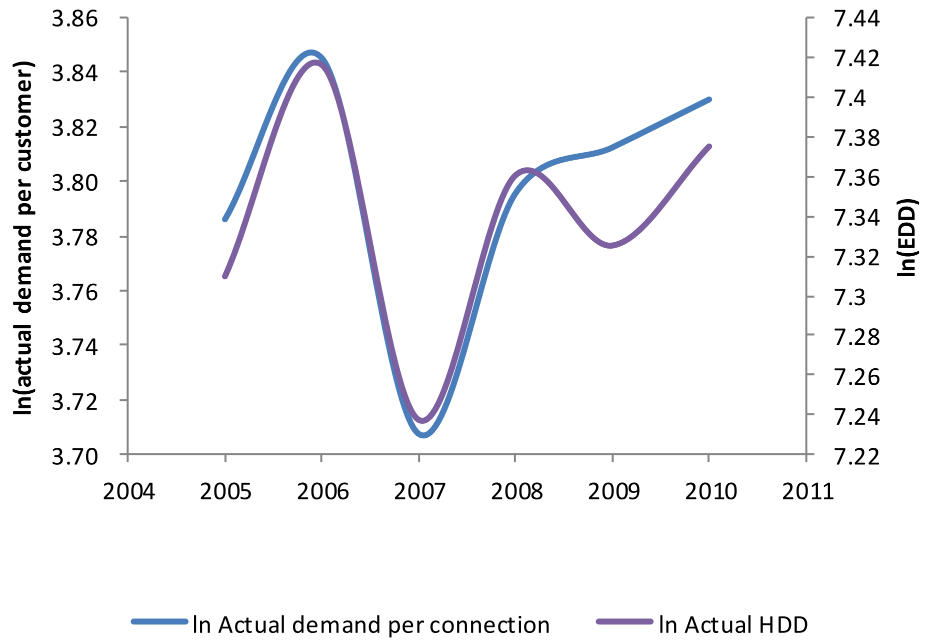
It shows a much clearer relationship between HDDs and average gas demand per residential customer than Figure 1 showed for industrial customers. That relationship is relatively constant throughout the period, although usage did not 'dip' with HDD in 2009. This constant relationship suggests that the economic drivers that influenced industrial demand were less important for residential demand and shows the impact of having a larger number of observations. These observations are consistent with the notion that residential gas demand is more sensitive than industrial gas demand to changes in weather (temperature).

Figure 2 **HDD and gas demand per customer – Tariff V residential customers**

Levels



Natural logarithms



Data source: (Core, 2012)

4.4.2 Envestra's approach to weather normalisation

Envestra's forecasts are based on the following five-step approach to weather normalisation (Core, 2012):

1. Obtain historical weather data for Albury Airport from the Bureau of Meteorology
2. Calculate HDD using the AEMO methodology described above
3. Use regression analysis to obtain a normalised set of HDD for Albury
4. Calculate abnormal HDD by comparing actual and normalised HDD
5. Use regression analysis to estimate the sensitivity of each tariff segment to HDD
6. Multiply abnormal HDD by the sensitivity to HDD to determine abnormal gas demand attributable to weather and subtract this from observed demand to obtain normalised demand

Using this approach and monthly consumption data, Core estimated weather sensitivities for each class of Envestra's customers. Those sensitivities are shown in Table 6.

Table 6 **Envestra Albury – submitted weather sensitivities**

Customer segment	Weather sensitivity (GJ/HDD/connection)
Tariff D industrial	12.0923
Tariff V Residential	0.0216
Tariff V Non-Residential	0.0746

Data source: (Core, 2012) Table 2.2

The weather sensitivity coefficients in Table 6 were estimated using linear regressions on monthly data.

For residential and commercial (Tariff V) customers, those regressions had the form shown in equation (1) below:

$$demand\ per\ customer = a + b(abnormal\ HDD) \tag{3}$$

Where:

demand per customer is gas consumption per customer by tariff class

abnormal HDD is the difference between actual HDD as reported by AEMO and projected HDD as reported by CSIRO

a is an intercept term

b is the weather sensitivity coefficient from Table 6

For Tariff D demand, the regression included the lag of usage, i.e. they had the form shown in equation (2) below:

$$demand\ per\ customer_t = a + b(abnormal\ EDD) + c(demand\ per\ customer_{t-1}) \tag{4}$$

Where:

Demand	is gas consumption per customer on Tariff D
abnormal HDD	is the difference between actual HDD as reported by AEMO (and Core) and projected HDD as reported by CSIRO
t	is a time index
a	is an intercept term
b	is the weather sensitivity coefficient from Table 6
c	is 0.3163

The regressions relating to Tariff V Residential and Commercial demand each have statistically significant coefficients and explain more than 95 per cent of the variation in historical data. These regressions support the notion that, for these customers, gas consumption varies mainly with the weather.

The regression for tariff D demand also has statistically significant coefficients, but it explains only around 70 per cent of the variation in historical demand. This suggests that, while weather is an important determinant of demand for Tariff D customers, other factors significant influence demand within this customer group.[8]

The key issue arising from this analysis is the assumption regarding 'normal' weather between 2005 and the present. This is discussed in the next section.

Normal weather – the choice of HDD inputs

Demand for gas varies significantly from year to year driven by weather. Some years are colder than others and some are hotter. Gas is commonly used for heating so, in colder years, demand for gas is higher and in warmer years it is lower. The purpose of weather normalisation is to remove this year by year

8 As noted above, it is also influenced by the fact that there are very few Tariff D customers on this network.

variation from the historical data to allow underlying trends in consumption to be observed. Projections of those trends are then prepared on the assumption that weather conditions will be "normal" because it is not possible to know in advance whether a particular year will be colder or hotter than "normal".

To do this requires an assumption as to what are "normal" weather conditions.

One approach to determining "normal" weather is to take the median weather conditions from a time series. The median of a series is a constant number (for a constant series) so using it as a projection of normal weather conditions assumes that these are stationary. In other words, it amounts to an assumption that, over time the median weather conditions (HDD in this case) will not change.

Envestra has argued that the long term data shows a warming trend and that assuming that the historical median weather will be repeated (on average) is inappropriate. This is consistent with arguments made by Envestra and the other distribution businesses that were accepted by the Essential Services Commission in its Final Decision in relation to the current access arrangement period (Essential Services Commission of Victoria, 2008).

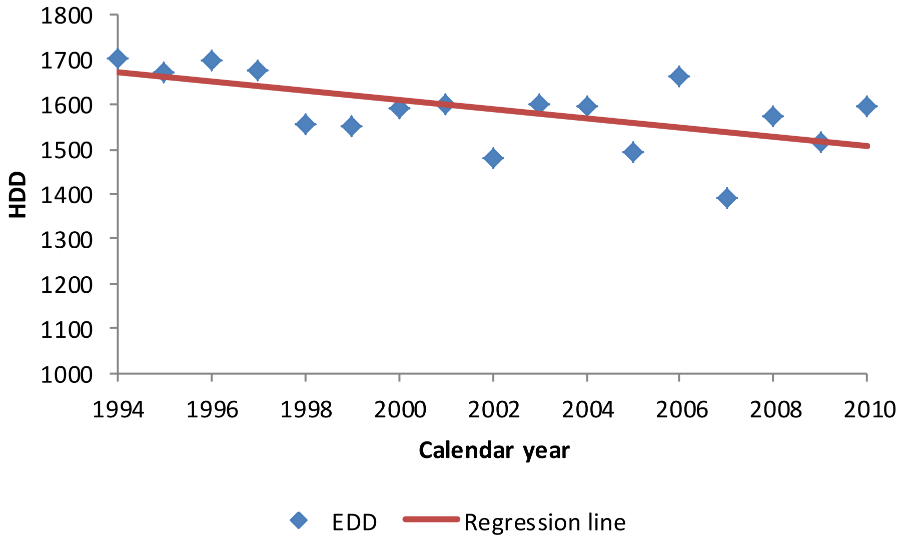
Analysis conducted by CSIRO and provided by Envestra in support of its access arrangement proposal supports this argument. That analysis shows that historical weather data for Victoria exhibits a warming trend (and a corresponding upward trend in the number of EDDs) over approximately the last 60 years. According to CSIRO this historical trend has been largely due to the Urban Heat Island (UHI) effect.[9]

Envestra and Core accounted for this trend by fitting a linear regression to the historical temperature data for Albury Airport. In effect they assumed that this projection reflects "normal" or 50 per cent probability of exceedence weather conditions between 2005 and 2010.

