Load forecast reconciliation

Review and reconciliation of AEMO's and ETSA Utilities' 2011 peak demand forecasts

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Version 0.2

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Glossary of Terms

Term	Description
ABS	Australian Bureau of Statistics
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMD	Agreed maximum demand
CP	Connection Point
°C	Celsius
DNSP	Distribution network service provider
DSP	Demand-side participation
ETSA	ETSA Utilities
ESCOSA	Essential Services Commission of South Australia
ESIPC	Electricity Supply Industry Planning Council of South Australia
ESOO	Electricity Statement of Opportunities
GDP	Australian Gross Domestic Product
GSP	South Australian Gross State Product
GWh	Gigawatt hours
HV	High voltage
IMF	International Monetary Fund
kW	Kilowatt
kWh	Kilowatt hour
MD	Maximum demand
MRET	Mandatory renewable energy target
MW	Megawatt
MWh	Megawatt hour
MVA	Megavolt-ampere
NSP	Network service provider
PoE	Probability of exceedence
PV	Photovoltaic
RBA	Reserve Bank of Australia
SASDO	South Australian Supply and Demand Outlook
TNSP	Transmission network service provider
W	Watt

Executive Summary

ElectraNet has reviewed and reconciled the 2011 state-wide demand forecasts published by AEMO and ETSA Utilities' 2011 connection point forecasts for the period 2011-12 to 2020-21.

The review has found a number of weaknesses in the state-wide forecasting model, which result in wide error margins around the forecasts published by AEMO. Several areas have been identified where the state-wide demand forecasts could be improved. In particular:

- the 2011 forecasts were produced using a model with relatively poor statistical properties and correspondingly wide error margins associated with its outputs. High standard errors associated with the annual regression model's estimated coefficients indicate that the forecasts could vary by around +/-190 MW around the mean forecasts;

- there are data input deficiencies and omissions in relation to assumed new spot loads, historic DSP and load shedding, and population. These factors are found to have understated the demand forecasts by 140 MW; and

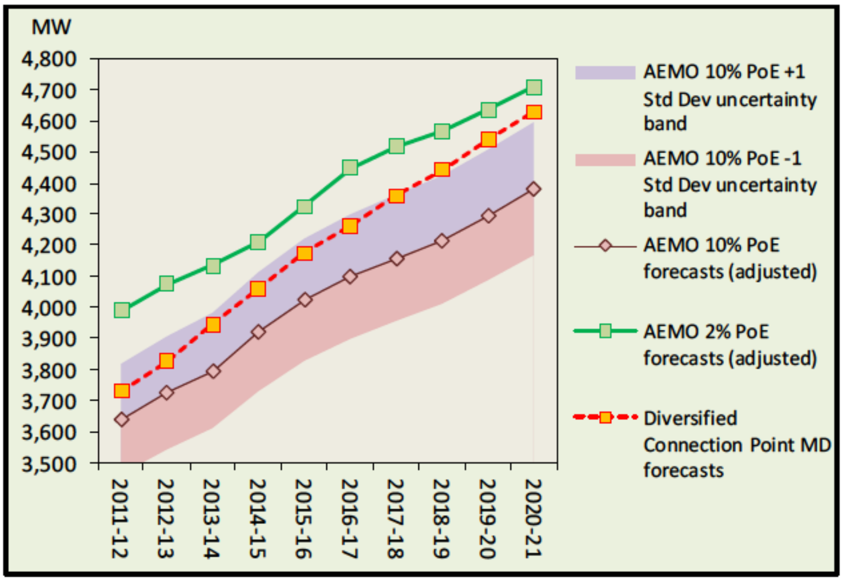
- the 2011 annual forecasting model is found to produce forecasts that are biased downwards to some extent due to the treatment of solar PV generation and changes in trend growth of the water heating load. ElectraNet has estimated this effect at between 45 MW and 68 MW.

ETSA Utilities' forecasting methodology and related assumptions were found to be reasonable and consistent with previous practise. Detailed testing of individual forecasts demonstrated that reliable data and adjustments have been used to prepare the forecasts. The forecasts have not changed in a material way from those submitted to the AER as part of the 2010 distribution network pricing determination.

Differences between the two sets of forecasts can be explained through a combination of adjustments for diversity, transmission losses and generator loads, and correcting for the uncertainties and omissions noted above in relation to the state-wide forecasts. The diversity factors used in the reconciliation assume small changes over time, consistent with trends observed in historic load diversity.

ElectraNet's reconciliation of the forecasts is summarised in the following figure.

Figure ES1 - Reconciliation of the 2011 peak demand forecasts



The reconciliation identifies a range of uncertainty around AEMO's (adjusted) 10% PoE forecasts, reflecting the plus/minus one standard deviation range of possible outcomes due to the relatively large standard errors associated with the estimated annual model's coefficients. The diversified connection point demand forecasts to 2017-18 lie entirely within this range.

ElectraNet's review has found that both sets of forecasts represent customer demand after the assumed impact of rooftop solar PV generation. As ETSA Utilities' and AEMO's assumptions about solar generation are quite similar, this has not been an issue in reconciling the forecasts. However, during the course of this review, ElectraNet has become aware of information published by ESCOSA regarding the level of solar generation installed as at 30 December 2011. This information indicates there is considerably more installed capacity than was assumed by either ETSA Utilities or AEMO early in 2011 when the forecasts were prepared.

<u>Conclusions</u>

1. While AEMO's underlying forecast methodology itself is sound, the 2011 state-wide forecast model is found to suffer from a number of weaknesses and shortcomings which result in a high degree of uncertainty surrounding the model outputs, reducing the reliance which can be placed upon the forecast.

2. ETSA Utilities connection point forecast methodology and assumptions are found to be reasonable and consistent with previous practice, are based on reliable data and adjustments, and produce a predictable and valid set of connection point level peak demand forecasts.

3. The divergence between the two sets of forecasts can be explained through a combination of adjustments for diversity, transmission losses and generator loads, and corrections for a number of uncertainties and omissions in relation to the state-wide forecast.

4. On the basis of the analysis undertaken and the information available in 2011, the differences between the two forecasts can be explained, and the connection point forecasts supplied by ETSA Utilities represent a sufficiently accurate and reasonable basis on which to plan and prepare for network augmentations for the 2013-2018 regulatory period.

5. New information on the extent of solar PV generation has become available since the preparation of the 2011 connection point and state-wide load forecasts. The impacts of this generation on peak load should be reviewed by the respective parties in preparing the 2012 load forecasts.

Acknowledgements

ElectraNet acknowledges the assistance of AEMO and ETSA Utilities in the preparation of this report.

1. Introduction

The purpose of this report is to review and reconcile South Australia's 2011 connection point maximum demand forecasts and the state-wide peak demand forecasts prepared by the Australian Energy Market Operator (AEMO) in 2011.

The report is structured as follows:

- Section 2 presents background information and ElectraNet's review of AEMO's state-wide peak demand forecasts. These forecasts were prepared in 2011 and reported in the *2011 Electricity Statement of Opportunities* (ESOO) and the *2011 South Australian Supply and Demand Outlook* (SASDO).

- Section 3 presents background information and ElectraNet's review of the 2011 connection point maximum demand forecasts. These forecasts are tabulated at *Attachment 6 – Connection point maximum demand forecasts.*

- Section 4 presents ElectraNet's reconciliation of the two sets of forecasts.

2. AEMO's 2011 peak demand forecasts

2.1 Background

In this section of the report ElectraNet summarises its review of AEMO's 2011 base case peak demand forecasts for South Australia and the models and assumptions underpinning those forecasts.

ElectraNet's objectives in conducting the review are to:

- identify how and why AEMO's forecasts have changed over time;
- review the underlying forecasting model to identify any shortcomings and improvements that could be made to the model;
- review the economic assumptions underpinning the forecasts; and
- quantify the extent of uncertainty in the forecasts so that this can be allowed for in the reconciliation of the state-wide forecasts and the connection point forecasts.

AEMO's 2011 South Australian electricity forecasts are tabulated at *Attachment 1 – AEMO's 2011 SA demand and energy forecasts*.

The scope and nature of the forecasts and related definitions are described at *Attachment 2 – Definitions and basis of AEMO's forecasts*.

2.2 Summary of ElectraNet's conclusions

AEMO's 2011 electricity forecasts are driven largely by the 2010-11 starting level of average annual demand, assumed increases in the population (which contribute around 0.8% growth each year), and unexplained trend growth (which contributes a further 0.7% growth each year). The forecast retail price level has an effect at the margin, with an elasticity of around minus 0.25, while the GSP forecasts have only a very small effect.

AEMO's forecasts of annual average demand are a key determinant of the peak demand forecasts. The overall regression fit of the 2011 annual model is poor, with an R^2 value of around 0.8. In practical terms this means predictions coming from the model will have a wide confidence interval (prediction interval) associated with them.

Only two of the five annual model regression coefficients are statistically significant at the 95% confidence level.

The coefficient on the income (GSP) variable implies an income elasticity of around 0.1%, which is considerably lower than elasticity values reported in the 2011 *ESOO* for South Australia and other states.

The annual model's income coefficient and the intercept term (which drives unexplained trend growth within the model) both have large standard errors relative to their estimated size. Adjusting either coefficient by its standard error results in the 2020-21 peak demand forecast being around +/- 4.9% higher or lower than the mean prediction. ElectraNet includes this range of uncertainty in its reconciliation of the connection point and peak demand forecasts.

The forecasting model does not deal adequately with solar PV generation or the water heating load.

- Trend growth of the water heating load has changed markedly in recent years, reducing annual average demand while not impacting peak demand levels. This may be a contributing factor to the poor overall fit of the annual model. Accounting for continuing falls in this load by way of a post model adjustment is an unreliable way to deal with the water heating load when its contribution to the unadjusted forecasts is unknown. ElectraNet concludes that the water heating load should be isolated and forecast separately, as is currently done with the Offset load, or an additional explanatory variable included in the annual model. Second round effects will also arise through the half hourly forecasting models due to the underlying change in the relationship between average demand and peak demand.

- The native demand measure used in the 2011 forecasting model omits significant levels of solar generation. The 2011 model is attempting to explain both supply and demand elements within a hybrid model that does not reflect customers' underlying demand for electricity. This is likely to be a further contributing factor to the poor overall fit of the annual model and the wide range of uncertainty in its outputs. ElectraNet concludes that solar generation should be added back into historic measures of native demand and forecast separately as a supply-side phenomenon.

- ElectraNet has made an estimate of the bias introduced into the 2011 forecasts due to AEMO's treatment of solar generation and the water heating load. This analysis indicates that the peak demand forecasts are understated by up to 68 MW, with a further second round bias likely to be introduced through the half hourly model structure. This potential bias is allowed for in the reconciliation of the connection point and state-wide demand forecasts.

There are several deficiencies in the historic data used to create the model, including an inconsistency in the historic population data and the omission of any DSP and load shedding that has occurred since 1 July 2009. This latter omission is likely to have had a negative impact on the peak demand forecasts and is allowed for in the reconciliation.

AEMO's Offset load assumptions differ from new spot loads assumed in the connection point forecasts. These differences are identified and allowed for in ElectraNet's reconciliation of state-wide and connection point forecasts. Differences in these assumptions could be avoided in the future through consultation between ETSA Utilities, AEMO and ElectraNet.

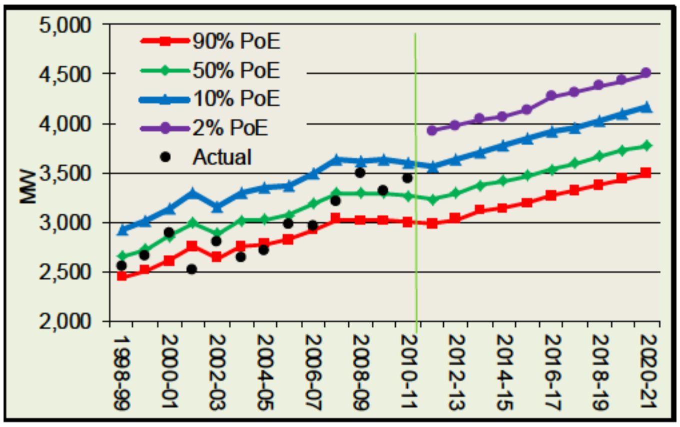
AEMO's post model adjustments for solar PV generation are broadly similar to ETSA Utilities' (implicit) assumptions, so this is not a factor in the reconciliation. However, ElectraNet observes that AEMO's forecasts of solar PV generation are much lower than indicated by information recently published in relation to the actual level of solar generation. AEMO's forecasts may therefore be revised to take this factor into account.

2.3 Overview of AEMO's forecasts

2.3.1 The 2011 forecasts

The following figure shows AEMO's back-cast and forecast peak demand PoE levels and past actual peak demands in South Australia.

Figure 2-1 Summer peak demand PoE levels

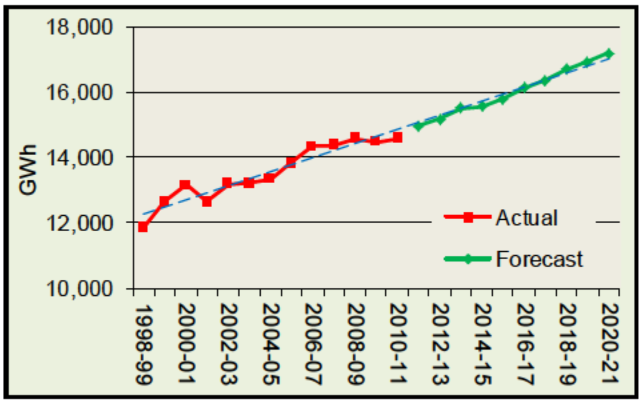


AEMO's 2011 back-casts show that South Australia has not experienced a 10% PoE peak demand outcome in any of the past 13 summers. Only four of these summers have produced an outcome above the back-cast 50% PoE level, with the highest of these being 3,490 MW in January 2009[1].

The back-casts also show a decline in historic PoE levels between 2007-08 and 2010-11. The 10% PoE level is forecast to decline again in 2011-12 by around 0.8% (28 MW) followed by a steady rise in future years. Average growth between 2010-11 and 2020-21 is projected at 1.5% (57 MW).

Annual energy volumes are a core component of AEMO's forecasting model and so ElectraNet has also considered these forecasts in its review. Actual and forecast annual energy are shown in the following figure.

Figure 2-2 Actual and forecast annual energy



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[1] AEMO's *2011 SASDO* reports a lower peak demand of 3,413 MW for 2008-09. That figure does not include load shedding that had occurred at the time.

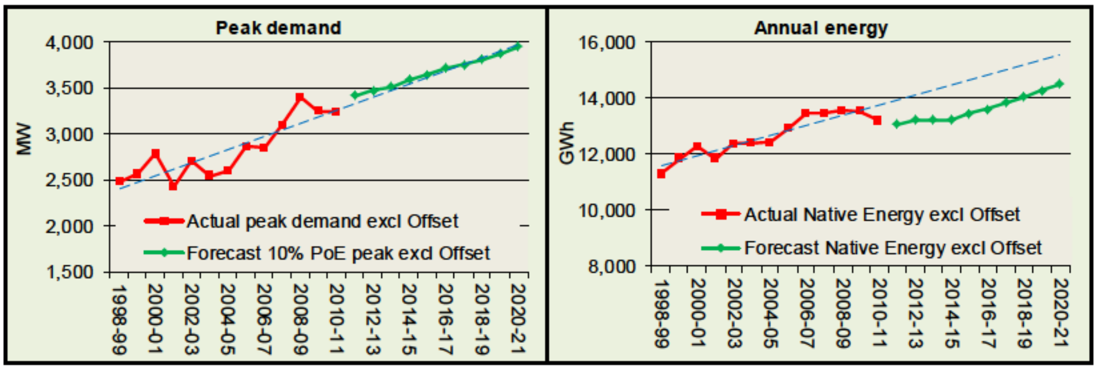
Unlike the 10% PoE demand level, which is forecast to fall in 2011-12, annual energy is projected to rise in 2011-12 by 2.7% (397 GWh). Average annual growth is projected at 1.7% from 2010-11 to 2020-21, broadly in line with the historic average rate observed between 1998-99 and 2010-11.

There are two notable observations from these charts.

- Annual energy is projected to continue growing broadly in line with the longer term trend rate of growth.
- The back-cast 10% PoE demand levels are assessed as having grown relatively steadily until 2007-08 and then plateauing or falling slightly for five years. Growth is projected to continue at around the historic rate from 2012-13, but at a level around 400 MW or so lower than implied by trend growth prior to 2007-08.

The Offset load, which includes large mining loads and new temperature insensitive loads, represents a significant component of total South Australian demand[2]. The following figure shows AEMO's forecasts after deducting the Offset load[3].

Figure 2-3 Demand and energy excluding the Offset load



After excluding the Offset load, the peak demand and energy forecasts reveal a very different outlook for South Australia's electricity requirements.

- Annual energy changed very little between 2006-07 and 2009-10, and then declined by 2.4% in 2010-11 to be around 250 GWh lower than in 2006-07. Annual energy is projected to fall again in 2011-12 by 1.1% (150 GWh). Average growth between 2011-12 and 2020-21 is projected at 1.2%, slightly lower than trend growth of 1.3% between 1998-99 and 2010-11. Although these growth rates are not materially different, growth from 2011-12 is coming off a low base,

[2] The base case Offset load forecast does not include major expansion of BHP-Billiton's Olympic Dam mine. It includes the Pt Stanvac desalination plant. Treatment of the Offset load within AEMO's forecasts is described in *Attachment 2 – Definitions and basis of AEMO's forecasts*.

[3] In making adjustments to the 10% PoE demand forecasts, ElectraNet has recognised that the forecasting methodology incorporates a probabilistic approach when including the Offset load into half hourly demand forecasts. We have therefore deducted forecast average Offset demand from the original 10% PoE forecasts rather than the Offset load peak demand.

with annual energy volumes in the future projected to be roughly 1,000 GWh below the longer term trend-line. Forecast annual energy does not rise above the 2008-09 level until 2016-17.

- The non-Offset 10% PoE demand level is forecast to rise almost directly in line with trend growth of past actual non-Offset peaks. This is an unexpected result as AEMO has assessed past actual peak demands as having been well below the 10% PoE level (refer *Figure 2-1* above). The explanation for this lays in the close relationship within AEMO's model between forecast peak demand levels and annual energy volumes. ElectraNet reviews this modelling relationship later in this section.

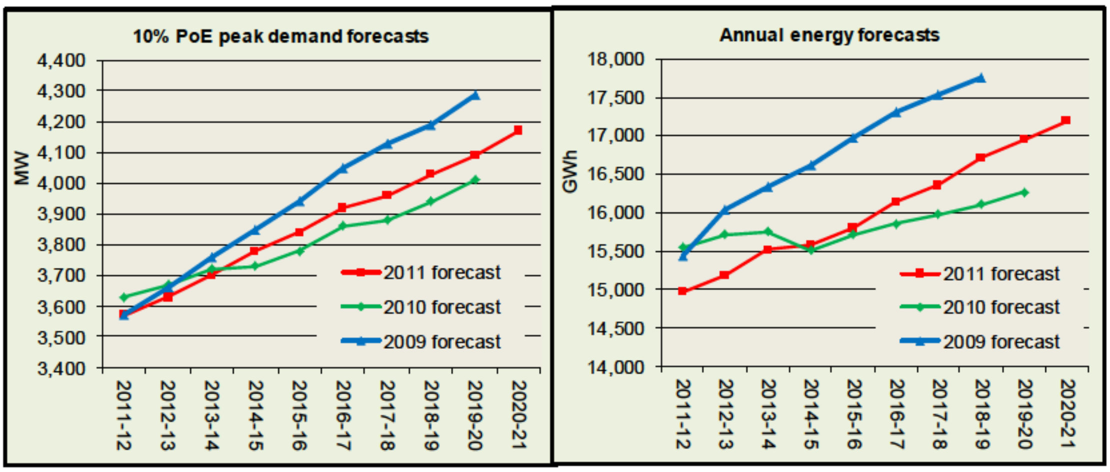
To the extent that AEMO's forecasts are correct, the data suggests that South Australia is in the midst of a generational change in energy demand patterns. Long range forecasting models based on historical relationships tend to become unstable in this type of environment due to the extra dimension of uncertainty. This is typically reflected in regression models with relatively poor explanatory power (low R^2 values), estimated coefficients that are not statistically significant (high standard errors relative to the size of estimated coefficients), and unexplained changes in forecasts from year-to-year (reflecting instability of the models as additional data become available).

2.3.2 Revisions to the forecasts over time

Stability of the electricity forecasts over time is a desirable property. That said, economies are sometimes subject to unpredictable external shocks and government policies may change, both of which may warrant revision of the forecasts.

ElectraNet has considered the evolution of AEMO's South Australian forecasts over time as part of its review. This provides perspective for assessing the relative importance of changes in the economic outlook, as opposed to model parameter changes, in determining the current level of the forecasts.

Figure 2-4 AEMO's forecasts 2009, 2010 and 2011



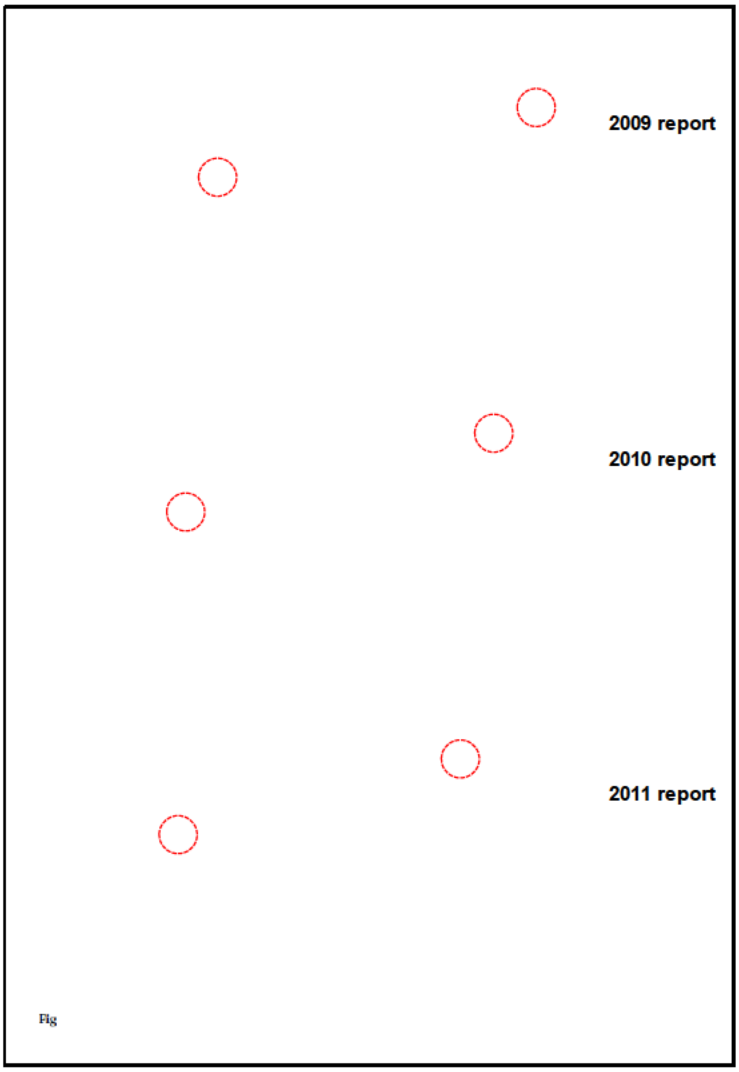
There have been significant revisions to the forecasts between 2009 and 2011, as shown in the above figure, with the revisions becoming more pronounced as the forecast horizon is extended.

- For the 2018-19 year, the most distant year common to the three sets of forecasts, annual energy was revised down by more than 9% (1,650 GWh) in the 2010 forecasts compared with the 2009 forecasts. The 10% peak for that year was revised down by 6% (250 MW).

- These changes were partly reversed in the 2011 set of forecasts, with projected energy in 2018-19 revised up by 3.8% (614 GWh) and the 10% PoE peak for that year rising by 2.3% (90 MW).

The period 2009-2011 has also seen changes in AEMO's modelling of historic PoE levels, as demonstrated in the following figure[4].

Figure 2-5 Changes in back-cast PoE levels



[4] The charts shown in this figure have been reproduced from Monash University's 2009, 2010 and 2011 forecasting reports to AEMO.

The back-cast 10% PoE levels have been revised upwards over time, with this effect particularly noticeable in the 2011 back assessment. In particular, the 2008-09 actual peak, which had previously fallen above the 10% PoE level, is shown to fall below the 10% level in the 2011 back-casts. Similar changes are apparent in relation to the 2000-01 peak demand. These changes reflect re-estimation of the underlying electricity demand model's parameters and additional temperature and demand information that becomes available each year.

Changes to the back-cast PoE levels highlight the dangers in stating that a particular year's peak demand was a "10% outcome" or some other particular value. This is a relevant consideration when ElectraNet reviews the connection point MD forecasts and reconciles them with the state-wide forecasts later in this report.

2.4 AEMO's forecasting model

The South Australian electricity forecasts for 2011, as in a number of earlier years, were prepared using a model developed by Monash University[5].

2.4.1 General description of the model structure

The forecasting model comprises the following components.

- An "annual model" is used to forecast the future annual average level of demand[6]. Annual average demand stood at 1,537 MW in 2010-11. The annual model is a multivariate regression equation explaining changes in annual average per capita demand in terms of changes in average per capita GSP, electricity prices and summer and winter cooling and heating degree days. AEMO's forecasts of the population, GSP and retail prices determine the forecast levels of annual average demand. The annual model forecasts are then used in conjunction with a series of half hourly models to produce simulated half hourly load traces.

- Forty eight "half hourly models" describe the behaviour of demand in each NEM trading interval. The dependent variable in these models is the natural logarithm of the ratio of half hourly demand to annual average demand. This variable is modelled as a function of short term temperatures and calendar effects such as time of day, day of week and time of year. This component of the model does not include variables to explain any changes in the ratio over time other than changes due to short term temperature and calendar effects.

[5] The forecasting model is described in *Demand forecasting for long-term peak electricity demand,* Rob J Hyndman and Shu Fan, IEEE Transactions on Power Systems, 2010 25(2) 1142-1153. The model, as it has evolved over time, is also described in a series of consulting reports to ESIPC, VENCORP and AEMO.

[6] The Offset load is excluded from this component of the model.

- These models are used in conjunction with historic half hourly temperature data to simulate different possible half hourly demand outcomes. A quasi-random annual temperature trace is created from historic temperature data and used to create predicted values of the demand ratio. These ratios are then used in conjunction with the average annual demand forecast from the annual model to predict a half hourly demand trace for a given year. One thousand simulations are run, each involving a different random selection of the temperature trace[7]. Each simulation also incorporates a random selection of the model errors so as to incorporate the effects of random behaviour into the results. Each simulation also includes a random selection from the Offset load distribution, which is determined from information provided by AEMO in relation to past and future average and peak demand levels for these loads. Annual energy is determined by summing the demand trace for a particular year for a given simulation. The peak demand from each of the 1,000 simulated load traces is identified and used to create a probability density function for the annual peak, which is used in turn to identify peak demand PoE levels. The models may be run in back-cast mode to identify historic PoE levels, or in forecast mode by introducing the economic forecasts to predict future PoE levels[8].

