REVIEW OF ETSA UTILITIES SALES AND DEMAND FORECASTS

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Executive Summary

The Australian Energy Regulator (AER) is conducting a review to determine the prices that will apply to the regulated services provided by ETSA Utilities for the period 1 July 2010 to 30 June 2015. ETSA Utilities is the principal distribution network service provider in South Australia.

During February 2009 the AER asked the South Australian Electricity Supply Industry Planning Council (ESIPC) to review and report on the sales and demand forecasts submitted by ETSA Utilities as part of its Regulatory Proposal. The ESIPC was dissolved on 30 June 2009, with most of its functions and responsibilities assumed by the Australian Energy Market Operator (AEMO) from 1 July 2009. The transfer of responsibilities to AEMO included the ESIPC's undertaking to report to the AER on ETSA Utilities' sales and demand forecasts.

A draft report was provided to the AER on 18 September 2009 and a final report on 1 October 2009. This is the final version of AEMO's report to the AER.

The AER requested that AEMO's review:

- provide an independent view of ETSA Utilities' annual sales by customer category for years 2010-11 to 2014-15 and apportion these to tariff categories;
- provide an independent view of state-wide distribution network peak demand at the 10% and 50% probability of exceedance (PoE) levels for years 2010-11 to 2014-15 and reconcile these with individual transmission connection point peak demand forecasts submitted by ETSA Utilities;
- test the sensitivity of AEMO's forecasts to changes in input assumptions, including using ETSA Utilities' input assumptions as the basis for one of the sensitivities; and
- identify and comment on the reasons for any differences between ETSA Utilities' and AEMO's sales and network-wide peak demand forecasts, and comment on the reasonableness of ETSA Utilities' approach and input assumptions.

Economic outlook

The economic assumptions underpinning AEMO's electricity forecasts for the South Australian distribution network were prepared by KPMG Econtech during March 2009. These forecasts, which included projected retail electricity prices, were made available by AEMO (then NEMMCO) to all NEM jurisdictional planning bodies to develop regional electricity forecasts for the *2009 Electricity Statement of Opportunities*.

In late April and early May 2009 the Australian Government proposed a number of changes to the expanded RET scheme and the CPRS. These changes resulted in KPMG issuing a supplementary report revising its projected retail electricity prices to reflect the likely new policy environment. KPMG's revised assumptions have been used in developing the electricity forecasts for this report.

KPMG's economic outlook was prepared against the backdrop of the global financial crisis and consequent recession in major world economies. Considerable risk surrounds the near term outlook, with the severity of the downturn and the timing and strength of recovery dependent on developments in the economies of Australia's major trading partners. KPMG note that potential exists for further shocks to the global economy to have adverse flow-on effects within Australia. On the upside, policy actions in major economies and an early rebound in China's economy could see Australia recover more strongly than forecast.

KPMG's forecasts show Australian GDP remaining flat in 2008-09, with real growth of 0.1%, and falling in real terms by 0.2% in 2009-10. Growth is projected to recover to 3.6% in 2010-11 and average 3.6% over the five years to 2014-15.

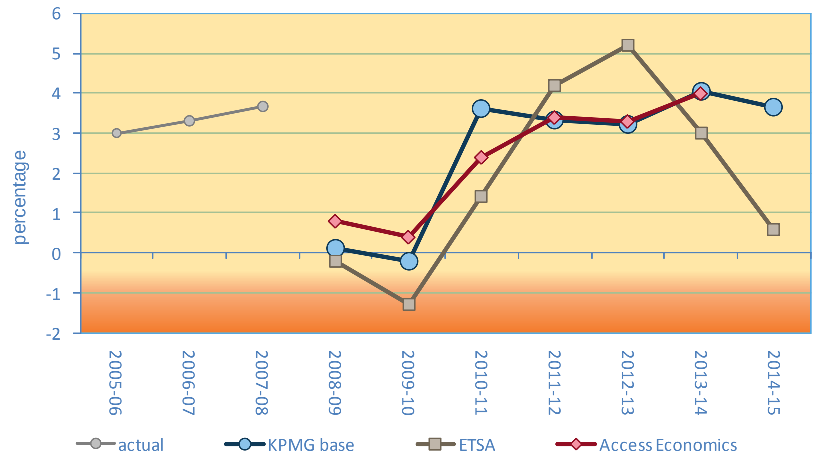
Given the uncertainty surrounding the economic outlook and the fact that KPMG's forecasts were prepared several months ago, AEMO has tested KPMG's forecasts against more recent projections published by Access Economics in its July 2009 *Business Outlook*.

Access Economics' July *Business Outlook* includes the following observations:

- Substantial and rapid international policy responses have put the worst of the global financial crisis behind us. Governments and central banks have successfully avoided a collapse of the financial system and have engineered a milder-than-otherwise global recession at the expense of a milder-than-otherwise recovery.
- Australia is emerging from this period with only collateral damage compared with some other economies. Domestic consumption spending has continued to grow, supported by lower interest rates and the Government's cash hand-outs; export volumes have actually risen 1.8% since the crisis started as China purchases key commodities at rates higher than it would have had there not been a crisis; and employment is being maintained as businesses, who until recently faced severe skills shortages, are hoarding workers through the downturn.
- Access Economics expects the strength of the recovery to be weighed down by a number of factors. Recently negotiated commodity price reductions have only just begun to have an impact on exports and profitability; business investment is likely to slow and unemployment is expected to rise as new job creation falls behind population growth; and consumption spending will begin slowing as the cash stimulus fades and unemployment rises. Over the medium term Australian growth will be constrained by the requirement to repair the Australian Government's underlying structural budget deficit.

Figure ES1on the following page compares KPMG's, Access Economics' and ETSA Utilities' forecasts for Australian GDP growth to 2014-15.

Figure ES1 Australian GDP growth rate projections



Access Economics expects a more moderate downturn in growth in 2008-09 and 2009-10 compared with KPMG's projections and a slightly weaker rebound in activity during 2010-11. The forecasts are almost identical in later years. The two sets of forecasts also show an almost identical level of cumulative growth over the period to 2013-14, with the main difference being the timing of this growth. Both KPMG and Access Economics therefore have a similar view of the ultimate size of the Australian economy by 2013-14.

ETSA Utilities' economic assumptions show considerably slower Australian GDP growth than the forecasts prepared by KPMG in five of the seven years to 2014-15. The cumulative level of GDP growth between 2008-09 and 2014-15 assumed by ETSA Utilities is 5.6% lower than implied by KPMG's base case projections, implying that the Australian economy would be considerably smaller in 2014-15 than forecast by either KPMG or Access Economics.

KPMG expect South Australia to perform more strongly in terms of GSP growth than some other States throughout the economic downturn and subsequent recovery, with growth supported by comparatively low housing costs, low personal debt levels and ongoing mining, defence and infrastructure investments.

Over the medium to longer term, demographic factors are a key driver of the level of economic activity. KPMG's base case projections show South Australia's population continuing to rise by around 1% annually. While this is less than the projected national average, it represents stronger growth than experienced in South Australia in recent years and would see the State's population reach 2 million persons by around 2029-30.

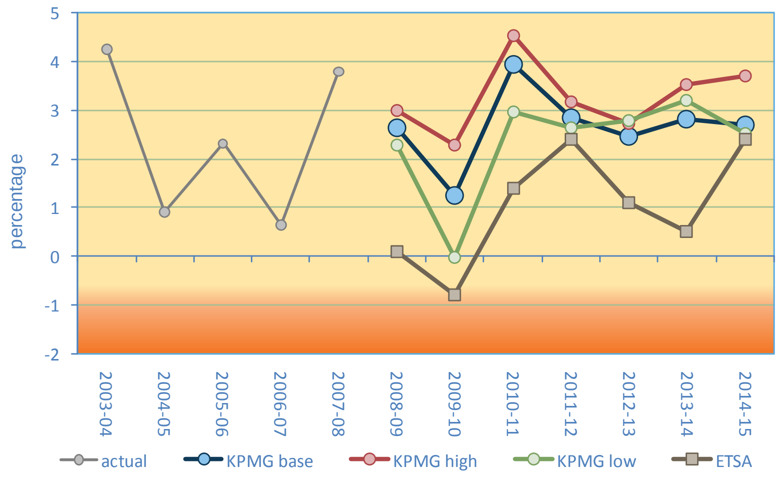
Other key features of South Australia's near term economic outlook include the following.

- The household sector's relatively lower income levels compared with the rest of Australia, and lower gearing and average house prices, mean there is less adjustment required to establish better savings habits, while fiscal stimulus payments such as the first home owners grant and cash hand-outs have a relatively greater effect than in most other States.

- South Australia has already lost many jobs in the financial and manufacturing sectors during the 1980's and 1990's and so is less exposed to further job losses in these areas than some other States. And although its mining sector is growing rapidly, the State is not as exposed as Queensland and Western Australia to a downturn in commodity prices and export volumes.
- Housing construction remains the strongest in Australia, supported by increasing numbers of international students and solid growth in the number of skilled migrants.
- South Australia's engineering and construction pipeline is supported by broadly based projects such as the Air Warfare Destroyer project, the new desalination plant, new road and rail projects, and ongoing investment in wind farms and mining activity.

Figure ES2 compares KPMG's and ETSA Utilities' forecasts for South Australian GSP growth to 2014-15

Figure ES2 South Australian GSP growth rate projections



Following relatively strong real growth in 2007-08 (3.8%) and 2008-09 (estimated at 2.6%), KPMG forecast South Australian GSP growth to fall to 1.2% in 2009-10 before recovering strongly to 3.9% in 2010-11. Near term downside risks associated with the global economy could see South Australian GSP falling slightly in real terms in 2009-10 and a weaker rebound in 2010-11. Over the medium term, real GSP growth is expected to average 2.6% annually, with the high and low case sensitivities showing average annual growth falling in the range of 2.4% to 2.9%.

ETSA Utilities' submission assumes considerably slower growth than forecast by KPMG in each year to 2014-15. The cumulative level of South Australian GSP growth to 2014-15 assumed by ETSA Utilities is 12.9% lower than shown by KPMG's base case projections, implying that the economy would be some $9.5bn smaller than forecast by KPMG for that year. This is a material difference in the economic outlook presented by the two organisations, with ETSA Utilities' assumptions at odds with current market sentiment as reflected in Access Economics' latest *Business Outlook*. Differences in the economic outlook are the main contributing factor to ETSA Utilities' annual sales forecasts being materially lower than AEMO's forecasts (see below).

Retail electricity price assumptions

Research undertaken by Monash University has found that electricity demand in South Australia is price inelastic, in that elasticity lies between zero and minus one. Monash also found that the price elasticity of peak demand levels is around half of that applying to annual sales volumes. These findings are reflected in AEMO's forecasts.

Future retail electricity prices will reflect movements in the underlying wholesale cost of energy, network charges and carbon pricing. KPMG developed models to project forward average retail electricity prices for each State as part of developing the economic outlook. These models use macroeconomic variables such as interest rates and commodity price projections to capture the underlying short and long term drivers of retail electricity prices. The assumed future levels of these variables are consistent with KPMG's broader economic outlook. These variables, which have been good predictors of past retail prices, are designed to capture the effects of the cost of capital and prices applying to fuel and capital equipment.