Weather observations have been recorded at Albury Airport since May 1993, though Core used data only since 1994, which is the first full year of data. Figure 3 shows HDD and Core's regression line for Albury Airport.

[9] In very simple terms the UHI effect is the result of increased 'urbanisation' and thus increased numbers of buildings and other man-made structures in urban areas. Those structures themselves radiate heat thus preventing minimum temperatures from being as low as they may otherwise have been.

Figure 3 **Albury Airport temperature data**



Data source: Bureau of Meteorology (private communication) and Core *(2012)*

Figure 3 shows that the number of EDDs observed each year has declined over the period since 1994. This is supportive of Envestra's choice to weather normalise to a trend rather than a static view of 'normal' weather conditions.

However, the rate of decline in HDD over time is sensitive to the length of the input data set.

Core's analysis was based on data from January 1994 to December 2010. This reflects the fact that Core's analysis was done before the end of 2011 and, therefore, 2011 data could not be taken into account.

Data for 2011 are now available. When the extra data are added to Core's analysis, the rate of decline in HDD reduces by almost 30 per cent from approximately 10.3 HDD per year to approximately 8 HDD per year.

The analysis is also sensitive to the treatment of missing data. ACIL Tasman sought to replicate Core's regression analysis, but was unable to do so exactly due to missing data. The data provided by the BoM contained eleven missing observations between 1994 and 2010. Core' imputed these values based on observations in the days immediately before and after the missing observations.

If the missing data are disregarded entirely, the total number of HDD in 1995 and 1998 is reduced by approximately 30 HDD. The number in 1999 is reduced by approximately 10 HDD. While these numbers are small relative to the annual number of HDD, which is usually in excess of 1,500 each year, the impact on the regression line is significant.

If 2011 HDD are added and Core's adjustment is not made, the rate of decline in EDD is approximately 9.6 per cent lower than if Core's adjustment is made.

To make no adjustment for missing data is equivalent to assuming that the average temperature was no less than 18ºC on the days for which data is missing. On this assumption, the rate of decline of EDD based on trend analysis is reduced by approximately 9 per cent, from 10.3 to 9.5 EDD per year. However, this assumption is probably less reasonable than CORE's, namely that the weather on the days for which data is missing was similar to that on the surrounding days.

These different approaches to normalising for weather have flow on impacts in the forecasts of gas demand. The impacts are shown in Table 7, where we have applied the three alternative approaches to defining 'normal' weather conditions to Core's demand forecasting model for Albury. The impact on forecast demand is always positive, that is, the forecasts based on data to 2010 as adjusted by Core produce the lowest demand forecasts. The magnitude of the difference varies from close to zero to more than two per cent.

Table 7 **The impact of redefining 'normal' weather**

	2013	2014	2015	2016	2017
Demand levels (GJ) based on HDD to 2010 as adjusted by Core					
Residential	849,446	846,533	845,678	845,768	848,111
Commercial	251,032	243,986	238,316	234,358	231,036
Industrial	1,711,500	1,619,432	1,544,413	1,483,075	1,426,768
2010 raw HDD data					
Residential	0.37%	0.44%	0.52%	0.60%	0.67%
Commercial	0.13%	0.16%	0.18%	0.20%	0.22%
Industrial	0.03%	0.03%	0.04%	0.04%	0.05%
Total impact (GJ)	0.14%	0.17%	0.20%	0.24%	0.27%
2011 HDD with Core adjustment					
Residential	1.27%	1.41%	1.56%	1.71%	1.86%
Commercial	0.56%	0.60%	0.64%	0.69%	0.73%
Industrial	0.11%	0.12%	0.13%	0.14%	0.15%
Total impact (GJ)	0.50%	0.57%	0.64%	0.71%	0.78%
2011 HDD with raw data					
Residential	1.59%	1.80%	2.02%	2.24%	2.46%
Commercial	0.67%	0.73%	0.80%	0.86%	0.92%
Industrial	0.13%	0.15%	0.16%	0.17%	0.18%
Total impact (GJ)	0.62%	0.72%	0.82%	0.92%	1.02%

Accordingly, we consider that it would be reasonable for the AER to require Envestra to re-estimate its demand forecasts for the Albury network on the basis of weather normalisation including the 2011 weather data, making appropriate adjustments for missing data in the historical records.

4.5 The impact of rising energy prices

Each of the DNSPs has made assumptions regarding changes in the price of gas over the regulatory period. Each has projected that gas prices will increase. Envestra's assumptions regarding gas price increases are set out in Table 8.

Table 8 **Envestra Albury – assumed gas price increases 2013 to 2017**

Price Impacts Not Seen In Historic Trend	2013	2014	2015	2016	2017
Carbon price impact on residential retail price	9.00%	0.66%	0.66%	0.66%	
Wholesale gas price increase	1.04%	2.06%	3.03%	3.92%	3.77%
Network price increase	13.47%	11.37%	6.37%	6.37%	6.37%

Table 8 shows that Envestra's forecasts are based on its assumptions that:

1. the retail price of gas will increase as a result of the impending carbon price
2. the wholesale gas price will increase in addition to the impact of the carbon price
3. network price increases will exceed those seen in the past.

Each of those assumptions is weighted by Envestra's assumed 'structure' of the typical bill of different types of customer. For example, Envestra has assumed that the majority (90 per cent) of the gas bill of an industrial customer is the wholesale cost of gas, so impacts on the wholesale gas price are weighted more heavily for Tariff D customers than others. The assumptions are set out in Table 9.

Table 9 **Envestra Albury – assumed structure of gas bill for different customer types**

Tariff V Residential	Residential	Commercial	Industrial
Network cost share of retail gas price	35%	30%	5%
Retail cost share of retail gas price	20%	10%	5%
Wholesale gas cost share of retail gas price	45%	60%	90%
Total retail gas price	100%	100%	100%

Data source: (CORE Energy Group, 2012)

The three components of Envestra's assumed price increase are discussed in section 4.5.1. The impact that those assumptions have on the gas demand forecasts is strongly influenced by Envestra's assumed price elasticity of demand, which is discussed in section 4.5.2.

4.5.1 Envestra's price change assumptions

Envestra has assumed that three factors will drive increases in gas prices during the regulatory period: the carbon price, other influences on the wholesale gas market and network prices.

Envestra's forecasting approach essentially involves two steps. First, demand is projected forward on the assumption that factors other than economic activity and Gross Household Disposable Income will be constant. Second, adjustments are made for other factors not taken into account in step 1.

It is reasonable, therefore, for Envestra to make adjustments to its forecasts to take account of price changes that are unlike those observed in the last regulatory period.[10]

The assumptions made by Envestra are discussed in turn in this section.

The impact of carbon price

The Commonwealth Government is in the process of introducing a carbon pricing scheme to address the externality cost of greenhouse gas emissions associated with energy use (and other sources). The carbon pricing scheme will begin with a period of fixed prices from 1 July 2012 until 30 June 2015. The intention is that it will then transition to a cap and trade type scheme where a finite quantity of greenhouse gas emissions are permitted and the carbon price is determined by the market.

The carbon trading scheme is designed to deliver reductions in Australia's greenhouse gas emissions at the lowest possible cost. The carbon price is designed to do this by internalising the cost of greenhouse gas emissions, thus giving emitters an incentive to reduce their emissions using the most cost-effective technologies available.

The carbon price will influence consumers' choices regarding energy use and suppliers' choices regarding technology. It will do this by increasing the cost (and thereby the price) of fuels, particularly electricity and gas.

As the price of gas increases customers will face incentives to reduce gas use, either by improving the energy efficiency of their appliances or by other means.

[10] Of course, to take account of anticipated network price increases Envestra must make an assumption as to the AER's final decision, making this an inherently circular discussion. This circularity is unavoidable.

However, the greenhouse emissions intensity of Australia's electricity supply is such that, in many applications, replacing electrical appliances with gas alternatives would reduce greenhouse gas emissions. Therefore, the relative impact of the carbon price on gas will be less than on electricity. To some extent energy customers will face an incentive to 'fuel switch' from electricity to gas.

Envestra has accounted for the impact of the carbon price on retail gas prices (reweighted for non-residential customers) based on Commonwealth Treasury modelling of the carbon trading scheme. There is significant uncertainty surrounding the carbon trading scheme and the impact it will have on prices. Therefore, there is a substantial risk that the impact on gas prices will be different than Envestra has assumed. Nevertheless, it is necessary to make an assumption for these purposes and, in our view, it is reasonable for Envestra to assume that price impacts will be in line with the Commonwealth Treasury modelling.