- When used in forecasting mode, a number of post model adjustments are incorporated to capture the effect of policy changes that are assumed not to be reflected in trends in the historic data. These adjustments are applied to the model outputs and are discussed further in the following section which reviews the economic assumptions underlying the 2011 demand forecasts.

2.4.2 Comments on the overall model structure

The half hourly models are used to predict the ratio of half hourly demand to annual average demand under given temperature and calendar conditions. These models do not include variables that explain any longer term trend changes in the ratio. Thus, for a given projection of annual average demand in the future, the forecast level of demand in any particular half hour reflects the average historic ratio of half hourly demand to average demand under similar temperature and calendar conditions.

This fixed multiplicative relationship means that we would expect to see approximately a 5% increase in the forecast 10% PoE demand level given a 5% increase in forecast annual average demand. The annual model is therefore a core determinant of the level of the 10% PoE forecasts and any shortcomings or biases in the annual model will be reflected directly in the

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[7] When the model is run in forecast mode, simulated temperatures include an adjustment to reflect climate change, with temperatures rising moderately over time.

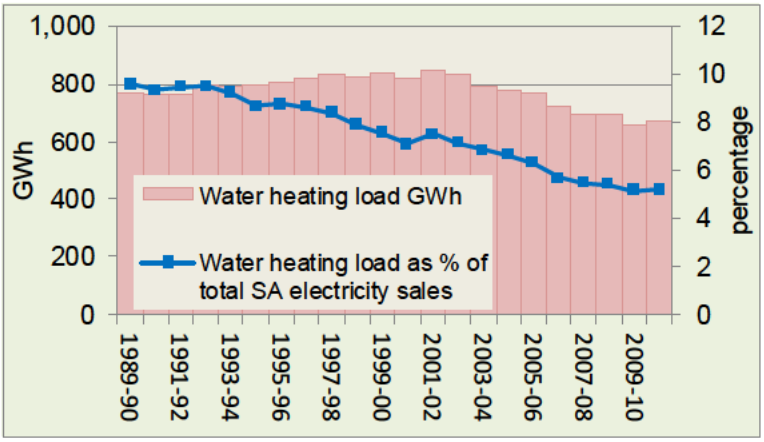
[8] The coefficient on the annual model price variable is adjusted when the model is used to predict demand PoE levels, reflecting the findings in Fan, S. and Hyndman, R.J. (2008) *The price elasticity of electricity demand in South Australia and Victoria*, Report for ESIPC and VENCORP.

forecast peak demand levels. The annual model is therefore reviewed in some detail in *Section 2.4.3 - The annual demand model*.

The fixed multiplicative relationship between half hourly and annual average demand is also a source of potential bias when there are underlying changes in customers' behaviour that affect the relationship between average and peak demand. Examples of these behavioural effects include changes in the overnight water heating load and recent rapid growth of solar PV generation.

The overnight water heating load has been falling by around 2% each year since 2000-01. This change has reduced average annual demand compared to what it might otherwise have been, but it is unlikely to have had any effect on peak demand levels. The following figure demonstrates the relative importance of this decline in water heating sales in the context of overall South Australian electricity sales.

Figure 2-6 South Australian water heating load



This behavioural change in electricity consumption is reflected within the forecasting model in several ways:

- The historic ratio of overnight demand to annual average demand has fallen markedly through time but the model assumes the ratio only changes in response to short term temperature and calendar effects. This will be a contributing factor to the poor fit of the half hourly demand models during overnight periods[9].
- The historic ratio of peak period demand to annual average demand will also have changed through time as a result of this effect[10]. The modelling structure, however, does not recognise this and its estimated parameters will reflect the best average fit over time. When used in forecasting mode, future peak period demand levels

[9] This is demonstrated in Figure 12 in Monash University's 2011 report to AEMO: *Forecasting long-term peak half-hourly electricity demand for South Australia*, Dr Shu Fan and Professor Rob J Hyndman, A report for the Australian Energy Market Operator, 13 May 2011.

[10] Changes in the ratio over time are shown in *Attachment 3 – Half hourly demand ratios*.

will tend to be understated as they reflect the average historical ratio under similar calendar and temperature conditions. This effect will be compounded if there are continuing changes in the ratio due to further declines in the water heating load.

ElectraNet concludes that the model's peak demand forecasts will be biased downwards due to this effect. Similar concerns also arise in relation to AEMO's treatment of solar PV generation, which will also have changed the relationship between average and peak demand levels.

AEMO's treatment of the water heating load and solar generation also introduce biases directly into the annual model – these might be thought of as first round effects, while the demand ratio effect discussed above is a second round effect. ElectraNet's review of the annual model in the next section includes an assessment of the extent to which this may have impacted the peak demand forecasts. ElectraNet allows for this effect in reconciling the state-wide demand forecasts with the connection point forecasts.

2.4.3 The annual demand model

The annual model is a multiple linear regression model where first differences of annual average per capita demand (Δ mean W/person) are regressed on the following variables:

- first differences in annual per capita GSP (Δ GSP/person)
- first differences in the average retail electricity price (Δ price)
- first differences in summer and winter cooling and heating degree days (Δ SCDD and Δ WHDD).

The model's estimated coefficients and related statistics are reported in the table below. The table also reports the W/person impact in terms of commonly understood changes in the driver variables as well as the 95% confidence interval for each coefficient. The overall regression has an R^2 value of around 0.80 and an adjusted R^2 of around 0.55.

Table 2-1 2011 annual model regression results

Variable	Coefficient	Std. error	t value	P value	change in mean W/person		95% confidence interval		
Intercept	6.834*10^-9	5.321*10^-9	1.284	0.217	6.834	per year that passes	-6.3	to	20.0
Δ GSP/person	2.016*10^-6	5.052*10^-6	0.378	0.711	2.016	per $1000 change in per capita GSP	-10.5	to	14.5
Δ price	-1.665*10^-8	6.763*10^-9	-2.462	0.026	-16.650	per 1 cent change in price	-33.4	to	0.07
Δ SCDD	1.111*10^-10	2.476*10^-11	4.489	0.000	11.110	per 100 change in SCDD	5.0	to	17.2
Δ WHDD	2.069*10^-11	3.277*10^-11	0.631	0.537	2.069	per 100 change in WHDD	-6.0	to	10.2

ElectraNet considers this to be an unreliable regression model upon which to base the electricity forecasts.

- The overall regression fit is poor, as reflected in the relatively low R^2 statistics. In practical terms, this means predictions coming from the model will have a wide confidence interval ("prediction interval") associated with them – the model can only say that, 95% of the time, the true value of the forecast will lie within a very wide range of possibilities. ElectraNet is not able to quantify the size of the overall regression prediction interval at specific confidence levels. However, in the following paragraphs we indirectly assess the marginal range of uncertainty in the forecasts associated with the standard errors of the estimated coefficients.

- Only two of the five estimated coefficients are statistically significant at the 95% confidence level. The coefficient on the income variable is not statistically different from zero, which is an unusual result from a classical economics perspective[11]. The estimated level of the income coefficient implies an income elasticity of around 0.1%, which is much lower than elasticity values reported elsewhere by AEMO for South Australia and other states[12].

- The income coefficient has a high standard error relative to its estimated size. Adjusting this coefficient by its standard error results in 2020-21 annual energy being around 700 GWh (4.6%) higher or lower than might otherwise be forecast. This translates to a range of uncertainty of approximately +/- 170 MW in the 2020-21 10% PoE peak demand forecast[13]. This range is calculated at the 68% confidence level – that is, the standard error tells us that 68% of the time the 10% peak demand is expected to fall within a 340 MW range due to uncertainty in the estimated size of this coefficient. ElectraNet allows for this type of uncertainty in reconciling the connection point and peak demand forecasts.

- The model includes an intercept term, which is unusual in a model based on first differences. The effect of the intercept term is to introduce unexplained trend growth into the forecasts. This unexplained trend is a material element of the forecasts, as it accounts for roughly half of the growth in the forecasts to 2020-21. The trend adds around 0.7% growth to the forecasts each year, with a compound effect of around 8.5% over the ten year forecast horizon. The trend contributes around 1,100 GWh and 220 MW to the rise in AEMO's forecasts by the 2020-21 year.

- The intercept term also has a high standard error relative to its size. ElectraNet estimates the marginal level of uncertainty in the 2020-21 10% PoE level to be of the order of +/- 200 MW (5.3%), given a +/- one standard error change in the intercept term.

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[11] Microeconomic theory postulates that typical goods and services will have a positive income elasticity and a negative price elasticity. (Elasticity is the percentage change in demand given a 1% change in income or price.) Thus we would expect to see a statistically significant positive income coefficient and a statistically significant negative price coefficient.

[12] *2011 ESOO* Table 3-38.

[13] ElectraNet is unable to re-estimate peak demand PoE levels directly. Instead, ElectraNet used AEMO's annual model coefficients to predict changes in average annual energy and applied a scaling factor of 2.1 to estimate peak demands, this being the ratio of peak to average demand in AEMO's 2020-21 forecasts.

- The electricity forecasts are influenced strongly by the population forecasts. Formulation of the model in terms of per capita demand and per capita income means there is an assumed (rather than estimated) one-for-one relationship with population growth. There is also a feedback loop working within the model, given the mathematical relationship between population, GSP and per capita GSP. A 1% change in population flows through to approximately a 1% change in demand; however, the rise in the population also reduces per capita GSP by around 1%, all other things being equal. The pure population effect is offset by this indirect effect on per capita GSP, which reduces demand by around 0.1%. The population effect dominates the outcome, with a much smaller elasticity associated with either GSP or per capita GSP.

ElectraNet concludes that this formulation of the model gives undue weight to population growth and an unexplained underlying trend, while not offering a satisfactory explanation of the role that incomes play in determining electricity demand. This is reflected in the low R^2 values of the regression and the large standard errors associated with several coefficients.

ElectraNet's reconciliation of state-wide and connection point peak demand forecasts allows for a +/- 4.9% range of uncertainty around the 10% PoE forecasts due to the high standard errors associated with the estimated income and trend coefficients. ElectraNet considers this to be a conservative estimate of the range of uncertainty associated with the model's forecasts.

2.4.4 Review of data used to create the forecasting model

As part of this review ElectraNet has also considered the historic data used to create the model. This data influences the model's goodness-of-fit and the reliability of the forecasts. ElectraNet's conclusions are as follows.

Historic population data

There is an inconsistency in the historic population data used to create the model. Population figures are based on end-of-year measures for some years and year-average measures for others. ElectraNet is unable to assess if this has contributed in a material way to the overall poor fit of the annual regression model or if has biased the forecasts in any way.

DSP and load shedding

Adjustments to add back DSP and load shedding in the period since June 2009 have not been included in the historic load trace used to create the model. This is unlikely to have had a material impact on the energy forecasts but there is likely have been a negative impact on forecast peak demand levels. Historic levels of DSP in South Australia have typically been in the 20 to 30 MW range. ElectraNet has therefore adjusted AEMO's peak demand forecasts by 20 MW in the reconciliation to allow for this omission.

Solar PV generation

Rooftop solar PV generation has risen rapidly from negligible levels several years ago to an estimated 113 GWh in 2010-11 and is expected to continue growing in the future. The existing level of installed capacity is well in excess of AEMO's assumptions. ElectraNet's estimates of solar generation and AEMO's assumptions are summarised and compared at *Attachment 4 – Rooftop solar PV generation*. ElectraNet's estimates take into account new information published by ESCOSA in January 2012. AEMO's 2011 forecasts may be revised to take this new information into account in preparing the *2012 SASDO* and *ESOO*.

In principle, solar generation should be added back into the historic demand data used in the forecasting models, as is done with other embedded and non-scheduled generation. AEMO has not done this in its 2011 forecasts. The consequence is that historic demand data for recent years has been artificially depressed and the forecasting model's estimated coefficients will be biased away from their true values as the model attempts to accommodate this effect.

The electricity forecasting model is intended to explain customers' demand for electricity from all sources (ie, native demand) in terms of familiar economic and climate driver variables. Rooftop solar generation is not a part of consumers' demand for electricity – instead, it reflects consumers entering the supply side of the electricity market. AEMO's 2011 modelling approach is effectively trying to explain both supply and demand elements within a hybrid model that no longer reflects underlying demand for electricity. This combination of supply and demand elements within the model may be partially responsible for the poor overall fit of the regression and the wide standard errors on some estimated coefficients.

The supply of electricity from solar generators may in part be driven by GSP and retail electricity prices but there are also other important variables that should accounted for within a model. These may include the technology shock that has seen solar generators become widely available, their capital cost and related subsidies, feed-in tariffs and recent changes to those tariffs.

Post model adjustments are not a satisfactory way to deal with solar generation, as they are being applied to potentially unreliable forecasts with an unknown level of this generation already implicit in the model's outputs. ElectraNet considers that the supply of solar generation should be modelled separately from the demand for electricity. Estimated solar output would then be deducted from native demand when other measures of demand are required for planning purposes, as is currently done with intermittent wind generation.

Water heating load

A broadly similar issue arises in relation to the controlled water heating load. As discussed earlier, this load grew in line with the general level of demand until around 2000-01 and then commenced a sharp downwards trend (see *Figure 2-6 South Australian water heating load*). Changes in electricity prices and per capita GSP will have some long term influence on the water heating load, but the dominant factor causing the turn-around in trend growth is recent policy changes to building standards.

AEMO's model does not include a variable that explains the impact of this change on annual energy growth. Again, the annual model coefficients will become less well fitting and biased away from their true values as they attempt to accommodate this effect. As with solar generation, post model adjustments are not an adequate way to deal with the water heating load when such adjustments are being applied to potentially unreliable forecasts.

Estimate of model bias due to solar generation and water heating load

ElectraNet has made an empirical estimate of the potential bias in the peak demand forecasts due to AEMO's treatment of solar generation and the water heating load. This analysis is reproduced at *Attachment 5 – Analysis of AEMO's model bias.* In this analysis ElectraNet created an approximate copy of AEMO's annual model and then adjusted this model to (a) add back solar generation to the demand measure, and (b) treat the water heating load as a separate offset load with independent forecasts. AEMO's post model adjustments for solar generation and the independent water heating forecasts were then reapplied to the forecasts. ElectraNet concludes from its analysis that the peak demand forecasts are understated by up to 68 MW. This understatement in the demand forecasts is allowed for in the reconciliation of connection point and state-wide demand forecasts.

2.4.5 Recent changes to the model's parameters

The forecasting model was changed in 2010 and re-expressed in terms of first differences of the annual data. The model coefficients were re-estimated again in 2011 using an additional year of data. The table below compares the estimated coefficients from the 2011 model with those estimated in 2010.

Table 2-2 Regression coefficients, 2010 and 2011 forecasting models

Variable	Coefficient	Std. error	t value	P value	Δ mean W/person		95% confidence interval		
2011 model coefficients									
Intercept	6.834*10^-9	5.321*10^-9	1.284	0.217	6.834	per year that passes	-6.3	to	20.0
Δ GSP/person	2.016*10^-6	5.052*10^-6	0.378	0.711	2.016	per $1000 Δ GSP/person	-10.5	to	14.5
Δ price	-1.665*10^-8	6.763*10^-9	-2.462	0.026	-16.650	per 1 cent Δ price	-33.4	to	0.07
Δ SCDD	1.111*10^-10	2.476*10^-11	4.489	0.000	11.110	per 100 Δ SCDD	5.0	to	17.2
Δ WHDD	2.069*10^-11	3.277*10^-11	0.631	0.537	2.069	per 100 Δ WHDD	-6.0	to	10.2
2010 model coefficients									
Intercept	1.106*10^-8	4.845*10^-9	2.283	0.037	11.06	per year that passes	-1.0	to	23.1
Δ GSP/person	8.100*10^-7	5.052*10^-6	0.160	0.875	0.810	per $1000 Δ GSP/person	-11.8	to	13.4
Δ price	-1.585*10^-8	6.744*10^-9	-2.350	0.033	-15.850	per 1 cent Δ price	-32.6	to	0.94
Δ SCDD	1.213*10^-10	2.447*10^-11	4.958	0.000	12.130	per 100 Δ SCDD	6.0	to	18.2
Δ WHDD	7.467*10^-11	3.454*10^-11	2.162	0.047	7.467	per 100 Δ WHDD	-1.1	to	16.1

The overall regression R^2 value fell slightly from 85% in 2010 to 80% in the 2011 model. Only a few coefficients are statistically significant in either model.

The trend and income coefficients both changed substantially in the 2011 model compared with the 2010 model while the other coefficients remained at around the same level.

ElectraNet has estimated the sensitivity of AEMO's electricity forecasts to these changes in the coefficients. Using identical economic assumptions

(KPMG's 2011 forecasts), we estimate that 2020-21 year peak demand falls by around 120 MW using the 2011 coefficients compared with the 2010 model coefficients. Annual energy in that year falls by around 500 GWh (3%).

There is also a change in the starting year used in the two models, and in particular, in the starting mean W/person demand level, which fell from around 960 in 2009-10 to around 930 in 2010-11. ElectraNet estimates this effect to have reduced the 2020-21 forecast peak by around 150 MW and annual energy by around 625 GWh (3.7%).

ElectraNet concludes that the forecasts have changed by a large amount simply due to re-estimation of the model, and in neither case were the underlying coefficients on the trend and income variables statistically significant. Model revision therefore appears to be another material dimension of uncertainty in the forecasts. However, ElectraNet does not allow specifically for this in the reconciliation of connection point and state-wide demand forecasts.

2.4.6 Conclusions regarding AEMO's forecasting model

ElectraNet's conclusions from its review of the forecasting model and historic data used to construct the model are as follows.

- The forecasts are driven largely by the starting level of average annual demand, population growth (which contributes around 0.8% growth each year) and an unexplained trend (which contributes a further 0.7% growth each year). The price level also has an effect at the margin, with an elasticity of around -0.25, while the income variable has only a very small effect on the forecasts.

- The overall regression fit of the annual model is poor, as reflected in the relatively low R^2 statistics. In practical terms this means predictions coming from the model will have a wide confidence interval (prediction interval) associated with them.

- Only two of the five estimated annual model coefficients are statistically significant at the 95% confidence level. The coefficient on the income variable implies an income elasticity of around 0.1%, which is much lower than elasticity values reported in the *2011 ESOO* for South Australia and other states.

- The income coefficient and the intercept (which drives unexplained trend growth within the model) both have very large standard errors relative to their estimated size. Adjusting either of these coefficients by its standard error results in the 2020-21 peak demand forecast being, on average, +/- 4.9% higher or lower than the mean prediction. This range of approximately +/- 190 MW reflects the marginal degree of uncertainty associated with each coefficient at the 68% confidence level. ElectraNet allows for this range of uncertainty in its reconciliation of the connection point and state-wide peak demand forecasts.

- The change in trend growth of the water heating load since 2000-01 is not dealt with adequately within the model. This is likely to be a contributing factor to the poor overall fit of the annual demand regression model. Accounting for continuing falls in this load by way of a post model adjustment is unreliable when the load's contribution to the unadjusted forecasts is unknown. ElectraNet concludes that the water heating load should be isolated and forecast separately, as is currently done with the Offset load, or an additional explanatory variable included in the annual model.

- The native demand measure used within the model is being corrupted by a failure to add back significant and rapidly growing levels of solar generation. AEMO's modelling approach is trying to explain both supply and demand elements within a hybrid model that no longer reflects underlying customer demand for electricity. This will give rise to similar issues associated with the change in trend growth of the water heating load and will be a further contributing factor to the poor overall fit of the model and the high level of uncertainty in its outputs. ElectraNet concludes that solar generation should be added back into historic measures of native demand and forecast separately as a supply-side phenomenon. When necessary, an allowance would be made for its assumed output at peak demand times in the same way that intermittent wind generation is treated. ElectraNet considers that post model adjustments are an inadequate way to deal with solar generation when its contribution to the unadjusted forecasts is unknown.

- ElectraNet has analysed the bias introduced into the forecasts due to AEMO's treatment of solar generation and the water heating load. ElectraNet concludes from its review that the peak demand forecasts are understated by up to 68 MW, with further bias likely to be introduced through the half hourly model structure. This effect is allowed for in the reconciliation of connection point and state-wide demand forecasts.

- There are deficiencies in the historic data used to create the model. These include an inconsistency in the historic population data and the omission of any DSP and load shedding that has occurred since 1 July 2009. This latter issue is likely to have had a negative impact on the peak demand forecasts and is allowed for in the reconciliation of connection point and state-wide demand forecasts.

- AEMO's 2011 forecasts may be revised in 2012 to take into account new information published by ESCOSA in relation to currently installed levels of rooftop solar generation.

2.5 AEMO's economic assumptions

AEMO's 2011 electricity forecasts are underpinned by economic forecasts prepared early in 2011 by KPMG. The economic variables of interest for the purposes of this review are KPMG's base case projections of South Australia's population, GSP and average retail electricity prices[14].

[14] KPMG prepares base, high and low case economic forecasts which underpin base, high and low case electricity forecasts. KPMG's economic report to AEMO indicates that the high

The electricity forecasts are also dependent on a number of post model adjustments and assumptions about the Offset load. These adjustments and assumptions are also reviewed in this section.

2.5.1 Review of AEMO's 2011 economic forecasts

AEMO provided ElectraNet with a copy of KPMG's economic forecasts for South Australia as they stood in around May 2011. ElectraNet has confirmed that these forecasts were used by Monash University to prepare the 2011 state-wide peak demand forecasts[15].

Key assumptions associated with the base case economic forecasts as they relate to South Australia include the following:

- Major expansion of the Olympic Dam mine is not included in the base case South Australian economic scenario.
- A carbon price of $10/tonne is assumed to apply in 2013-14 and an emissions trading scheme is assumed to be introduced in 2014-15[16].

KPMG has summarised its main assumptions and the global economic outlook as it stood early in 2011 in the following terms.

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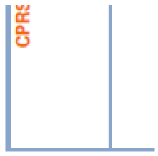
and low scenarios "*adopt extreme assumptions, meaning the likelihood of either the low or high scenarios eventuating is remote*". Only base case electricity and economic forecasts are considered throughout ElectraNet's report.

[15] KPMG's 2011 economic forecasts currently published on AEMO's website are dated August 2011, several months after the 2011 peak demand forecasts were prepared. ElectraNet has not considered whether there are differences between the economic data used to prepare the electricity forecasts and the data currently available on AEMO's website.

[16] After KPMG's economic forecasts were prepared the Australian Government announced that it would introduce a fixed carbon price from 1 July 2012 with a transition to emissions trading within three to five years. KPMG subsequently advised AEMO that its longer term carbon price trajectory would essentially remain unchanged as a result of this policy decision, there would not be any material impacts on its macroeconomic forecasts, and there would only be a small impact on the overall long term trend in its electricity price forecasts.

Figure 2-7 Assumptions underlying KPMG's base case economic forecasts[17]



Since KPMG's forecasts were prepared the International Monetary Fund (IMF) has revised down its global economic growth projections on two occasions due to ongoing political debate in the US regarding fiscal consolidation and the deteriorating sovereign debt situation in Europe.

The Reserve Bank of Australia (RBA), in its February 2012 *Bulletin*, notes that the Australian economy is continuing to undergo a prolonged adjustment process as resources move into the mining sector and the traded goods sector adjusts to the high $A exchange rate. The RBA also notes the heightened risks to global and Australian growth should the Euro-zone enter a prolonged recession.

[17] This figure has been reproduced from KPMG's report: *Stage Two: Economic Scenarios and Forecasts 2009-10 to 2034-2035*, A Report to the Australian Energy Market Operator (AEMO), 4 April 2011.

The RBA has revised down its Australian GDP growth forecasts since its February 2011 *Bulletin* (which was released at about the same time that KPMG's forecasts were prepared):

- the RBA's forecast for growth in 2011-12 has been revised down from 3¾% a year ago to 3½% in the February 2012 *Bulletin*;
- forecast growth in 2012-13 has been revised down from 4% a year ago to the 3%-3½% range; and
- growth in 2013-14 is forecast to be in the 3%-4% range.

In comparison, KPMG's 2011 forecasts show Australian GDP growing by 3.9% in 2011-12, 2.5% in 2012-13, and 3.3% in 2013-14.

There is a notable difference between KPMG's 2012-13 forecast (2.5%) and the RBA's current forecast for that year (3% to 3½% range).

The following table and figures summarise KPMG's South Australian economic history and forecasts as they were used to prepare the 2011 electricity forecasts[18]. Some of the figures include a long term trend-line calculated over the period 1989-90 to 2010-11 and extrapolated out to 2020-21.

Table 2-3 Comparison of historic and forecast average annual growth rates

	GSP	Population	Per capita GSP	Ave retail electricity price
Historic ave ann growth 89-90 to 10-11 (%)	2.4	0.7	1.7	-0.3
Forecast ave ann growth 10-11 to 20-21 (%)	2.6	0.8	1.7	0.7

[18] Historic data used to construct the table and figures reflect data provided to ElectraNet by AEMO and used in the electricity forecasting model. Figures for the 2010-11 year are KPMG's estimates of full year outcomes. ElectraNet has treated these as "actuals" as they were used to create the forecasting model. Some of this data differs from the latest available data from the Australian Bureau of Statistics. AEMO's historic data has been used throughout this report to ensure consistency with the information used to create the forecasts.