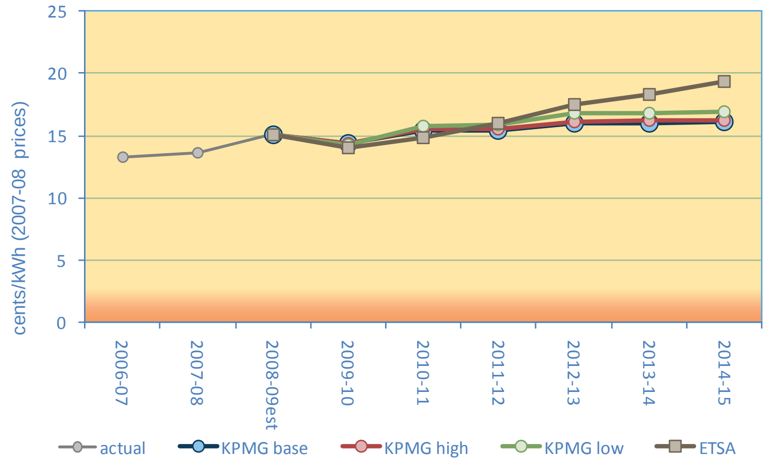
The introduction of carbon pricing and policies to promote green energy generation will also have an effect on retail electricity prices. Some uncertainty surrounds the final form of the proposed RET scheme and the CPRS and their passage through the Australian Parliament. The outcome of the United Nations Climate Change Conference to be held in Denmark during December 2009 may also influence the final form of the CPRS.

KPMG's electricity price forecasts reflect policy changes announced by the Australian Government in April and May 2009 in regard to the expanded RET scheme and the CPRS. In particular, the forecasts assume that implementation of the CPRS is delayed until July 2011, with a fixed permit price of $10 per tonne applying in the first year. The carbon price is assumed to rise to $23 per tonne in 2012-13 and increase by 4% annually thereafter.

The high growth scenario adopts similar assumptions to the base case, except future technology developments are assumed to reduce the carbon intensity of the economy and cause the permit price to fall in some years. The low growth scenario assumes the CPRS-15 targets are adopted with a higher carbon price of $32 per tonne applying in 2012-13.

KPMG's base case projections show the real average retail price rising by 18.5% between 2007-08 and 2014-15, or an average annual increase of 2.4%. In comparison, ETSA Utilities' assumptions show the real price rising by 42.3% over this period, or an average increase of 5.2% annually. The following figure compares KPMG's and ETSA Utilities' retail price projections to 2014-15.

Figure ES3 South Australian retail electricity price forecasts



Information provided in ETSA Utilities' submission indicates that its retail price projections assume South Australian network tariffs will rise as proposed in its Regulatory Proposal. The assumed network tariff increases account for the majority of the retail price increases assumed by ETSA Utilities. This, in turn, is also a cause of ETSA Utilities' sales forecasts being lower than AEMO's. The reasonableness of this assumption will depend on the AER's final determination for the South Australian distribution network. AEMO would also point out that there is a degree of circularity in ETSA Utilities' approach to its price forecasts, with higher prices driving sales lower, requiring that a higher price be set by the AER and so forth.

Energy efficiency policies

AEMO's South Australian electricity forecasts have been developed using a top down modelling approach, with the effects of energy efficiency policies treated as post model adjustments to baseline forecasts. In using a top down approach, the net effect of the many micro-drivers of electricity demand, both positive and negative, is reflected in the historic data used in the forecasting models. This data directly reflects the key variables the models are attempting to forecast. Statistical tests are used to identify which macro variables best explain the historic data and project demand and energy levels into the future. Given a particular set of assumptions about the future economic environment, the forecasts therefore offer an objective view of future electricity sales and demand levels. These forecasts should only be modified when there are strong grounds for considering that past relationships between the variables will change materially in the future and there is sufficient information to make a balanced estimate of the likely impact of new energy efficiency policies.

When using a top-down forecasting approach, the potential exists for double counting efficiency effects in both the macro forecasts and the post model adjustments, or for biased adjustments to be made which selectively include some micro effects while omitting closely related offsetting effects.

- Double counting might occur, for example, when the baseline forecasts include a consumer response to rising prices, while separate post model adjustments are also included to reflect programs aimed at assisting consumers discover and implement changes to economise on electricity use in a rising price environment. AEMO's thinking is that price effects are not exclusively about "switching appliances off", but come about in part because some policies facilitate the process of consumers becoming more efficient in their use of electricity. Forecasts should include either the price effect or the policy effect – not both, because, to some extent at least, they are not additive effects but different perspectives on the same phenomenon.

- Historic sales and demand data includes the impact of efficiency measures introduced in the past. Baseline forecasts built upon this data therefore include the effects of past policies. The baseline forecasts also implicitly assume that further new measures will continue to be introduced with similar frequency and intensity in the future. As such, care must be taken to ensure that post model adjustments do not double count new efficiency policies that are already reflected in the forecasts by way of existing trends in the data. Adjustments should only be made to capture incremental efficiency effects if the frequency of introducing new policies increases in the future, or if the intensity of their effect increases relative to past measures.

- Biases in the application of post model adjustments may also be introduced in a variety of other situations. An example is the rapidly rising penetration of energy-hungry flat screen televisions and prospective improvements in the minimum energy performance standards (MEPS) applying to these appliances. The higher than average growth of electricity use associated with these appliances presents a prima facie case for including a post model adjustment to capture incremental electricity sales that may not be reflected in baseline forecasts. However, if such upside adjustments are made to the forecasts, recognition should also be given to the tightening of television MEPS and improvements in efficiency. Biases will be introduced if post model adjustments reflect only one aspect of changes occurring in particular market sectors - either both effects should be allowed for, or both excluded.

AEMO considers that energy efficiency policy effects are particularly important in the context of ETSA Utilities' sales forecasts, as these forecasts, together with the individual connection point peak demand forecasts, are key inputs into the AER's final determination. The network-wide peak demand forecasts are not used directly in the determination. The efficiency effects relating to annual sales also occur within the residential sector, indicating that the overall size of savings should be assessed in the context of the level of residential sector sales.

AEMO has used its own residential sector sales forecasting models in conjunction with ETSA Utilities' macroeconomic assumptions and efficiency savings and has been able to replicate ETSA Utilities' residential sales forecasts to within +/-1%. This indicates that ETSA Utilities' residential sales forecasting model performs in essentially the same way as AEMO's model, regardless of how ETSA Utilities' actual model has been constructed. It follows that the same considerations in regard to biases and double counting of efficiency effects also apply to ETSA Utilities' residential sales forecasts.

Table ES1 compares ETSA Utilities' and AEMO's estimates in relation to new energy efficiency policies affecting South Australian residential sales. AEMO's estimates only include efficiency gains which have been treated as adjustments to its top down forecasts. AEMO acknowledges that all of the programs listed in the table are likely to produce efficiency gains in their own right, but many of these savings will already be reflected in the baseline forecasts and have therefore been excluded from AEMO's post model adjustments.

Table ES1 Efficiency measures affecting annual residential sales (GWh)

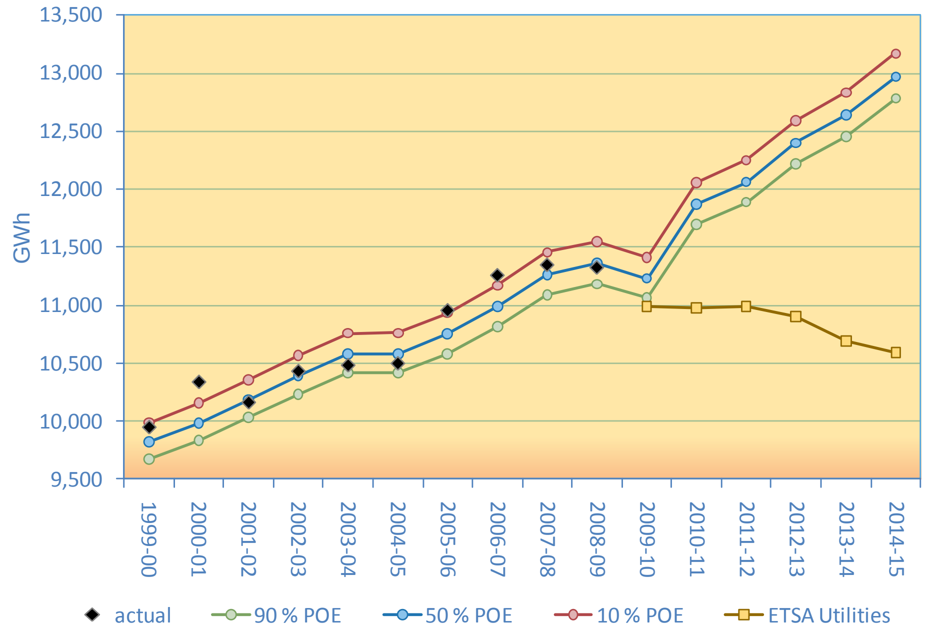
		2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Installation of small scale solar PV units	ETSA	12.1	15.8	19.0	21.6	24.3	26.9
	AEMO	11.3	15.1	18.9	22.7	26.4	30.2
Residential Energy Efficiency Scheme	ETSA	23.5	44.6	66.6	88.6	110.6	132.6
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
Air conditioner MEPS	ETSA	0.0	6.0	11.9	17.7	23.4	29.0
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
Television MEPS	ETSA	9.0	18.0	27.0	36.0	45.0	54.0
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
Set-top box MEPS	ETSA	1.8	3.6	5.4	7.2	9.0	10.8
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
Standby power MEPS	ETSA	14.9	29.7	44.6	59.4	74.3	89.1
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
Lighting MEPS	ETSA	62.9	83.9	104.8	125.8	146.8	159.9
	AEMO	28.7	58.2	88.8	120.1	153.9	189.7
Federal insulation program	ETSA	18.6	30.9	37.1	37.1	37.1	37.1
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
ETSA Direct Load Control program	ETSA	0.0	0.0	0.0	0.0	0.0	0.0
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
Total across all policy areas	**ETSA**	**142.8**	**232.5**	**316.4**	**393.4**	**470.5**	**539.4**
	AEMO	**40.0**	**73.3**	**107.7**	**142.8**	**180.3**	**219.9**

As indicated in the table, AEMO has excluded many areas of efficiency gains from its post model adjustments as it believes these effects are already reflected in baseline forecasts or because the adjustments would introduce biases. AEMO's reasoning in relation to each excluded policy effect is detailed in the body of the report. In comparison, ETSA Utilities' residential sales forecasts have effectively included all of these effects. AEMO believes that this has contributed to ETSA Utilities' forecasts being significantly lower than AEMO's.

Comparison of AEMO's and ETSA Utilities' annual sales forecasts

Figure ES4 compares AEMO's base case 10%, 50% and 90% PoE annual sales forecasts with ETSA Utilities' total annual sales forecasts. The figure also shows past actual sales and associated PoE levels estimated by AEMO.

Figure ES4 Total distribution network sales



AEMO's forecasts show total sales increasing at an annual average rate of 2.9% between 2009-10 and 2014-15. The effect of slowing economic growth in 2009-10, the projected rebound in activity the following year and additional sales associated with the new desalination plant are clearly visible in the figures. The apparent stagnation of actual sales between 2006-07 and 2008-09 is also seen to be a reflection of variability in weather rather than a genuine slowing of underlying sales growth.

ETSA Utilities' sales forecasts show a materially different outlook to 2014-15:

- its total sales forecast for the 2014-15 year is 2,374 GWh (18.3%) lower than AEMO's base case 50% PoE forecast for that year; and
- its forecasts imply average annual growth of -0.7% between 2009-10 and 2014-15 compared with AEMO's forecast growth of 2.9% over this period.

These differences largely reflect the use of different economic assumptions (including the treatment of energy efficiency savings) rather than effective underlying model differences.

Table ES2 compares the main components of ETSA Utilities' and AEMO's forecasts.