The impact of wholesale gas price increases

Envestra's forecasts are based on the assumption that the wholesale price of gas will increase as shown in Table 10. That assumption is based on the same Australian Treasury modelling from which it drew the impact of the carbon price.

Table 10 **Envestra Albury – assumed increases in wholesale gas price**

	2013	2014	2015	2016	2017
Projected Annual wholesale gas price increase (%)	1%	2%	3%	4%	4%

Data source: Core, Table 5.7

As Core states in its report to Envestra, "there is a high degree of variation in projected wholesale gas prices." Both ACIL Tasman and Core have projected, under certain assumptions, larger increases than Envestra. Such increases may be driven by growing demand for gas in the power generation sector and by the potential impact of LNG exports on domestic gas prices in the eastern Australian market. In our view Envestra's assumed increases in wholesale gas price are reasonable.

The impact of network price increases

The third component of upward impact on gas price that Envestra has assumed is the impact on network prices.

Envestra has adjusted its demand forecasts to account for its entire proposed increased in network charges, which are as shown in Table 11.[11]

Table 11 **Envestra Albury – assumed increases gas network prices**

	2013	2014	2015	2016	2017
Projected increase in gas network charges	13.47%	11.37%	6.37%	6.37%	6.37%

This approach raises the question whether all of Envestra's proposed network price increase should be treated as an adjustment. To the extent that Envestra's customers have experienced increases in gas network prices in recent history, this would be reflected in the trend data and it would be unnecessary to make an adjustment.

However, in 2008 the Essential Services Commission determined that, for the previous regulatory period, Envestra Albury should provide a decrease in real prices in 2008. After that, Envestra was not provided with an increase in real prices.

Therefore, in weighted average terms across the customer base, Envestra's customers have not experienced increases in real gas network prices for several years.[12] Before that, prices were decreased by 6.1 per cent (real) in 2008.

Under these circumstances, we accept that it is appropriate to take into account the whole of the (anticipated) network price increase in determining the expected future delivered price of gas to customers on the Envestra Albury network.

4.5.2 The price elasticity of demand – quantifying the impact of gas price increases

Our views regarding Envestra's assumed changes in gas prices are outlined in the previous section. We agree with Envestra that the price of gas is likely to increase significantly over the regulatory period and that this is an important factor to take into account in forecasting gas demand.

In addition, ACIL Tasman expects that the price of electricity will also increase over the regulatory period. While Envestra makes no mention of this, we also consider this to be an important factor in forecasting gas demand over the regulatory period.

11 The assumed increases in retail prices due to this factor are less than the figures shown in Table 11 as they are weighted by the proportions in Table 9.

12 Individual customer classes may have experienced increases during the regulatory period but, in weighted average terms, these have 'balanced out'.

In summary, increases in gas price are likely to lead to a reduction in gas demand through the price effect. Increases in electricity price *relative to gas price* are likely to lead to an increase in demand for gas as an alternative (substitute) to electricity through the substitution effect. It is difficult to estimate the likely size of these competing effects with any confidence.

Each of the relationships can be described using an elasticity. The price effect is summarised using the "own price elasticity of demand for gas". The substitution effect is summarised using the "cross price elasticity of demand for gas". These two elasticities are discussed in turn below.[13]

Own price elasticity of demand for gas

The own price elasticity of demand, (commonly 'price elasticity') describes the relationship between the price of a good and the quantity of it that will be demanded. Being an elasticity it is expressed in percentage terms. For example a price elasticity of -1 suggests that for a one per cent increase (decrease) in price, the quantity demanded will decrease (increase) by one per cent.

The price elasticity of demand is an important input into the forecasting process. Given the price increases forecast for the coming regulatory period, an overly high elasticity estimate would lead to gas demand forecasts being understated and, in turn, to gas prices being higher than necessary.

Each of the DNSPs has used its own assumed price elasticity in preparing forecasts. The assumptions are shown Table 12.

Table 12 **Price elasticity assumptions**

DNSP	Price elasticity	Source/ Basis
SP AusNet – Residential SP AusNet - Commercial	-0.17 -0.77	CIE analysis of SP AusNet data
Multinet – All customer classes	-0.28	Not specified
Envestra (Victoria and Albury)	-0.30	AER determination for Envestra in South Australia and literature review

The fact that the different DNSPs have made different assumptions regarding price elasticity is not surprising. Each DNSP is independent of the others and the regulatory proposals were prepared independently as well.

13 The own price elasticity of demand is relevant to the estimated impact of the carbon price as well as to the impact of rising gas prices generally.

Envestra's assumption of a 0.30 elasticity is consistent with the AER's recent decision regarding its access arrangement in South Australia. It is also broadly supported by analysis undertaken by Core which resulted in an estimated price elasticity (stated to be "short run" – but see discussion at page 16) of about –0.27 for all customer classes.

The basis for Multinet's assumed elasticity of –0.28 for all customer classes is not explained by Multinet or its consultant NIEIR (Multinet, 2012), (NIEIR, 2011).

CIE for SP AusNet has produced elasticity estimates based on recent experience with SP AusNet's own customers (SP AusNet, 2012), (CIE, 2012). That experience led CIE to conclude that the price elasticity of demand for gas is –0.17 for SP AusNet's residential customer group (that is, Tariff V Residential) and –0.77 for its commercial customer group (that is Tariff V Non-residential). The reason for the large difference in price elasticity between the two customer groups was not discussed by CIE. However we note that on a volume-weighted average basis (using the above elasticity estimates and actual consumption data for residential and non-residential Tariff V customers) the price elasticity across all Tariff V customers would be –0.27. On this basis, the CIE price elasticity estimates can be viewed as being comparable to the assumptions made by Envestra and Multinet. The CIE report makes no specific reference to price elasticity for Tariff D customers.

In light of the foregoing, we consider that Envestra's own-price elasticity assumption of –0.3 can be regarded as being consistent with the estimates used by the other distribution businesses and with recent precedent. Accordingly we consider the assumption to be not unreasonable.

Cross price elasticity of demand

The cross price elasticity of demand summarises the relationship between the price of one good and the quantity demanded of another. In this case, the cross price elasticity of interest summarises the relationship between the price of electricity and the quantity of gas demanded.

A positive cross price elasticity suggests that as the price of one good increases demand for the other good also increases. These goods are defined as substitutes.[14]

[14] A negative cross price elasticity suggests that as the price of one good increases demand for the other good falls. These goods are defined as complements.

Neither Envestra nor its consultant Core has directly addressed the issue of whether rising electricity prices are likely to mitigate the price elasticity effect of rising gas prices on gas demand.

Given that electricity and gas can be used similarly it would be reasonable to expect that they are substitutes (with a positive cross price elasticity of demand). The need to change appliances to allow substitution to occur suggests that the cross price elasticity of demand may become larger as it is measured over a longer time frame.

However, the extent to which rising electricity prices are likely to offset the reduction in gas demand cause by higher gas prices is not clear. In the next regulatory period, all of the DNSPs are anticipating that the price of both electricity and gas will increase significantly, largely due to the carbon trading scheme and LNG exports. However, with the exception of SP Ausnet, none of the DNSPs appear to have considered the impact that higher electricity prices will have on gas demand.

In its report to SP AusNet, CIE examined the substitution effect using two different measures of the price of electricity. The results were contradictory. In one model the relationship CIE found between electricity price and gas demand[15] was positive, as would be expected, and very small. In the second model the relationship was negative, which is contrary to the theoretical expectation.[16] On this basis, CIE concluded that the price of electricity should not be included in its models of gas demand.

Given the ambiguous nature of the results and the low absolute cross-elasticity values observed in the CIE analysis, as well as the lack of other relevant evidence, we consider that Envestra's reliance on own-price elasticity estimates alone is not unreasonable.

4.5.3 Policy factors affecting the forecasts - 6-star building policy

Aside from the introduction of the carbon price, discussed in the previous section, the only policy factor that Core took into account explicitly in preparing the Envestra Albury forecasts was the introduction of the 6-star building standard for new homes in Victoria.

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[15] In this case the estimated cross price elasticity was 0.001.

[16] In the second model the cross price elasticity was -0.019 whereas the own price elasticity was -0.133.