Figure 2-8 South Australian economic forecasts - levels

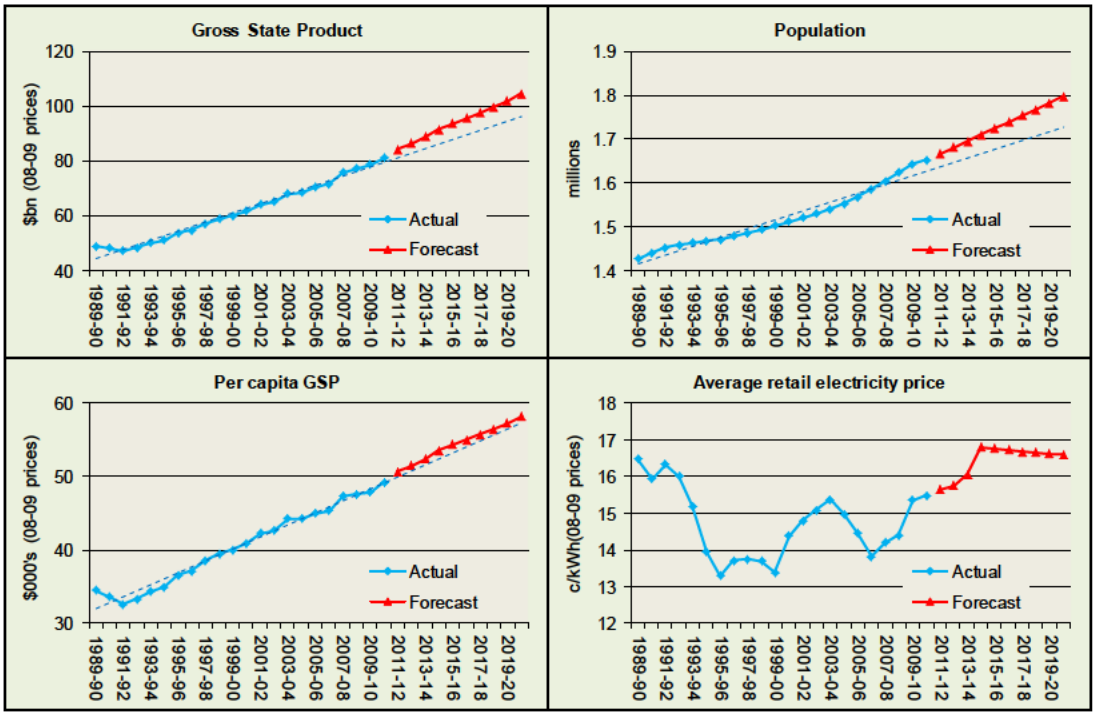
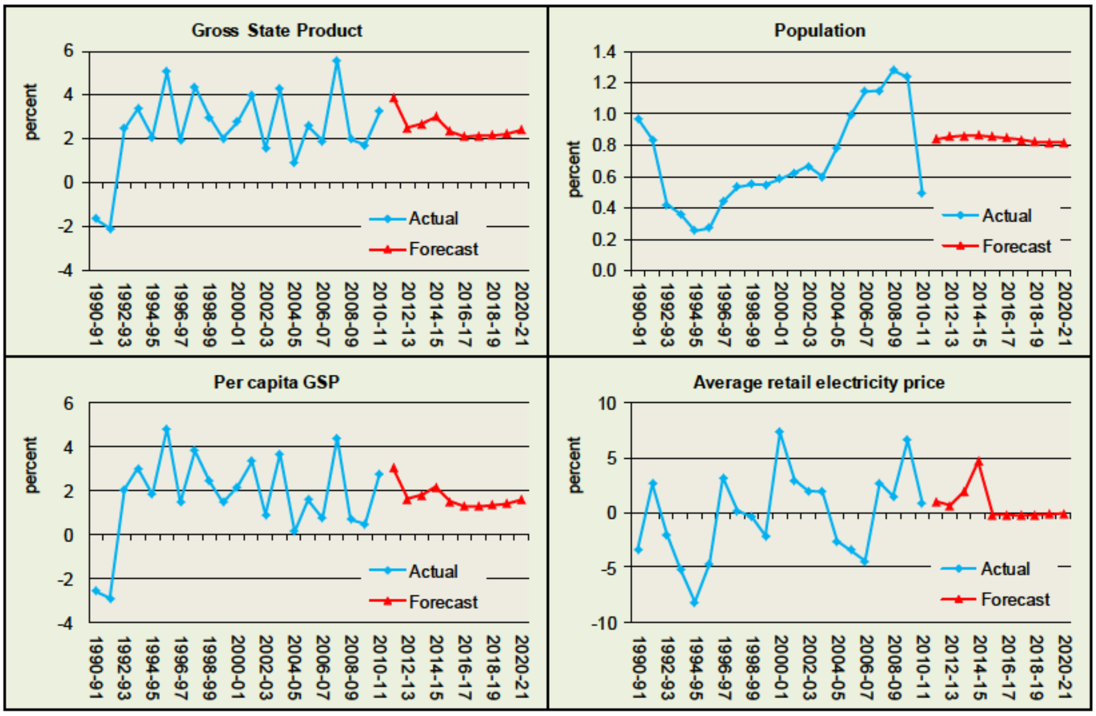


Figure 2-9 South Australian economic forecasts – growth rates



Notable features of the South Australian economic data include the following points.

- Economic growth has been below average in 2008-09 and 2009-10, reflecting the impact of the global financial crisis, downsizing in the automotive sector and a major plant outage at Olympic Dam. KPMG expects South Australia's medium term growth to be supported by ongoing population growth, new dwelling and infrastructure investment, higher consumption expenditure and rising mining output, offset by further declines in automotive manufacturing and wine exports.

- Average GSP growth over the ten year forecast horizon (2.6%) is marginally above the longer term historic trend (2.4%), with stronger growth expected in the earlier years compared with later years.

- Growth of South Australia's population is forecast to slow markedly to around 0.8% annually compared to the much larger increases experienced in five of the past six years. Nevertheless, population growth is expected to remain slightly above the longer term average of 0.7% calculated over the period since 1989-90.

- Growth of per capita GSP is forecast to be similar to the longer term trend rate of increase. This reflects slightly above trend increases in growth of both GSP and population.

- The state-average retail electricity price is forecast to rise in real terms by an average of 0.7% annually over the forecast horizon. Relatively large increases are forecast in 2013-14 (2%) and 2014-15 (4.7%), with small declines in the real price forecast in later years. The assumed movements in the overall state-average retail price are not inconsistent with the size of recent historic price changes.

2.5.2 Variations in the economic forecasts over time

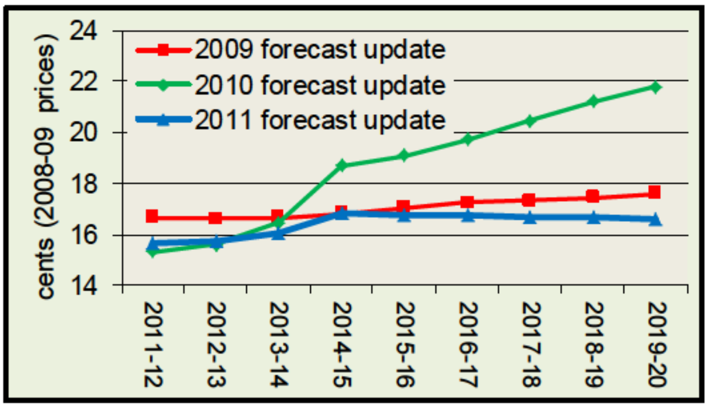
The economic forecasts change from year to year in line with evolving expectations about government policy actions and external shocks to the economy. The changing economic environment introduces a degree of uncertainty distinct from uncertainties associated with the electricity forecasting process itself.

ElectraNet has used AEMO's 2011 forecasting model coefficients to assess how changes in the economic forecasts (in the absence of model changes) have impacted on the electricity forecasts. Changes to the price assumptions are considered first. The impact of changes to the population and GSP forecasts are considered together due to the relationship between population, GSP and per capita GSP.

The following figure shows AEMO's assumed average retail electricity prices to 2019-20 as they stood in 2009, 2010 and 2011[19].

[19] The 2019-20 year has been used as the end point in the following comparisons as that was the end of the forecast horizon in 2009.

Figure 2-10 Electricity price assumptions - 2009, 2010 and 2011



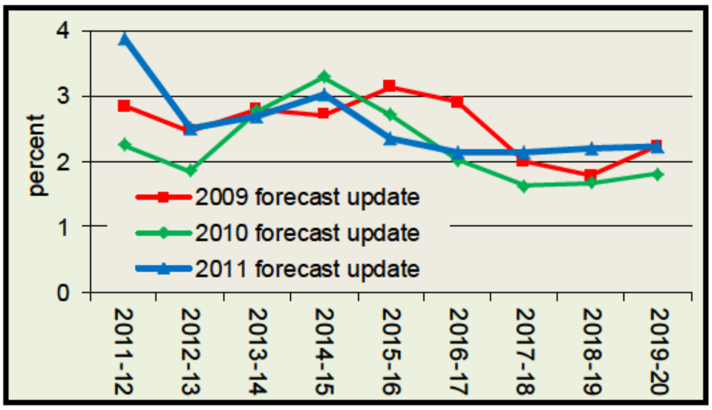
The average retail electricity price assumptions have been volatile over time, reflecting the uncertain policy environment surrounding introduction of carbon pricing and emissions trading. The price forecasts for 2014-15 and later years were revised upwards significantly in the 2010 forecasting round and revised down again by a broadly similar amount in 2011.

The average forecast price across the ten years to 2019-20 was 17.0 c/kWh in 2009, 18.3 c/kWh in 2010 and 16.3 c/kWh in the 2011 forecast update (all measured in constant 2008-09 prices).

Holding the 2011 model coefficients constant, ElectraNet estimates these changes to be consistent with a downward revision of around 185 MW in the 2020-21 peak demand between the 2009 forecast round and the 2010 round, and an upward revision of around 175 MW between the 2010 and 2011 forecast rounds.

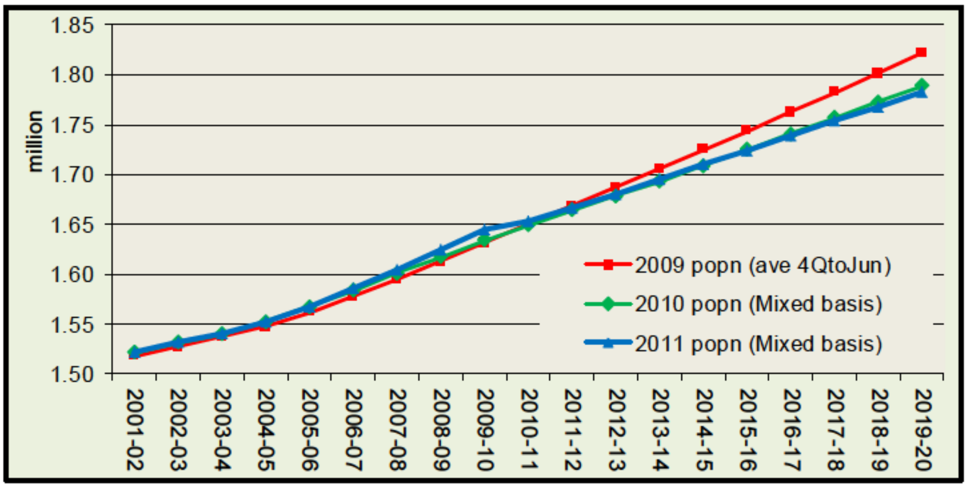
Changing expectations regarding the future retail electricity price have clearly resulted in large changes in the electricity forecasts in recent years and represent a major source of uncertainty in AEMO's forecasts.

Figure 2-11 GSP growth rate forecasts – 2009, 2010 and 2011



The GSP growth rate assumptions in each year since 2009 have tended to predict a relatively buoyant medium term outlook followed by a moderate decline in growth towards the latter part of the forecast horizon. Average GSP growth rates assumed to apply over the nine years to 2019-20 are broadly similar in the 2009 (2.5%) and 2011 (2.6%) forecasting rounds, with a less bullish outlook presented in the 2010 update (2.2%).

Figure 2-12 Population forecasts – 2009, 2010 and 2011



The historic and forecast population data used in the 2009, 2010 and 2011 electricity forecasting rounds are shown in the above figure. The figure highlights two notable points:

- The historic data used to estimate the 2009 model and the population forecasts in that year were both based on average population through the year. The 2010 and 2011 forecasting rounds have used a combination of year-average and end-of-year historic data to re-estimate the model and the forecasts in both these years use end-of-year population data.

- The 2010 and 2011 population forecasts are very similar and lie well below the 2009 forecasts. Average annual growth in the nine years to 2019-20 was assumed to be 1.1% in the 2009 forecasting round. This fell to 0.9% in the 2010 round and 0.8% in the 2011 forecasts[20].

Holding the 2011 model coefficients constant, these changes to population and GSP forecasts are consistent with a downward revision of around 70 MW in the 2020-21 peak demand between the 2009 forecast round and the

[20] KPMG's Stage 2 economic report (*op. cit.* page 64) makes the following remarks in relation to South Australia's population growth outlook: "*Whilst population growth for South Australia remains well below the national average, recent years have seen the growth rate accelerate on the back of increases in net overseas migration. Notably, South Australia has achieved population growth due to gains in the international student market which has offset losses due to net interstate migration. In the year to March 2010, South Australia experienced its most rapid population growth since 1975 at 1.3 per cent. Population growth for the state is now expected to slow in line with a tightening of federal migration policies. In particular, a scaling back of the skilled migration program, through the streamlined Skilled Occupations List, will impact the state's ability to accept international students. Declining fertility is also expected to constrain population growth in the state; SA has a lower fertility rate than the national average as it has an older population.*"

2010 round, and a small upward revision of around 5 MW between the 2010 and 2011 forecast rounds. These impacts are considerably smaller than those identified earlier in relation to the changing expectations about electricity prices and therefore do not appear to represent such a large source of uncertainty in AEMO's electricity forecasts.

2.5.3 Offset load assumptions

As discussed in *Section 2.4.1 - General description of the model structure*, AEMO's forecasting methodology treats several large customer loads (both existing and assumed new loads) differently from the remainder of the state's load.

The Offset loads are typically insensitive to weather conditions and may be subject to large step changes which are not driven by short term economic conditions in South Australia. Including these loads in historic data used to create the forecasting models is likely to distort the modelled relationships between the general level of electricity demand and local economic conditions. Forecasts of peak and average demand levels for these loads are prepared by AEMO and incorporated probabilistically into the forecasts for the rest of the state.

Key points to note about the base case Offset load forecasts are as follows:

- The Port Stanvac desalination plant is included and assumed to have a peak demand of 80 MW (50 MW at the time of state-wide peaks). The plant is assumed to be fully operational from 2013-14.
- Major expansion of capacity at the Olympic Dam mine is not included in AEMO's base case forecasts, although some business-as-usual load growth is assumed.

AEMO's 2011 Offset load forecasts are summarised below.

Table 2-4 Base case Offset load forecasts

	Peak MW	Ave MW
2011-2012	200	154
2012-2013	205	158
2013-2014	240	185
2014-2015	245	189
2015-2016	245	189
2016-2017	262	203
2017-2018	262	203
2018-2019	279	216
2019-2020	279	216
2020-2021	279	216

ElectraNet notes that there are some differences between AEMO's Offset load assumptions and new spot loads assumed in the connection point forecasts. These differences are identified and allowed for in ElectraNet's reconciliation of the state-wide and connection point forecasts.

2.5.4 Post model adjustments

AEMO applies several post model adjustments to the raw outputs of the forecasting model. These adjustments reflect AEMO's judgement that several influences on future peak demand and annual energy levels are not adequately reflected in trends in the historic data used to create the model. AEMO's post model adjustments are summarised in the following table.

Table 2-5 Post model adjustments

		Post model adjustment to Summer peak MW	Post model adjustment to Annual sales GWh
Small domestic and commercial solar PV units	2011-12	7	19
	2012-13	8	23
	2013-14	9	26
	2014-15	11	30
	2015-16	12	34
	2016-17	13	38
	2017-18	15	42
	2018-19	16	45
	2019-20	18	49
	2020-21	19	53
Controlled load water heating	2011-12	0	103
	2012-13	0	124
	2013-14	0	143
	2014-15	0	161
	2015-16	0	179
	2016-17	0	195
	2017-18	0	211
	2018-19	0	227
	2019-20	0	242
	2020-21	0	255
Phase out of incandescent GLS lights	2011-12	0	89
	2012-13	0	120
	2013-14	0	154
	2014-15	0	190
	2015-16	0	191
	2016-17	0	196
	2017-18	0	201
	2018-19	0	205
	2019-20	0	210
	2020-21	0	210
ETSA Utilities direct load control program	2011-12	10	0
	2012-13	15	0
	2013-14	15	0
	2014-15	16	0
	2015-16	16	0
	2016-17	16	0
	2017-18	17	0
	2018-19	17	0
	2019-20	17	0
	2020-21	17	0
Total	2011-12	17	211
	2012-13	23	266
	2013-14	25	323
	2014-15	26	381
	2015-16	28	404
	2016-17	30	429
	2017-18	31	454
	2018-19	33	477
	2019-20	35	502
	2020-21	36	518

These adjustments have remained unchanged for several years and appear not to have been reviewed in detail when AEMO prepared the 2011 forecasts. ElectraNet has observed earlier in the report that AEMO's forecasts of solar generation are much smaller than information recently published by ESCOSA in relation to the actual level of solar generation in 2010-11 (see *Attachment 4 – Rooftop solar PV generation*).

ElectraNet also commented earlier on AEMO's treatment of solar generation and the water heating load in *Section 2.4.4 - Review of data used to create the forecasting model*. In particular, ElectraNet concluded from its analysis that solar generation should be modelled as a supply-side phenomenon and the water heating load should be modelled as an offset load.

2.5.5 Conclusions regarding AEMO's economic assumptions

ElectraNet's conclusions after reviewing the economic assumptions used to prepare the 2011 electricity forecasts are as follows.

- Official organisations such as the IMF and the RBA have revised down their short and medium term outlooks for both the global and Australian economies since KPMG's economic forecasts were prepared early in 2011. That said, KPMG's forecast for Australian GDP growth in 2012-13 (2½%) remains below the RBA's February 2012 forecast for growth in that year (3-3½%). KPMG's assumptions, at least in the short to medium term, therefore remain on the conservative side of the current official Australian economic outlook.

- The electricity price assumptions have been volatile in recent years, reflecting the uncertain and changing policy environment. Further potentially material changes to the price forecasts cannot be ruled out, either due to further changes in carbon pricing policy or a re-assessment of the impact of the current policy. ElectraNet's review has identified that the peak demand forecasts in later years can shift by around 180 MW in response to a 1½ to 2 c/kWh revision in the assumed average retail price over the forecast horizon. This element of uncertainty in both electricity prices and peak demand levels is likely to remain as the economy transitions towards a low carbon future and pricing mechanisms are used as instruments of government policy.

- ElectraNet's review of the impact of recent changes to the South Australian population and GSP forecasts indicates that the electricity forecasts have not varied a great deal due to changeability in these forecasts over time. The downward revision to projected population and GSP growth in 2010 is estimated to have reduced the 2020-21 peak demand by around 70 MW. There was only a very small impact on the electricity forecasts in 2011 due to further revisions to the economic outlook. This is not surprising, given the strong unexplained trend term in the forecasting model, the assumed one-for-one relation with population growth, and the much smaller income elasticity associated with AEMO's modelling.

- ElectraNet considers the main uncertainty in relation to the economic assumptions, apart from price, to be in relation to the population forecast. KPMG has projected a marked fall in growth from the 1+% annual increases experienced between 2006-07 and 2009-10. Ongoing average growth at around 1.2%, as opposed to the 0.8% forecast by KPMG, would see 2020-21 peak demand approximately 120 MW higher than the existing forecast.

- AEMO's Offset load assumptions differ from new spot loads assumed in the connection point forecasts. These are identified and allowed for in ElectraNet's reconciliation of state-wide and connection point forecasts.

3. 2011 connection point peak demand forecasts

3.1 Background

ElectraNet's transmission network is the conduit for transporting electricity between generators and a number of bulk supply points throughout South Australia. These bulk supply points – or connection points – deliver power to ElectraNet's customers. These customers include ETSA Utilities, which transports the power to end-users via its distribution network, and several large industrial companies connected directly to the transmission network.

Connection point peak demand forecasts are projections of the maximum electricity demand expected at each bulk supply point in the future. The forecasts, which are prepared by ElectraNet's customers, play an important role in determining whether transmission network augmentations are required to accommodate increases in peak demand. ElectraNet's customer's 2011 base case connection point forecasts are tabulated at *Attachment 6 – Connection point maximum demand forecasts*.

The majority of South Australia's connection points deliver electricity to ETSA Utilities' distribution network. ElectraNet's review focusses on these forecasts because the distribution network falls within the regulatory regime applying across the National Electricity Market.

Forecasts for the other connection points are based on Agreed Maximum Demand levels contracted between ElectraNet and its unregulated customers. While these forecasts are referred to extensively throughout the report, ElectraNet has not reviewed the peak demand requirements of its unregulated customers as part of this review.

3.2 Summary of ElectraNet's conclusions

The connection point forecasts are not designed to reflect a particular PoE level of peak demand. Instead, they represent peak demand levels that might be expected under extreme heatwave conditions. It is therefore appropriate to compare the connection point forecasts with AEMO's 10% PoE forecasts as well as other PoE level forecasts in the reconciliation.

ETSA Utilities' uses what might be termed a "modified geometric extrapolation methodology" to prepare its forecasts. ElectraNet tested the within-sample forecasting performance of this methodology using historic data for the Western Suburbs supply system. The forecasting error six years into the future was estimated at 3.9%, which compares with a range of uncertainty of around 4.9% associated with AEMO's forecasts due to high standard errors of some estimated model coefficients.

ElectraNet's review has identified that the connection point forecasts are sensitive to the following factors.

- The 2001 and 2009 reference levels of demand used in the forecasting model and any once off adjustments made to these reference demands. ElectraNet reviewed in detail a large number of individual connection point forecasts using independent data and was able to replicate ETSA Utilities' forecasts with a high level of accuracy and found no unexplained anomalies.

- The temperature adjustment applied to the 2001 reference demand. ElectraNet reviewed adjustments based on AEMO's back-cast PoE levels and concluded that instability and uncertainty associated with these back-casts makes this type of adjustment unreliable. ElectraNet therefore conducted its own assessment of an appropriate temperature adjustment and concludes that ETSA Utilities' adjustment is not unreasonable

- Assumed spot loads. ElectraNet has not evaluated the degree of certainty associated with these assumptions and notes that there are some differences between ETSA Utilities' assumptions and AEMO's assumptions. These differences are identified and adjusted for in the reconciliation.

The connection point forecasting model does not include typical economic driver variables. ETSA Utilities' ensures its forecasts are consistent with its economic outlook by reconciling the diversified demands with its network-wide peak demand forecasts. In this regard, ElectraNet notes that ETSA Utilities' forecasting model extrapolates demand growth into the future based on historic growth between 2001 and 2009. The connection point forecasts may therefore be regarded as implicitly assuming that economic growth into the future is similar to that observed between 2001 and 2009. These historic growth rates have been slightly higher than assumed by AEMO in its forecasts, and the electricity price did not change in real terms between 2001 and 2009. These may be contributing factors to differences between the two sets of forecasts.

ETSA Utilities' forecasts include a small implicit allowance for solar PV generation, as the 2009 reference level of demand was not adjusted to add back this generation. The result is that ETSA Utilities' 2011 set of forecasts include a similar level of solar generation in the future as assumed by AEMO in its post model adjustments. As such, assumed levels of solar generation are not an issue that requires adjusting for in the reconciliation. However, it is possible that ETSA Utilities' may revise its 2011 forecasts to take into account the recent information published by ESCOSA in relation to currently installed levels of solar generation.

ElectraNet observes that ETSA Utilities' connection point forecasts have not changed in a material way compared with those submitted as part of the AER's 2010 distribution network pricing determination.

3.3 Review of ETSA Utilities' forecasting methodology

3.3.1 Introduction

In this section of the report ElectraNet outlines its review of ETSA Utilities' forecasting methodology and the underlying assumptions used to prepare the forecasts. ElectraNet also assesses the level of reliability that might be expected from the methodology.

In the subsequent section ElectraNet then reviews a number of the individual connection point forecasts in detail to assess if the methodology has been applied as stated, to test the underlying data used by ETSA Utilities, and to identify particular assumptions and adjustments made in respect of individual forecasts.

Throughout the review ElectraNet also considers how the methodology compares with the AER's recently stated principles in regard to what it considers best practise in demand forecasting[21]. These principles include the following.

- Accuracy and unbiasedness
- Transparency and repeatability
- Incorporation of key drivers
- Model validation and testing
- Accuracy and consistency at different levels of aggregation
- Use of the most recent input information
- Spatial (bottom-up) forecasts validated by independent system level (top-down) forecasts
- Weather normalisation
- Adjusting for temporary transfers and discrete block loads

ElectraNet's review has benefited from communications with ETSA Utilities' staff responsible for preparing the connection point forecasts. During the course of these communications ETSA Utilities provided a report documenting its forecasting methodology. The report is reproduced at *Appendix A.*

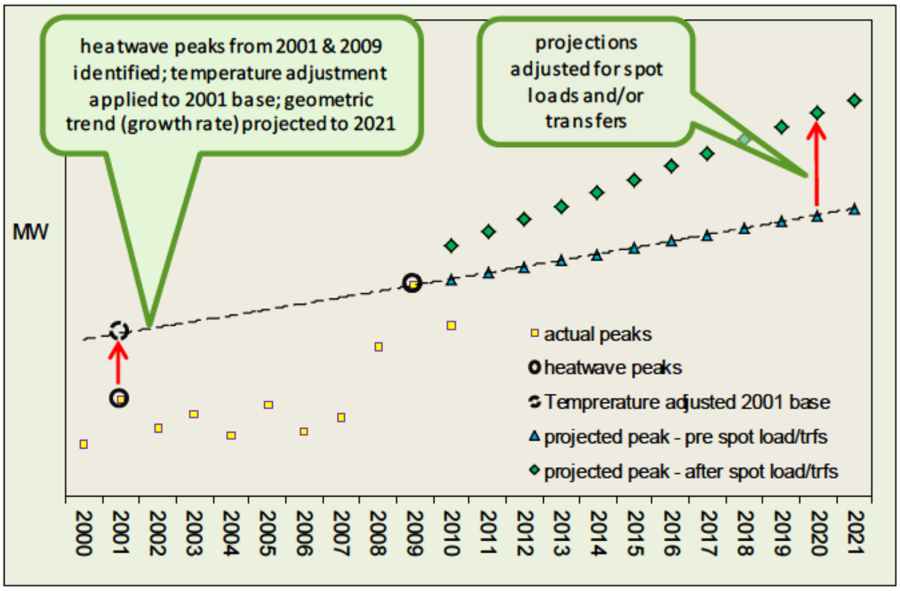
3.3.2 Overview of the forecasting methodology

ETSA Utilities' connection point forecasts are not associated with a particular PoE level. The forecasts are intended to represent peak demand levels that might be expected under extreme heatwave conditions that have tended to occur in South Australia once or twice a decade. Prolonged heatwaves occurred in January 1997, February 2001 and January 2009. There was also a short duration and milder heatwave in January 2011.

ETSA Utilities' forecasts are prepared using what might broadly be termed a "modified geometric extrapolation methodology". The methodology is easily explained in terms of a schematic representation of the process.

[21] Presentation to ENA Working Group, Energy and Demand Forecasting, AER, 18 March 2011.

Figure 3-1 ETSA Utilities' demand forecasting methodology



Key features of the forecasting process are as follows:

- Historic demand data are reviewed to correct for load transfers and discrepancies such as load shedding or meter data errors. Any DSP or embedded generation that cannot be relied upon for network support is also added back. ETSA Utilities maintains databases to manage this information in a secure and controlled manner.
- Peak demands from the 2001 and 2009 heatwaves are identified. A temperature adjustment is applied to the 2001 peak to place the 2001 and 2009 values on a comparable temperature footing. ETSA Utilities has used an uplift factor of 1.4% to adjust 2001 peaks. Different reference years are adopted in relation to several connection points where ETSA Utilities has judged that conditions in 2001 or 2009 were not representative of peak demands in that particular region.
- Peak demand levels are extrapolated forward from the 2009 peak using the average percentage growth rate that applied between the (adjusted) 2001 peak and the 2009 peak.
- Spot load increases are then added to projected peaks where ETSA Utilities consider these to be of sufficient size and certainty so as not to be reflected in the business-as-usual growth rate. The forecasts are also adjusted to reflect anticipated load transfers between connection points and any large committed disconnections.

This approach makes the forecasts highly sensitive to the following factors.

- The accuracy of the historic data (and any adjustments made to that data) to identify the reference levels of peak demand in 2001 and 2009. These reference demand levels are key to identifying the growth rate used to drive the forecasts forward. ElectraNet has tested this aspect of the forecasts by using independent historic information to replicate a number of ETSA Utilities' forecasts (see *Section 3.5 - Review of individual connection point forecasts*). We were able to replicate these forecasts to a high level of accuracy and conclude that the data and adjustments used by ETSA Utilities are reliable.

- The temperature adjustment applied to the 2001 peak, as this also has a strong influence on determining the trend growth rate which drives the forecasts forward. ElectraNet considers the issue of temperature adjustment later in this section.