Table ES2 Major components of total sales forecasts (GWh)

	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	AVE ANN GROWTH %
Business							
AEMO high	7,030.0	7,519.5	7,703.5	7,960.5	8,308.8	8,767.4	4.5
AEMO base	6,935.7	7,367.9	7,515.8	7,727.7	7,960.9	8,255.9	3.5
AEMO low	6,819.7	7,164.1	7,250.0	7,494.2	7,738.6	8,005.9	3.3
ETSA Utilities	6,728.9	6,716.1	6,778.4	6,733.2	6,657.1	6,696.0	-0.1
Residential							
AEMO high	3,542.4	3,626.7	3,619.1	3,667.1	3,687.3	3,741.4	1.1
AEMO base	3,541.4	3,624.2	3,617.3	3,668.4	3,691.1	3,743.3	1.1
AEMO low	3,537.0	3,611.9	3,569.7	3,611.0	3,617.7	3,667.5	0.7
ETSA Utilities	3,556.4	3,465.5	3,392.6	3,304.5	3,214.9	3,130.2	-2.5
Water heating							
AEMO high	638.5	616.1	595.0	575.0	556.1	538.2	-3.4
AEMO base	636.7	613.9	592.4	571.9	552.5	534.1	-3.5
AEMO low	636.2	613.3	591.6	571.0	551.4	532.8	-3.5
ETSA Utilities	591.9	535.9	483.8	432.7	382.7	333.9	-10.8
Public lighting							
AEMO high	116.0	118.6	121.3	123.9	126.6	129.2	2.2
AEMO base	116.0	118.6	121.3	123.9	126.6	129.2	2.2
AEMO low	116.0	118.6	121.3	123.9	126.6	129.2	2.2
ETSA Utilities	113.9	116.8	119.6	122.6	125.7	128.8	2.5
Desalination plant							
AEMO high	0.0	143.0	215.0	307.0	307.0	307.0	na
AEMO base	0.0	143.0	215.0	307.0	307.0	307.0	na
AEMO low	0.0	143.0	215.0	307.0	307.0	307.0	na
ETSA Utilities	0.0	143.0	215.0	307.0	307.0	307.0	na
Total sales							
AEMO high	11,326.9	12,024.0	12,253.8	12,633.6	12,985.8	13,483.2	3.5
AEMO base	11,229.8	11,867.6	12,061.8	12,398.9	12,638.0	12,969.4	2.9
AEMO low	11,108.9	11,650.9	11,747.5	12,107.1	12,341.3	12,642.4	2.6
ETSA Utilities	10,991.1	10,977.3	10,989.5	10,900.0	10,687.5	10,595.9	-0.7

Significant differences exist in the business sales and residential sales forecasts, reflecting the different economic outlook and efficiency effects assumed by ETSA Utilities. The majority of the differences relate to differences in the economic outlook.

- AEMO's business sector forecasts show average annual growth of 3.5% to 2014-15 compared with ETSA Utilities' forecasts which show average growth of -0.1%.
- AEMO's residential sector sales forecasts show average annual growth of 1.1% compared with ETSA Utilities' average growth rate of -2.5%.

Smaller but material differences are also apparent in the water heating forecasts.

AEMO's water heating sales forecasts are based on a model which reasonably replicates historic sales and customer numbers over the past five years. This period has seen significant structural change in this market sector as customers' preferences have switched towards gas and solar-electric water heating units. AEMO's historic model identified a slower effective rate of replacement of electric storage heaters and higher average consumption of electricity than assumed by ETSA Utilities in preparing its forecasts. AEMO's model assumes these recently observed parameters continue to apply in the future, with the result that AEMO's sales forecasts are somewhat higher than ETSA Utilities' forecasts. ETSA Utilities' forecasts effectively assume a break with recent trends and accelerating structural change in this market sector, as reflected in the following comparative growth rates:

- annual growth during the 12 years to 2001-02 averaged around 0.8%;
- growth during the 6 years to 2008-09 averaged around -2.6%;
- AEMO's forecasts show growth averaging -3.5% to 2014-15; and
- ETSA Utilities' forecasts show growth averaging -10.8% to 2014-15.

AEMO's sales forecasts regarding the desalination plant and public lighting are similar to ETSA Utilities' forecasts.

Considerable uncertainty surrounds the energy requirements of the desalination plant and AEMO has adopted ETSA Utilities' assumptions for this plant in the absence of clearer advice from SA Water. It is quite feasible that energy used by the desalination plant could be almost double that shown in the forecasts, which assume a load factor of only 50% for the plant.

Reconciliation of AEMO's network-wide demand forecasts with ETSA Utilities' connection point peak demand forecasts

Load diversity factors observed during the 2008-09 summer heatwave have been applied to ETSA Utilities' connection point peak demand forecasts and the sum of these adjusted demands compared with AEMO's peak demand forecasts. This comparison provides an indication of whether the connection point forecasts in aggregate are consistent with AEMO's network-wide peak demand forecasts. AEMO's evaluation assumes that recently observed diversity factors remain unchanged in the future.

The 2008-09 summer was exceptional in that the network-wide peak on 29 January is estimated to have been approximately a 1% PoE outcome. Such an extreme outcome is expected only once in every one hundred years on average and has not been seen before in the South Australian electricity data available to AEMO.

Diversity factors are likely to change with the extremity of the level of demand - progressively higher system-wide demands during heatwaves are driven in part by the convergence of diversity factors towards unity. Accordingly, AEMO has identified two sets of diversity factors to conduct its evaluation.

- One set has been derived from connection point loads observed at the time of the 1% PoE system-wide peak on 29 January. As these diversity factors are associated with a very low PoE level of demand, they have been used to compare ETSA Utilities' connection point forecasts with AEMO's 2% PoE peak demand forecasts (1% PoE forecasts are not available).
- A second set of diversity factors has also been identified for 10% PoE demand conditions and used to compare ETSA Utilities' forecasts with AEMO's 10% PoE peak demand forecasts. Demand was very near to the 10% PoE level on a number of occasions throughout the 2008-09 summer. AEMO has used the average diversity factor observed during the afternoons of 29 and 30 January and on 6 February when network-wide demand was within several MW's of the 10% PoE level.

The following two figures compare AEMO's forecasts with ETSA Utilities' connection point forecasts after adjusting for load diversity observed at the 10% and 1% PoE conditions.

Figure ES 5 Connection point peak demands (adjusted using 10% PoE diversity factors) compared with AEMO's 10% PoE network-wide peak demand forecasts

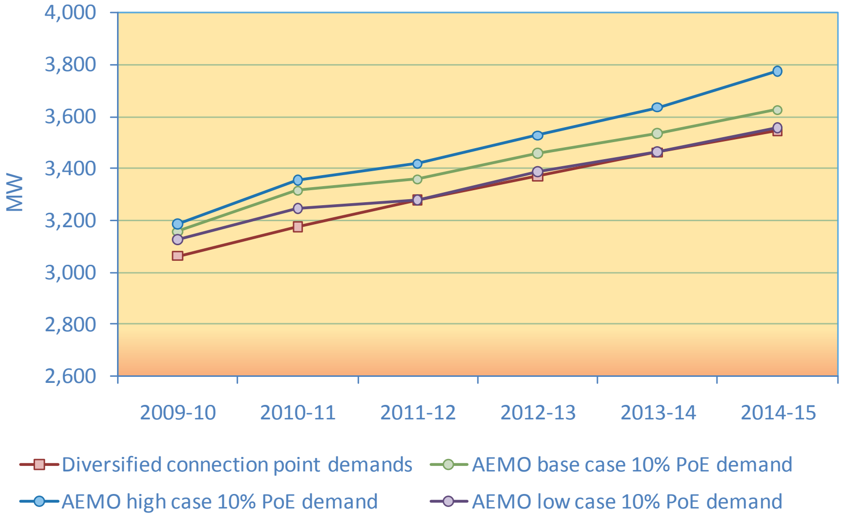


Figure ES 6 Connection point peak demands (adjusted using 1% PoE diversity factors) compared with AEMO's 2% PoE network-wide peak demand forecasts

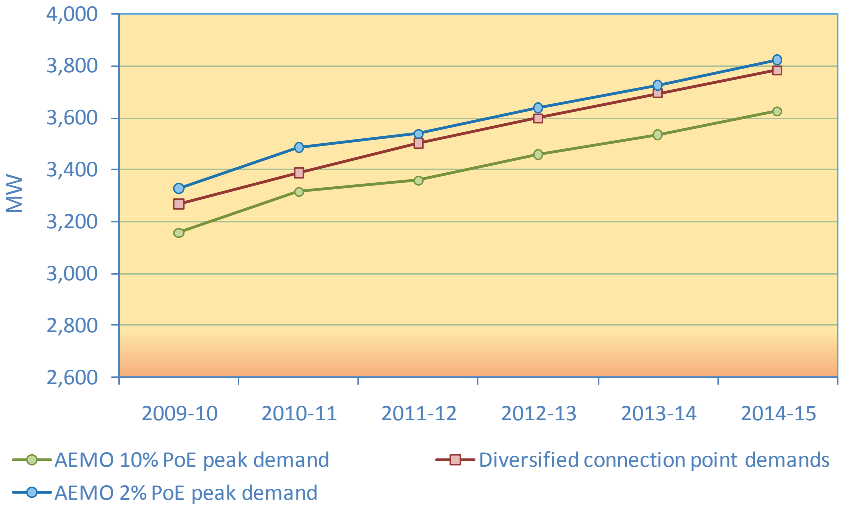


Figure ES5 indicates that the connection point forecasts, adjusted for diversity experienced at the 10% PoE demand level, are broadly consistent with AEMO's peak demand forecasts and lie towards the bottom of the high-low range predicted under the three economic scenarios developed by KPMG. The adjusted connection point forecasts are around 90 MW on average below AEMO's base case 10% PoE forecasts. AEMO considers this to be a tolerable discrepancy and within the range of error that might be associated with inherent variability of load diversity across various points within the network.

Figure ES6 compares AEMO's 2% and 10% PoE base case forecasts with ETSA Utilities' connection point forecasts after adjusting for diversity factors observed at the time of the 1% PoE peak demand event on 29 January. This chart is interesting in that it indicates that the network may be able to cope with system-wide peak demands near to the 2% PoE level under certain circumstances. (Indeed, the network connection points were able to withstand the 1% PoE State-wide demand level seen on 29 January 2009.) However, this does not necessarily imply that the network is being constructed to a 1% or 2% PoE planning standard. Rather, it implies that a system-wide 2% PoE demand level, when driven by convergence of diversity which occurs under widespread extreme temperature conditions such as observed on 29 January 2009, should be able to be accommodated by the network.

Figure ES 5 indicates that the adjusted connection point forecasts are consistent with AEMO's 10% PoE peak demand forecasts. AEMO also conducted a pre-lodgement review of ETSA Utilities' data sources and approach to compiling its spatial demand forecasts at three different levels within the distribution network and its approach to reconciling these forecasts with one another. This was a sound approach that offered a self-checking mechanism to ensure the forecasts are internally consistent with one another and that consistent data had been used in the preparation of the forecasts. AEMO therefore concludes that ETSA Utilities' connection point peak demand forecasts are reasonable.

Consistency of peak demand and annual sales forecasts

AEMO has also reviewed the overall level of consistency between the network-wide peak demand forecasts and the annual sales forecasts by comparing actual and projected trends in the distribution network load factor.

The actual load factor has shown a definite downward trend over the ten years to 2008-09, reflecting more rapid growth of peak demand levels than annual sales volumes.

AEMO's sales and peak demand forecasts imply that the system load factor will continue to fall substantially in line with the historic trend rate of decline. In comparison, ETSA Utilities' forecasts show the load factor falling much more rapidly in the future to be around 20% (or 8 percentage points) below the trend value expected by 2014-15. As AEMO's and ETSA Utilities' peak demand forecasts for 2014-15 are broadly in line with one another, this difference reflects the significantly lower level of annual sales forecast by ETSA Utilities and reflects, in AEMO's view, a degree of inconsistency between ETSA Utilities' annual sales and peak demand forecasts.