A key factor in projecting gas demand in the residential sector is the likely gas requirement of new homes. For a gas DNSP growth in residential customer numbers can take one of only three forms:

4. Existing home connected to gas due to 'infill' of customers in gas connected areas without gas access without major renovation or new home construction.
5. Existing home connected to gas due to extension of gas network into a new area.
6. New home (or substantial renovation), either replacing an existing home without gas supply or in a newly developed residential area.

In most cases the number of new customers in the first two categories is likely to be relatively small compared to the third category.

Therefore, the majority of a gas DNSP's new customers are likely to be customers with newly built homes (or substantially renovated homes).

Each of the DNSPs has taken a broadly similar approach to projecting growth in demand by residential customers. That approach is to forecast the number of new customers expected to connect to gas supply in the region and to multiply that number by the estimated average gas demand per customer. The source of new customer projections varied. In Envestra's case it was a trend based model.

Conceptually it would be possible to produce a forecast of demand from new residential customers by multiplying the projected number of new customers by the average gas demand of the existing (residential) customer base. However, each of the DNSPs has argued that this would be inappropriate.

While the approaches differ, each DNSP has argued that, on average, their new residential customers use less gas than 'older' customers. The reasons are, broadly, that new houses and the appliances they contain are more energy efficient than older houses and appliances.

The gradual replacement of existing houses and appliances with more efficient options is a contributing factor to the gradual decline in gas usage by existing customers. Another factor is the replacement of gas fuelled appliances with alternatives that use different fuels, in particular substituting (electric) reverse cycle air conditioners for gas space heaters and solar water heaters for gas alternatives.

An additional factor that each of the DNSPs argues should be considered is the introduction of mandatory 6-star energy efficiency ratings for new homes.

In 2009, the Council of Australian Governments (COAG) requested the Australian Building Codes Board to modify the Building Code of Australia

(BCA) to require that all new homes and major renovations would achieve a six-star energy efficiency rating (or equivalent). The necessary changes were included in BCA 2010 and subsequently enacted in State and Territory legislation.

The Victorian Government was reported to have reconsidered that commitment in early 2012 as part of a drive to reduce red-tape. However, in mid-April 2012, the Premier of Victoria reaffirmed his government's commitment to the mandatory 6 star energy efficiency rating. Therefore, the DNSPs have argued that new homes (and major renovations) in the distribution regions will use significantly less gas, on average, than older homes.

In deciding to implement the 6-star energy efficiency requirement, COAG had regard to a Regulation Impact Statement (RIS) prepared by the Centre for International Economics (CIE).[17] In that RIS, CIE estimated that the introduction of the 6-star energy efficiency requirement would cause new house in Victorian to use on average approximately 6.561 GJ/a less gas than they would if the energy efficiency requirement remained at 5-star.

Core has adopted this estimate and assumed that from 2013 new homes in the Envestra Albury distribution area will use 12 per cent, or approximately 5.3 GJ less gas than they would have used without the 6-star energy efficiency requirement.

We consider this assumption to be reasonable in light of the RIS on the 6-star energy efficiency requirement prepared by CIE.

4.5.4 Network Price Increase

The last adjustment made to reach the Final Forecast for Tariff V demand takes into account the fact that Envestra's proposed network price increases will reduce customer demand in accordance with the assumed own-price elasticity of demand for gas. Core has used a process whereby an intermediate demand forecast is created and applied to the Post Tax Revenue Model (PTRM) to determine the X factors. These X factors are then fed back into Core's model to arrive at the final demand forecast (a similar process was used in the last review of Envestra's South Australian and Queensland networks). The network price adjustment results in a reduction in Tariff V Residential demand of 3 TJ/a in 2013, rising to 15 TJ/a in 2017. The corresponding reduction in Tariff V Non- residential demand is 0 TJ/a in 2013, rising to 4 TJ/a in 2017.

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[17] CIE prepared the demand forecasts for SP AusNet.

5 Assessment of the forecasts

In this chapter we review Envestra's forecasts themselves, to consider whether the application of the methodologies and assumptions has produced forecast results for the Envestra Albury network that are reasonable in light of historical patterns of demand as well as current and anticipated influences on retail gas demand in the distribution area. We consider separately the forecasts for the Volume and Demand sectors of the market.

5.1 Use of trend extrapolation for forecast verification

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

Note that the scale of the Y axis in the following charts has been chosen to allow the relationships between forecasts, historical trends and confidence intervals to be seen clearly. This has the effect of exaggerating the apparent extent of deviations from historical trends, when in fact the changes may be much less pronounced when viewed in absolute terms. Care should therefore be exercised in interpreting the charts.

5.2 Tariff V Customer forecasts

5.2.1 Tariff V customer numbers

The forecast of total customer numbers for the Tariff V customer sector is summarised and compared with historical actual customer numbers in Figure 4.

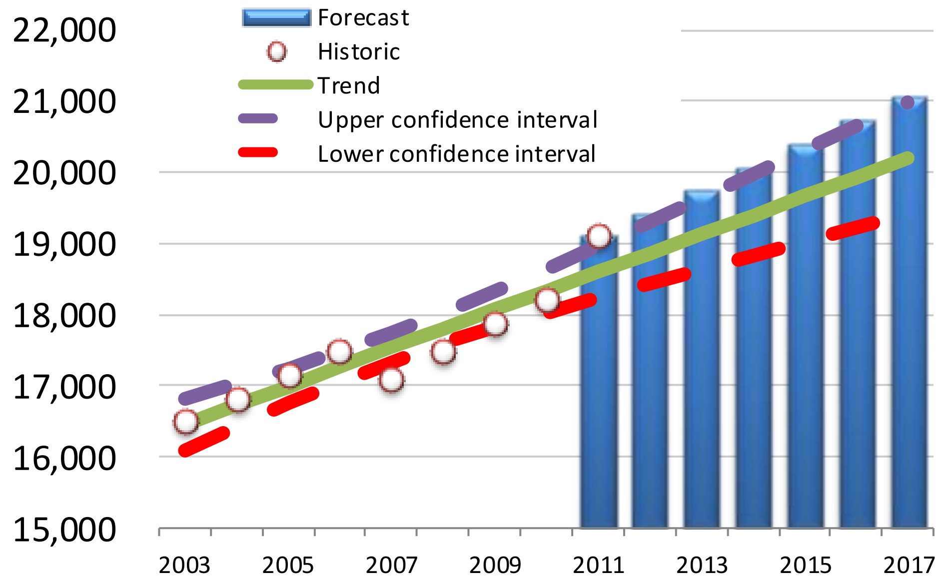
Forecast growth in customer numbers is greater than the historical trend rate, which was generated using an Ordinary Least Squares (OLS) regression on actual customer numbers from 2003 to 2011.

By 2017 the forecast is 865 residential customers above the trend line and 74 above the upper bound of the 90% confidence interval around the historical trend. Offsetting this is the fact that commercial customer numbers are forecast to be flat. By 2017 they are significantly below the lower bound of the

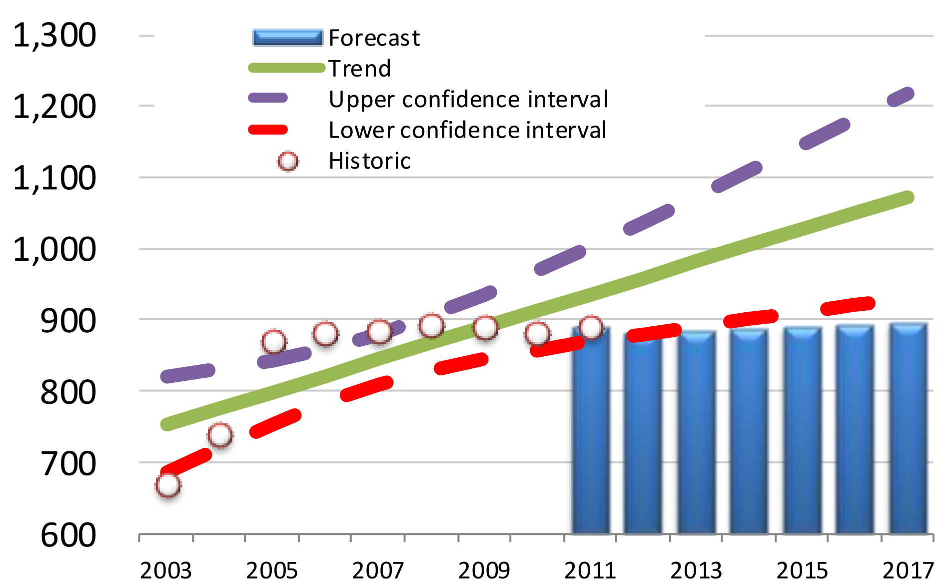
90% confidence interval around the historic trend. However, this trend includes data points for 2003 and 2004 which show much lower numbers of commercial customers. It is our understanding that the discontinuity in the data series relates to changes in the definitional arrangements relating to residential and non-residential Tariff V customers. As can be seen by inspection of the data since 2005, the forecast for commercial customer numbers closely follows the trend of the historical data from 2005 on.