- The extent of spot loads added to the base-line projections. ETSA Utilities' spot load increases are reported in the following table. It is beyond the scope of this review to independently assess the degree of certainty associated with these loads. The spot load increases assumed in relation to the Southern Suburbs relate to the Pt Stanvac desalination plant. The Western Suburbs and Para System spot loads are related to Federal and State Government planning programmes.

Table 3-1 Spot loads included in ETSA Utilities' forecasts

	Southern Suburbs	Western Suburbs	Para System	Total (MW)
2011-12	60	5	0	65
2012-13	65	15	7	87
2013-14	66	21	14	101
2014-15	67	27	18	112
2015-16	68	33	22	123
2016-17	69	34	26	129
2017-18	70	35	34	139
2018-19	70	35	38	143
2019-20	70	35	42	147
2020-21	70	35	46	151

3.3.3 Is the methodology reliable?

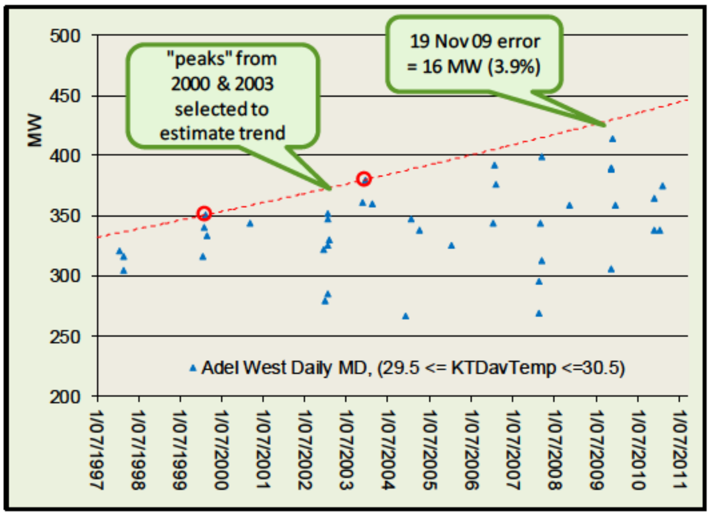
A number of the AER's preferred criteria for assessing forecasts relate to the reliability and robustness of the process – "accuracy and unbiasedness", "model validation and testing", and "use of the most recent input information".

The methodology employed by ETSA Utilities relies on identifying peak demands from two recent heatwaves. The information used by ETSA Utilities is clearly the most recent available.

The relative infrequency of heatwaves, however, makes model validation and testing for accuracy problematic. A similar issue arises in relation to the state-wide forecasts, where indirect tests must be applied to assess the 10% PoE forecast accuracy. ElectraNet therefore developed an indirect test to apply to ETSA Utilities' methodology to gauge the degree of accuracy that might be expected over a reasonably long forecasting horizon.

In particular, ElectraNet identified all days between July 1997 and July 2011 where the daily average temperature at the Kent Town weather station fell in the range 29.5^{o}C to 30.5^{o}C. These are reasonably high temperature days and provide a sample of 43 observations. We identified the daily peak demand on the Western Suburbs system on each of these days and applied a within-sample test of the forecasting methodology's accuracy. Given the selected temperature range, it turned out that historic "peak demands" occurred in 2000 and 2003. We extrapolated the growth rate between these peaks to project demand (at this temperature level) into the future and compared the results with actual "peaks" in later years. The most recent "peak" occurred in November 2009, six years beyond the data used to construct the forecasts. We found the error in the forecast to be only 16 MW, or 3.9%. This compares with a range of uncertainty in the state-wide forecasts of around 4.9% due to high standard errors associated with the trend and income coefficients of AEMO's 2011 model. ElectraNet therefore concludes from this limited indirect testing that ETSA Utilities' methodology is capable in principle of producing reasonably accurate forecasts over a long term horizon. The results of ElectraNet's test are presented graphically in the following figure.

Figure 3-2 Within-sample test of ETSA Utilities' methodology



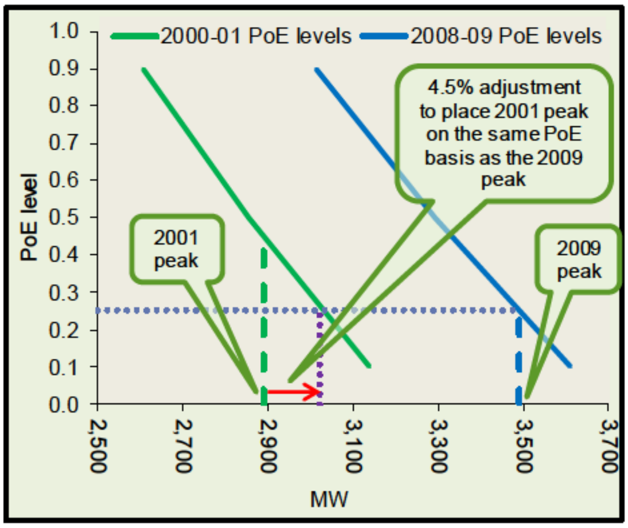
3.3.4 Temperature adjustment

The AER's preferred criteria include temperature adjustment of historic demand data.

ETSA Utilities applied an uplift factor of 1.4% to the 2001 reference level of demand to place the two base year values on a comparable basis, reflecting the fact that temperatures were higher during the 2009 heatwave compared with the 2001 heatwave. The daily average temperature at Kent Town weather station was 33.9 °C on the day of the 2001 peak and 38.7 °C on the day of the 2009 peak.

ElectraNet has considered this adjustment in the context of AEMO's 2011 back-assessment of historic PoE levels. The PoE curves assessed to have applied in 2001 and 2009 are shown in the following figure.

Figure 3-3 2000-01 and 2008-09 back-cast PoE levels



AEMO's back assessment indicates that the 2001 peak was approximately a 45% PoE outcome, while the 2009 peak was approximately a 25% PoE outcome. The 2000-01 25% PoE demand level was around 4.5% greater than the actual peak in that year.

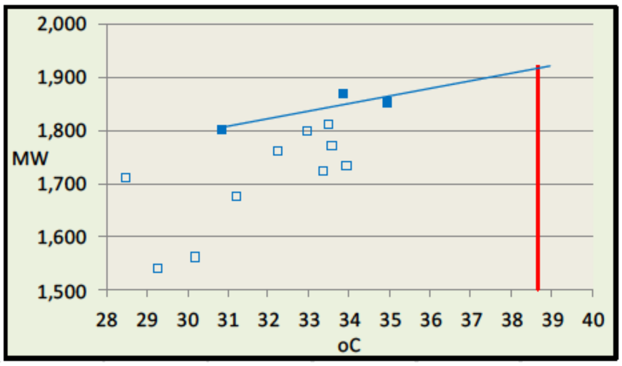
- If ETSA Utilities had used a temperature adjustment value of 4.5%, ElectraNet estimates that the combined level of 2020-21 maximum demands would be around 150 MW lower than currently forecast.

- If both reference year demands are adjusted to reflect AEMO's historic 10% PoE levels, an uplift factor of 8.6% would be applied to the 2001 peaks and 3.4% to the 2009 peaks. ElectraNet has tested these alternative temperature adjustments on the major metropolitan system forecasts and found they have a relatively small impact on the 2020-21 forecasts. The combined Eastern, Southern and Western system forecasts in 2020-21 would be around 50 MW lower in total, while the Para system forecast would rise by around 1 MW.

ElectraNet notes that AEMO's back-cast PoE levels have been unstable over time (refer *Figure 2-5 Changes in back-cast PoE levels*). Given this instability and the uncertainties noted earlier in relation to AEMO's 2011 forecasting model, ElectraNet cannot be confident that temperature adjustments based on AEMO's historic PoE levels will result in reliable adjustments to ETSA Utilities' 2001 base year reference demand levels.

ElectraNet has therefore considered an alternative assessment method. The following figure shows a plot of daily peak demand for the combined metropolitan systems against daily average temperature for high demand days during the 2000-01 summer. We fitted a linear trend-line to the upper envelope of these observations to project the daily peak at a temperature of 38.7 °C, the same temperature underlying the 2009 peak.

Figure 3-4 Daily peak demands and temperatures, 2000-01 summer



This projection suggests a peak demand of around 1,910 MW at 38.7 ^{o}C, 2.3% higher than the actual peak of 1,866.4 MW. However, this projection is based on an extrapolation which assumes demand continues to rise in a direct linear relationship with temperature. ESIPC has reported that South Australian demand shows a tendency to plateau at extreme temperatures, indicating that a linear extrapolation may not be appropriate[22]. ETSA Utilities' 1.4% temperature adjustment implies a peak demand of 1,893 MW at 38.7 ^{o}C, some 27 MW higher than the actual 2001 peak and 17 MW below the linear extrapolation. ElectraNet considers that this adjustment is not unrealistic and concludes that ETSA Utilities' temperature adjustment assumption is therefore reasonable.

3.3.5 Implied economic assumptions

The AER's criteria for judging forecasts and the underlying models include "the incorporation of key drivers".

ETSA Utilities' spatial demand forecasting report states that "*the primary objective [of the connection point forecasts] is to predict the longer-term (5-10 year) trends in demand growth for each point, rather than the shorter-term variations associated with economic factors*". The spatial demand forecasting model does not include explicit economic driver variables. Nevertheless, the forecasts might be regarded as implicitly assuming that trends in economic growth and electricity prices between 2001 and 2009 continue into the future. The table below compares these historic growth rates with those forecast by AEMO for the period 2010-11 to 2020-21.

Table 3-2 ETSA Utilities' implied economic growth assumptions

	GSP	Population	Per capita GSP	Ave retail electricity price
Historic ave ann growth 2000-01 to 2008-09 (%)	2.8	0.9	1.9	0.0
AEMO forecast ave ann growth 2010-11 to 2020-21 (%)	2.6	0.8	1.7	0.7

[22] *Annual Planning Report*, ESIPC, June 2009, page 39.

Population and GSP growth between 2000-01 and 2008-09 were both slightly stronger than has been forecast by AEMO for future years. The average retail electricity price was largely unchanged between 2001 and 2009 (there were offsetting movements in intervening years), while AEMO has forecast an average annual rise of 0.7% over the forecast horizon. These differences may contribute to some disagreement between the state-wide and connection point forecasts.

3.3.6 Treatment of solar generation

ETSA Utilities' connection point forecasts do not include a specific element recognising the likely impact of increasing levels of rooftop solar PV generation. They do, however, include a small implicit allowance as the 2009 reference levels of demand were not adjusted to add back solar generation.

Recently published information reviewed by ElectraNet indicates that there was approximately 15 MW of solar generation installed in 2008-09 and the total output at system peak demand times was likely to be of the order of 8 MW (refer *Attachment 4 – Rooftop solar PV generation*). As ETSA Utilities' forecasts are extrapolated from 2009 peak demands the forecasts in total will implicitly include an increase of around 1 MW per year in solar generation. It is not possible to attribute this effect to particular connection point forecasts without detailed knowledge of the location of solar generators and their output at the time of peak demand at each point.

ETSA Utilities, in a response to questions asked by ElectraNet, has indicated that "*The impact of PV has not been considered. Any PV installed in 2008/9 summer automatically included as use measured peaks. PV installations until 2011/12 have been not been considered as material. Plan to consider for future forecasts for Connection Points as PV may have a material impact at time of some CP peaks (which unlike Distribution peaks tend to occur earlier in the day when PV operating).*"

ElectraNet's indicative estimates of solar generation suggest that there could be material levels of this type of generation operating at times of system-wide peak demand by 2020-21. ElectraNet considers that some downward adjustment to the forecast peak demands may occur if ETSA Utilities reviews the impact of solar generation on connection point peak demands. This would require consideration of the geographical spread of solar generation and regard to the timing of peak demands in relation to the reliability of solar output at each location. Consideration of the level of exports/imports of solar generation between connection points may also be required.

3.4 Changes to ETSA Utilities' forecasts since 2009

ETSA Utilities submitted connection point maximum demand forecasts for the period 2010-11 to 2014-15 to the AER in 2009 as part of the recent South Australian distribution network pricing determination.

ETSA Utilities' current (2011) forecasts to 2014-15 have not changed in a material way since then, as shown in the following table.

Table 3-3 Changes to ETSA Utilities' forecasts since 2009

Connection Point	2011-12	2012-13	2013-14	2014-15
Eastern Suburbs	0.0	0.4	0.4	0.4
Southern Suburbs	-20.0	-15.0	-14.0	-13.0
Western Suburbs	-10.0	-5.0	-4.0	2.0
Para System	0.0	0.0	0.0	4.0
Ardrossan West	0.5	2.6	2.7	2.8
Berri	-2.1	-2.2	-2.2	-2.2
Blanche	0.0	0.0	0.0	5.0
Brinkworth	0.9	1.0	1.0	1.0
Hummocks	-0.3	-2.4	-2.5	-2.7
Keith	-1.3	-1.3	-1.4	-1.5
Mt Gambier	0.0	0.0	0.0	-5.0
Snuggery Industrial	-10.0	-10.0	-10.0	-10.0
Snuggery Rural	0.9	1.3	1.6	2.1
Stony Point	0.6	0.6	0.6	0.6
Templers	1.9	2.7	3.5	4.3
Total revision	-38.9	-27.3	-24.3	-12.2

3.5 Review of individual connection point forecasts

The AER's best practise forecasting principles include “transparency and repeatability”.

In this section ElectraNet therefore reviews a number of the individual connection point forecasts to assess if the methodology has been applied as stated, to test the underlying data used by ETSA Utilities, and to identify particular assumptions and adjustments made in respect of individual forecasts. ElectraNet has applied a materiality criteria based on the forecast change in maximum demand levels between 2010-11 and 2020-21 in determining which particular forecasts to review.

In aggregate, the connection point forecasts show an increase of 1,078 MW in (undiversified) maximum demand between 2010-11 and 2020-21. ElectraNet has ranked each connection point according to its contribution to this total increase and identified 17 connection points that between them account for 95% of the total increase. Each of these forecasts has been reviewed. The rankings and relative increases in demand are reported in the following table. Those connection points appearing in the top panel have been reviewed in detail.

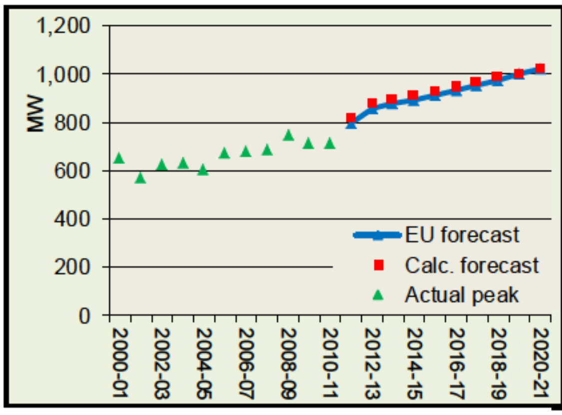
Table 3-4 Change in maximum demand forecast between 2010-11 and 2020-21

Connection Point	2010-11 forecast MD (MW)	2020-21 forecast MD (MW)	Forecast increase in MD for this CP (MW)	Cumulative forecast increases (MW)	Cumulative percentage increase (%)
Eastern Suburbs	781	1021	240	240	22
Southern Suburbs	812	1019	208	448	42
Para System	380	572	192	639	59
Western Suburbs	479	594	115	754	70
Mt Barker/Mt Barker Sth	107	185	78	832	77
Dorrien	68	92	24	855	79
Port Lincoln Terminal	45	67	22	878	81
Berri	96	117	21	899	83
Templers	33	53	20	919	85
Mobilong	43	62	19	938	87
Keith	30	46	15	954	88
Kadina East	28	43	15	969	90
Blanche	37	51	15	984	91
Snuggery Rural	17	31	14	997	93
Port Pirie System	86	97	11	1008	94
Ardrossan West	15	23	9	1017	94
Kincraig	23	31	8	1025	95
Clare North	13	21	7	1032	96
Whyalla Terminal	92	99	7	1039	96
Davenport West	33	40	7	1046	97
Angas Creek	21	27	7	1053	98
Waterloo	12	18	7	1059	98
Hummocks	15	19	5	1064	99
Dalrymple	10	14	4	1068	99
Yadnarie	12	15	4	1071	99
Penola West	14	17	3	1074	100
Wudinna	16	18	3	1077	100
Kanmantoo	2	4	2	1079	100
Baroota	9	11	2	1080	100
North West Bend	29	31	2	1082	100
Tailem Bend	27	29	1	1083	101
Brinkworth	5	6	1	1084	101
Mannum	14	15	1	1085	101
Whyalla LMF	13	13	0	1085	101
Leigh Creek South	2	2	0	1085	101
Neuroodla	1	1	0	1085	101
Stony Point	1	1	0	1085	101
Mt Gunson	0	0	0	1085	101
Mt Gambier	28	27	-1	1084	101
Snuggery Industrial	41	35	-6	1078	100
Total	**3487**	**4565**	**1078**		

Each review considered how closely ETSA Utilities' forecasts could be replicated using ElectraNet's metering data and applying the spatial demand forecasting methodology. In several instances ETSA Utilities advised that different reference years were used in the model due to un-representative peak demands in either 2001 or 2009 and we have taken these into account. We have also allowed for load transfers and spot load increases as advised by ETSA Utilities.

The results of each review are presented in the following series of figures together with a brief comment where appropriate. ElectraNet was able to replicate each forecast with a good degree of accuracy and no unexplained anomalies were found.

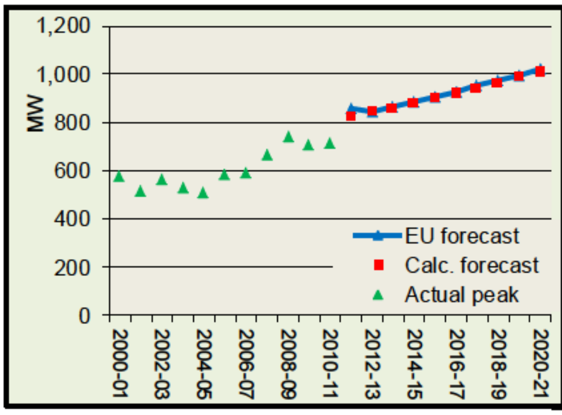
Eastern Suburbs



	adjustments/ spot loads included	divergence between EU & calculated value MW	divergence between EU & calculated value %
2011-12	0	22	2.7
2012-13	41	20	2.3
2013-14	42	18	2.1
2014-15	43	16	1.8
2015-16	44	14	1.6
2016-17	45	12	1.3
2017-18	46	10	1.1
2018-19	47	8	0.8
2019-20	48	6	0.6
2020-21	49	4	0.4

Comment: Transfer relates to load shift from Southern Suburbs. ETSA Utilities included an adjustment to the 2009 peak demand reflecting a metering data error. Evidence was sought and provided to support this adjustment.

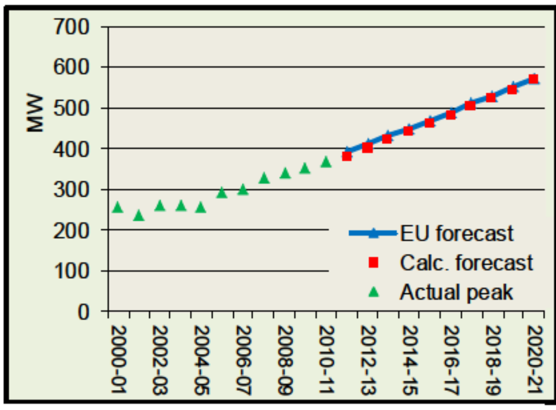
Southern Suburbs



	adjustments/ spot loads included	divergence between EU & calculated value MW	divergence between EU & calculated value %
2011-12	65	-38	-4.4
2012-13	65	-3	-0.3
2013-14	66	-4	-0.4
2014-15	67	-5	-0.5
2015-16	68	-6	-0.6
2016-17	69	-7	-0.8
2017-18	70	-8	-0.9
2018-19	70	-9	-1.0
2019-20	70	-11	-1.1
2020-21	70	-12	-1.2

Comment: 2009 starting demand value adjusted down to reflect load shift to Eastern Suburbs. Spot load assumption relates to Pt Stanvac desalination plant.

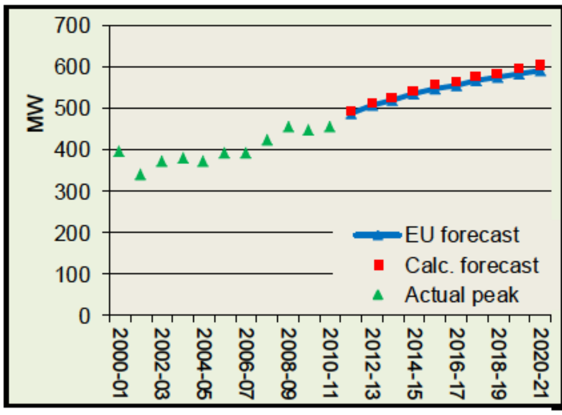
Para System



	adjustments/ spot loads included	divergence between EU & calculated value MW	divergence between EU & calculated value %
2011-12	0	-11	-2.8
2012-13	7	-10	-2.5
2013-14	14	-10	-2.3
2014-15	18	-9	-2.0
2015-16	22	-9	-1.8
2016-17	26	-8	-1.6
2017-18	34	-7	-1.4
2018-19	38	-6	-1.2
2019-20	42	-5	-1.0
2020-21	46	-4	-0.8

Comment: Forecast appears to use 2010-11 peak rather than 2009 adjusted peak as advised. Spot load relates to Federal Government 30 year growth plan.

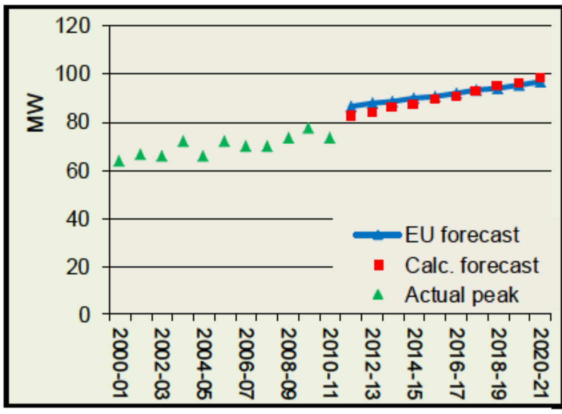
Western Suburbs



	adjustments/ spot loads included	divergence between EU & calculated value MW	divergence between EU & calculated value %
2011-12	5	3	*0.6*
2012-13	15	4	*0.7*
2013-14	21	5	*0.9*
2014-15	27	5	*1.0*
2015-16	33	6	*1.2*
2016-17	34	7	*1.3*
2017-18	35	8	*1.5*
2018-19	35	9	*1.6*
2019-20	35	10	*1.8*
2020-21	35	12	*1.9*

Comment: 2009 demand increased by 6 MW, reflecting curtailed load. Review of data indicates this is warranted. Spot load relates to State and Federal programs.

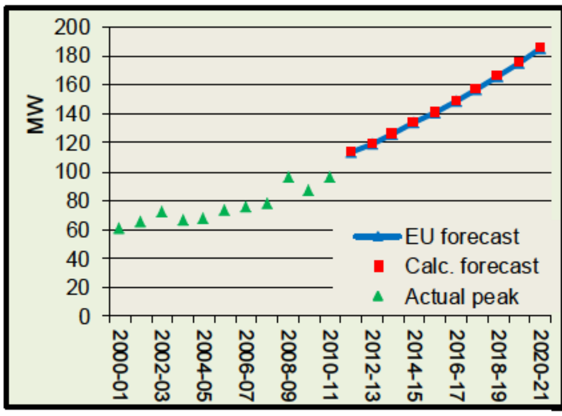
Pt Pirie System



	adjustments/ spot loads included	divergence between EU & calculated value MW	divergence between EU & calculated value %
2011-12	0	-4	*-5.0*
2012-13	0	-4	*-4.2*
2013-14	0	-3	*-3.5*
2014-15	0	-2	*-2.7*
2015-16	0	-2	*-1.9*
2016-17	0	-1	*-1.2*
2017-18	0	0	*-0.5*
2018-19	0	0	*0.2*
2019-20	0	1	*0.8*
2020-21	0	1	*1.5*

Comment: 2009-10 peak demand used in place of 2008-09 as new peak achieved in that year.

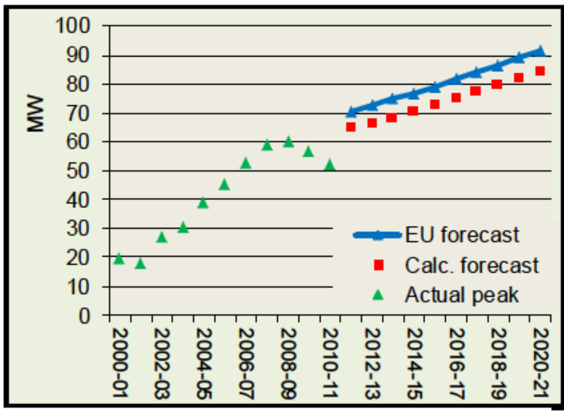
Mt Barker



	adjustments/ spot loads included	divergence between EU & calculated value MW	divergence between EU & calculated value %
2011-12	0	0	*0.1*
2012-13	0	0	*0.0*
2013-14	0	0	*0.1*
2014-15	0	0	*0.1*
2015-16	0	0	*0.1*
2016-17	0	0	*0.1*
2017-18	0	0	*0.2*
2018-19	0	0	*0.2*
2019-20	0	0	*0.2*
2020-21	0	0	*0.2*

Comment: nil

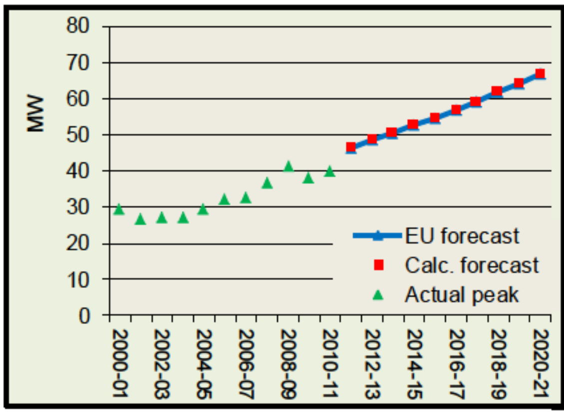
Dorrien



	adjustments/ spot loads included	divergence between EU & calculated value MW	divergence between EU & calculated value %
2011-12	0	-6	-8.4
2012-13	0	-6	-8.4
2013-14	0	-6	-8.4
2014-15	0	-6	-8.4
2015-16	0	-7	-8.4
2016-17	0	-7	-8.4
2017-18	0	-7	-8.4
2018-19	0	-7	-8.3
2019-20	0	-7	-8.3
2020-21	0	-8	-8.4

Comment: 2007-08 peak used in conjunction with assumed growth rate of 3%. Divergences reflect the fact that ETSA Utilities includes the unused portion of Adelaide Brighton's AMD in its forecasts.