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1. Introduction

The Australian Energy Regulator (AER) is conducting a review to determine the prices that will apply to the regulated services provided by ETSA Utilities for the period 1 July 2010 to 30 June 2015. ETSA Utilities is the principal distribution network service provider in South Australia.

During February 2009 the AER asked the South Australian Electricity Supply Industry Planning Council (ESIPC) to review and report on the sales and demand forecasts submitted by ETSA Utilities as part of its Regulatory Proposal to the AER. ETSA Utilities lodged its Proposal with the AER on 1 July 2009. The AER's Draft Determination is due by 27 November 2009 and its Final Determination by 13 April 2010.

The ESIPC was dissolved on 30 June 2009, with most of its functions and responsibilities assumed by the Australian Energy Market Operator (AEMO) from 1 July 2009. The transfer of responsibilities to AEMO included the ESIPC's undertaking to report to the AER on ETSA Utilities' sales and demand forecasts.

The AER requested that a draft report be provided by 21 August 2009 and a final report by 4 September 2009. This is the draft version of AEMO's report to the AER.

1.1 Scope of the review

The AER requested that AEMO's review:

- provide an independent view of ETSA Utilities' annual sales by customer category for years 2010-11 to 2014-15 and apportion these to tariff categories;
- provide an independent view of state-wide distribution network peak demand at the 10% and 50% probability of exceedance (PoE) levels for years 2010-11 to 2014-15 and reconcile these with individual transmission connection point peak demand forecasts submitted by ETSA Utilities;
- test the sensitivity of AEMO's forecasts to changes in input assumptions, including using ETSA Utilities' input assumptions as the basis for one of the sensitivities; and
- identify and comment on the reasons for any differences between ETSA Utilities' and AEMO's sales and network-wide peak demand forecasts, and comment on the reasonableness of ETSA Utilities' approach and input assumptions.

AEMO's review is not intended to:

- comment on ETSA Utilities' demand forecasts at the sub-station level;
- provide customer number forecasts; or
- respond to matters raised in submissions from interested parties.

1.2 Approach to conducting the review

In developing an independent view of sales and peak demand forecasts for the South Australian distribution network, AEMO:

- adopted the economic assumptions prepared by KPMG Econtech during March 2009 and which were used to develop electricity forecasts for the *2009 Electricity Statement of Opportunities*;
- used KPMG Econtech's retail electricity price projections which assume the Australian Government's proposed Carbon Pollution Reduction Scheme (CPRS) will be introduced from July 2011 with an initial permit price cap of $10 per tonne;
- engaged Monash University to prepare peak demand forecasts on a consistent basis with sector-specific annual sales forecasts for South Australia; and
- incorporated specific recognition of policies aimed at greenhouse gas abatement and promoting energy efficiency throughout the economy.

An important part of this review also involves comparing AEMO's and ETSA Utilities' sales and demand forecasts and underlying input assumptions. At a general level, the forecasting process may be characterised as involving several distinct steps which provide useful points of reference for comparing the forecasts. These steps involve:

- preparing business-as-usual (or baseline) forecasts using suitable models in conjunction with forecasts of driver variables such as retail electricity prices and the level of economic activity; and
- applying post model adjustments to the baseline forecasts to capture electricity consumers' responses to recently introduced or proposed energy efficiency policies.

Differences between AEMO's and ETSA Utilities' electricity sales and peak demand forecasts may therefore reflect a combination of factors, including differences in:

- the assumed economic outlook and future retail electricity prices,
- underlying forecasting models relied upon by each organisation, and
- post model adjustments applied to the baseline forecasts.

This report has been structured as follows, reflecting the above potential sources for differences between the forecasts.

- Section 2 compares and discusses AEMO's and ETSA Utilities' economic assumptions and the assumed effects of energy efficiency policies.
- Section 3 describes AEMO's sales and peak demand forecasts for the three economic scenarios developed by KPMG Econtech.

- Section 4 compares ETSA Utilities' sales and demand forecasts with a set of forecasts prepared by AEMO using ETSA Utilities' macroeconomic and related assumptions. This comparison provides an indirect evaluation of the underlying forecasting models relied upon by ETSA Utilities. If ETSA Utilities' electricity forecasts are closely replicated by AEMO's models when ETSA Utilities' macroeconomic assumptions are applied, it is reasonable to conclude that the models work in a broadly similar fashion for all practical purposes regardless of how ETSA Utilities' models are actually constructed.
- Section 5 compares AEMO's and ETSA Utilities' sales and demand forecasts and comments on the reasons for any differences. This section also includes a reconciliation of AEMO's peak demand forecasts and the individual connection point forecasts submitted by ETSA Utilities.
- The Attachment provides further detail regarding the models used to develop AEMO's electricity forecasts.

2. Economic and related assumptions

The economic assumptions underpinning AEMO's electricity forecasts for the South Australian distribution network were prepared by KPMG Econtech during March 2009. These forecasts, which included projected retail electricity prices, were made available by AEMO (then NEMMCO) to all NEM jurisdictional planning bodies to develop regional electricity forecasts for the *2009 Electricity Statement of Opportunities*.

In late April and early May 2009 the Australian Government proposed a number of changes to the expanded RET scheme and the CPRS. These changes resulted in KPMG issuing a supplementary report revising its projected retail electricity prices to reflect the likely new policy environment. KPMG's revised assumptions have been used in developing the electricity forecasts for this report.

The electricity forecasting process also requires assumptions to be made regarding consumers' responses to recently introduced or proposed energy efficiency policies. These assumptions are incorporated into AEMO's forecasts via post model adjustments which are applied to baseline (business-as-usual) forecasts.

This section of the report compares the major assumptions underlying AEMO's and ETSA Utilities' electricity forecasts. The discussion is organised around the following key areas:

- Australian and South Australian economic outlook to 2014-15;
- future retail electricity prices; and
- the impact of energy efficiency policies on electricity sales and demand levels.

2.1 Economic outlook for Australia and South Australia

KPMG's economic outlook for Australia and each State was prepared against the backdrop of the global financial crisis and consequent recession in major world economies. Considerable risk surrounds Australia's near term outlook, with the severity of the downturn and the timing and strength of recovery dependent on developments in the economies of Australia's major trading partners. KPMG identifies the main uncertainties as the length of time that credit markets remain dysfunctional and the pace of global economic recovery. This will depend on the extent of financial institutions' asset write downs and the speed with which confidence returns to global financial markets and business activity more generally.

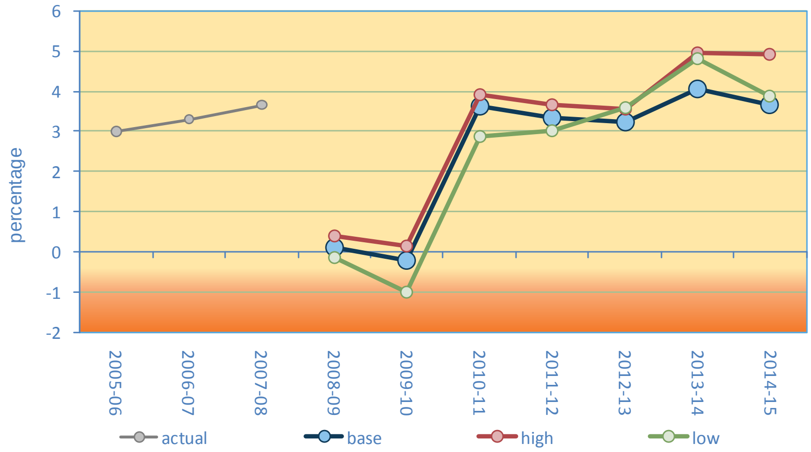
KPMG note that potential exists for further shocks to the global economy to have adverse flow-on effects within Australia. On the upside, policy actions in major economies and an early rebound in China's economy could see Australia recover more strongly than forecast.

Outlook for the Australian economy

Major contributors to the slowdown in the Australian economy are expected sharp falls in business investment and exports and some contraction in household consumption. Growth in public investment is expected to provide a buffer to weakness elsewhere in the economy and moderate the severity of the downturn.

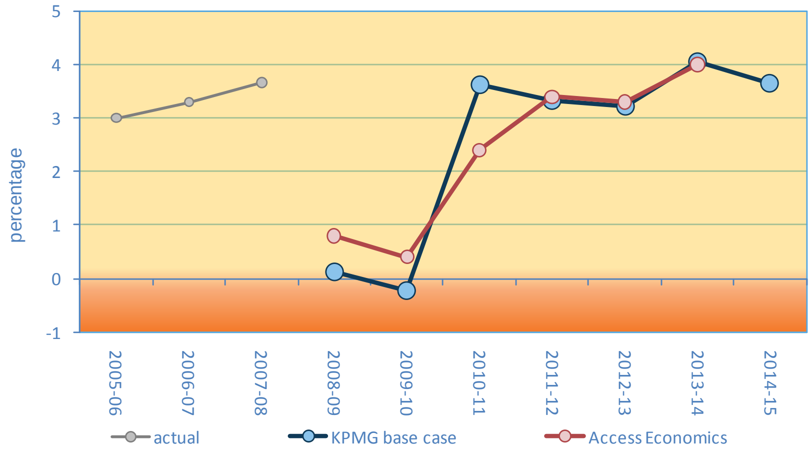
KPMG's forecasts show Australian GDP remaining flat in 2008-09, with real growth of only 0.1%, and falling in real terms by 0.2% in 2009-10. Growth is projected to recover to 3.6% in 2010-11 and average 3.6% over the five years to 2014-15. The low case shows a deeper downturn and weaker recovery in 2010-11, while the high case shows a slightly stronger recovery. KPMG's projected growth rates for Australian GDP are shown in Figure 1.

Figure 1: KPMG's Australian GDP growth rate forecasts



Given the level of uncertainty surrounding the near term economic outlook and the fact that KPMG's forecasts were prepared several months ago, AEMO has tested KPMG's economic outlook against more recent projections published by Access Economics in its July 2009 *Business Outlook*. The two sets of forecasts are compared in Figure 2.

Figure 2: Access Economics' Australian GDP growth rate forecasts



Access Economics expects a more moderate downturn in growth in 2008-09 and 2009-10 compared with KPMG's projections and a slightly weaker rebound in activity during 2010-11. The forecasts are almost identical in later years. The two sets of forecasts also show an almost identical level of cumulative growth over the period to 2013-14, with the main difference being the timing of this growth. Both KPMG and Access Economics therefore have a similar view of the ultimate size of the Australian economy by 2014-15.

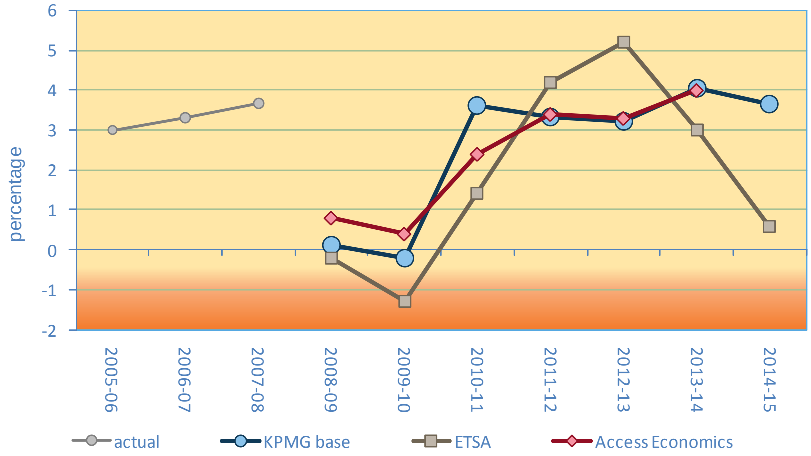
Access Economics' July *Business Outlook* includes the following observations:

- Substantial and rapid international policy responses have put the worst of the global financial crisis behind us. Governments and central banks have successfully avoided a collapse of the financial system and have engineered a milder-than-otherwise global recession at the expense of a milder-than-otherwise recovery.
- Australia is emerging from this period with only collateral damage compared with some other economies. Domestic consumption spending has continued to grow, supported by lower interest rates and the Government's cash hand-outs; export volumes have actually risen 1.8% since the crisis started as China purchases key commodities at rates higher than it would have had there not been a crisis; and employment is being maintained as businesses, who until recently faced severe skills shortages, are hoarding workers through the downturn.
- Access Economics expects the strength of the recovery to be weighed down by a number of factors. Recently negotiated commodity price reductions have only just begun to have an impact on exports and profitability; business investment is likely to slow and unemployment is expected to rise as new job creation falls behind population growth; and consumption spending will begin slowing as the cash stimulus fades and unemployment rises. Over the medium term Australian growth will be constrained by the requirement to repair the Australian Government's underlying structural budget deficit.