Figure 4 **Historical and forecast customer numbers—Tariff V**

Residential



Commercial



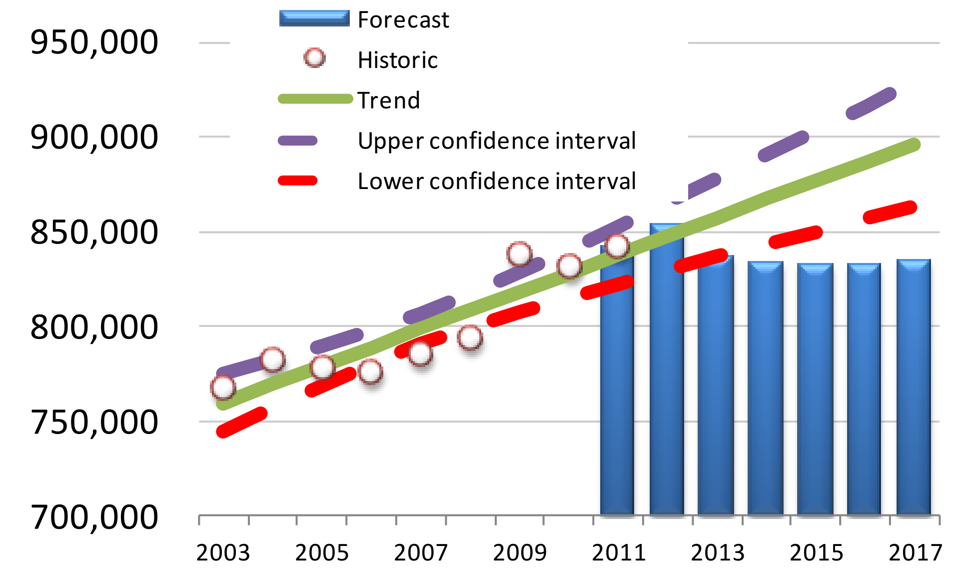
Data source:(NIEIR, 2007); (Core, 2012); ACIL Tasman analysis

On balance, we consider that the forecasts for Tariff V customer numbers appear reasonable when compared with historical trends.

5.2.2 Tariff V gas demand

The forecast of gas demand for the Tariff V residential customers is summarised and compared with weather normalised historical data in Figure 5. The corresponding comparison for the Tariff V Business customers group is shown in Figure 6.

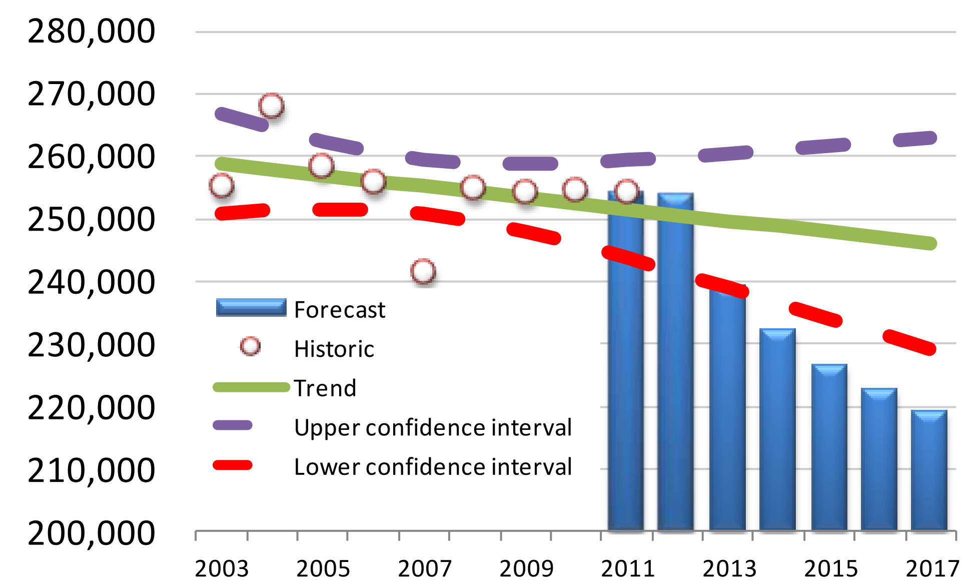
Figure 5 **Forecast consumption compared to weather-adjusted historical trend—Tariff V Residential customer sector**



Note: Consumption in GJ/year.

Data source:(NIEIR, 2007); (Core, 2012); ACIL Tasman analysis

Figure 6 **Forecast consumption compared to weather-adjusted historical trend—Tariff V Business customers**



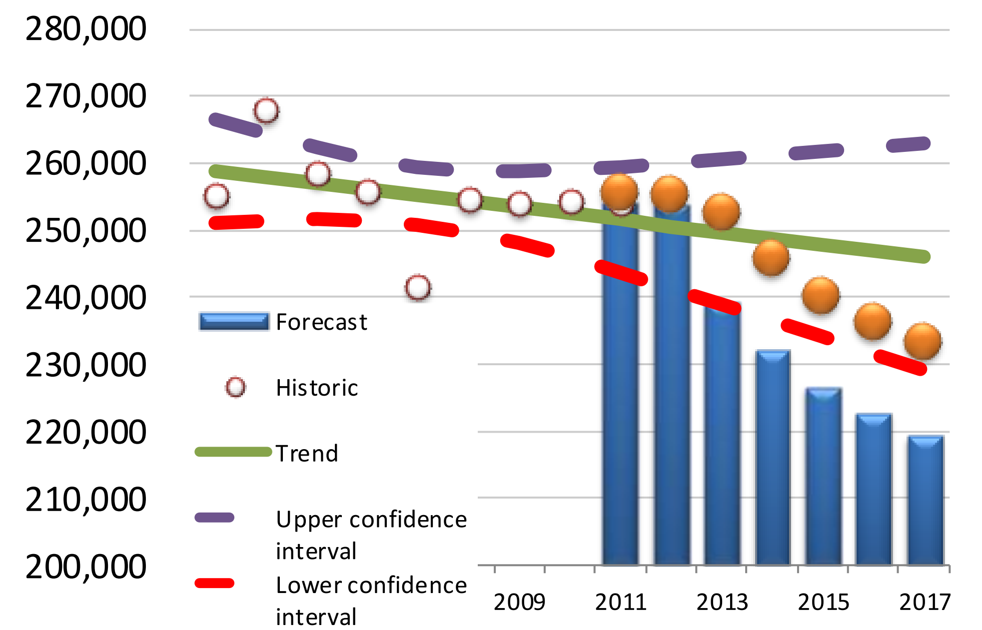
Note: Consumption in GJ/year

Data source:(NIEIR, 2007); (Core, 2012); ACIL Tasman analysis

The forecast demand levels for Tariff V residential and commercial customers diverge noticeably from the historical trend, rapidly falling below the 90 per cent confidence interval. The inflection in the forecast numbers between 2013 and 2014 suggests that the adjustments for policy and external changes (most likely wholesale gas price) are having a significant influence.

However, as discussed in section 4.4.2, Envestra's approach to defining 'normal' weather appears to have understated demand as well. Figure 7 shows that a forecast based on HDD data including 2011 lies within the confidence interval around the historic trend in the data. In our view, this represents a reasonable forecast for sales in this region, subject to adjustment for inclusion of the 2011 weather data.