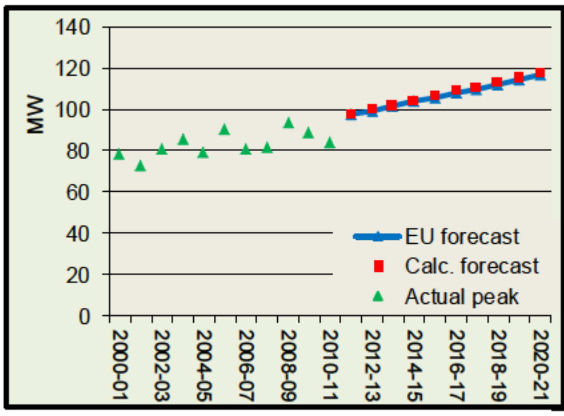
Port Lincoln Terminal



	adjustments/ spot loads included	divergence between EU & calculated value MW	divergence between EU & calculated value %
2011-12	0	0	0.0
2012-13	0	0	0.0
2013-14	0	0	0.0
2014-15	0	0	0.0
2015-16	0	0	0.1
2016-17	0	0	0.0
2017-18	0	0	0.1
2018-19	0	0	0.0
2019-20	0	0	0.1
2020-21	0	0	0.0

Comment: nil

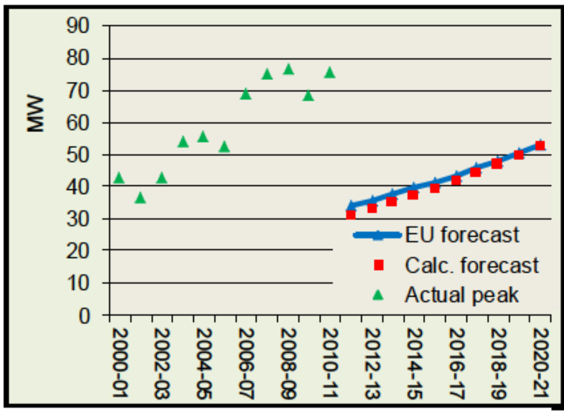
Berri



	adjustments/ spot loads included	divergence between EU & calculated value MW	divergence between EU & calculated value %
2011-12	-2	0	0.2
2012-13	-2	0	0.3
2013-14	-2	0	0.4
2014-15	-2	0	0.4
2015-16	-2	0	0.5
2016-17	-2	1	0.6
2017-18	-2	1	0.7
2018-19	-2	1	0.8
2019-20	-2	1	0.8
2020-21	-2	1	0.8

Comment: Negative spot load reflects major customer shut-down.

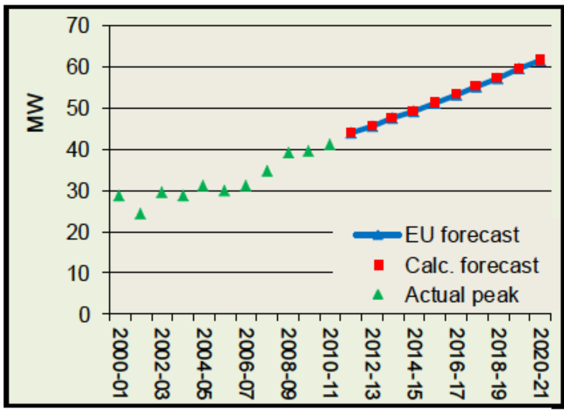
Templers



	adjustments/ spot loads included	divergence between EU & calculated value MW	divergence between EU & calculated value %
2011-12	0	-3	-8.6
2012-13	0	-3	-7.7
2013-14	0	-3	-6.9
2014-15	0	-2	-6.0
2015-16	0	-2	-5.0
2016-17	0	-2	-4.1
2017-18	0	-1	-3.3
2018-19	0	-1	-2.4
2019-20	0	-1	-1.4
2020-21	0	0	-0.5

Comment: Step down in load reflects earlier load transfer. 6% growth rate implied in forecast. (ETSA Utilities has adjusted this down from an historic rate of 7.4%).

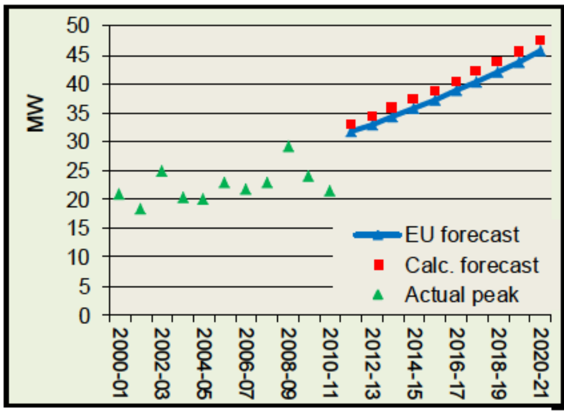
Mobilong



	adjustments/ spot loads included	divergence between EU & calculated value MW	divergence between EU & calculated value %
2011-12	0	0	-0.1
2012-13	0	0	0.1
2013-14	0	0	0.0
2014-15	0	0	0.0
2015-16	0	0	0.0
2016-17	0	0	0.1
2017-18	0	0	0.1
2018-19	0	0	0.1
2019-20	0	0	0.1
2020-21	0	0	0.0

Comment: nil

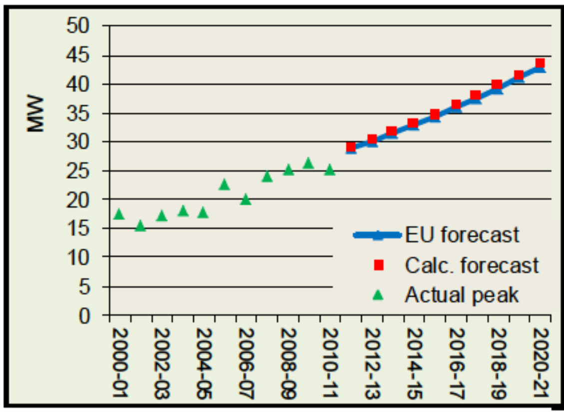
Keith



	adjustments/ spot loads included	divergence between EU & calculated value MW	divergence between EU & calculated value %
2011-12	0	1	3.9
2012-13	0	1	3.9
2013-14	0	1	3.8
2014-15	0	1	3.9
2015-16	0	1	3.8
2016-17	0	2	3.9
2017-18	0	2	3.9
2018-19	0	2	3.8
2019-20	0	2	3.6
2020-21	0	2	3.6

Comment: nil

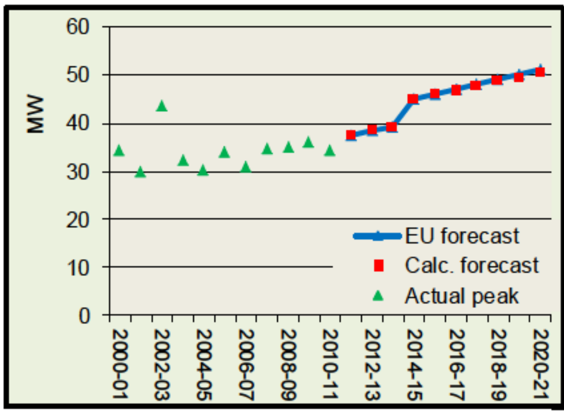
Kadina East



	adjustments/ spot loads included	divergence between EU & calculated value MW	divergence between EU & calculated value %
2011-12	0	0	*0.2*
2012-13	0	0	*0.3*
2013-14	0	0	*0.6*
2014-15	0	0	*0.7*
2015-16	0	0	*0.7*
2016-17	0	0	*0.7*
2017-18	0	0	*0.8*
2018-19	0	0	*0.9*
2019-20	0	0	*0.9*
2020-21	0	0	*1.1*

Comment: nil

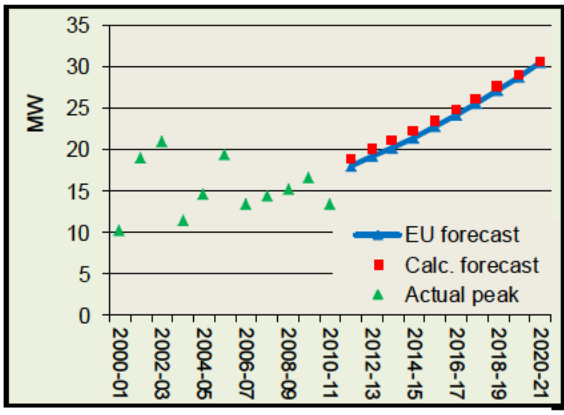
Blanche



	adjustments/ spot loads included	divergence between EU & calculated value MW	divergence between EU & calculated value %
2011-12	0	0	*0.0*
2012-13	0	0	*-0.2*
2013-14	0	0	*-0.1*
2014-15	5	0	*-0.2*
2015-16	5	0	*-0.4*
2016-17	5	0	*-0.7*
2017-18	5	0	*-0.8*
2018-19	5	-1	*-1.2*
2019-20	5	-1	*-1.2*
2020-21	5	-1	*-1.5*

Comment: 2001-02 base year used in forecast (reflects earlier temporary load transfers). Load transfer from Mt Gambier expected in 2014-15.

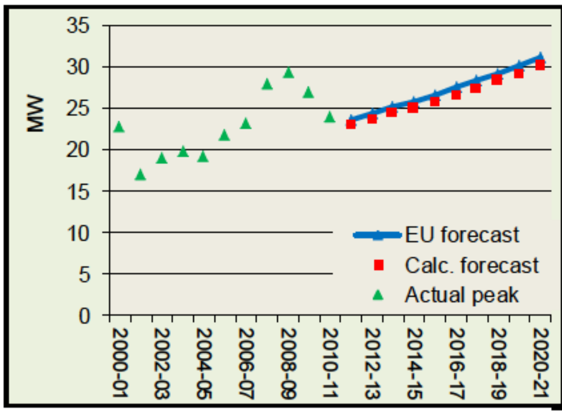
Snuggery Rural



	adjustments/ spot loads included	divergence between EU & calculated value MW	divergence between EU & calculated value %
2011-12	0	1	*4.5*
2012-13	0	1	*4.0*
2013-14	0	1	*3.8*
2014-15	0	1	*3.4*
2015-16	0	1	*2.9*
2016-17	0	1	*2.3*
2017-18	0	0	*1.6*
2018-19	0	0	*1.3*
2019-20	0	0	*1.0*
2020-21	0	0	*0.3*

Comment: Reference year demands adjusted to reflect load shifts between Snuggery Rural and Snuggery Industrial.

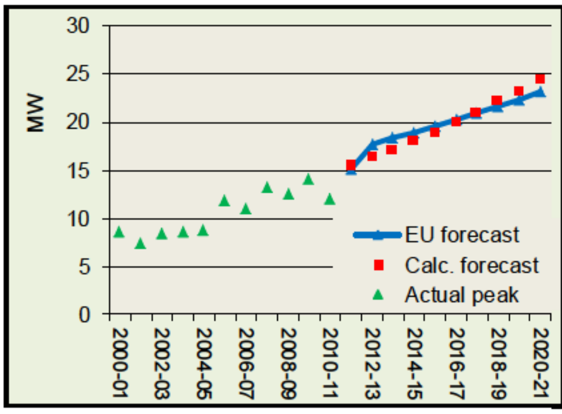
Kincraig



	adjustments/ spot loads included	divergence between EU & calculated value MW	divergence between EU & calculated value %
2011-12	0	-1	*-3.2*
2012-13	0	-1	*-3.1*
2013-14	0	-1	*-3.2*
2014-15	0	-1	*-3.0*
2015-16	0	-1	*-3.0*
2016-17	0	-1	*-3.3*
2017-18	0	-1	*-3.1*
2018-19	0	-1	*-3.2*
2019-20	0	-1	*-3.2*
2020-21	0	-1	*-3.4*

Comment: 2009-10 reference peak used and adjusted down to reflect transfer of load to Penola West.

Ardrossan West



	adjustments/ spot loads included	divergence between EU & calculated value MW	divergence between EU & calculated value %
2011-12	0	0	*2.2*
2012-13	0	-1	*-8.2*
2013-14	0	-1	*-6.6*
2014-15	0	-1	*-4.8*
2015-16	0	-1	*-2.9*
2016-17	0	0	*-1.3*
2017-18	0	0	*0.4*
2018-19	0	0	*2.2*
2019-20	0	1	*4.2*
2020-21	0	1	*5.9*

Comment: 2007-08 (New Years' Eve) peak used as reference point. 2000-01 peak appears to have been adjusted upwards by 0.8 MW.

4. Reconciliation of the peak demand forecasts

4.1 Introduction

In this section of the report ElectraNet reconciles AEMO's state-wide peak demand forecasts with the connection point maximum demand forecasts.

The reconciliation process requires that a number of adjustments be made to each set of forecasts to place them on a comparable footing. In making these adjustments ElectraNet draws on its review of the two sets of forecasts and the conclusions outlined in previous sections of the report.

ElectraNet's reconciliation also recognises that the connection point forecasts are not based on a particular PoE outcome but are intended to reflect demand under extreme heatwave conditions. The connection point forecasts are therefore compared with AEMO's 10% and 2% PoE peak demand forecasts.

4.2 Adjustments to the state-wide forecasts

ElectraNet's review of the state-wide peak demand forecasts concludes that several adjustments are warranted to place the forecasts on a comparable basis to the connection point forecasts and to adjust for omissions and biases found in the underlying modelling.

Adjustments for omission of DSP, bias and uncertainty

ElectraNet has added 20 MW to AEMO's forecasts in recognition of the exclusion of historic DSP and load shedding from data used to construct the forecasting model. ElectraNet has also added between 45 MW and 68 MW in recognition of its estimate of the downward bias introduced into AEMO's forecasts due to the treatment of solar generation and the water heating load within its forecasting model.

ElectraNet's reconciliation also recognises the uncertainty inherent in AEMO's 2011 forecasting model results by identifying a range of +/- 4.9% around the 10% PoE forecasts. This range of uncertainty is based on the standard errors associated with estimated coefficients in AEMO's annual model. ElectraNet's review of the state-wide forecasts identified a number of other sources of uncertainty in AEMO's forecasts, but these have not been allowed for in the reconciliation.

Differences in spot load assumptions

AEMO's forecasts are also adjusted to reflect differences in relation to once off load increases. AEMO's Offset load assumptions include some business-as usual expansion of the Olympic Dam/Prominent Hill load and commissioning of the Port Stanvac desalination plant. These assumptions differ from the assumed load growth underlying the connection point forecasts. The connection point forecasts also include several new spot loads that were not included in AEMO's forecasts. These differences have been added back into AEMO's forecasts to place them on a comparable footing to the connection point forecasts. ElectraNet has allowed for diversity of these loads in making the adjustments. The following table summarises the adjustments made to AEMO's forecasts.

Table 4-1 Adjustments for differences in assumed new loads

	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
MW included in undiversified Connection Point forecasts										
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ENet - new mining/desal (various locations)	0	0	0	11	16	16	33	33	57	57
ETSA - Pt Stanvac Desal (in Sthn Suburbs)	60	65	66	67	68	69	70	70	70	70
ETSA - new spot loads (in Western Suburbs)	5	15	21	27	33	34	35	35	35	35
ETSA - new spot loads (in Para System)	0	7	14	18	22	26	34	38	42	46
Total (undiversified demand)	**257**	**287**	**330**	**390**	**444**	**456**	**483**	**487**	**515**	**519**
MW included in diversified Connection Point forecasts										
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ENet - new mining/desal (various locations)	0	0	0	7	10	10	21	21	36	36
ETSA - Pt Stanvac Desal (in Sthn Suburbs)	56	60	60	61	61	62	62	62	61	61
ETSA - new spot loads (in Western Suburbs)	5	14	19	25	30	31	32	31	31	31
ETSA - new spot loads (in Para System)	0	7	14	17	21	25	32	36	40	44
Total (diversified demand)	**203**	**229**	**263**	**308**	**349**	**358**	**377**	**380**	**398**	**401**
MW included AEMO's peak demand forecasts										
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ENet - new mining/desal (various locations)	0	0	0	0	0	0	0	0	0	0
ETSA - Pt Stanvac Desal (in Sthn Suburbs)	0	5	11	16	16	33	33	50	50	50
ETSA - new spot loads (in Western Suburbs)	0	0	0	0	0	0	0	0	0	0
ETSA - new spot loads (in Para System)	0	0	0	0	0	0	0	0	0	0
Total (diversified demand)	**200**	**205**	**240**	**245**	**245**	**262**	**262**	**279**	**279**	**279**
Difference - added to AEMO's forecasts	**3**	**24**	**23**	**63**	**104**	**96**	**115**	**101**	**119**	**122**

4.3 Adjustments to the connection point forecasts

The process of reconciling the forecasts also requires that several adjustments be made to the connection point forecasts. These include:

- allowing for differences in the timing of connection point peak demands and state-wide peak demands. In determining an appropriate set of diversity factors to use in the reconciliation, ElectraNet has reviewed historic metering data and found evidence that diversity factors have changed over time. Small ongoing changes in diversity have therefore been allowed for in the reconciliation. These assumed changes are an important element in reconciling the growth rate of undiversified connection point demands with growth of the state-wide peak demand forecasts. ElectraNet's analysis of diversity factors is summarised at *Attachment 7 – Analysis of historic diversity factors*; and

- allowing for generator use of electricity and transmission network losses. AEMO's forecasts include these elements of demand while the connection point forecasts do not. Transmission losses and generator use of electricity have therefore been added to the sum of diversified connection point demand to place the forecasts on a comparable footing. This adjustment has been estimated as 5.5% of the 10% PoE peak demand level, and reflects the actual level of losses and generator loads on 31 January 2011, that being the most recent extreme demand day in South Australia.

4.4 Treatment of solar generation

Neither set of forecasts has been adjusted in the reconciliation in relation to assumed solar generation levels.

- AEMO's forecasts are effectively on the basis of "Native Demand after the assumed impact of solar generation".
- ETSA Utilities' forecasts include an implicit whole-of-state allowance for rising levels of solar generation, as the 2009 reference levels of demand used in its forecasting model were not adjusted to add back solar generation. ETSA Utilities' forecasts are also effectively on the basis of "demand after the impact of solar generation".

AEMO's post model adjustments for solar generation and ElectraNet's estimates of the extent of solar generation implicit in ETSA Utilities' forecasts are shown in the following table.

Table 4-2 Comparison of solar generation assumptions

	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
ETSA Utilities' implicit solar generation (MW)	10	11	12	13	14	15	16	17	18	19
AEMO post model adjustment for solar generation (MW)	7	8	9	11	12	13	15	16	18	19

As the two sets of assumptions show reasonably close alignment, adjustments are not required to place the forecasts on a comparable basis.

However, ElectraNet observes that in both cases these assumptions are considerably lower than new information regarding the actual level of solar generation installed during 2010-11. This information was not available at the time the 2011 forecasts were prepared. A detailed re-assessment of the level of solar generation may find both the state-wide forecasts and the connection point forecasts being revised down from the 2011 forecast levels.

4.5 Results of the reconciliation

ElectraNet has identified a band of uncertainty around AEMO's (adjusted) 10% PoE forecasts. This band reflects the plus/minus one standard deviation range of possible forecast outcomes associated with the uncertainty found to be present in AEMO's forecasts. The diversified connection point demands to 2017-18, which cover the period of the regulatory determination, lay within this one standard deviation range around AEMO's 10% PoE demand forecasts.

The results of ElectraNet's reconciliation of the 2011 forecasts are summarised in the following figure and table.

Figure 4-1 Reconciliation of the 2011 peak demand forecasts

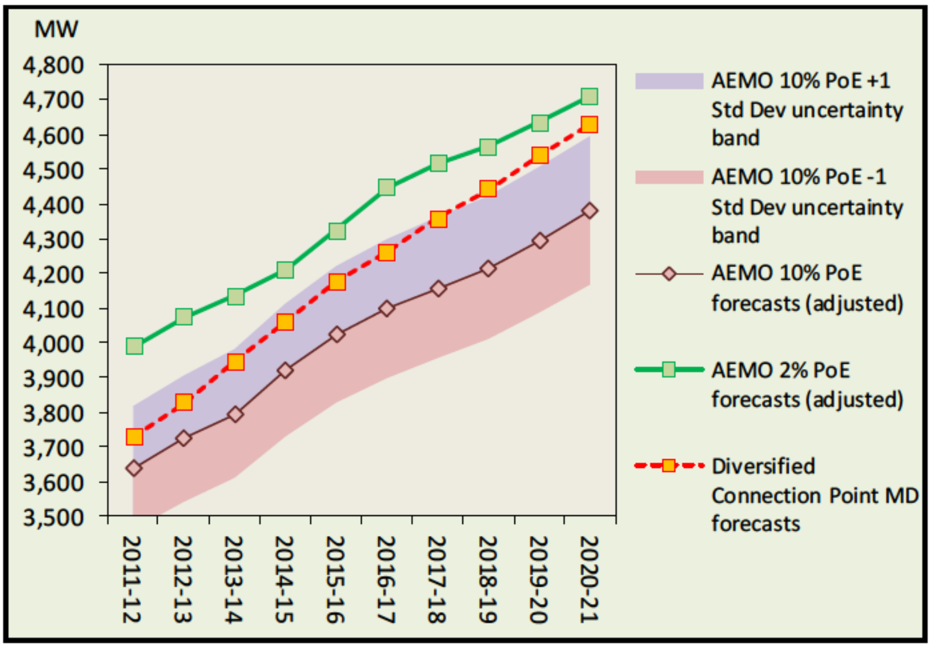


Table 4-3 Diversified connection point demands and the state-wide forecasts

	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
AEMO 10% PoE +1 Std Dev uncertainty band	3,816	3,905	3,981	4,112	4,220	4,298	4,362	4,423	4,507	4,595
AEMO 10% PoE forecasts (adjusted)	3,638	3,722	3,795	3,920	4,023	4,097	4,158	4,216	4,296	4,381
AEMO 10% PoE -1 Std Dev uncertainty band	3,460	3,540	3,609	3,728	3,826	3,897	3,955	4,010	4,086	4,166
AEMO 2% PoE forecasts (adjusted)	3,988	4,072	4,135	4,210	4,323	4,447	4,518	4,566	4,636	4,711
Diversified connection point peak demand forecasts	3,728	3,827	3,943	4,061	4,175	4,262	4,358	4,441	4,541	4,629

5. Attachments

5.1 Attachment 1 – AEMO's 2011 SA demand and energy forecasts

Table 5-1 AEMO's 2011 SA demand and energy forecasts

	Summer peak demand (MW)					Native energy (GWh)	
	Actual	90% PoE level	50% PoE level	10% PoE level	2% PoE level	Actual	Forecast
1998-99	2,545	2,433	2,651	2,929		11,855	
1999-00	2,661	2,508	2,723	3,009		12,644	
2000-01	2,890	2,608	2,856	3,138		13,148	
2001-02	2,519	2,751	2,986	3,294		12,643	
2002-03	2,803	2,628	2,881	3,153		13,173	
2003-04	2,639	2,744	3,010	3,303		13,195	
2004-05	2,702	2,774	3,026	3,341		13,339	
2005-06	2,971	2,818	3,066	3,372		13,817	
2006-07	2,955	2,917	3,181	3,486		14,343	
2007-08	3,213	3,022	3,290	3,636		14,375	
2008-09	3,490	3,012	3,291	3,609		14,575	
2009-10	3,321	3,016	3,294	3,626		14,475	
2010-11	3,433	2,994	3,260	3,598		14,567	
2011-12		2,980	3,230	3,570	3,920		14,964
2012-13		3,020	3,290	3,630	3,980		15,180
2013-14		3,110	3,370	3,700	4,040		15,513
2014-15		3,140	3,420	3,780	4,070		15,569
2015-16		3,190	3,470	3,840	4,140		15,800
2016-17		3,260	3,530	3,920	4,270		16,131
2017-18		3,320	3,590	3,960	4,320		16,363
2018-19		3,370	3,670	4,030	4,380		16,716
2019-20		3,430	3,730	4,090	4,430		16,947
2020-21		3,490	3,770	4,170	4,500		17,195

5.2 Attachment 2 – Definitions and basis of AEMO's forecasts

Electricity demand in South Australia is measured on a half hourly basis and is usually reported in megawatts (MW). Although this report is primarily concerned with AEMO's peak demand forecasts, the annual volume of electricity consumed plays a core role within the forecasting models and so these forecasts are also discussed in the report. Annual electricity consumption is typically reported in gigawatt hours (GWh).

AEMO's electricity forecasts are prepared on an as-generated Native Demand basis and cover all loads connected to the South Australian electrical network. Remote communities and mining sites not connected to the grid are excluded from the forecasts.

The concept of Native Demand and Native Energy

Native Demand (referred to simply as demand throughout the report) is measured as the total amount of electricity produced each half hour by all generators connected to the grid, including non-scheduled generators and small generators embedded within the distribution network[23].

This measure of demand includes network losses and generator house loads and auxiliary use of electricity in addition to customers' loads.

Native Energy (referred to as energy or annual energy in the report) represents the total electrical energy produced and consumed within a given period, typically a year. It is calculated by aggregating Native Demand over time[24].

Treatment of DSP

The electricity forecasts are prepared using historic demand data that has been adjusted to add-back known levels of demand side participation (DSP), controlled load shedding and loads that have been lost due to major unplanned generator or transmission plant outages[25].

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[23] Rooftop solar PV generators are an important emerging class of embedded generators and should, in principle, be included in measures of Native Demand. These generators are believed to have produced a significant volume of electricity in recent years and their contribution is expected to continue to grow over time. While AEMO's forecasts include post model adjustments to expected future levels of demand to reflect this trend, the past output of these generators has not been included in the historical measures of demand used to create the forecasts. The implications of this are considered within the body of the report.

[24] In addition to Native Demand and Native Energy, AEMO's forecasting publications also report demand and energy measures on a "scheduled" and "sent-out" basis and on a customer sales basis. Scheduled sent-out energy excludes non-scheduled and embedded generators as well as generator auxiliary loads, while customer sales reflect electricity consumption measured at end-users' meters.

[25] ElectraNet's review of AEMO's demand forecasts has identified that historic levels of DSP since 1 July 2009 have not been added back into the historic demand data used in AEMO's forecasting models. The implications of this are considered in the body of the report.

These adjustments are made so as to better approximate the underlying level of customers' demand and avoid forecasts which implicitly assume future plant outages or voluntary load shedding that may or may not be available in the future[26].

Offset loads

AEMO's forecasting methodology includes the identification of a relatively large Offset load which is treated differently from other loads within the forecasting process. The Offset load includes demand at the Olympic Dam and Prominent Hill mining sites and any potential large new industrial-type loads assumed to come on-line in the future.

The treatment of the Offset load within the forecasting model is discussed in *Section 2.4.1 General description of the model*, and forecasts of the Offset load are reported in *Section 2.5.3 Offset load assumptions*.

Offset loads are treated separately as they are typically insensitive to weather conditions and large once off changes are not driven by short term economic conditions in South Australia. Including these types of loads in historic data used to create forecasting models is likely to distort estimated relationships between the general level of electricity demand and important driver variables such as South Australia's economic conditions, electricity prices and the weather.

Forecasts of peak and average demand levels for these loads are generally provided by the customers themselves and incorporated probabilistically into AEMO's forecasts for the rest of the state.

At some points throughout this report ElectraNet has deducted the Offset loads from AEMO's state-wide forecasts to better understand the driving factors behind the implied forecasts for the remainder of the state.

Probabilistic basis of the forecasts

Peak electricity demand in any particular year is subject to random influences, including variations in customers' behaviour and day-to-day weather conditions which drive air conditioning and heating loads.