ETSA Utilities' projections for the Australian economy

Figure 3 compares KPMG's and Access Economics' Australian GDP growth rate projections with the assumptions underlying ETSA Utilities' Regulatory Proposal.

Figure 3: ETSA Utilities' Australian GDP growth rate assumptions



ETSA Utilities' economic assumptions show lower Australian GDP growth than forecasts prepared by KPMG and Access in five of the seven years to 2014-15. The cumulative level of GDP growth between 2008-09 and 2014-15 assumed by ETSA Utilities is 5.6% lower than implied by KPMG's base case projections, implying that the Australian economy would be considerably smaller in 2014-15 than forecast by either KPMG or Access Economics.

Economic outlook for South Australia

KPMG expect South Australia to perform more strongly in terms of GSP growth than some other States throughout the economic downturn and subsequent recovery, with growth supported by comparatively low housing costs, low personal debt levels and ongoing mining, defence and infrastructure investments.

Western Australia and Queensland are expected to remain the fastest growing regions due to their large mining sectors. In contrast, New South Wales and Victoria are likely to experience the sharpest downturns due to relatively high personal debt levels (NSW) and larger exposure to the manufacturing sector (Victoria).

Over the medium to longer term, demographic factors are a key driver of the level of economic activity. KPMG's base case projections show South Australia's population continuing to rise by around 1% annually. While this is less than the projected national average, it represents stronger growth than experienced in South Australia in recent years and would see the State's population reach 2 million persons by around 2029-30.

Other key features of South Australia's near term economic outlook include the following.

- The household sector's relatively lower income levels compared with the rest of Australia, and lower gearing and average house prices, mean there is less adjustment required to establish better savings habits, while fiscal stimulus payments such as the first home owners grant and cash hand-outs have a relatively greater effect than in most other States.

- South Australia has already lost many jobs in the financial and manufacturing sectors during the 1980's and 1990's and so is less exposed to further job losses in these areas than some other States. And although its mining sector is growing rapidly, the State is not as exposed as Queensland and Western Australia to a downturn in commodity prices and export volumes.

- Housing construction remains the strongest in Australia, supported in part by increasing numbers of international students and solid growth in the number of skilled migrants.

- South Australia's engineering and construction pipeline is supported by broadly based projects such as the Air Warfare Destroyer project, the new desalination plant, a number of new road and rail projects, ongoing investments in wind farms and mining-related activity.

- Although commercial building approvals have weakened to two year lows, major projects currently underway include redevelopment of a number of metropolitan hospitals, construction of a new aquatic centre at Marion, refurbishment of the Hallett Cove shopping centre, construction of Techport Australia, and upgrades to major sporting facilities.

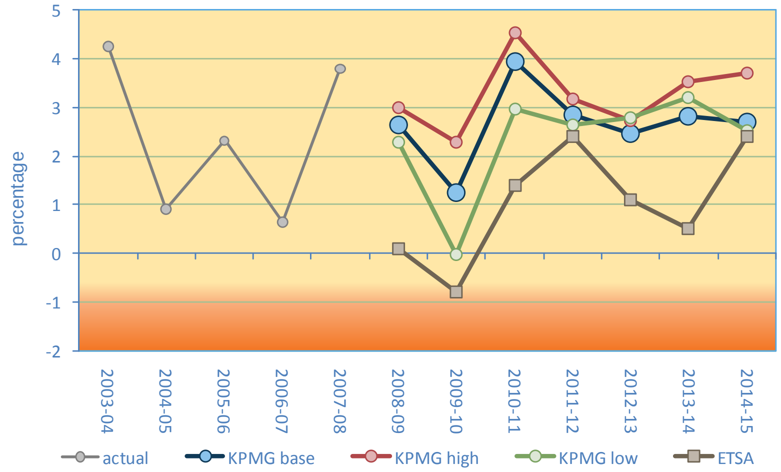
Following relatively strong real growth of GSP in 2007-08 (3.8%) and 2008-09 (estimated at 2.6%), South Australian GSP growth is expected to fall to 1.2% in 2009-10 before recovering strongly to 3.9% in 2010-11.

The projected strong rebound in 2010-11 reflects past economic cycles where growth tends to be strong coming out of a downturn as pent-up housing demand is met by increased activity, and the continuing effects of Government fiscal stimulus packages which are expected to support further investment in infrastructure.

Near term downside risks associated with the global economy could see South Australian GSP falling slightly in real terms in 2009-10 and a weaker rebound in 2010-11. Over the medium term, real GSP growth is expected to average 2.6% annually, with the high and low case sensitivities showing average annual growth falling in the range of 2.4% to 2.9%.

Figure 4 compares KPMG's growth rate projections for South Australian GSP with the assumptions adopted in ETSA Utilities' submission.

Figure 4: South Australian GSP growth Rate forecasts



ETSA Utilities' submission assumes considerably slower growth than forecast by KPMG in each year to 2014-15.

The cumulative level of South Australian GSP growth to 2014-15 assumed by ETSA Utilities is 12.9% lower than shown by KPMG's base case projections, implying that the economy would be some $9.5bn smaller than forecast by KPMG for that year. This is a material difference in the economic outlook presented by the two organisations.

Sectoral outlook for the South Australian economy

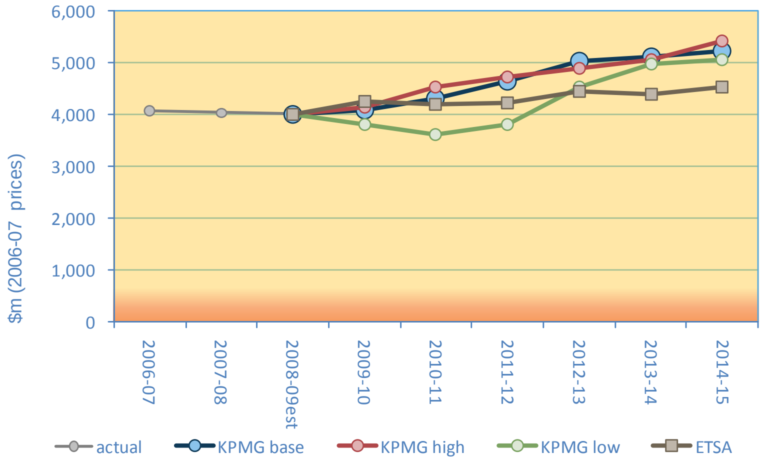
The forecasting models used by AEMO do not use GSP directly as a driver variable, but instead use different components of GSP in sector-specific models of electricity demand. Modelling different sectors of the economy separately allows the electricity sales and demand forecasts to better reflect differences in the energy intensity of different parts of the economy.

The key variables used in AEMO's electricity forecasting models include:

- dwelling investment;
- manufacturing sector gross valued added (GVA); and
- other sectors' combined GVA (excluding agriculture, mining and home ownership).

ETSA Utilities' Regulatory Proposal notes that its forecasting models also rely on projections of sector-specific economic activity, so it is appropriate to compare KPMG's and ETSA Utilities' forecasts for the above components of South Australian GSP.

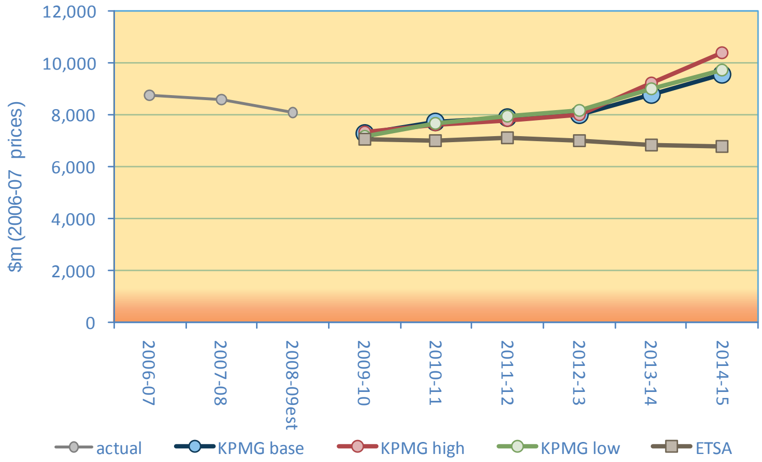
Figure 5: South Australian dwelling investment



ETSA Utilities' projected levels of dwelling investment are similar to KPMG's forecasts to 2010-11 and then show considerably slower growth in later years.

Annual growth of dwelling investment across the six years to 2014-15 averages 2.0% for ETSA Utilities' forecasts, less than half the 4.5% average growth shown in KPMG's base case forecasts. KPMG' low growth scenario shows average growth of 3.9%.

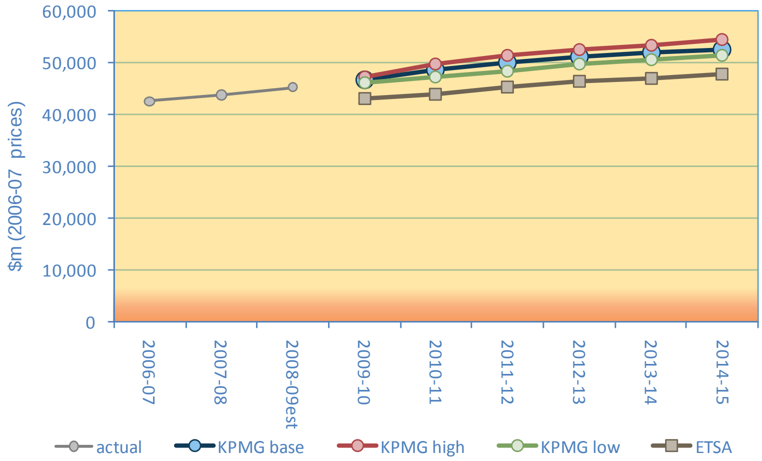
Figure 6: South Australian manufacturing sector Gross Value Added



ETSA Utilities' forecasts assume an annual average real decline of 3% in manufacturing sector GVA across the forecast horizon.

KPMG's base case forecasts show an annual average increase of 2.8%

Figure 7: Other sectors' Gross Value Added



ETSA Utilities' forecasts show other industry GVA (excluding agriculture, mining, manufacturing and the housing sector) falling in real terms by 4.9% in 2009-10 compared with KPMG's base case forecast for growth of 3.2%. Annual output by these sectors during the 2014-15 year is projected by ETSA Utilities to be around 9% less than KPMG's forecasts. This difference would have a large impact on electricity use.

2.2 Retail electricity price forecasts

Research undertaken by Monash University has found that electricity demand in South Australia is price inelastic, in that elasticity lies between zero and minus one. Monash's research also found that the price elasticity of summer peak demand levels is around half of that applying to annual sales volumes. These findings have been reflected in the forecasting models used by AEMO.