Figure 7 **Forecast consumption compared to weather-adjusted historical trend—Tariff V Business customer – revised definition of 'normal' weather**



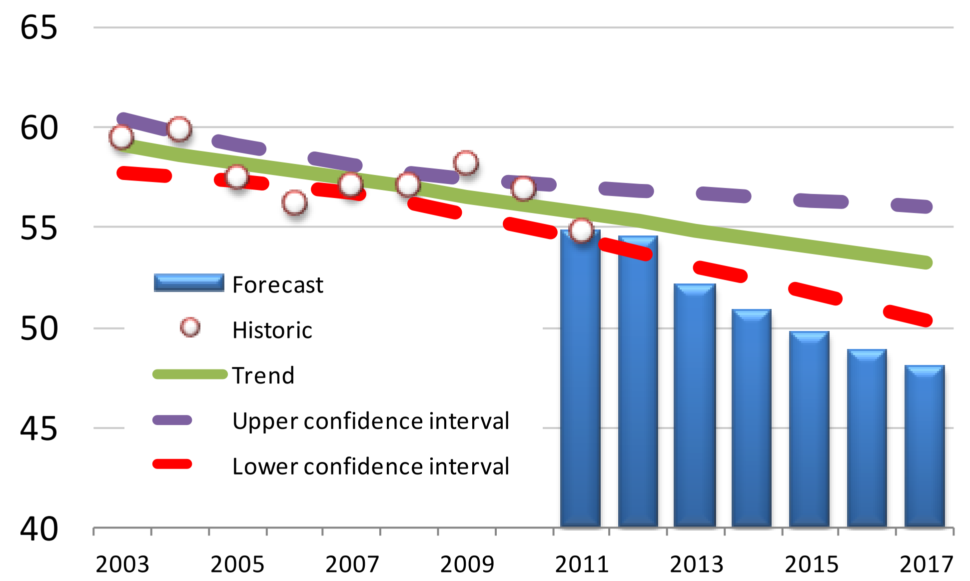
Note: Consumption in GJ/a

Data source:(NIEIR, 2007); (Core, 2012); ACIL Tasman analysis

5.2.3 Tariff V forecast average consumption

Assumptions regarding average gas consumption per customer for the Tariff V sector are critically important to the overall demand forecasts because the forecasts are generated by applying average gas consumption rates to the projected customer numbers in each demand segment. The implied average gas consumption per Customer in the Tariff V sector as a whole is shown in Figure 8.

Figure 8 **Actual vs forecast average gas consumption per Volume Customer, after weather normalisation**

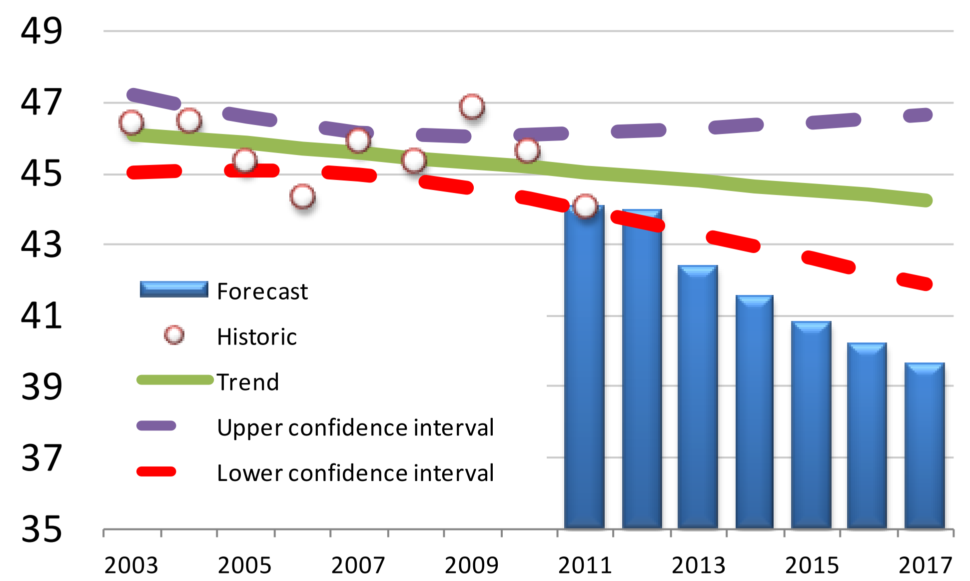


Note: Annual demand in GJ/connection

Data source:(NIEIR, 2007); (Core, 2012); ACIL Tasman analysis

The corresponding comparisons for the Tariff V Residential and Tariff V Business (Commercial & Industrial) customer groups are shown in Figure 9 and Figure 10 respectively

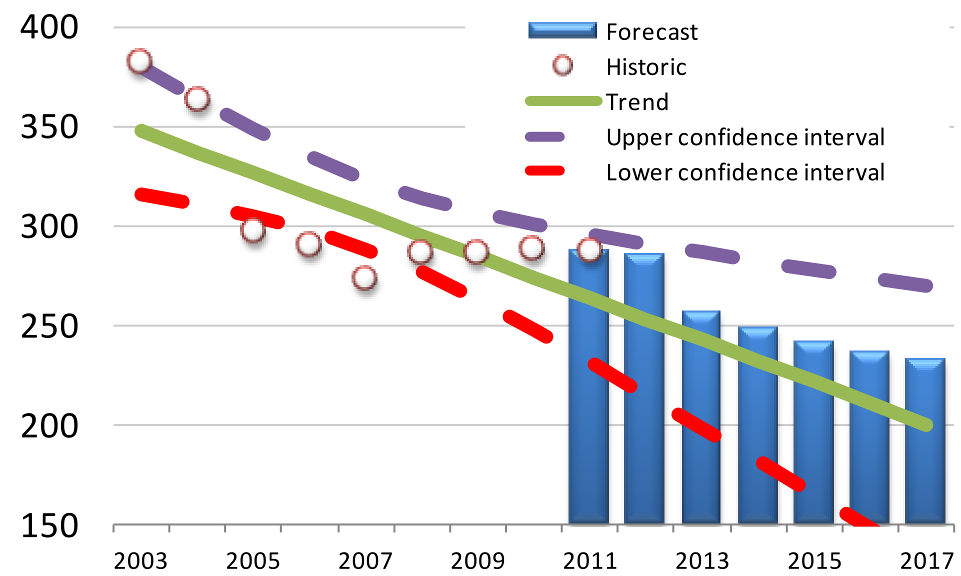
Figure 9 **Actual vs forecast average gas consumption per customer, after weather normalisation—Tariff V Residential customers**



Note: Annual demand in GJ/connection

Data source:(NIEIR, 2007); (Core, 2012); ACIL Tasman analysis

Figure 10 **Actual vs forecast average gas consumption per customer, after weather normalisation—Tariff V Business customer**



Note: Annual demand in GJ/connection

Data source:(NIEIR, 2007); (Core, 2012); ACIL Tasman analysis

The forecast average consumption per customer for both residential and non-residential Tariff V customers continues long term downward trends, driven by improved appliance efficiency and government policies aimed at reducing energy consumption and associated greenhouse gas emissions. As the charts show, the forecasts lie close to historical trends and well within the 90 per cent confidence interval. On this basis we consider that the forecasts of average consumption for Tariff V customers are not unreasonable.

5.3 Tariff D customer forecasts

5.3.1 Tariff D customer numbers

The Tariff D customer class represents large gas users (>10TJ/year), and includes both commercial and industrial customers.

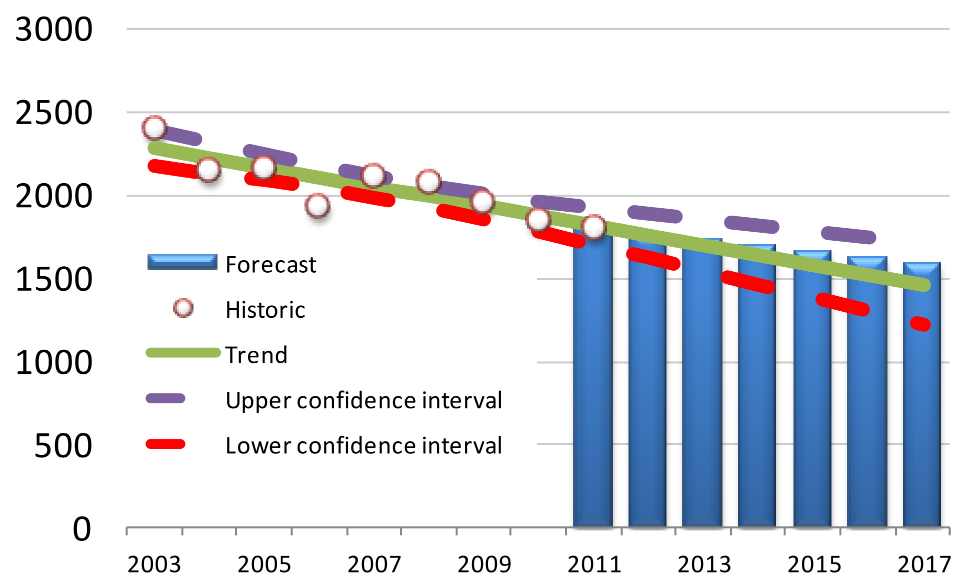
Historically, Envestra Albury has supplied nine tariff D customers. Core forecasts that this will fall to seven by the end of the regulatory period. The Regulatory Information Notification also shows customer numbers declining to 7 by 2017. Envestra Access Arrangement Information(Envestra, 2012c, p. 187) states that Tariff V customer numbers in the Albury distribution network are projected to decline to 9 by 2017. This is consistent with the “final amended forecast” presented with the Core demand model.