As day-to-day weather conditions are only predictable over very short horizons and random influences are unpredictable by their nature, it is not possible to produce reliable point estimates of actual peak demands in future years. Annual peak demand forecasts are therefore prepared on a probability of exceedence (PoE) basis.

An X% PoE forecast has an X% probability of being exceeded in any given year. Thus, a 10% PoE forecast for a particular year's peak demand is likely to be exceeded once in every ten years on average.

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[26] AEMO deducts predicted future levels of voluntary DSP from the peak demand forecasts when it assesses the state's overall supply-demand balance and identifies the level of generation reserves expected to be available in future years.

Peak demand PoE level forecasts (and "back-cast" PoE levels that applied in the past) are identified from estimated probability density functions which are unique to each year and intended to describe the entire range of possible peak demand outcomes in a particular year. The probability density function forecasting methodology was developed by Monash University and is described in the body of this report.

AEMO's 2011 demand forecasts

AEMO prepares separate peak demand forecasts for the summer and winter seasons and generally adopts a ten year forecast horizon. Forecasts are typically reported at the 10%, 50% and 90% PoE levels[27]. Separate sets of forecasts are also produced for base, high and low case economic assumptions.

ElectraNet's review is primarily concerned with AEMO's base case summer 10% PoE peak demand forecasts as reported in its publication *2011 South Australian Supply and Demand Outlook*. These forecasts were prepared by Monash University in around May 2011 and cover the period 2011-12 to 2020-21. The electricity forecasts are based on economic forecasts developed for AEMO by KPMG at around the same time.

[27] Although AEMO generally only reports 10%, 50% and 90% PoE forecasts in its publications, the underlying forecasting model results allow the identification of other PoE level forecasts and back-casts. ElectraNet refers to these other PoE level forecasts at certain points within this report. These have been obtained from Monash University's reports to AEMO.

5.3 Attachment 3 – Half hourly demand ratios

The following figures show the natural logarithm of the ratio of NEM trading period 4 and trading period 33 half hourly demand to annual average demand for the period 1997-98 to 2010-11. Only figures for working days in the period November to March each year are shown.

These ratios are used in AEMO's demand forecasting models and are assumed to change only in response to short term temperature and calendar effects. However, there has been a change in these ratios over time which is consistent with declines in the overnight water heating load. This effect is particularly noticeable in the period 4 ratio. There is also an apparent upward movement in the peak period ratio in recent years that would be consistent with this change in the water heating load.

If changes in these ratios are not modelled correctly there will be an exponential impact on the resulting demand forecasts as the ratios are expressed in logarithms.

Figure 5-1 Trading period 4 demand ratio

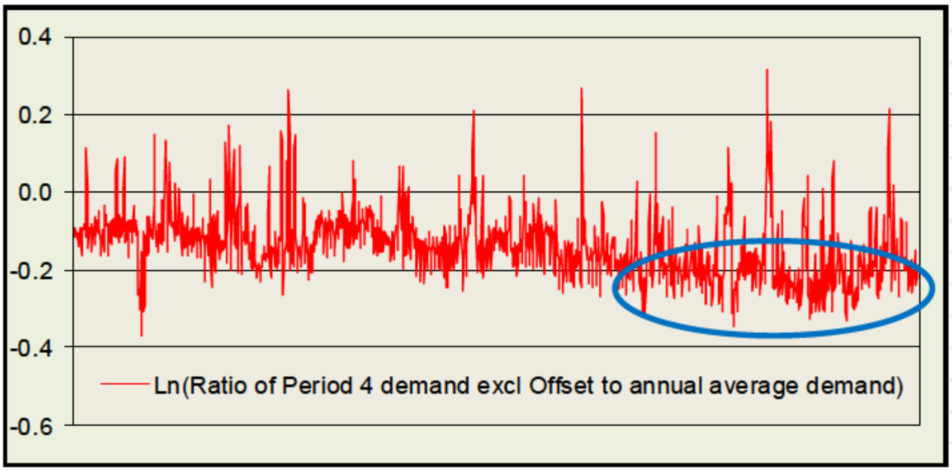
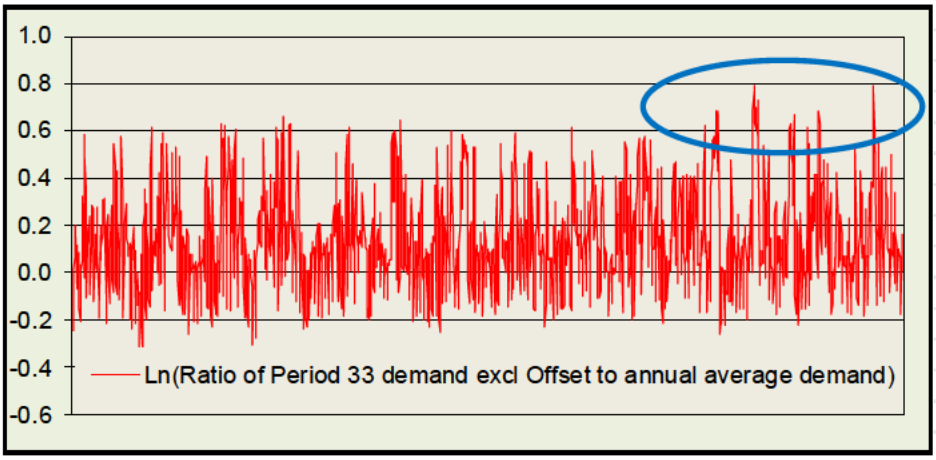


Figure 5-2 Trading period 33 demand ratio



5.4 Attachment 4 – Rooftop solar PV generation

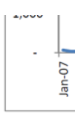
Comprehensive data relating to rooftop solar PV generation in South Australia is not available to ElectraNet's knowledge. ElectraNet has therefore relied on limited information reported by ESCOSA in the *2012 Determination of Solar Feed-in Tariff Premium – Final Price Determination*, January 2012, and a research report prepared for the Electricity Supply Industry Planning Council[28].

ESCOSA reports that, as at 30 December 2011, there were 83,741 premises with solar PV cells and total installed capacity of approximately 195 MW. Average nameplate capacity was therefore 2.33 kW per installation, with approximately 9% of all households having a unit of some type at that time.

ESCOSA also reports there has been a rapid increase in connections since early 2010, with monthly connections appearing to have peaked at around 7,000 in November 2011. There is a general expectation within the electricity industry that new connections will fall substantially following recent changes to feed-in tariff arrangements.

The following figure, which shows monthly connections over the past few years, has been reproduced from ESCOSA's January 2012 price determination report.

Figure 5-3 Number of new PV systems connected monthly by ETSA Utilities



The 2008 research report prepared for ESIPC concludes that residential rooftop solar PV units are expected to operate with an average annual capacity factor of around 16%, and to be operating at around 50% of name plate capacity at the time of summer peak demands[29].

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[28] Donna Chapman, David Sambell, Lesley A. Ward and Vanessa Wong, *The value to the electricity market and the electricity network of photovoltaic generation*. Final Report to the Electricity Supply Industry Planning Council, December 2007.

[29] Western Power has made a confidential 2011 report available to ElectraNet which finds a slightly lower operating factor at peak demand times in Western Australia.

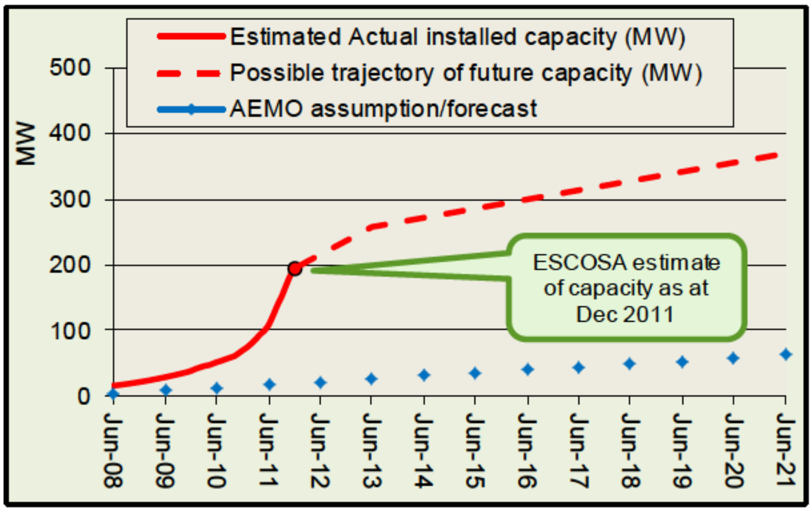
ElectraNet has used these findings and the information reported in ESCOSA's chart to back-cast indicative levels of historic solar generation and estimate possible future levels. In preparing these estimates, ElectraNet has adopted what it believes to be a conservative rate of new installations in the period post 30 December 2011. In particular, monthly installations are assumed to fall to back to 1,500 in the period January 2012 to June 2013, and then fall further to 500 in later months. ElectraNet's estimates are set out in the table below[30].

Table 5-2 Estimated solar PV output

	Estimated number of installations (year ave)	Assumed average nameplate rating	Estimated installed capacity MW	Expected annual avereage capacity factor %	Estimated annual energy produced GWh	Expected output at time of summer peak demand % of nameplate capacity	Expected output at time of summer peak demand MW	AEMO's assumed installed capacity MW
2006-07	2,846	1.53	4	16	6	50	2	
2007-08	5,865	1.53	9	16	13	50	4	4
2008-09	9,827	1.53	15	16	21	50	8	9
2009-10	17,528	1.93	34	16	47	50	17	13
2010-11	34,591	2.33	81	16	113	50	40	18
2011-12	69,741	2.33	162	16	228	50	81	22
2012-13	101,741	2.33	237	16	332	50	118	27
2013-14	113,741	2.33	265	16	371	50	132	31
2014-15	119,741	2.33	279	16	391	50	139	36
2015-16	125,741	2.33	293	16	410	50	146	40
2016-17	131,741	2.33	307	16	430	50	153	45
2017-18	137,741	2.33	321	16	450	50	160	49
2018-19	143,741	2.33	335	16	469	50	167	54
2019-20	149,741	2.33	349	16	489	50	174	58
2020-21	155,741	2.33	363	16	508	50	181	63

These estimates of past and possible future installed capacity are materially higher than assumed by AEMO in its 2011 modelling. ElectraNet's estimates based on the new information published by ESCOSA are compared with AEMO's 2011 assumptions in the following figure.

Figure 5-4 Estimated nameplate capacity of rooftop solar generators



30 These estimates should not be relied upon as forecasts. They are only indicative of outcomes if new installations turn out to be as assumed in the calculations.

5.5 Attachment 5 – Analysis of AEMO's model bias

This attachment reproduces ElectraNet's analysis of bias in the state-wide demand forecasts due to AEMO's treatment of rooftop solar generation and the water heating load within the annual model and subsequent application of post model adjustments.

This first set of figures show ElectraNet's approximate replication of AEMO's annual forecasting model and the derivation of indicative energy and demand forecasts. The second set of figures show that materially higher energy and demand forecasts are obtained if the model is altered to remove biases associated with the treatment of solar generation and the water heating load.

The forecasts do not, and are not intended to, replicate AEMO's forecasts exactly. They are intended to identify how the forecasts change under different treatments of the water heating load and solar generation. ElectraNet considers these changes will be representative of changes in AEMO's forecasts if water heating and solar generation had been treated differently within its model.

AEMO's existing model approach

Historic and forecast data used in the model

	GSP	Population	Aveerage price	Annual energy incl Offset, GWh	Annual energy Offset load, GWh	Annual energy NON-Offset load, GWh	Average SA Demand incl Offset, MW	Average SA Offset demand, MW	Average SA NON-Offset demand, MW	Ave annual W/person
1989/1990	49,153.9	1,427.2	16.48	9,191.7	146.9	9,044.9	1,049.3	16.8	1,032.5	723.5
1990/1991	48,346.3	1,441.0	15.92	9,369.8	164.2	9,205.7	1,069.6	18.7	1,050.9	729.3
1991/1992	47,336.9	1,453.1	16.34	9,242.1	185.3	9,056.8	1,052.2	21.1	1,031.1	709.6
1992/1993	48,503.5	1,459.2	16.01	9,600.9	226.6	9,374.3	1,096.0	25.9	1,070.1	733.4
1993/1994	50,143.6	1,464.4	15.18	9,833.2	229.4	9,603.7	1,122.5	26.2	1,096.3	748.6
1994/1995	51,194.6	1,468.1	13.94	10,582.3	228.5	10,353.8	1,208.0	26.1	1,181.9	805.1
1995/1996	53,801.5	1,472.1	13.29	10,512.9	298.6	10,214.4	1,196.8	34.0	1,162.8	789.9
1996/1997	54,834.8	1,478.6	13.71	10,861.3	460.8	10,400.5	1,239.9	52.6	1,187.3	803.0
1997/1998	57,239.9	1,486.5	13.73	11,449.9	400.7	11,049.2	1,307.1	45.7	1,261.3	848.5
1998/1999	58,948.6	1,494.7	13.68	11,855.3	573.0	11,282.3	1,353.3	65.4	1,287.9	861.7
1999/2000	60,138.2	1,502.9	13.39	12,643.7	816.1	11,827.6	1,439.4	92.9	1,346.5	895.9
2000/2001	61,802.0	1,511.7	14.37	13,147.7	887.8	12,259.8	1,500.9	101.4	1,399.5	925.8
2001/2002	64,266.3	1,521.1	14.79	12,642.9	821.9	11,820.9	1,443.3	93.8	1,349.4	887.1
2002/2003	65,269.3	1,531.3	15.08	13,173.3	811.0	12,362.3	1,503.8	92.6	1,411.2	921.6
2003/2004	68,072.0	1,540.4	15.37	13,194.9	810.0	12,384.9	1,502.2	92.2	1,409.9	915.3
2004/2005	68,695.8	1,552.5	14.97	13,338.6	921.2	12,417.4	1,522.7	105.2	1,417.5	913.0
2005/2006	70,483.9	1,567.9	14.46	13,816.7	895.9	12,920.9	1,577.3	102.3	1,475.0	940.7
2006/2007	71,820.9	1,585.8	13.82	14,343.2	883.1	13,460.0	1,637.3	100.8	1,536.5	968.9
2007/2008	75,838.7	1,604.0	14.19	14,375.1	923.7	13,451.4	1,636.5	105.2	1,531.4	954.7
2008/2009	77,342.3	1,624.5	14.40	14,575.5	1,026.4	13,549.1	1,663.9	117.2	1,546.7	952.1
2009/2010	78,671.3	1,644.6	15.35	14,485.0	943.7	13,541.3	1,653.5	107.7	1,545.8	939.9
2010/2011	81,250.3	1,652.7	15.48	10,444.1	962.3	9,481.8	1,693.3	156.0	1,537.3	930.1
2011/2012	84,410.6	1,666.6	15.64							
2012/2013	86,517.4	1,680.9	15.74							
2013/2014	88,835.1	1,695.4	16.05							
2014/2015	91,529.7	1,710.0	16.81							
2015/2016	93,684.9	1,724.7	16.76							
2016/2017	95,678.7	1,739.3	16.72							
2017/2018	97,723.8	1,753.8	16.68							
2018/2019	99,863.1	1,768.2	16.64							
2019/2020	102,100.4	1,782.7	16.62							
2020/2021	104,573.4	1,797.3	16.61							

Regression results

Regression Statistics	
Multiple R	0.803
R Square	0.645
Adjusted R Square	0.556
Standard Error	16.194
Observations	21.000

ANOVA

	df	*SS*	*MS*	*F*
Regression	4.000	7629.850	1907.462	7.273
Residual	16.000	4196.188	262.262	
Total	20.000	11826.038		

	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	7.229	4.977	1.452	0.166
Chg $000 GSP/person	2.602	4.978	0.523	0.608
Chg price	-17.007	6.337	-2.684	0.016
Chg 100 SCDD	9.747	2.224	4.383	0.000
Chg 100 WHDD	3.233	3.861	0.837	0.415

Regression model inputs and outputs

	Ave annual W/person	GSP/person $000	Aveerage price	100 SCDD	100 WHDD
1989/1990	723.47	34.44	16.48	5.33	9.99
1990/1991	729.26	33.55	15.92	5.36	8.92
1991/1992	709.58	32.58	16.34	4.17	9.85
1992/1993	733.38	33.24	16.01	4.31	9.97
1993/1994	748.63	34.24	15.18	3.71	8.57
1994/1995	805.06	34.87	13.94	5.45	10.18
1995/1996	789.91	36.55	13.29	4.20	9.56
1996/1997	802.97	37.09	13.71	4.81	9.78
1997/1998	848.52	38.51	13.73	4.77	10.30
1998/1999	861.65	39.44	13.68	5.60	9.75
1999/2000	895.91	40.01	13.39	5.88	9.17
2000/2001	925.78	40.88	14.37	7.35	9.31
2001/2002	887.12	42.25	14.79	2.42	8.56
2002/2003	921.60	42.62	15.08	5.30	8.79
2003/2004	915.29	44.19	15.37	5.11	9.55
2004/2005	913.04	44.25	14.97	4.36	8.70
2005/2006	940.75	44.95	14.46	5.82	10.15
2006/2007	968.93	45.29	13.82	6.71	8.55
2007/2008	954.72	47.28	14.19	6.79	8.33
2008/2009	952.10	47.61	14.40	5.46	8.37
2009/2010	939.94	47.84	15.35	7.47	8.23
2010/2011	930.13	49.16	15.48	5.22	10.21
2011/2012	935.97	50.65	15.64	5.25	9.31
2012/2013	943.65	51.47	15.74	5.25	9.31
2013/2014	947.98	52.40	16.05	5.25	9.31
2014/2015	945.35	53.52	16.81	5.25	9.31
2015/2016	955.34	54.32	16.76	5.25	9.31
2016/2017	965.05	55.01	16.72	5.25	9.31
2017/2018	974.88	55.72	16.68	5.25	9.31
2018/2019	984.68	56.48	16.64	5.25	9.31
2019/2020	994.36	57.27	16.62	5.25	9.31
2020/2021	1004.21	58.18	16.61	5.25	9.31

	Chg W/person	Chg $000 GSP/person	Chg price	Chg 100 SCDD	Chg 100 WHDD
1990/1991	5.79	-0.89	-0.56	0.02	-1.08
1991/1992	-19.68	-0.97	0.41	-1.19	0.93
1992/1993	23.80	0.66	-0.33	0.14	0.13
1993/1994	15.25	1.00	-0.82	-0.59	-1.41
1994/1995	56.43	0.63	-1.24	1.74	1.61
1995/1996	-15.15	1.68	-0.65	-1.26	-0.62
1996/1997	13.06	0.54	0.42	0.62	0.22
1997/1998	45.55	1.42	0.02	-0.05	0.52
1998/1999	13.14	0.93	-0.05	0.84	-0.54
1999/2000	34.25	0.58	-0.29	0.28	-0.58
2000/2001	29.87	0.87	0.98	1.47	0.14
2001/2002	-38.66	1.37	0.42	-4.93	-0.75
2002/2003	34.48	0.37	0.29	2.89	0.23
2003/2004	-6.31	1.57	0.29	-0.19	0.76
2004/2005	-2.25	0.06	-0.40	-0.75	-0.86
2005/2006	27.71	0.71	-0.51	1.46	1.45
2006/2007	28.19	0.34	-0.64	0.89	-1.60
2007/2008	-14.22	1.99	0.37	0.08	-0.21
2008/2009	-2.62	0.33	0.21	-1.33	0.04
2009/2010	-12.16	0.23	0.95	2.01	-0.14
2010/2011	-9.81	1.32	0.13	-2.25	1.98
2011/2012	5.84	1.49	0.16	0.03	-0.90
2012/2013	7.68	0.82	0.10	0.00	0.00
2013/2014	4.33	0.93	0.31	0.00	0.00
2014/2015	-2.63	1.13	0.75	0.00	0.00
2015/2016	9.99	0.79	-0.04	0.00	0.00
2016/2017	9.71	0.69	-0.04	0.00	0.00
2017/2018	9.83	0.71	-0.04	0.00	0.00
2018/2019	9.80	0.76	-0.04	0.00	0.00
2019/2020	9.69	0.80	-0.02	0.00	0.00
2020/2021	9.85	0.91	-0.01	0.00	0.00

Final forecasts are produced using the model outputs, population forecasts and post model adjustments. ElectraNet has assumed that the peak to average demand ratio in 2020-21 is 2.1, in line with the *2011 SASDO* forecast results.

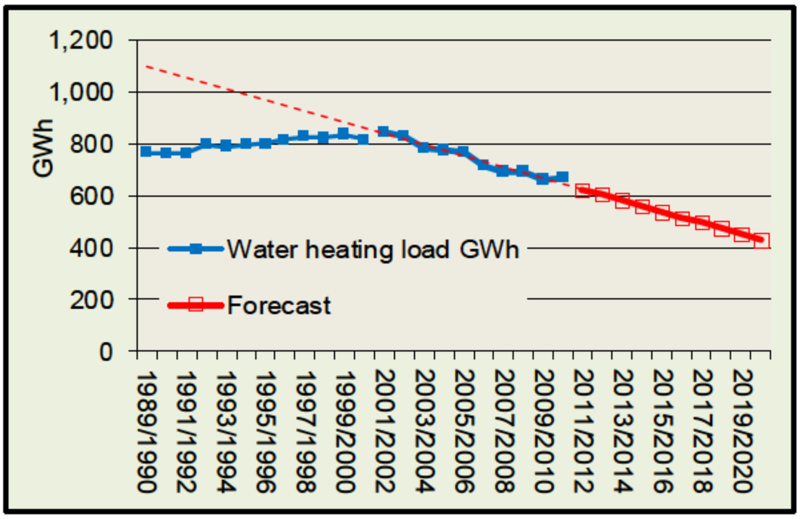
	F'cast average annual W/person	Annual energy pre Offset & Post Mod Adjs GWh	Plus forecast Offset load GW	Less adj for solar PV GWh	Less adj for water heating GWh	Less adj for lighting MEPS GWh	Forecast annual energy GWh	Average annual demand MW	Indicative 10% PoE demand MW
2011/2012	935.97	13,702.2	1,349.0	-18.9	-103.1	-88.8	14,840.5	1,694.1	3,557.6
2012/2013	943.65	13,894.8	1,384.1	-22.7	-123.5	-120.1	15,012.5	1,713.8	3,598.9
2013/2014	947.98	14,078.7	1,621.7	-26.4	-142.9	-153.9	15,377.3	1,755.4	3,686.3
2014/2015	945.35	14,161.3	1,656.8	-30.2	-161.3	-189.7	15,436.8	1,762.2	3,700.6
2015/2016	955.34	14,473.3	1,656.8	-34.0	-178.8	-191.0	15,726.3	1,795.2	3,770.0
2016/2017	965.05	14,703.9	1,775.9	-37.8	-195.4	-196.2	16,050.5	1,832.2	3,847.7
2017/2018	974.88	14,977.7	1,775.9	-41.6	-211.2	-200.7	16,300.1	1,860.7	3,907.6
2018/2019	984.68	15,252.4	1,895.1	-45.4	-226.7	-205.4	16,670.0	1,903.0	3,996.2
2019/2020	994.36	15,571.2	1,895.1	-49.1	-242.2	-210.2	16,964.7	1,936.6	4,066.9
2020/2021	1004.21	15,810.5	1,895.1	-52.9	-255.0	-210.2	17,187.4	1,962.0	4,120.3

Alternative approach to dealing with solar generation and water heating

Historic and forecast data are identical – but in this instance average annual W/person is adjusted to add back solar generation and deduct the water heating load. The water heating load is now treated as an offset load with independent forecasts based on the recent trend decline in sales. AEMO's 2011 post model adjustments for solar generation and lighting MEPs are deducted from the final forecasts in the same way as in the original forecasts.

	GSP	Population	Aveerage price	Annual energy NON-Offset load, GWh	Deduct Water heating load GWh	Add back PV generation GWh		Annual energy NON-Offset load, GWh	Average SA NON-Offset demand, MW	Ave annual W/person
1989/1990	49,153.9	1,427.2	16.48	9,044.9	-768.5	0.0		8,276.4	944.8	662.0
1990/1991	48,346.3	1,441.0	15.92	9,205.7	-764.2	0.0		8,441.5	963.6	668.7
1991/1992	47,336.9	1,453.1	16.34	9,056.8	-765.2	0.0		8,291.6	943.9	649.6
1992/1993	48,503.5	1,459.2	16.01	9,374.3	-796.6	0.0		8,577.7	979.2	671.1
1993/1994	50,143.6	1,464.4	15.18	9,603.7	-791.0	0.0		8,812.7	1,006.0	687.0
1994/1995	51,194.6	1,468.1	13.94	10,353.8	-800.0	0.0		9,553.8	1,090.6	742.9
1995/1996	53,801.5	1,472.1	13.29	10,214.4	-802.8	0.0		9,411.6	1,071.4	727.8
1996/1997	54,834.8	1,478.6	13.71	10,400.5	-817.8	0.0		9,582.7	1,093.9	739.8
1997/1998	57,239.9	1,486.5	13.73	11,049.2	-828.5	0.0		10,220.7	1,166.8	784.9
1998/1999	58,948.6	1,494.7	13.68	11,282.3	-824.3	0.0		10,458.0	1,193.8	798.7
1999/2000	60,138.2	1,502.9	13.39	11,827.6	-836.9	0.0		10,990.7	1,251.2	832.5
2000/2001	61,802.0	1,511.7	14.37	12,259.8	-817.5	0.0		11,442.3	1,306.2	864.0
2001/2002	64,266.3	1,521.1	14.79	11,820.9	-845.3	0.0		10,975.6	1,252.9	823.7
2002/2003	65,269.3	1,531.3	15.08	12,362.3	-831.4	0.0		11,530.9	1,316.3	859.6
2003/2004	68,072.0	1,540.4	15.37	12,384.9	-787.2	0.0		11,597.8	1,320.3	857.1
2004/2005	68,695.8	1,552.5	14.97	12,417.4	-775.5	0.0		11,641.8	1,329.0	856.0
2005/2006	70,483.9	1,567.9	14.46	12,920.9	-767.7	0.0		12,153.2	1,387.3	884.9
2006/2007	71,820.9	1,585.8	13.82	13,460.0	-719.3	6.1		12,746.8	1,455.1	917.6
2007/2008	75,838.7	1,604.0	14.19	13,451.4	-694.8	12.6		12,769.2	1,453.7	906.3
2008/2009	77,342.3	1,624.5	14.40	13,549.1	-690.7	21.1		12,879.5	1,470.3	905.0
2009/2010	78,671.3	1,644.6	15.35	13,541.3	-658.7	47.4		12,930.0	1,476.0	897.5
2010/2011	81,250.3	1,652.7	15.48	9,481.8	-671.5	112.9		8,923.2	1,473.5	891.5
2011/2012	84,410.6	1,666.6	15.64							
2012/2013	86,517.4	1,680.9	15.74							
2013/2014	88,835.1	1,695.4	16.05							
2014/2015	91,529.7	1,710.0	16.81							
2015/2016	93,684.9	1,724.7	16.76							
2016/2017	95,678.7	1,739.3	16.72							
2017/2018	97,723.8	1,753.8	16.68							
2018/2019	99,863.1	1,768.2	16.64							
2019/2020	102,100.4	1,782.7	16.62							
2020/2021	104,573.4	1,797.3	16.61							

The water heating load forecasts are based on the trend decline in sales observed since 2000-01.