Future retail electricity prices will reflect movements in the underlying wholesale cost of energy, network charges and carbon pricing. KPMG developed models to project forward average retail electricity prices for each State as part of developing the economic outlook. These models use macroeconomic variables such as interest rates and commodity price projections to capture the underlying short and long term drivers of retail electricity prices. The assumed future levels of these variables have been taken from KPMG's forecasting models for the Australian economy and are consistent with the broader economic outlook described in the previous section. These variables, which have been good predictors of past retail prices, are designed to capture the effects of the cost of capital and prices applying to fuel and capital equipment.

The introduction of carbon pricing and policies designed to promote various forms of green energy generation will also have an important effect on retail electricity prices. Some uncertainty surrounds the final form of the proposed RET scheme and the CPRS and their passage through the Australian Parliament. The outcome of the United Nations Climate

Change Conference to be held in Denmark during December 2009 may also influence the final form of the CPRS.

KPMG's electricity price forecasts reflect policy changes announced by the Australian Government in April and May 2009 in regard to the expanded RET scheme and the CPRS. In particular, the forecasts assume that implementation of the CPRS is delayed until July 2011, with a fixed permit price of $10 per tonne applying in the first year. The carbon price is assumed to rise to $23 per tonne in 2012-13 and increase by 4% annually thereafter.

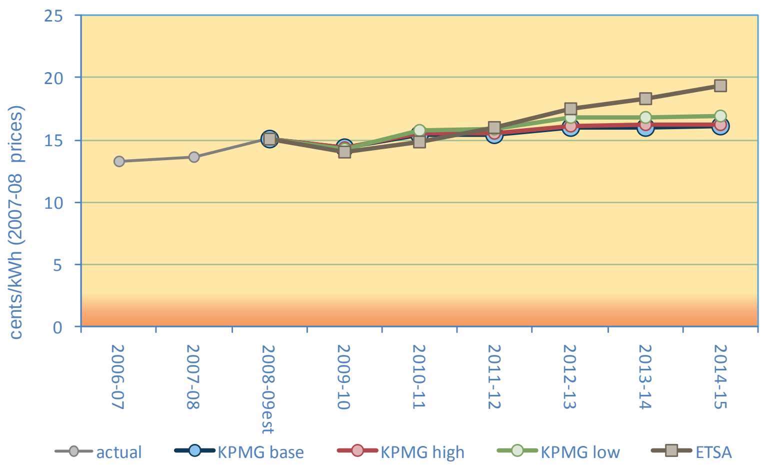
The high growth scenario adopts similar assumptions to the base case, except future technological developments are assumed to reduce the carbon intensity of the economy and cause the permit price to fall in some years. The low growth scenario assumes the CPRS-15 targets are adopted with a higher carbon price of $32 per tonne applying in 2012-13.

The expanded RET target of 12,500 GWh is assumed to apply from January 2010, with annual increments lifting the target to 45,000 GWh in 2020. The target is assumed to continue until 2030. The RET scheme penalty charge is assumed to increase from $40 to $65 per MWh.

The Australian Government has also announced that if global agreement is reached to stabilise greenhouse gasses at 450 parts per million, Australia will commit to a 25% reduction in emissions from 2000 levels rather than the 15% reduction underlying the CPRS-15 targets. This would imply higher carbon prices, and ultimately higher retail electricity prices, than have been assumed by KPMG.

KPMG's base case projections for South Australia show the real average retail price rising by 18.5% between 2007-08 and 2014-15, or an average annual real increase of 2.4%. In comparison, ETSA Utilities' assumptions show the real price rising by 42.3% over this period, or an average increase of 5.2% annually. Figure 8 compares KPMG's and ETSA Utilities' retail price projections to 2014-15.

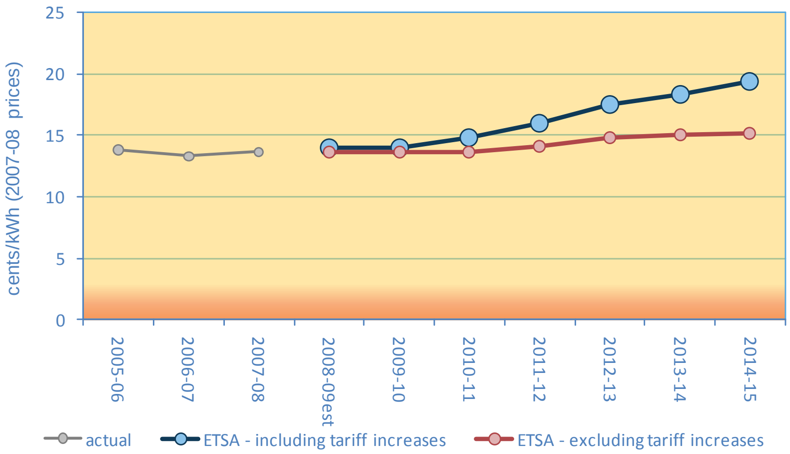
Figure 8: Average South Australian electricity retail prices



Information provided in support of ETSA Utilities' submission to the AER indicates that its retail price projections assume South Australian network tariffs will rise as proposed in its Regulatory Proposal.

The assumed network tariff increases account for the majority of the retail price increases assumed by ETSA Utilities, as shown in Figure 9. The overall real price increase between 2007-08 and 2014-15 assumed by ETSA Utilities before adding its proposed tariff increases is 11.3%. This rise reflects its assumptions regarding the impact of the CPRS and other general economic factors. After adding the assumed tariff increases, ETSA Utilities' price projections show a real rise in the average retail price of 42.3% over the same period.

Figure 9: ETSA Utilities' assumed retail prices



2.3 Assumptions relating to energy efficiency policies

Background considerations

Ensuring that the effects of new energy efficiency policies are appropriately reflected in sales and demand forecasts is a difficult area that necessarily involves a degree of judgement. The issues as AEMO understands them are highlighted in this background section before comparing AEMO's and ETSA Utilities' assumptions in the following section.

Energy efficiency effects may be accounted for in one of two ways when forecasting electricity sales and demand levels. Each approach presents its own challenges.

The forecasts might be constructed using a bottom-up or micro approach which attempts to model electricity use on an appliance-by-appliance basis for typical households and business units and then scale up individual usage to reflect the total number of households and business units. This approach requires a very detailed set of historic data regarding the number of households and business units and their key characteristics, the stock of appliances and its distribution throughout the population, and the electrical characteristics of different appliances. The model would then be used in conjunction with a range of assumptions regarding changes in the population and customers' behaviour, and changes in the penetration rates and electrical characteristics of the different appliance types. In principle, the bottom-up approach offers the potential to internalise many of the difficult issues surrounding the forecasting process, such as differences in the growth rates applying to different appliance types and changes in their electrical efficiency. However, the bottom up approach is very difficult to apply successfully in practise due to a lack of quality data and the requirement to overlay a large number of assumptions about future changes in the size, behaviour and profile of the population and changes in the stock and efficiency profile of different appliances.

An alternative approach, which is used by AEMO in developing its South Australian forecasts, is to use a top-down or macro model to produce baseline (or business-as-usual) forecasts, and then make post model adjustments to capture efficiency effects which are not already included in the baseline forecasts.

- Baseline forecasts reflect historic relationships between aggregated electricity sales or demand levels and high level macroeconomic and climate driver variables. These relationships are used in conjunction with independent forecasts of the driver variables to project forward electricity sales and/or demand levels. Key advantages of this approach are that it requires much less data and far fewer assumptions than the micro approach, it is transparent and easily understood, and the models are based on objective and verifiable data and statistically proven relationships.

- Post model adjustments are then applied to the baseline forecasts to account for any energy efficiency effects not already reflected in the historic macro-level relationships. A degree of judgement is required here to avoid double counting of efficiency effects and the introduction of biased or one-sided adjustments.

When using a top-down forecasting approach, the potential exists for double counting efficiency effects in both the macro forecasts and the post model adjustments, or for biased adjustments to be made which selectively include some micro effects while omitting closely related offsetting effects.

- Double counting might occur, for example, when the baseline forecasts include a consumer response to rising prices, while separate post model adjustments are also included to reflect programs aimed at assisting consumers discover and implement changes to economise on electricity use in a rising price environment. AEMO's thinking is that price effects are not exclusively about "switching appliances off", but come about in part because some policies facilitate the process of consumers becoming more efficient in their use of electricity. Forecasts should include either the price effect or the policy effect – not both, because, to some extent at least, they are not additive effects but different perspectives on the same phenomenon.

- Historic sales and demand data includes the impact of efficiency measures introduced in the past. Baseline forecasts built upon this data therefore include the effects of past policies. The baseline forecasts also implicitly assume that further new measures will continue to be introduced with similar frequency and intensity in the future. As such, care must be taken to ensure that post model adjustments do not double count new efficiency policies that are already reflected in the forecasts by way of existing trends in the data. Adjustments should only be made to capture incremental efficiency effects if the frequency of introducing new policies increases in the future, or if the intensity of their effect increases relative to past measures.

- Biases in the application of post model adjustments may also be introduced in a variety of other situations. An example is the rapidly rising penetration of energy-hungry flat screen televisions and prospective improvements in the minimum energy performance standards (MEPS) applying to these appliances. Data presented in the AECOM report submitted by ETSA Utilities as part of its Proposal indicates that energy consumed by televisions is likely to grow at an annual compounding rate in excess of 5% between 2008 and 2020 in the absence of tighter MEPS for these appliances. The higher than average growth of electricity use associated with these appliances presents a prima facie case for including a post model adjustment to capture incremental electricity sales that may not be reflected in baseline forecasts. However, if such upside adjustments are made to the forecasts, due recognition should also be given to the tightening of television MEPS and expected improvements in efficiency. In AEMO's view biases will be introduced if post model adjustments reflect only one aspect of the changes occurring in this market sector - either both effects should be allowed for, or both excluded.

Several other background considerations are also important when comparing ETSA Utilities' and AEMO's estimates of energy efficiency savings in the South Australian forecasts.

- Although efficiency improvements are identified in relation to both annual sales volumes and network-wide peak demand levels, AEMO believes the assumptions made in relation to annual sales are much more important in the context of this report than those made in relation to network-wide peak demand. This is because the AER's final determination will turn in part on ETSA Utilities' sales forecasts and individual connection point peak demand forecasts, rather than be directly influenced by network-wide peak demand levels. ETSA Utilities' connection point peak demand forecasts have been prepared independently of its network-wide demand forecasts. It is unclear to AEMO how the efficiency measures identified in ETSA Utilities' submission have been reflected in its connection point forecasts. Section 5.3 of this report compares AEMO's network-wide peak demand forecasts with ETSA Utilities' connection point forecasts.
- The efficiency effects discussed in this section are assumed to occur within the residential sector and exclude the water heating load. (Energy savings and other changes associated with water heating are modelled separately.) The relative size of the efficiency measures should therefore be considered in the context of residential sales levels.

- In commenting on ETSA Utilities' assumed efficiency improvements, it is also necessary to have some understanding of its overall residential sales forecasts. Do its forecasts reflect a bottom-up approach which includes above average growth in some appliance areas and offsetting efficiency gains in other areas, with the reported level of energy savings representing only one part of an array of complex changes assumed to be occurring within this sector? Alternatively, do its forecasts reflect a top down approach, with the reported efficiency savings representing post model adjustments? If so, then careful consideration is required to avoid the double counting and potential biases referred to above. AEMO does not have sufficient information regarding ETSA Utilities' sales forecasting models to comment directly on this issue. However, this does not really matter in practise as AEMO's top down model for residential sales forecasts very closely replicates ETSA Utilities' forecasts when ETSA Utilities' macroeconomic assumptions are used and its efficiency savings are treated as post-model adjustments. (See section 4.1 for further details.) For all practical intents and purposes, ETSA Utilities' residential sales forecasts may therefore be thought of as having been developed using a top down approach similar to AEMO's model, indicating that considerations regarding double counting and biases also apply to its forecasts. It also follows that ETSA Utilities' (effective) underlying baseline forecasts grow over time in line with general macroeconomic variables and therefore do not incorporate allowances for some appliance categories to show increasing growth rates over time.