With numbers this small it is extremely difficult to be confident in forecasts. It is equally difficult to reach a view that it is unreasonable to expect that one or two industrial customers will close in Albury and surrounds over the next five years, or conversely that one or two new customers will emerge and so cause a significant change in sector gas demand.

5.3.2 Tariff D demand

The historical gas demand and demand forecasts for the Tariff D customer group in aggregate are shown in Figure 11. The historical data, which is drawn from a combination of information presented in (NIEIR, 2007) for 2003 and 2004, and (Envestra, 2012b) for 2005 to 2011, shows that while Tariff D customer numbers have been stable over the past decade, total gas consumption within the customer group has fallen fairly steadily, from almost 2.4 PJ/a in 2003 to around 1.8 PJ/a in 2011. This can be attributed to a combination of energy and environmental policies that have driven efficiency improvements, as well as to weak economic circumstances that have affected the manufacturing sector in particular. Envestra's forecast for gas consumption in the Tariff D customer sector sees this decline in consumption continue on much the same downward trend.

Figure 11 **Tariff D customer gas demand**



Note: Gas demand in TJ per year

Data source:(NIEIR, 2007); (Core, 2012); ACIL Tasman analysis

The ongoing decline in consumption reflects the combined effects rising wholesale gas prices and carbon pricing which are expected to put downward pressure on gas demand in the industrial sector, as well as the ongoing influence of energy efficiency and emission reduction policies. We consider this forecast to be not unreasonable.

5.3.3 MHQ forecasts for Tariff D customers

Relationship between MHQ and gas demand

While it is important to consider the volume forecasts for Tariff D customers, it is the forecasts of Maximum Hourly Quantity (MHQ) bookings that are of most importance in terms of implications for tariff setting. This is because the charges for Tariff D customers are calculated on the basis of the system capacity (MHQ) used, rather than the physical quantity of gas delivered.

The relationship between gas demand and MHQ is complex. The ratio of average hourly throughput to peak hourly throughput (that is, the "load factor") varies widely from customer to customer. MHQ is directly related to peak daily requirements, rather than average daily requirements.

Hence the loss or gain of a demand customer has an impact on aggregate system MHQ requirements that is not necessarily proportional to the corresponding impact on total gas demand. A very low load factor customer such as a peaking electricity generator may have a large MHQ requirement, but may consume only a small quantity of gas over the course of a year.

The impact of changes in MHQ is further complicated by the fact that capacity is not uniform throughout the pipeline network. Hence the cost impact of adding or subtracting a customer with a given MHQ requirement may vary depending on where that requirement is located within the system.

MHQ history and forecast

Historical and forecast MHQ for the Tariff D customer group as a whole is shown in Figure 12. We have noted some apparent inconsistencies between the Tariff D MHQ forecasts set out in the Core Energy Demand Forecast Model (Envestra, 2012b) and the Regulatory Information Notification submitted by Envestra. These differences are summarised in Table 13. The major discrepancies relate to the historical data which shows the values from the Core Energy model to be between 20% and 25% higher than shown in the Regulatory Information Notification (RIN); MHQ estimates for 2011 and 2012 are the same in both sources, while in the period after 2012 the MHQ values shown in the RIN are around 2% higher than in the Core Energy model. Adjustments made by Envestra to the Core forecasts bring the projected MHQ levels for the period 2013 to 2017 into line with the RIN values. In the following analysis of historical and forecast trends in Tariff D customer MHQ, we have relied as far as possible on the values set out in (Envestra, 2012b) including the Envestra adjustments (that is, in line with the RIN values).

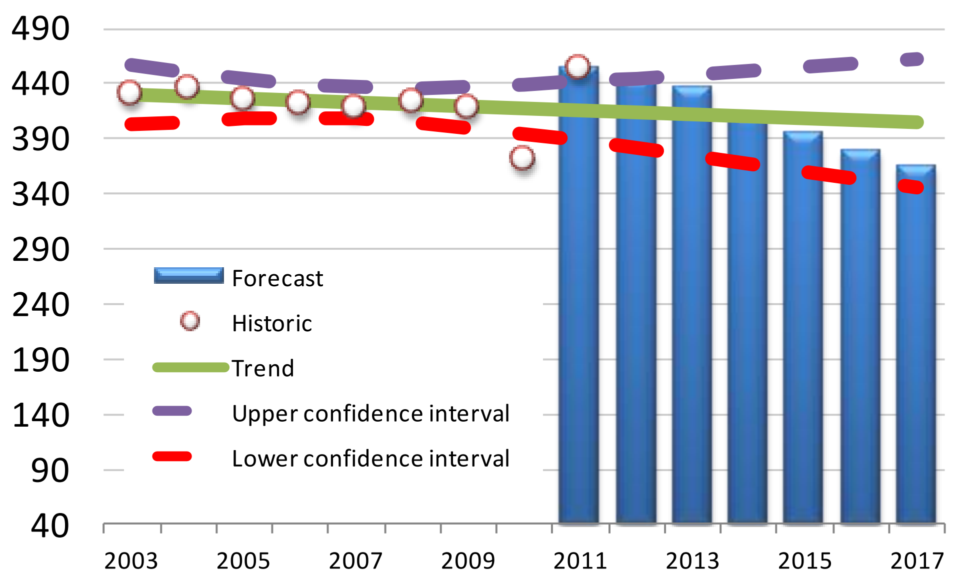
Table 13 **Comparison of MHQ values for Tariff D customer group, CORE Energy Model vs Regulatory Information Notification**

	CORE Energy model	RIN
2005	510.9	
2006	518.1	
2007	511.8	418.1
2008	524.9	423.2
2009	506.3	418.1
2010	471.6	372.5
2011	455.0	455.0
2012	445.2	445.2
2013	430.1	436.4
2014	407.0	413.3
2015	388.1	394.4
2016	372.7	379.0
2017	358.6	364.9

Note: Maximum Hourly Quantity expressed in GJ/hour.
Data source: *(Envestra, 2012a)*, *(Envestra, 2012b)*

Figure 12 illustrates the historical Tariff D Customer MHQ requirement and compares the trends in the historical data with the forecasts prepared by Core Energy. MHQ has trended slowly downward over the past decade. The rate of decline has not been as strong as for Tariff D consumption (Figure 11) and the values for 2010 and 2011 appear to be somewhat anomalous.

Figure 12 **Tariff D Customer Maximum Hourly Quantity (MHQ)—TOTAL**



Note: Maximum Hourly Quantity in GJ/hour
Data source:(NIEIR, 2007); (Core, 2012); *(Envestra, 2012b)*; ACIL Tasman analysis

The forecast decline of Tariff D customer MHQ does not appear to be statistically different from the estimated historical trend, and in view of the anticipated impacts of carbon pricing, higher wholesale gas prices and increased network charges the forecast does not appear to be unreasonable.

6 Conclusions

Notwithstanding the methodological issues identified in Core's analysis of gas demand in the Envestra Albury network, we have concluded that a more rigorous approach would not necessarily produce a more reliable forecast. This is because of the limitations of available data and the difficulties involved in reliably estimating the coefficients associated with each of the variables in a fully specified demand function.

Accordingly, while recommending that consideration be given in future to the methodological issues identified, we consider that in the circumstances the approach used by Core to develop the Envestra Albury demand forecasts is acceptable.

In considering the approach to weather normalisation of historical data, the key issue arising is the assumption regarding "normal" weather between 2005 and the present. The Envestra forecasts are based on an HDD trend that is sensitive to the input period. Those projections were based on all data available when they were prepared. However, since then, another year of data has become available. If that year is included in the projection, the outlook is for significantly cooler 'normal' weather conditions and consequently higher demand for gas.