Regression results

Regression Statistics	
Multiple R	0.820
R Square	0.673
Adjusted R Square	0.591
Standard Error	15.341
Observations	21.000

ANOVA

	df	*SS*	*MS*	*F*
Regression	4.000	7752.064	1938.016	8.235
Residual	16.000	3765.399	235.337	
Total	20.000	11517.463		

	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	8.217	4.715	1.743	0.101
Chg $000 GSP/person	2.815	4.716	0.597	0.559
Chg price	-16.057	6.003	-2.675	0.017
Chg 100 SCDD	10.063	2.106	4.777	0.000
Chg 100 WHDD	3.125	3.657	0.855	0.405

Regression model inputs and outputs

	Ave annual W/person	GSP/person $000	Average price	100 SCDD	100 WHDD
1989/1990	662.00	34.44	16.48	5.33	9.99
1990/1991	668.72	33.55	15.92	5.36	8.92
1991/1992	649.63	32.58	16.34	4.17	9.85
1992/1993	671.06	33.24	16.01	4.31	9.97
1993/1994	686.97	34.24	15.18	3.71	8.57
1994/1995	742.85	34.87	13.94	5.45	10.18
1995/1996	727.83	36.55	13.29	4.20	9.56
1996/1997	739.83	37.09	13.71	4.81	9.78
1997/1998	784.89	38.51	13.73	4.77	10.30
1998/1999	798.70	39.44	13.68	5.60	9.75
1999/2000	832.52	40.01	13.39	5.88	9.17
2000/2001	864.04	40.88	14.37	7.35	9.31
2001/2002	823.68	42.25	14.79	2.42	8.56
2002/2003	859.62	42.62	15.08	5.30	8.79
2003/2004	857.11	44.19	15.37	5.11	9.55
2004/2005	856.02	44.25	14.97	4.36	8.70
2005/2006	884.85	44.95	14.46	5.82	10.15
2006/2007	917.59	45.29	13.82	6.71	8.55
2007/2008	906.30	47.28	14.19	6.79	8.33
2008/2009	905.05	47.61	14.40	5.46	8.37
2009/2010	897.51	47.84	15.35	7.47	8.23
2010/2011	891.55	49.16	15.48	5.22	10.21
2011/2012	898.95	50.65	15.64	5.25	9.31
2012/2013	907.89	51.47	15.74	5.25	9.31
2013/2014	913.70	52.40	16.05	5.25	9.31
2014/2015	913.01	53.52	16.81	5.25	9.31
2015/2016	924.12	54.32	16.76	5.25	9.31
2016/2017	934.93	55.01	16.72	5.25	9.31
2017/2018	945.86	55.72	16.68	5.25	9.31
2018/2019	956.77	56.48	16.64	5.25	9.31
2019/2020	967.59	57.27	16.62	5.25	9.31
2020/2021	978.61	58.18	16.61	5.25	9.31

	Chg W/person	Chg $000 GSP/person	Chg price	Chg 100 SCDD	Chg 100 WHDD
1990/1991	6.73	-0.89	-0.56	0.02	-1.08
1991/1992	-19.09	-0.97	0.41	-1.19	0.93
1992/1993	21.43	0.66	-0.33	0.14	0.13
1993/1994	15.91	1.00	-0.82	-0.59	-1.41
1994/1995	55.88	0.63	-1.24	1.74	1.61
1995/1996	-15.03	1.68	-0.65	-1.26	-0.62
1996/1997	12.00	0.54	0.42	0.62	0.22
1997/1998	45.07	1.42	0.02	-0.05	0.52
1998/1999	13.81	0.93	-0.05	0.84	-0.54
1999/2000	33.82	0.58	-0.29	0.28	-0.58
2000/2001	31.53	0.87	0.98	1.47	0.14
2001/2002	-40.36	1.37	0.42	-4.93	-0.75
2002/2003	35.94	0.37	0.29	2.89	0.23
2003/2004	-2.50	1.57	0.29	-0.19	0.76
2004/2005	-1.10	0.06	-0.40	-0.75	-0.86
2005/2006	28.84	0.71	-0.51	1.46	1.45
2006/2007	32.74	0.34	-0.64	0.89	-1.60
2007/2008	-11.29	1.99	0.37	0.08	-0.21
2008/2009	-1.25	0.33	0.21	-1.33	0.04
2009/2010	-7.54	0.23	0.95	2.01	-0.14
2010/2011	-5.96	1.32	0.13	-2.25	1.98
2011/2012	7.40	1.49	0.16	0.03	-0.90
2012/2013	8.94	0.82	0.10	0.00	0.00
2013/2014	5.81	0.93	0.31	0.00	0.00
2014/2015	-0.69	1.13	0.75	0.00	0.00
2015/2016	11.11	0.79	-0.04	0.00	0.00
2016/2017	10.80	0.69	-0.04	0.00	0.00
2017/2018	10.93	0.71	-0.04	0.00	0.00
2018/2019	10.91	0.76	-0.04	0.00	0.00
2019/2020	10.82	0.80	-0.02	0.00	0.00
2020/2021	11.02	0.91	-0.01	0.00	0.00

The forecast average annual W/person metric now grows considerably faster, at 0.94% pa, compared with the previous model structure, which shows average growth at 0.74% pa. This difference has a compound effect of almost 2% over the ten year forecast horizon, indicating the extent of bias implicit in AEMO's original structure.

Final forecasts are produced using the model outputs, population forecasts and post model adjustments. AEMO's original adjustments for solar generation and lighting MEPs are deducted but the independent water heating load forecast is used in place of the original post model adjustment applied by AEMO.

The final indicative energy and 10% PoE demand levels are higher than forecast using AEMO's 2011 approach.

	F'cast average annual W/person	Annual energy pre Offset & Post Mod Adjs GWh	Plus forecast Offset load GW	Less adj for solar PV GWh	Add back new water heating f'cast GWh	Less adj for lighting MEPS GWh	Forecast annual energy GWh	Average annual demand MW	Indicative 10% PoE demand MW	Difference in 10% PoE
2011/2012	898.95	13,160.2	1,349.0	-18.9	626.0	-88.8	15,027.6	1,715.5	3,602.5	45
2012/2013	907.89	13,368.2	1,384.1	-22.7	604.5	-120.1	15,214.0	1,736.8	3,647.2	48
2013/2014	913.70	13,569.6	1,621.7	-26.4	583.0	-153.9	15,594.1	1,780.2	3,738.3	52
2014/2015	913.01	13,676.9	1,656.8	-30.2	561.5	-189.7	15,675.3	1,789.4	3,757.8	57
2015/2016	924.12	14,000.3	1,656.8	-34.0	540.0	-191.0	15,972.1	1,823.3	3,828.9	59
2016/2017	934.93	14,245.0	1,775.9	-37.8	518.5	-196.2	16,305.4	1,861.4	3,908.8	61
2017/2018	945.86	14,531.8	1,775.9	-41.6	497.0	-200.7	16,562.4	1,890.7	3,970.4	63
2018/2019	956.77	14,820.1	1,895.1	-45.4	475.5	-205.4	16,940.0	1,933.8	4,060.9	65
2019/2020	967.59	15,152.0	1,895.1	-49.1	454.0	-210.2	17,241.8	1,968.2	4,133.3	66
2020/2021	978.61	15,407.4	1,895.1	-52.9	432.6	-210.2	17,471.9	1,994.5	4,188.5	68

5.6 Attachment 6 – Connection point maximum demand forecasts

Table 5-3 Base case connection point maximum demand forecasts

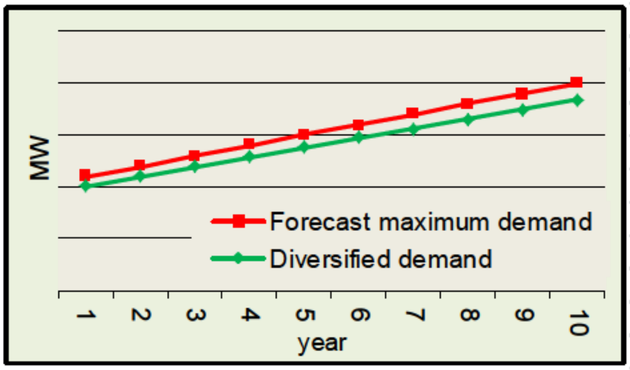
Connection Point	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Eastern Suburbs	798.5	857.8	876.7	896.0	915.7	935.9	956.5	977.5	999.0	1021.0
Southern Suburbs	861.2	844.3	864.8	885.7	907.2	929.2	951.7	973.7	996.3	1019.5
Western Suburbs	489.5	507.3	521.2	535.2	549.3	558.6	567.9	576.5	585.1	593.9
Para System	392.4	412.4	432.7	450.6	468.8	487.6	510.8	530.6	550.8	571.6
Port Pirie System	86.7	87.7	88.7	89.8	90.8	91.9	93.1	94.3	95.5	96.8
Angas Creek	21.4	22.0	22.6	23.3	23.9	24.6	25.3	26.0	26.7	27.4
Ardrossan West	15.1	17.7	18.3	18.9	19.5	20.2	20.9	21.6	22.3	23.1
Baroota	9.0	9.2	9.4	9.5	9.7	9.8	10.0	10.2	10.4	10.5
Berri	97.8	99.7	101.7	103.8	105.9	108.0	110.1	112.3	114.6	116.9
Blanche	37.5	38.4	39.2	45.1	46.1	47.1	48.1	49.2	50.2	51.3
Brinkworth	5.7	5.8	5.8	5.8	5.8	5.9	5.9	5.9	6.0	6.0
Clare North	14.0	14.6	15.3	16.0	16.7	17.5	18.2	19.1	19.9	20.8
Dalrymple	10.3	10.6	11.0	11.3	11.7	12.1	12.4	12.8	13.2	13.7
Davenport West	33.6	34.2	34.8	35.5	36.2	36.9	37.6	38.3	39.0	39.7
Dorrien	70.4	72.5	74.7	76.9	79.2	81.6	84.0	86.5	89.1	91.8
Hummocks	14.9	13.5	14.1	14.7	15.4	16.1	16.9	17.6	18.4	19.3
Kadina East	28.9	30.2	31.5	32.9	34.4	36.0	37.6	39.3	41.1	42.9
Kanmantoo	2.0	2.2	2.4	2.5	2.7	3.0	3.2	3.5	3.7	4.0
Keith	31.7	33.0	34.4	35.8	37.3	38.8	40.4	42.1	43.9	45.7
Kincraig	23.7	24.4	25.2	25.9	26.7	27.6	28.4	29.3	30.2	31.2
Leigh Creek South	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Mannum	14.4	14.5	14.6	14.6	14.7	14.8	14.9	14.9	15.0	15.1
Mobilong	44.2	45.8	47.6	49.4	51.3	53.2	55.2	57.3	59.5	61.8
Mt Barker/Mt Barker Sth	113.2	119.6	126.3	133.4	140.8	148.7	157.0	165.8	175.1	184.9
Mt Gambier	28.3	28.8	29.2	24.6	25.0	25.4	25.8	26.1	26.5	26.9
Mt Gunson	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Neuroodla	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
North West Bend	29.1	29.3	29.4	29.6	29.7	29.9	30.0	30.2	30.3	30.5
Penola West	14.0	14.2	14.5	14.8	15.1	15.4	15.6	15.9	16.2	16.6
Port Lincoln Terminal	46.5	48.4	50.4	52.5	54.6	56.9	59.2	61.7	64.2	66.9
Snuggery Industrial	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
Snuggery Rural	18.1	19.2	20.3	21.5	22.8	24.2	25.7	27.2	28.8	30.6
Stony Point	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Tailem Bend	27.3	27.4	27.6	27.7	27.8	28.0	28.1	28.2	28.4	28.5
Templers	34.1	35.8	37.6	39.5	41.4	43.5	45.7	48.0	50.4	52.9
Waterloo	12.3	12.9	13.5	14.1	14.7	15.4	16.1	16.8	17.5	18.3
Whyalla Terminal	92.6	93.3	94.0	94.7	95.4	96.2	96.9	97.7	98.4	99.2
Whyalla LMF	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2
Wudinna	15.9	16.1	16.4	16.6	16.9	17.1	17.4	17.7	17.9	18.2
Yadnarie	12.1	12.4	12.7	13.1	13.4	13.8	14.1	14.5	14.9	15.3
sub total - ETSA Utilities connection points	**3598.4**	**3707.1**	**3810.6**	**3913.2**	**4018.6**	**4122.8**	**4232.6**	**4340.2**	**4450.5**	**4564.7**
[redacted]										
sub total - Direct connect customers	**308.0**	**317.9**	**373.5**	**422.5**	**465.6**	**471.7**	**488.8**	**488.8**	**512.9**	**513.0**
Total Connection Point Loads	**3906.4**	**4025.0**	**4184.0**	**4335.7**	**4484.2**	**4594.5**	**4721.4**	**4829.0**	**4963.4**	**5077.7**

5.7 Attachment 7 – Analysis of historic diversity factors

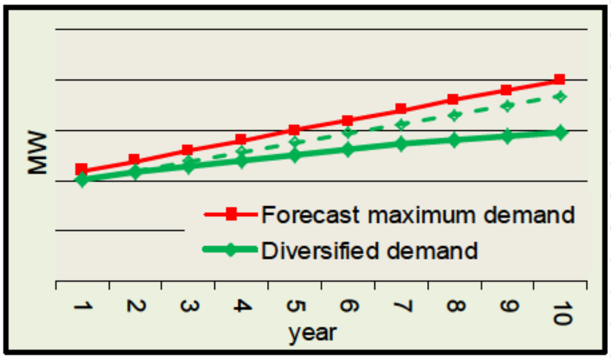
Background

A diversity factor is the ratio of a connection point's demand - measured at the time of the overall system peak - to the annual maximum for that connection point. So, if demand at the connection point was 90 MW at the time of the system peak and the connection point's annual maximum was 100 MW, the diversity factor will be 0.9. Diversity factors measured in this way will always be less than or equal to unity.

Connection point peak demand forecasts must be "diversified" before they can be added together and reconciled with the system-wide peak demand forecast. This simply means multiplying each connection point maximum demand forecast by its diversity factor to estimate its contribution to the system peak. The effect on the connection point forecasts is demonstrated in the following figure.



In reviewing which diversity factors to use in the reconciliation, ElectraNet has asked the question: what happens if diversity factors change through time? For example, the timing between system peak demand and a connection point's peak may be drifting apart due to behavioural changes in consumers' patterns of electricity usage. The result will be a gradual fall in the 0.9 diversity factor as time passes. The impact on diversified demand forecasts is shown in the following figure.



In this situation the diversified demands are not only lower than the original forecasts, they are also seen to be growing at a slower rate, reflecting the progressive decline in contribution to the system peak. If this effect were to be occurring in reality, it would be a powerful means for explaining why individual undiversified connection point peak demands are seen to be growing faster than system-wide peak demand.

ElectraNet has therefore reviewed historical metering data to test for this effect. The analysis is outlined in this attachment.

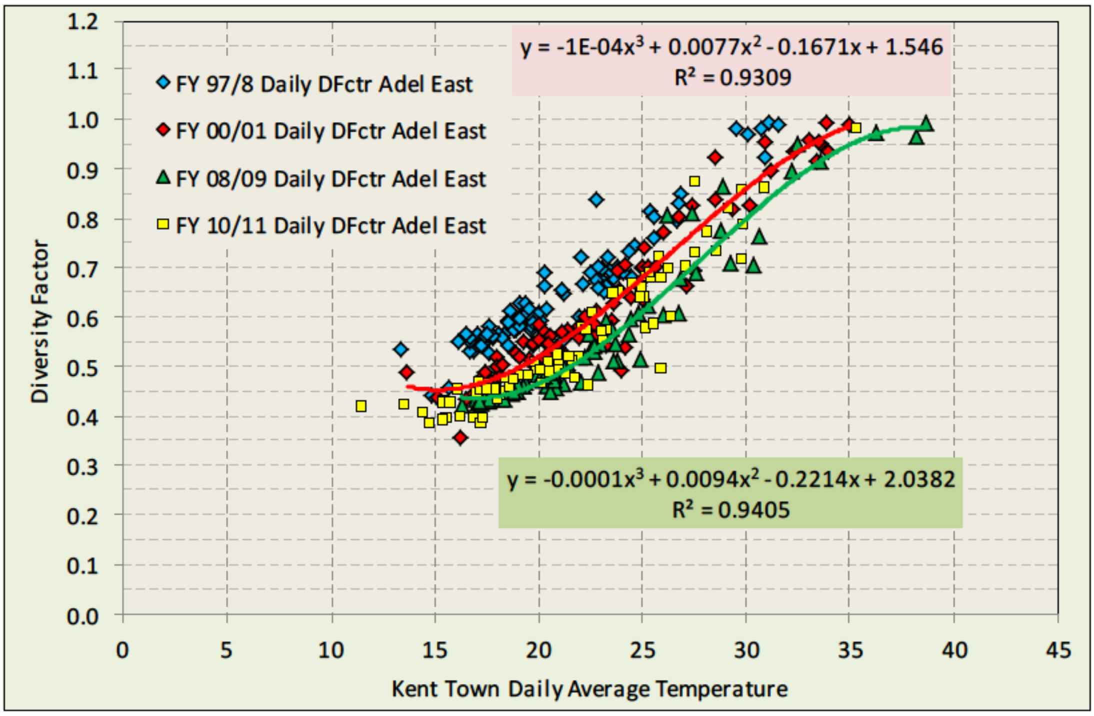
ElectraNet concludes from its analysis that there is some statistical evidence indicating that diversity factors have been falling slightly over time. This effect is therefore allowed for in ElectraNet's reconciliation of connection point peak demand forecasts and AEMO's state-wide peak demand forecasts.

Summary of ElectraNet's analysis

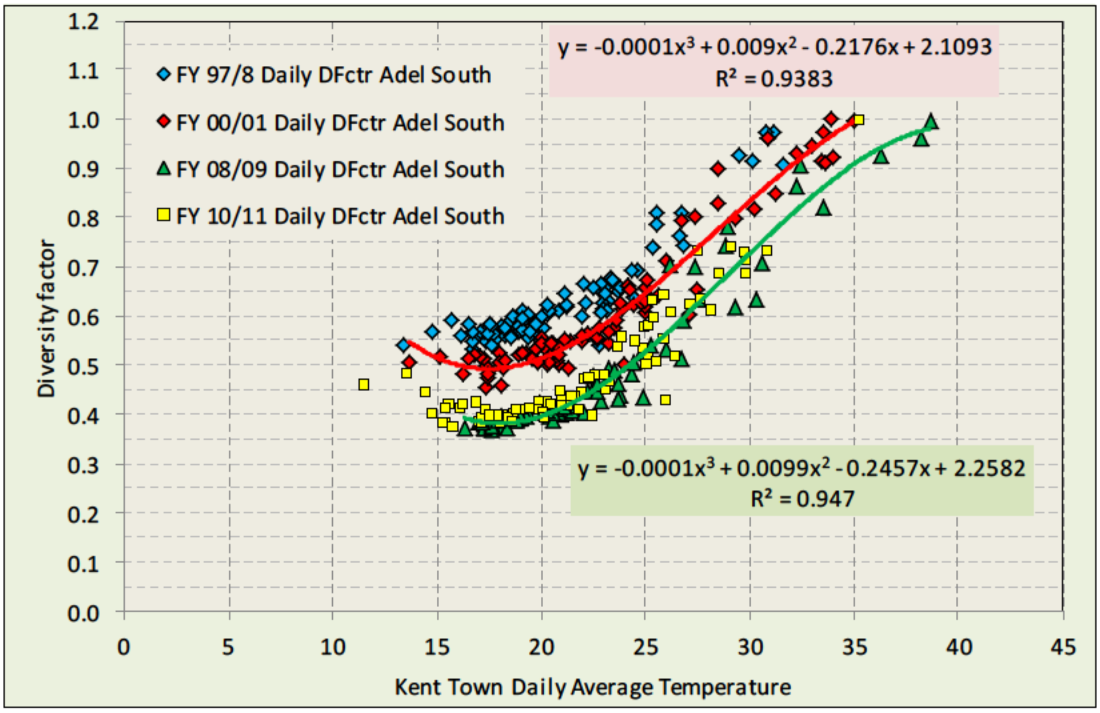
A typical reconciliation of forecasts will calculate a single diversity factor for each connection point. This will usually be based on connection point demands as they were at the time of the most recent system 10% PoE peak demand, or whichever recent peak is deemed as being closest to a 10% outcome.

As 10% PoE demands occur only very infrequently, they provide insufficient observations on which to base an analysis of changes in diversity over time. ElectraNet has therefore calculated "daily diversity factors" for each summer business day since 1997-98 for the four main metropolitan supply systems. These diversity factors have been calculated as the ratio of connection point demand on each day - measured at the time of the system peak on that day – to the outright peak demand for that connection point in each year. By plotting these daily diversity factors against temperature, we are able to see how they approach unity at progressively higher temperatures. When we separate these plots by year, we are able to see how they have changed over time. The following figures show these plots for the four metropolitan supply systems. Only selected years have been shown to keep the plots from becoming overly cluttered. A polynomial regression line has been fitted to the data for 2000-01 and 2008-09, as these years recorded high PoE demand outcomes at the system wide level and have been used by ETSA Utilities to identify reference levels of demand in its model. The plots indicate there has been a progressive decline in the diversity factors over time at most temperature levels.

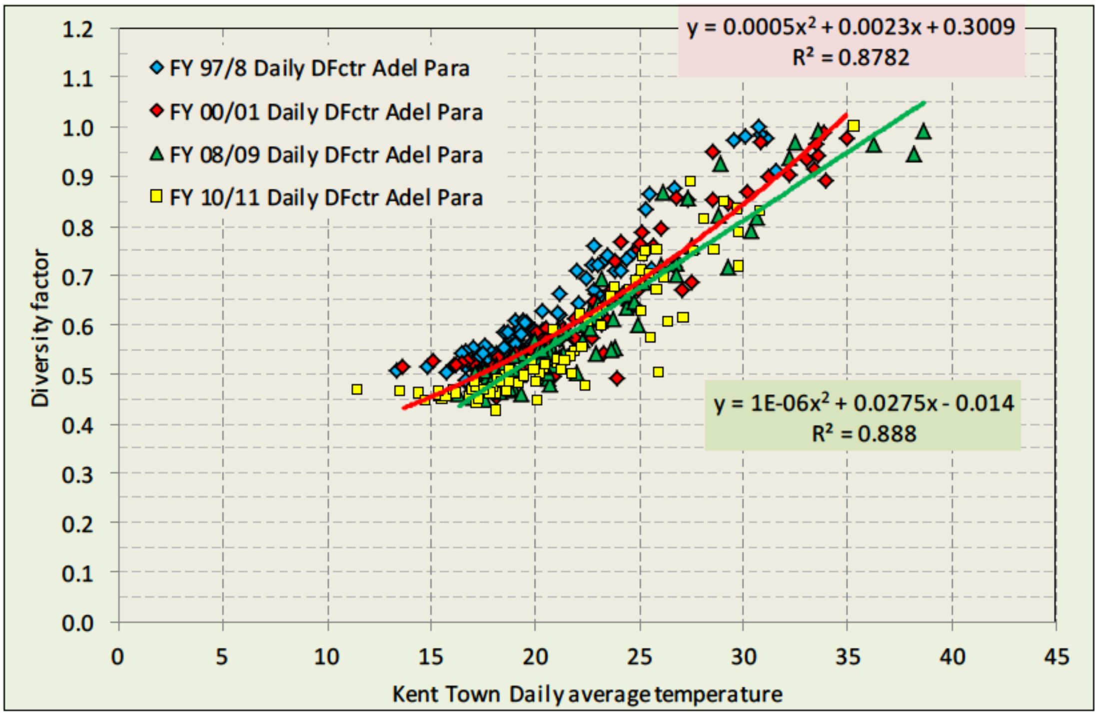
Eastern suburbs system



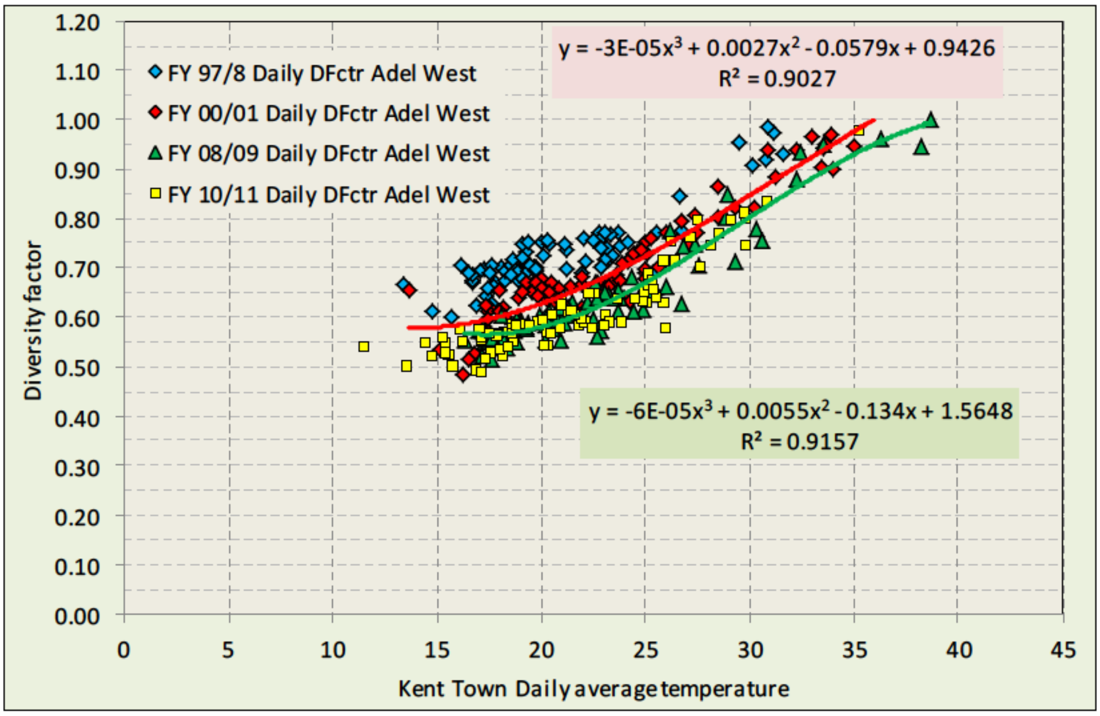
Southern suburbs system



Para system



Western suburbs system



ElectraNet has used these estimated regression relationships for the 2000-01 and 2008-09 years to "predict" the diversity factor at a daily average temperature of 36 ^{o}C, which reflects the type of temperature that might be expected under heatwave conditions in South Australia. The change in the diversity factor has then been averaged across the eight years to provide an indication of the annual decline for each system. ElectraNet's results are shown in the following table.