AEMO makes a number of adjustments to its baseline forecasts for South Australia to allow for new energy efficiency policy effects, but attempts to do so only in carefully considered circumstances. In using a top down approach, the net effect of the many micro-drivers of electricity demand, both positive and negative, is reflected in the historic data used in the forecasting models. This data directly reflects the key variables the models are attempting to forecast. Statistical tests are used to identify which macro variables best explain the historic data and project demand and energy levels into the future. Given a particular set of assumptions about the future economic environment, the forecasts therefore offer an objective view of future electricity sales and demand levels. These forecasts should only be modified when there are strong grounds for considering that past relationships between the variables will change materially in the future and there is sufficient information to make a balanced estimate of the likely impact of new energy efficiency policies.

Comparison of ETSA Utilities' and AEMO's energy efficiency estimates

Table 1 and Table 2 compare ETSA Utilities' and AEMO's estimates in relation to new energy efficiency policies affecting South Australian electricity use.

AEMO's estimates only include efficiency savings which have been treated as post model adjustments to its top down forecasts. AEMO acknowledges that all of the programs listed in the table are likely to produce efficiency gains in their own right, but many of these savings will already be reflected in the baseline forecasts and have therefore been excluded from the post model adjustments.

ETSA Utilities' efficiency savings for residential sales shown in the tables may also be thought of as effective post model adjustments, as AEMO has been able to closely replicate ETSA Utilities' residential sales forecasts using a top down modelling approach and treating these savings as post model adjustments. That is, regardless of how ETSA Utilities' sales forecasts have actually been constructed, they largely perform as if they have been developed using a top down macro model with adjustments made in line with the estimates shown in the table.

Table 1: Efficiency measures affecting annual sales forecasts (GWh)

		2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Installation of small scale solar PV units	ETSA	12.1	15.8	19.0	21.6	24.3	26.9
	AEMO	11.3	15.1	18.9	22.7	26.4	30.2
Residential Energy Efficiency Scheme	ETSA	23.5	44.6	66.6	88.6	110.6	132.6
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
Air conditioner MEPS	ETSA	0.0	6.0	11.9	17.7	23.4	29.0
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
Television MEPS	ETSA	9.0	18.0	27.0	36.0	45.0	54.0
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
Set-top box MEPS	ETSA	1.8	3.6	5.4	7.2	9.0	10.8
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
Standby power MEPS	ETSA	14.9	29.7	44.6	59.4	74.3	89.1
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
Lighting MEPS	ETSA	62.9	83.9	104.8	125.8	146.8	159.9
	AEMO	28.7	58.2	88.8	120.1	153.9	189.7
Federal insulation program	ETSA	18.6	30.9	37.1	37.1	37.1	37.1
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
ETSA Direct Load Control program	ETSA	0.0	0.0	0.0	0.0	0.0	0.0
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
Total across all policy areas	**ETSA**	**142.8**	**232.5**	**316.4**	**393.4**	**470.5**	**539.4**
	AEMO	**40.0**	**73.3**	**107.7**	**142.8**	**180.3**	**219.9**

Table 2: Efficiency measures effecting peak demand forecasts (MW)

		2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Installation of small scale solar PV units	ETSA	2.8	3.6	4.3	4.9	5.5	6.1
	AEMO	4.0	5.4	6.7	8.1	9.4	10.8
Residential Energy Efficiency Scheme	ETSA	3.1	6.0	8.9	11.8	14.7	17.7
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
Air conditioner MEPS	ETSA	0.0	6.0	12.0	17.8	23.5	29.2
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
Television MEPS	ETSA	1.3	2.5	3.8	5.0	6.3	7.6
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
Set-top box MEPS	ETSA	0.1	0.3	0.4	0.6	0.7	0.9
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
Standby power MEPS	ETSA	0.8	1.5	2.3	3.1	3.8	4.6
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
Lighting MEPS	ETSA	0.0	0.0	0.0	0.0	0.0	0.0
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
Federal insulation program	ETSA	28.4	41.6	48.2	48.2	48.2	48.2
	AEMO	0.0	0.0	0.0	0.0	0.0	0.0
ETSA Direct Load Control program	ETSA	0.0	0.0	0.0	0.0	0.0	0.0
	AEMO	0.0	5.0	10.0	15.0	15.3	15.6
Total across all policy areas	**ETSA**	**36.5**	**61.5**	**79.9**	**91.4**	**102.7**	**114.3**
	AEMO	**4.0**	**10.4**	**16.7**	**23.1**	**24.7**	**24.6**

As indicated in these tables, AEMO has excluded many areas of residential energy efficiency savings from its post model adjustments as it believes these effects are already reflected in its baseline forecasts or because the adjustments would introduce unwanted biases into the forecasts.

AEMO believes that adjustments are warranted in relation to the rising penetration of small scale solar PV units and the recently introduced policy to tighten MEPS applying to lighting appliances as these policy effects have the potential to significantly change the existing profile of demand. Lighting comprises a relatively large share of residential demand and this load makes a significant contribution to winter peak demand, while roof top solar PV units have the potential to make a reasonably large contribution to residential users' net energy requirements from the shared grid, particularly over the longer term if the current high rates of growth continue over a decade or more. While there are some differences in the size of the impacts assumed by ETSA Utilities and AEMO in these two policy areas, the differences are relatively small and are a reflection of the imprecise nature of the assumptions required to estimate the impact of each policy.

AEMO has also included small downward adjustments, amounting to around 15 MW in 2014-15, to its peak demand forecasts in recognition of the possibility that ETSA Utilities' Beat the Peak direct load control program will continue and grow modestly over time. In an October 2008 media release, ETSA Utilities indicated that "... *we can show that we have achieved significant peak demand reduction when the system is activated ... we are confident it can deliver major benefits. Therefore, we intend to continue to expand and refine the project*." ETSA Utilities has not included any adjustment to its peak demand forecasts in relation to this program on the assumption that demand reductions may not be available at the time of system peak demand.

AEMO believes that post model adjustments are not required in respect of the following policies as they would either introduce biases or double count savings.

(a) Televisions, set top boxes and air conditioners

ETSA Utilities' consultants, in estimating the potential energy savings associated with new efficiency standards for televisions, set top boxes and air conditioners, reported that penetration of these appliances is rising rapidly and growth of energy consumption associated with their use is likely to far outstrip that for other appliance categories. For example, data presented in AECOM's report indicates annual growth of energy used by televisions and set top boxes is likely to grow at an annual compounding rate of more than 5% between 2008 and 2020 in the absence of tighter MEPS for these appliances. Similarly, the AECOM report indicates that the share of residential electricity consumption attributable to air conditioning is expected to rise from 6% in 2005 to 9% in 2020.

The higher than average growth rates for electricity used by these appliances presents a prima facie case for including post model adjustments to capture the incremental additions to baseline sales forecasts. In AEMO's view it is inappropriate to make post model reductions to baseline forecasts to reflect possible improvements in the efficiency of these appliances unless similar adjustments are also made to reflect their increasing penetration and use.

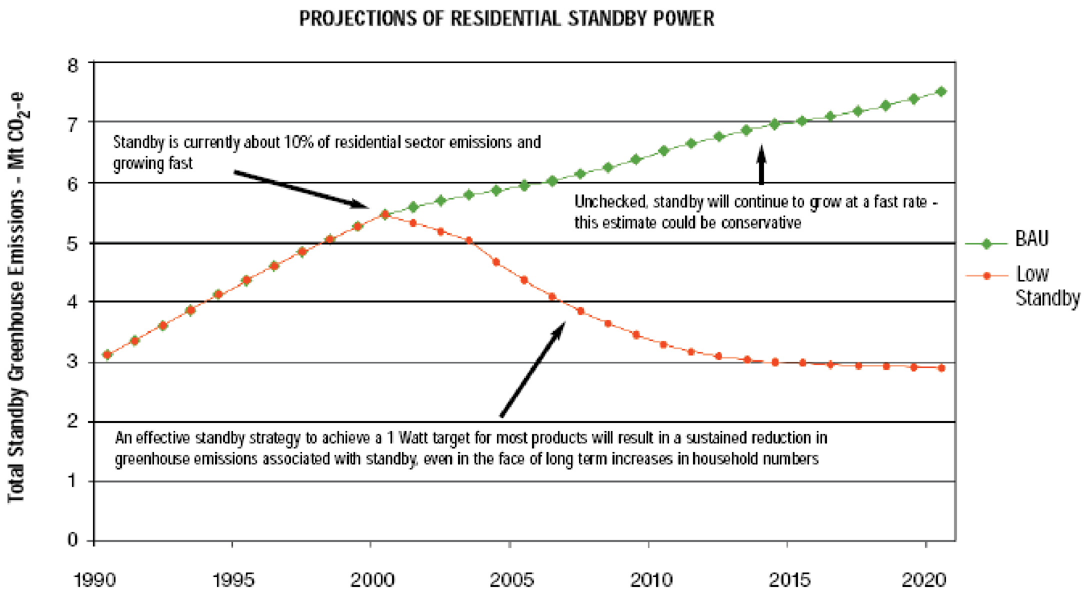
(b) Standby power

ETSA Utilities has identified relatively large energy savings in respect of standby power usage. By way of background, the National Appliance and Equipment Energy Efficiency Program (NAEEEP) adopted a policy in 2002 to substantially reduce standby power usage in Australia. The following figure, reproduced from the NAEEEP's 2002 report, indicates the extent and timing of energy savings expected under the program[1]. Importantly, the majority

[1] National Appliance and Equipment Energy Efficiency Program Report No. 2002/12, *Australia's Standby Power Strategy 2002–2012*

of savings were expected to have been achieved by 2009, with limited additional savings occurring in the 2010-2015 period.

Figure 10: NAEEEP “1 Watt Target” for standby power savings



The savings were expected to be achieved through a number of channels, including star ratings on appliances, provision of information to consumers and inclusion of standby power usage requirements in MEPS for a number of appliances.

ETSA Utilities estimated savings associated with standby power usage have been derived using information presented in Table 24 of AECOM’s background report to ETSA Utilities. That table reports that standby power usage (excluding televisions and air conditioners) averages 83.3 watts per household, compared with a figure of 34 watts assumed to apply once the NAEEEP 1 Watt Target has been achieved. The AECOM report makes an unsubstantiated assertion that all existing appliances will meet the 1 watt standard by 2020. This assertion appears to be the basis for the derivation of ETSA Utilities’ savings estimate.

AEMO has reviewed the original source document underlying Table 24 in AECOM’s report to ETSA Utilities. The information, which relates to standby power consumption in 2005, has been taken from page iii of an EES report to the NAEEEP[2]. The EES report goes on to compare changes in average standby power usage between 2000 and 2005 and comments as follows on the outlook for the future:

> *The data in this report suggests that there is likely to be a significant growth in standby power in Australian households. While there is some uncertainty about the precise rate of*

[2] Energy Efficient Strategies report to the E3 Committee of the NAEEP, *2005 Intrusive Residential Standby Survey Report, March 2006*

growth, it would appear to be a minimum increase of the order of 2.5% per annum per household, which is extremely rapid if this rate persists over a long period. However, this rate could be as high as 5% per annum per household or even higher in absolute terms (total national standby, given continued new household formation). There certainly appears to be a proliferation of products within households that have the potential to use standby power and all evidence suggests that there is rapid growth in the number of products that are connected to the mains and that use some power when not performing their main function.