We consider that it would be more appropriate for Envestra to include the 2011 data in its weather normalisation process. We estimate that, based on HDD data from 1994 (earliest available) to the present, this change would increase total forecast demand levels in the Envestra Albury system by between approximately 0.5 and 1.0 per cent per annum. We therefore recommend that AER should require Envestra to modify its weather normalisation process so that the 2011 data is included.

We agree with Envestra that the price of gas is likely to increase over the regulatory period and that this is an important factor to take into account in forecasting gas demand.

We accept that it is appropriate to take into account the whole of the (anticipated) network price increase in determining the expected future delivered price of gas to customers on the Envestra Albury network.

The analysis has assumed a value of -0.30 for the own-price elasticity of demand for gas, consistent with the AER's recent decision regarding access arrangement in South Australia. This is broadly supported by analysis undertaken by Core which found an estimated price elasticity of about -0.27

for all customer classes on the Envestra Albury network, and is generally consistent with the estimates used the other distribution businesses.

Envestra and its consultant Core do not appear to have considered the impact that higher electricity prices will have on gas demand. In its report to SP AusNet, CIE concluded that the price of electricity should not be included in its models of gas demand (CIE, 2012). Given the ambiguous nature of the results and the low absolute cross-elasticity values observed in the CIE analysis, as well as the lack of other relevant evidence, we consider that Envestra's reliance on own-price elasticity estimates alone is not unreasonable.

We have reviewed the forecasts themselves, to consider whether the application of the methodologies and assumptions used by Core have produced forecast results for the Envestra Albury network that are reasonable in light of historical patterns of demand as well as current and anticipated influences on retail gas demand in the distribution area.

Based on a comparison with historical trends and statistical confidence intervals around those trends, we find that the forecasts of customer numbers, average demand per customer and total demand by customer class are not unreasonable, with the proviso that the AER should require Envestra to modify the forecasts by including actual 2011 weather data in its weather normalisation process.

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A Curriculums Vitae

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

Paul Balfe

Paul Balfe is an Executive Director of ACIL Tasman and has overall responsibility for ACIL Tasman's gas business. Paul has more than 30 years experience in the energy and resources sectors. Previously he held a number of senior executive positions in the Queensland Department of Minerals and Energy. He has a Masters in Business Administration and a degree in Science.

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

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

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

Joel Etchells

Joel Etchells is a Consultant in ACIL Tasman's Brisbane office. Prior to joining ACIL Tasman Joel was employed by the Federal Treasury as a member of the International and Model Development Unit, within the Macroeconomic Modelling Division. In this role he was required to produce and analyse economic modelling results, including results from a variety of models. Joel used CGE models to forecast the impact of alternative climate change mitigation policies on the Australian economy and its major trading partners.

This involved examining the broad macroeconomic impacts of proposed polices, through to sector specific analysis within a CGE framework.

Since joining ACIL Tasman, Joel has used CGE modelling techniques to analyse the economic impact of variety of infrastructure/capital investments and economic policies; ranging from large natural resource development projects, through to an analysis of the impact of geospatial information for the Tasmanian economy. This work involved formulating and subsequently simulating economic shocks associated with a particular scenario as well as the qualitative analysis of the model output. He has also worked on gas access regulation in Victoria.

Joel has an Honours degree in economics from the University of Queensland and is currently completing a Bachelor of Applied Mathematics at the Queensland University of Technology. His honours year encompassed 12 months of postgraduate coursework and research with a major in econometrics, equipping him with the requisite skills to undertake a wide range of economic analysis.

Jeremy Tustin

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

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

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

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

Jeremy recently conducted (with others) the following projects:

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

Dr Leo Yanes

Leo Yanes is a Senior Consultant in ACIL Tasman's Brisbane Office. Dr Yanes has a strong background in quantitative economics, with an emphasis on econometrics, planning, valuation (discounted cash flows, cost-benefit analysis), quantitative risk analysis (Monte Carlo simulation, real options), and general equilibrium analysis.

Dr Yanes' modelling expertise encompasses supply chain modelling (including consolidated valuation using discounted cash flows, tax modelling and quantitative risk analysis), partial and general equilibrium models, input-output analysis and cost-benefit analysis.

Dr Yanes' regulatory and policy experience includes the following economic impact studies:

- Oil & gas sector expansion in Venezuela (PDVSA, Venezuela, 1994-1997)
- Santos GLNG project (Santos/Petronas/Total/KoGas, QLD, 2008)
- Australia-Pacific LNG project (Origin/ConocoPhillips, QLD, 2009)
- Impact to 2070 of the educational aspects of the National Reform Agenda, encompassing early childhood, schools and tertiary (Department of Education, Employment and Workplace Relations, ACT, 2010)

Dr Yanes has several years of econometrics training, most of it received at the London School of Economics (U.K.), were he completed the M.Sc. and Ph.D. in economics. His econometrics expertise includes non-parametric methods (Data Envelopment Analysis or D.E.A.), time series, cross-section and panel data studies, using classical econometrics. His experience in this field includes:

- Forecasting private mining exploration expenditure and mining production for NSW to 2025. These forecasts were based on time series and dynamic panel data econometrics, and required forecasting the Reserve Bank of Australia's Commodity Price Index (for the NSW Geological Survey, 2010)

- A time series (co-integration) analysis of oil sector linkages in Venezuela, spanning 1950-1995 (for PDVSA, the National oil company of Venezuela, 1995)
- Forecasts for the Eastern Australia gas market to 2100. These forecasts were based on market growth projections (for Santos, 2009)

Dr Yanes' commercial/business planning experience includes project appraisal using discounted cash flow and long and short-run forecasting. He has built cash flow models for various oil & gas projects at Santos and PDVSA (the Venezuelan national oil company). Among these, Dr Yanes contributed to the construction of an integrated supply chain model for the Santos GLNG project, which encompasses all aspects of the production process, from a module forecasting gas and water flows through to LNG delivery.

As a lecturer at the School of Economics, University of Queensland (2002-2008), Dr Yanes taught and carried out research in industrial economics (monopoly, oligopoly & antitrust), mathematical economics, game theory, international trade, economic growth and firm structure. His research concentrated on analysing the impact of oligopolies on economic growth and international trade (in dynamic general equilibrium).

B Terms of Reference

The AER is seeking independent advice through written reports on the demand forecasts contained in the access arrangement proposals submitted by the Victorian transmission and distribution businesses to assist it in its decision about whether to approve the access arrangement proposals.

The consultant will be required to provide advice on whether the demand forecasts for each business have been arrived at on a reasonable basis and represent the best forecast for demand in the circumstances.

The review will require the consultant to undertake the following:

(i) a desktop review of demand forecasts and any relevant materials contained in the access arrangement proposals submitted by service providers

(ii) formulate a series of detailed questions on areas where it is considered that further information or clarification is required from the service providers to substantiate the demand forecasts

(iii) analyse all material provided and prepare separate reports for each service provider containing a list of issues identified from the review, and recommendations on whether the demand forecasts for each service provider have been arrived at on a reasonable basis and represent the best forecast for demand in the circumstances.

(iv) provide alternative forecasts of demand for the service providers if the consultant finds that the proposed demand forecasts have not been arrived on a reasonable basis and do not represent the best forecast for demand in the circumstances.

If requested by the AER the consultant will also:

(v) provide further advice on the revised access arrangement proposals from service providers scheduled to be submitted after the release of the AER's draft decisions.

The AER's decisions are subject to merits review by the Australian Competition Tribunal and judicial review by the Federal Court. The consultant's analysis and reports must be produced to a standard that is commensurate with scrutiny at that level. The consultant must describe in its written report the qualitative and/or quantitative methodologies applied in any calculation or formulae, the input values used or assumed, the rationale for any substituted values used or assumptions made and the conclusions reached in sufficient detail to support the AER in meeting its obligations under the relevant clauses of Part 9 of the NGR.

In addition to the draft and final reports, the consultant must provide supporting spreadsheets and analysis to ensure the AER can meet the requirements set out in Rules 59 and 62 of the NGR for the making and publication of decisions.

The consultant will be required to liaise with service providers and AER staff during the course of the access arrangement review. These consultations may include e-mail and telephone communications with AER staff and service providers.

C Establishment of Confidence Intervals around historical trend lines

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

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

Confidence Intervals (CI's) have the form:

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

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

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

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

and

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