		Modelled diversity factor	Intercept	x3	x2	x
South	2000-01	0.998	2.109330	-0.000106	0.009003	-0.217611
	2008-09	0.938	2.258173	-0.000114	0.009909	-0.245664
	difference	-0.060				
	average annual change	-0.008				
	annual % decline	-0.75				
West	2000-01	1.000	0.942579	-0.000028	0.002677	-0.057926
	2008-09	0.947	1.564830	-0.000062	0.005478	-0.134024
	difference	-0.053				
	average annual change	-0.007				
	annual % decline	-0.67				
East	2000-01	0.999	1.546038	-0.000098	0.007746	-0.167054
	2008-09	0.983	2.038172	-0.000113	0.009403	-0.221368
	difference	-0.016				
	average annual change	-0.002				
	annual % decline	-0.19				
Para	2000-01	1.000	0.300940	0.000000	0.000527	0.002290
	2008-09	0.976	-0.014015	0.000000	0.000001	0.027461
	difference	-0.024				
	average annual change	-0.003				
	annual % decline	-0.30				

These results have been applied in ElectraNet's reconciliation of the state-wide and connection point forecasts. In particular, the predicted diversity factor for the 2008-09 year has been used as the initial diversity factor for each of the major metropolitan supply systems. Diversity factors applied in 2011-12 and subsequent years are then reduced according to the average annual decline identified in the analysis.

For ETSA Utilities' other connection points ElectraNet has identified the average diversity factor that applied on extreme demand days in 2008-09 and 2010-11 and assumed an annual decline of 0.0048 in subsequent years, this being the average decline across the four metropolitan supply networks. Diversity factors applying to ElectraNet's direct connect customers have not been adjusted downwards over time as these are single-user industrial operations and their diversity factors are unlikely to change in a predictable way over time.

Load forecast reconciliation

Appendices

March 2012

Version 0.2

Appendix A ETSA Utilities' spatial demand forecasting report

A copy of ETSA Utilities' spatial demand forecasting report is attached.

ETSA Utilities

We do everything in our power to deliver yours

Attachment E.9

ETSA Utilities' Spatial Peak Demand Forecasting Approach

Revision 1

www.etsautilities.com.au

Attachment E.9

Spatial peak demand forecasting processes
Description of ETSA Utilities' approach

A5.7.1 Summary

In this Attachment to the revised regulatory Proposal, ETSA Utilities describes the processes it has established to develop forecasts of the peak demand at individual locations within the distribution network. The electricity consumed by customers varies significantly by the time of day and by the type of day (weekday or weekend) , as they individually control the operation of the appliances and plant at their premises.

The elements of equipment, which together make up the transmission and distribution networks, must be capable of supplying the customers' peak demand. If this were not the case, customers would have to be disconnected near peak times, to limit the demand at each location to within the capacity of the network equipment. Overloading of network equipment is not permitted, as it would lead to equipment failure and have potentially serious safety consequences.

These forecasts of customer demand, collectively termed spatial demand forecasts, are used to determine where the capacity of the transmission and distribution networks need to be augmented, to ensure they are capable of supplying growing customer demand for electricity. The forecasts are of the total demand that would be imposed on the network equipment, in units of MVA[1].

In the case of the transmission network, the Electricity Supply Industry Planning Council (the Planning Council) previously carried out the planning of this network using demand forecasts at the connection or bulk supply points provided by ETSA Utilities. As of 1 July 2009, the Planning Council became part of the Australian Energy Market Operator (AEMO), which has the role of planning the interconnected national grid. The planning of the South Australian distribution networks is the responsibility of ETSA Utilities.

The spatial demand forecasts underpin each network planning process, in which options to meet or manage the demand imposed on the network at specific locations are evaluated. The demand forecasts are thus important drivers of the capital expenditure forecasts. They also constitute an input to the operating expenditure forecasts.

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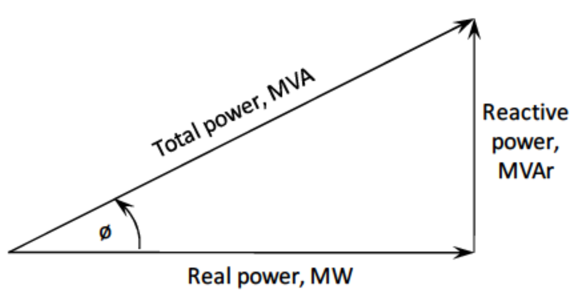
1 The total demand comprises two components. The 'real' component is usually measured in Kilowatts (kW) or megawatts (MW). This is the component that is associated with energy delivery to customers' appliances and equipment and is usually metered to determine the customers' bill. In practice, a 'reactive' component measured in Kilovolt-Amps reactive (kVAr) or Megavolt-amps reactive (MVAr) is also supplied at the same time and whilst this performs no useful work it requires additional capacity on the network for its delivery.

Reactive power is separately metered only in the case of large business customers, who may be charged for their Power factor, which is a measure of the proportion of reactive power the customer requires.

The total demand imposed on the network is the vector sum of the real and reactive quantities. The relationship between these quantities is shown in the diagram and formulae below:



Mathematical relationships

$$\text{Total power} = \sqrt{(\text{Real power})^2 + (\text{Reactive power})^2}$$

$$\text{Power factor} = \text{Cos}(\varphi) = \frac{\text{Real power}}{\text{Total power}}$$

A5.7.2 Characteristics of a robust forecasting process

An adequate, soundly based approach to spatial peak demand forecasting would embody the following characteristics:

- Secure and reliable data collection and storage, to ensure the integrity of the base data from which the forecast is prepared;
- A forecast modelling process which will provide consistent and repeatable results and accommodates the material drivers of demand;
- Quantification of the historic relationship of changes in electricity consumption and demand;
- Where there can be a degree of judgement in determining factors influencing demand, definition of the factors to be considered in making that judgement;
- Production of electricity forecasts by inputting projections into forecast models;
- Ongoing monitoring and review of the forecasts against outcomes, with the view to process improvement;
- A level of documentation sufficient to be used by staff as a work instruction and by third parties to review the appropriateness of the processes; and
- Appropriate governance and approval processes on key input assumptions, process and outputs.

The spatial peak demand forecasting process employed by ETSA Utilities is very similar to that employed by a number of other Australian distributors[2],[3]. The process makes use of the available relevant data and has been logically structured and comprehensively documented. Written procedures and work instructions have been designed to ensure the quality and repeatability of forecast outcomes. Moreover, for consistency, the forecast is compared with the global demand forecast, which is developed from consideration of the economic drivers of demand.

The spatial peak demand forecasting process is therefore an appropriate basis from which to construct capital and operating cost forecasts, which reasonably reflect a realistic expectation of the requirement to meet or manage demand growth on the network.

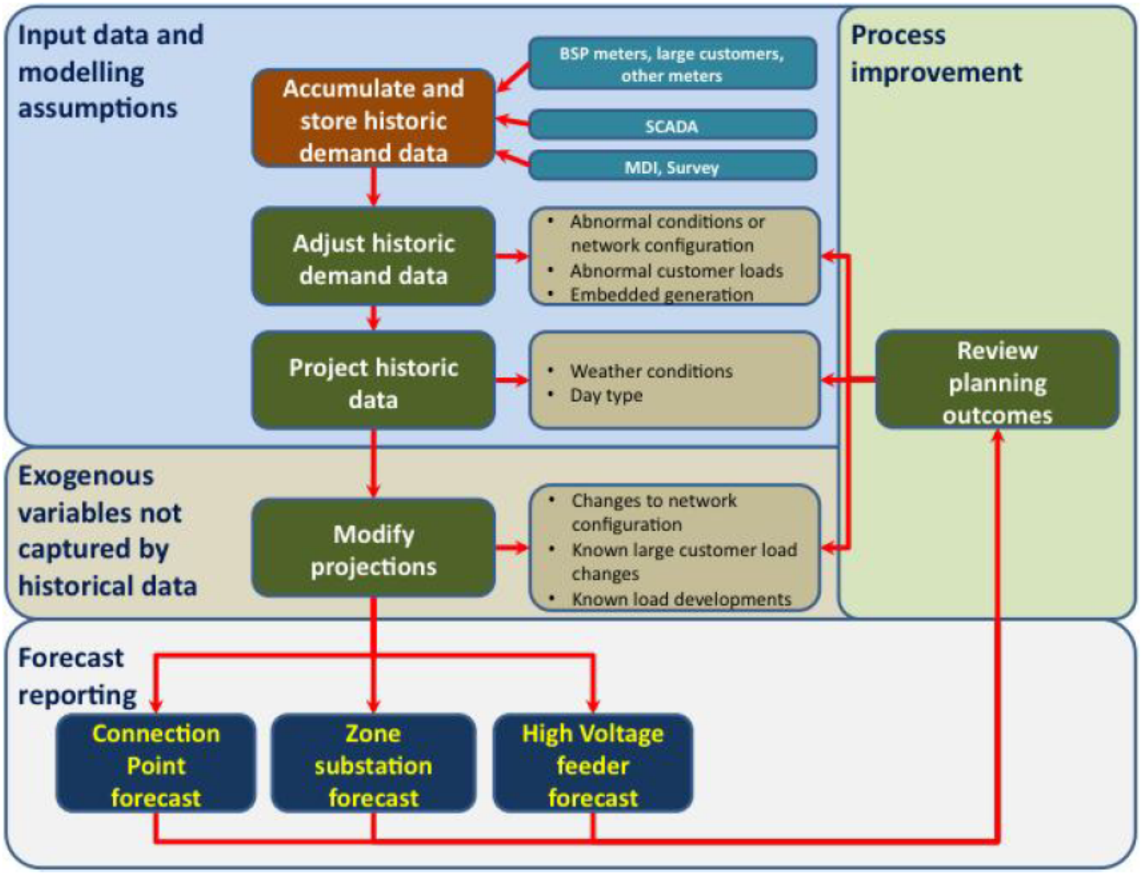
2 Australian Energy Market Commission, 13 May 2009, Advice on Development of a National Framework for Electricity Distribution Network Planning and Expansion - Sinclair Knight Mertz, Appendix E.

3 McLennan Magasanik and Associates, Final report to the Australian Energy Regulator - Review of Energex's maximum demand forecast for the 2010 t0 2015 price review, 19 October 2009, p.51.

A5.7.3 p ea nd forecast process

e r n used b ET A Jtilities is illustrated in Figure 1 and described in th ollowing sections.

Figure 1 - p t p ɔcess



Inputs to the spatial peak demand forecasts

e n h al m s h r r oːiated with each location for w s r o r rm the basis of historical fro h th rojections of future demand at the respective location are made.

e nd asur e r o tained from the following sources:

- ***Connection Points:*** the half- u l l e r r r s d o at r d narket e n ɪnnection to the transmission network (Bulk Supply Points);
- ***or u t s f e ers:*** (including most zone substations) half- ls from meteri u r r i n p o (st n r l Acq on or SCADA records);
- ***Major customers:*** the half- o er billing;
- ***Minor zone substations:*** o i h e rd the maximum dem n e ɔstation; and
- ***Other locations:*** tering survey equipm used to record the demand, generally on a tri- nnu c

'he network data repository

The metering data is stored in ETSA Utilities' secure Oracle data base servers at Keswick with controlled read access via specialised ETSA Utilities' programs. All data bases are backed up and monitored according to ETSA Utilities' IT procedures.

The National Grid meter data for the Bulk Supply Connection Points and major customers are stored in an ETSA Utilities data base named NESS. This data base receives frequent updates each day from the National Grid meter data system in PowerCor (MDS). The NESS data base contains all the historical readings for each meter for every half hour metered quantity. The data populated within the NESS data base is validated by ETSA Utilities' internal Services Revenue Protection team.

The metering data for the zone substations and feeders is stored in an ETSA Utilities data base named Substation Load (SUBSLOAD). This data base is updated overnight from ETSA Utilities Operational SCADA system with every half hour metered quantity transferred for each metering point. The Operational SCADA system accuracy is managed by ETSA Utilities' internal quality management systems. SUBSLOAD has numerous data checking algorithms to ensure the stored data is credible and is checked by ETSA Utilities' Network Planning Department as valid when new metering points are added.

When ETSA Utilities' Network Planning Department access the metered data stored in the NESS and SUBSLOAD data bases for the purposes of demand forecasting they check the accuracy of the data by redundant data comparison and historical trends.

)etermining growth trends from historical demand data

At most locations on the network, the effect of air conditioning load is evident in the historical demand data. The demand increases significantly on hot summer days (for South Australia, generally in the period from early January to late February but occasionally as early as November or as late as March).

Heatwave conditions, which the network must be capable of withstanding, do not occur every year. High demands were recorded on weekdays during heatwave conditions in the summers of 2001 and 2009[4]. In the intervening years, the weather conditions were either not as extreme, or occurred over weekends. This aspect is problematic for the forecasting of spatial peak demands, since there are relatively few valid observations of peak demand, from which the projection of peak demand can be based.

The underlying demand growth trend at each location must thus be established from a small sample of observations. In this respect, ETSA Utilities' forecasting task is more onerous than that of other DNSPs on the eastern coast of Australia, where the climactic conditions are not as extreme. The variability in ETSA Utilities' peak summer demand with temperature is greater than that of most other authorities.

It would require very significant resources to correct the recorded demand each year for normalised weather conditions at over 200 diverse locations on the network. The weather normalisation of demand is thus carried out at the global level, using the recorded data inputs to the network.

In selecting which peak historical demand records are used at each location as the basis for projecting future underlying trends, the following approach has been established to ensure that changing trends or new developments are adequately recognised and that the forecasting process will yield repeatable outcomes:

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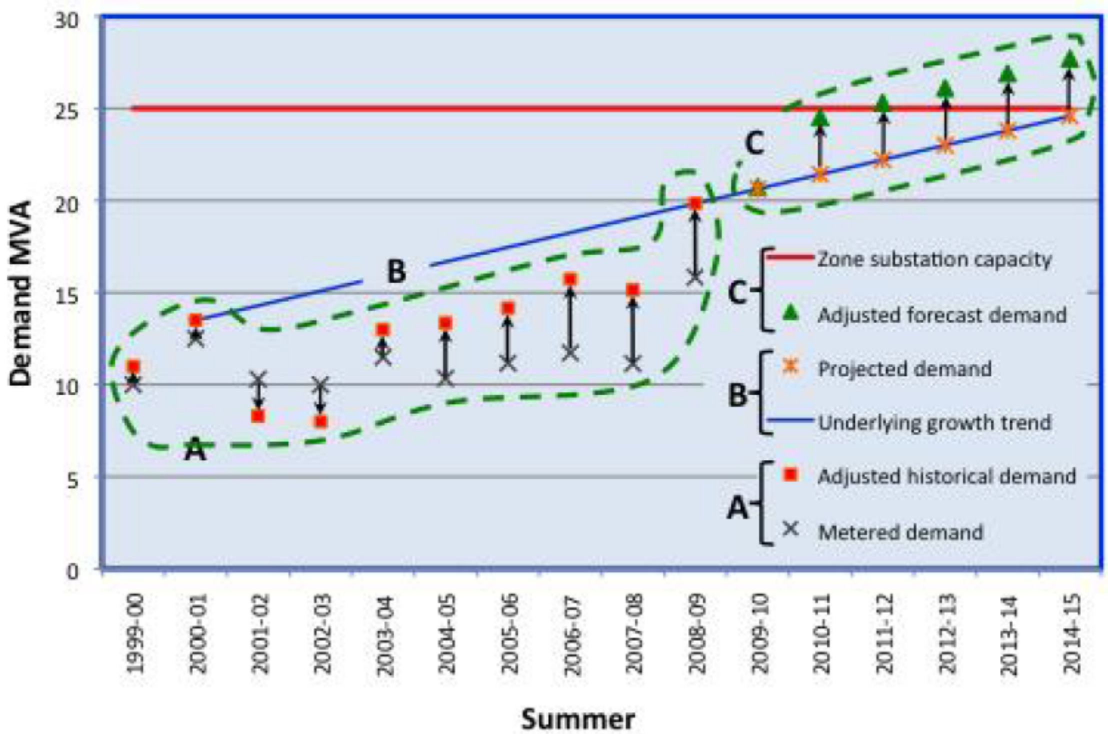
[4] The January/February 2009 heatwave conditions consisted of consecutive weekdays with a maximum daily temperature of well over 40^{o}C.

- If, after adjustment for abnormal conditions, the measured demand at a location exceeds its forecast then the demand at that location is reset to the higher value;
- If a system wide peak demand year occurs (1997, 2001 and 2009), then the demands at all locations are reviewed and may be reset to a higher value if one was recorded;
- Local factors are also considered when completing a total reset (e.g. were peak conditions experienced at that location); and
- In years where a peak demand did not occur, the recorded demand at each location is reviewed for relevance by use of temperature adjusted measured peak for ETSA Utilities' system.
- When calculating the growth rates between peak demand years a global temperature adjustment is made to bring the peak years to approximately the same probability of exceedence. (The present growth rate has been calculated using the growth between the 2001 and 2009 peaks adjusted for load transfers and abnormalities. The 2001 peak was temperature corrected by a factor prior to the growth rate calculation to match the 2009 probability of exceedence.)

n e b T ties ts p e n l t for a hypothetical zone substation, in Figure 2.

Figure 2 – Forecasting growth trends (ill ative example)



e r a r e o b r r s f ars 1999-00 to 2008- 9 observations are used in the preparation of forecasts in the following three stages.

A: Adjustment of o a d and records

e r n r d u ed, er necessary, to correct for the effect of historical r o n tions at the time of peak demand. Examples of the s ar d in he following:

- t a z b ations, where load d temporarily been transferred between them;
- ab t o n u o nd h p a d would be corrected;
- The demand would b r se u u a e t in service at the time of peak demand. I h a ion is sub wor p t i po e n t be available for service. Smaller embedded generators are not d m part of the historical demand records and are thus included in the growth trends; and
- ad ch h n ntially at the request of ETSA Utilities or a Retailer, or u o s o be estimated and added back to the historical data.

The overall objective of making these adjustments is to ensure that the historical high demand records from which trends are projected are representative of a consistent customer base. The adjusted historical records are represented as red squares in Figure 2.

B Projecting future demand trends

If the capacity of the network were to prove inadequate to supply the demand at a particular location, load would be shed to avoid overloading and damage to network equipment. A high proportion of ETSA Utilities' assets are meeting summer demands that approach their rated capacity. Moreover, at most locations, the level of security of supply afforded by ETSA Utilities' network does not provide for alternative 'standby' or 'reserve' equipment to be used to supply the load in the event of an equipment overload or failure.

The consequence of failing to supply customer demand at times of peak load would be so severe, that the forecasting process aims to predict the maximum demand likely to be revealed at each location on the network during heatwave weather conditions. This does differ from the approach adopted by transmission organisations and by some distributors. Where planning standards provide for inherently higher levels of supply security, unusually high demands may be met without load shedding by making use of 'reserve' network capacity.

Specifically, ETSA Utilities' approach is not intended to create a spatial demand forecast with a 50% or even a 10% probability exceedence[5], but rather to predict the likely maximum demand at each location in heatwave weather conditions. A statistical approach to calculating the peak demand would not in any case be practicable, for the large number of locations involved and their diverse characteristics[6].

The adjusted historical demand records in heatwave conditions are used to forecast the future demand at each location. The objective of this forecasting process is to determine the maximum demand that is likely to be imposed on the distribution network at each location. The demands at different locations may occur at different times and on different days, depending upon the predominant consumption characteristics of the customers connected at the location.

Extrapolating the historical trend in peak demand growth forms ETSA Utilities' demand projection for each location. This is shown as the blue line in Figure 2. The primary objective is to predict the longer-term (5-10 year) trends in demand growth for each point, rather than the shorter-term variations associated with economic factors.

C: Forecast demand growth

The third stage of preparation of the spatial forecasts makes further necessary adjustments to the peak demand trend projections at individual locations, to accommodate the following factors:

- Network configuration changes, which arise as the network develops and can result in the transfer of load between locations and in changes to the proportion of demand met by individual components of the network;
- Planned network load transfers;

[5] A forecast is described as having a 50% Probability of Exceedance (PoE) if there is a statistical probability of 50% that the peak demand will exceed the forecast level. This equates to the likelihood that the forecast will be exceeded on one year in two. Likewise, for a forecast with a 10% PoE, the forecast would be exceeded in 10% of years, or an average of one year in ten.

[6] The transmission Connection Point load forecasts which ETSA Utilities develops from aggregating zone substation demands have been accepted by AEMO as having a 10% PoE, for the purpose determining power system security and reliability under clause 4.9.1 (e) of the Rules.

- Committed new large customer connections and committed increases in large customer demand;[7] and
- Large customer committed reductions or closures.

The adjusted forecast trends are shown as green triangles in Figure 2. ETSA Utilities' planners compare the trend with the capacity available at each particular location, after taking into account the influence of any potential demand management. The substation capacity is illustrated by the red line and in this hypothetical example, augmentation of the capacity at this location would be required before summer 2012-13.

Spatial peak demand forecast outputs

Spatial demand forecasting is carried out at three levels within the ETSA Utilities network, as follows:

- *Connection Point forecast:* at each of the 45 points of connection to Electranet's transmission network, where electricity is supplied in bulk to ETSA Utilities' distribution network. These bulk supply connection points are at a voltage level 66 kV[8];
- *Zone Substation forecast:* at each of the 266 zone substations plus 163 smaller substations, customer substations and regulators in ETSA Utilities' network, where the supply voltage is transformed from subtransmission levels[9] of 66 or 33 kV to the High Voltage levels of 11 or 7.6 kV;
- *High Voltage Feeder forecast:* of the loading on 1024 individual 11 and 7.6 kV feeders.

The *Connection Point* forecast is now supplied to the AEMO. It is used by that organisation to:

- Determine the adequacy of the transmission network and generation capacity both in South Australia and the interconnected States, to meet the connected demand; and
- To formulate plans for the reinforcement of the transmission network and identify opportunities for the connection of new generation and interconnection capacity, through the Statement of Opportunities.

The *Zone Substation* forecast is used by ETSA Utilities to determine the adequacy of elements of the subtransmission network and plan for their reinforcement. The forecasts are used directly, when the capacity of the relevant zone substation is being assessed. The forecasts at individual locations may also be aggregated, for example to determine the adequacy of subtransmission lines suppling more than one zone substation.

The *High Voltage Feeder forecast* is used by ETSA Utilities to ensure that the capacity of those feeders is adequate to meet the connected load and, where necessary, to plan for their reinforcement.

In the case of the connection point forecast and where the adequacy of the subtransmission network is determined from the aggregation of zone substation forecasts, allowance may need to be made for the *diversity* of peak demand at individual locations. The concept of diversity is explained with reference to the following illustrative example.

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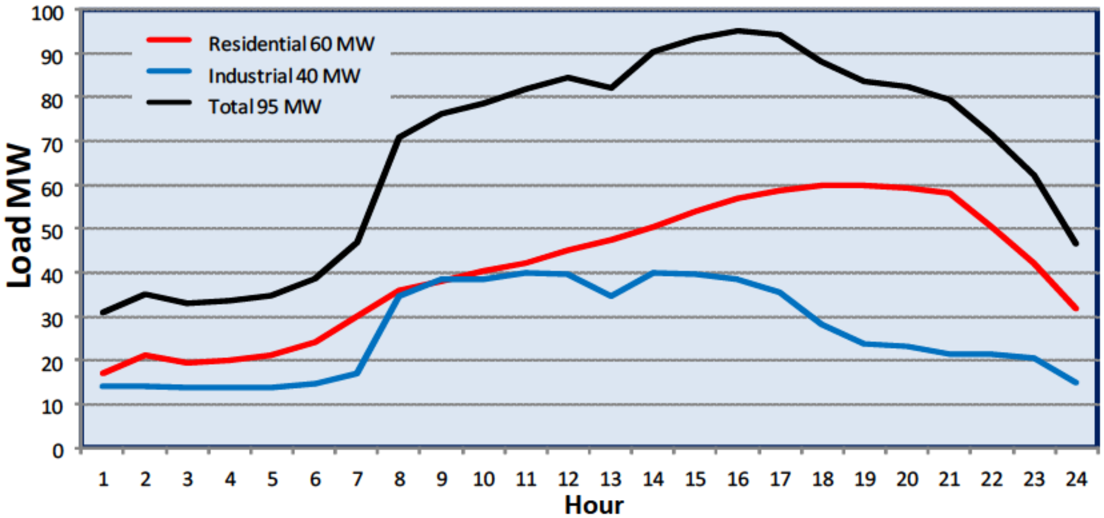
7 A large development has been defined as ≥ 5% of the existing peak load at the substation.

8 The term transmission network here has the same meaning as in the Rules.

9 In ETSA Utilities' case, subtransmission assets include lines and cables which operate at voltages of 66 and 33 kV and substations and switching stations connected at those primary voltages with a secondary voltage of 11 or 7.6 kV.

Figure 3 - Load diversity



In this illustration, a residential load of 60 MW and an industrial load of 40 MW are supplied from a common point on the network. The loads have different patterns and their peak values occur at different times of day. As a result, the maximum demand which the network capacity must be able to supply in this case is not 100 MW, but 95 MW.

A5.7.3.5 Process management and improvement

The forecasting outcomes are reviewed annually by the Network Planning Engineering team leaders and the Manager Network Planning, with a view to modifying the process or underlying assumptions as necessary. In particular, any instance where network capacity had proven inadequate to meet the demand of the customers at a location is carefully considered.

The process has also been reviewed by an external consultant every five years and compared to current Australian Distribution Industry Practice[10].

The spatial demand forecasting process is comprehensively documented to ensure its quality and repeatability. The 'process owners' are the Planning Engineers responsible for planning the capacity of the network in each region.

A5.7.4 Variations in the spatial demand growth rates

There is a considerable difference in the forecast demand growth rates at different locations within the network over the period from 2005-10. For example:

- ***Connection Points***: Growth rates range from slightly negative up to 5.6% p.a.
- ***Substations:*** Growth rates range from slightly negative up to 7.5% p.a.

These differences in growth rates are to be expected, as they arise from:

- The detailed consideration of the demand drivers, which are unique to each point on the network; and
- Customer connections.

[10] PB Power Group, 150519A – ETSA Utilities 2010-2020 Reset Submission Summary Report, 12 September 2008.

Independent analysis has shown that if the global demand forecast were to be used as the basis for producing a spatial demand forecast, significant errors would result. Initial analysis of sample test data shows that errors of up to 49% in the forecast at specific locations would be involved.

A5.7.5 Comparison of spatial demand and global demand forecasts

ETSA Utilities also prepares a global demand forecast, which is constructed from the consideration of economic drivers affecting different sectors of its customer base. The process by which this forecast is developed is described in Attachment 5.8.

The forecasts employ some common demand drivers, as follows:

- Changing appliance trends are factored into the growth rates at specific locations;
- The impact of known major customer developments (eg. desalination, mining) are separately considered in both global and spatial forecasts; and
- The temperature and day type are very significant common drivers of demand, especially in summer.

There are also differences between the global and spatial demand forecasts, which serve to limit the extent to which a direct comparison may be made between them:

- The global forecast of peak demand is in MW.
- The spatial forecast is produced for the purpose of ensuring the network capacity is adequate and is of MVA.
- When the spatial demand forecast is aggregated to create a system total, allowances must be made for the diversity of demand between the zone substations, which requires knowledge of the load profiles as well as the peak demands at individual zone substations. Changing power factors at the zone substation level will also alter the aggregate spatial demand.

Notwithstanding these fundamental differences, which arise from the different purposes for which the forecasts are constructed, it is instructive to compare the growth rates of the global demand and aggregate spatial demand forecasts. A reasonable degree of correspondence between the two serves to confirm that the economic assumptions, which underpin the global demand forecast and the sales forecast, are consistent with the detailed knowledge of local developments and trends used to develop the spatial demand forecast.