While most products appear to be improving their standby power consumption attributes over time (new products have lower standby than older products for many product types), this is more than offset by the increase in the number of products connected to the mains in an average house.

AEMO concludes from these comments that the NAEEEP 1 Watt Policy is not presently meeting its objectives and finds no support for the view that the targets will be achieved by 2020, as assumed in ETSA Utilities' submission. In fact quite the contrary would appear to be occurring in this area of electricity consumption, with additional sales due to connecting increasing numbers of appliances that use standby power likely to outstrip any savings associated with improvements in the standby efficiency of some appliance types.

(c) Federal home insulation program and the South Australia Residential Energy Efficiency Scheme

The Australian Government implemented a policy supporting the installation of home insulation throughout Australia as part of its February 2009 economic stimulus package. Some energy savings are likely to be associated with this program.

The South Australian Residential Energy Efficiency Scheme (REES) imposes obligations on retailers to reduce greenhouse gas emissions attributable to residential customers, 35% of whom must be low income households. Energy savings are expected to be achieved through behavioural changes resulting from consumer advice and audits, and through offering incentives that would partially cover the cost of energy saving initiatives such as installing insulation, more efficient lighting or more efficient water heating appliances.

ETSA Utilities has identified large energy savings in respect of these two programs. AEMO believes that adjustments to its forecasts are not required for the following reasons.

- South Australia already has a high penetration of home insulation and, where it is installed under the new program, customers may elect to take the benefits in the form of greater comfort levels as opposed to energy savings.
- Rising penetration of insulation and consumer programs supporting energy audits and related advice have occurred in the past, indicating that these effects are likely to be captured to some extent within past trends and relationships in the historic data.

- Energy efficiency gains in relation to tighter lighting MEPS and water heating loads are already recognised in the forecasts as stand-alone items.
- The sales and demand forecasts include a consumer response to rising electricity prices. These types of programs reflect the means by which such price responses will be achieved and they should not be accounted for a second time.

3. AEMO's sales and peak demand forecasts

3.1 Sales forecasts by customer category

AEMO's annual sales forecasts by customer category for years 2009-10 to 2014-15 are shown in Table 3 for the base, high and low economic scenarios prepared by KPMG. Total sales are projected to increase at an annual average rate of 2.9% between 2009-10 and 2014-15 for the base case economic scenario.

Table 3: Sales forecasts by customer category (GWH)

	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	AVE ANN GROWTH %
Business							
Base	6,935.7	7,367.9	7,515.8	7,727.7	7,960.9	8,255.9	3.5
High	7,030.0	7,519.5	7,703.5	7,960.5	8,308.8	8,767.4	4.5
Low	6,819.7	7,164.1	7,250.0	7,494.2	7,738.6	8,005.9	3.3
Residential							
Base	3,541.4	3,624.2	3,617.3	3,668.4	3,691.1	3,743.3	1.1
High	3,542.4	3,626.7	3,619.1	3,667.1	3,687.3	3,741.4	1.1
Low	3,537.0	3,611.9	3,569.7	3,611.0	3,617.7	3,667.5	0.7
Water heating							
Base	636.7	613.9	592.4	571.9	552.5	534.1	-3.5
High	638.5	616.1	595.0	575.0	556.1	538.2	-3.4
Low	636.2	613.3	591.6	571.0	551.4	532.8	-3.5
Public lighting							
Base	116.0	118.6	121.3	123.9	126.6	129.2	2.2
High	116.0	118.6	121.3	123.9	126.6	129.2	2.2
Low	116.0	118.6	121.3	123.9	126.6	129.2	2.2
Desalination plant							
Base	0.0	143.0	215.0	307.0	307.0	307.0	na
High	0.0	143.0	215.0	307.0	307.0	307.0	na
Low	0.0	143.0	215.0	307.0	307.0	307.0	na
Total							
Base	**11,229.8**	**11,867.6**	**12,061.8**	**12,398.9**	**12,638.0**	**12,969.4**	**2.9**
High	**11,326.9**	**12,024.0**	**12,253.8**	**12,633.6**	**12,985.8**	**13,483.2**	**3.5**
Low	**11,108.9**	**11,650.9**	**11,747.5**	**12,107.1**	**12,341.3**	**12,642.4**	**2.6**

3.2 Annual sales PoE levels

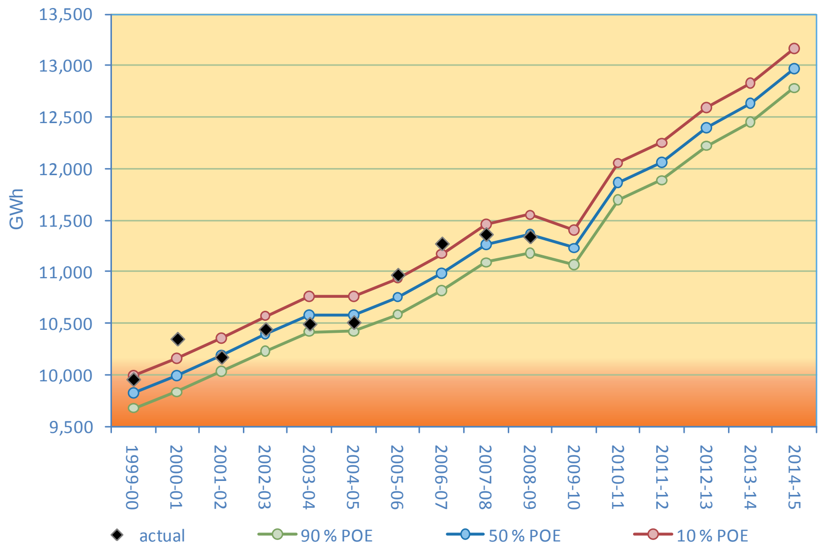
AEMO's total sales forecasts reported in Table 3 are median, or 50% PoE, forecasts for each economic scenario. Subject to the economic assumptions being accurate, actual sales volumes observed in the future may turn out to higher or lower than the median forecasts due to variability in weather conditions each year and because of the inherent randomness in consumers' behaviour.

As part of its forecasting work for AEMO, Monash University has also identified the probability distribution of total annual sales volumes for each year being forecast. These distributions have been created using the same simulation techniques that are applied to identify the probability distribution of annual maximum demands. In this case, however, the integral of simulated annual demand traces is used as the random variable, as opposed to the annual peak.

The forecast annual sales distributions indicate that there is an 80% probability that sales in any year will lie within +/-1.4% to +/-1.6% of the median forecast, subject to the economic assumptions.

Figure 11 shows the forecast 10%, 50% and 90% PoE levels for annual sales for the base case economic assumptions together with historic actual sales and PoE levels. The effect of slowing economic growth in 2009-10, the projected rebound in activity the following year and additional sales associated with the new desalination plant are clearly visible in the figures. The apparent stagnation of actual sales between 2006-07 and 2008-09 is also seen to be a reflection of variability in weather rather than a genuine slowing of underlying growth.

Figure 11: POE levels for base case total annual sales (GWh)



3.3 Sales forecasts by voltage level

Sales forecasts by voltage level are summarised in Table 4. The residential and controlled load projections are identical to the sales forecasts by customer category. Business sales have been distributed across voltage levels in the same proportions assumed by ETSA Utilities in its Proposal. Sales are apportioned across tariff categories at Attachment 2.

Table 4: Sales forecasts by voltage level (GWh)

	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
base case						
Major Business	1,304.9	1,506.1	1,609.9	1,733.4	1,744.1	1,794.5
High Voltage Business	967.9	1,030.8	1,050.5	1,080.7	1,117.8	1,158.9
Low Voltage Business	4,779.0	5,092.5	5,191.7	5,344.5	5,532.5	5,738.6
Residential	3,541.4	3,624.2	3,617.3	3,668.4	3,691.1	3,743.3
Controlled Load	636.7	613.9	592.4	571.9	552.5	534.1
Total sales	**11,229.8**	**11,867.6**	**12,061.8**	**12,398.9**	**12,638.0**	**12,969.4**
high case						
Major Business	1,322.3	1,536.1	1,648.4	1,782.9	1,816.4	1,900.1
High Voltage Business	980.8	1,051.3	1,075.6	1,111.5	1,164.1	1,227.1
Low Voltage Business	4,842.9	5,193.8	5,315.7	5,497.0	5,761.8	6,076.4
Residential	3,542.4	3,626.7	3,619.1	3,667.1	3,687.3	3,741.4
Controlled Load	638.5	616.1	595.0	575.0	556.1	538.2
Total sales	**11,326.9**	**12,024.0**	**12,253.8**	**12,633.6**	**12,985.8**	**13,483.2**
low case						
Major Business	1,283.4	1,465.9	1,555.4	1,683.8	1,697.9	1,742.9
High Voltage Business	952.0	1,003.3	1,014.9	1,049.7	1,088.2	1,125.6
Low Voltage Business	4,700.4	4,956.5	5,015.9	5,191.6	5,386.0	5,573.6
Residential	3,537.0	3,611.9	3,569.7	3,611.0	3,617.7	3,667.5
Controlled Load	636.2	613.3	591.6	571.0	551.4	532.8
Total sales	**11,108.9**	**11,650.9**	**11,747.5**	**12,107.1**	**12,341.3**	**12,642.4**

3.4 Description of AEMO's sales forecasting models

Key features of the models used to develop AEMO's annual sales projections are described in the following sections. Full specification of the models is provided at Attachment 1.

Annual business sales model

The annual business sales model is an OLS regression based on data for years 1989-90 to 2008-09. The driver variables include the SA average retail electricity price (lagged by one year) and two components of industry gross value added (GVA). The driver variables were selected on the basis of 5-year-ahead out-of-sample forecasting performance, regression statistics (R^2 and coefficient t-statistics) and obtaining sensible signs on the coefficients.

Average retail electricity price (lagged) is included as a driver variable as sales are known to be responsive to price changes. The t-statistic for the price variable coefficient is significant at the 2.5% level and the coefficient has the expected sign. Price elasticity changes with the price level and varies between -0.170 and -0.224 for the historic data set used to develop the model. The value estimated at the sample median is -0.188.

Two industry GVA variables are included as this provides a more focussed measure of business sector activity compared with broader-based GSP data. This approach also allows the model to distinguish between activity in different industry sectors.

- Manufacturing sector GVA is included as this sector is believed to be more electrically intense than some other sectors and is unlikely to grow as quickly in the near term as some other sectors.
- GVA aggregated across all other industrial sectors – with the exclusion of those noted below – is included to capture the relationship between electricity demand and non-manufacturing activity. These sectors are generally less electrically intense than manufacturing and may grow more quickly than manufacturing in the near term.
- Mining sector GVA is not included as most mining loads are supplied by electricity generation sources that are not connected to the distribution network.
- Agricultural sector GVA is not included as this varies from year to year with commodity price movements and climate/drought conditions.
- GVA attributable to the ownership of dwelling is not included as this is more closely related to residential sector electricity use.

The coefficients on the two industry GVA driver variables have the expected sign and the t-statistics indicate they are significant. The relative size of the coefficients is as expected, with sales being more responsive to manufacturing GVA than other industrial activity.

The preferred model's forecasting performance was tested by fitting the model to the 15 years of historical data to 2003-04 then forecasting sales levels for the 5 years to 2008-09. The model performed well in producing the 5-year-ahead out-of-sample forecasts, with a mean absolute percentage error (MAPE) for the 5 out-of-sample forecasts of 1.6%.

Annual residential sales model

The residential sales model is a simple OLS regression based on annual data for years 1989-90 to 2008-09. The driver variables include the average retail electricity price (lagged by one year), cooling degree days for the extended summer period 1 October to 31 March, an index value based on the cumulative level of real dwelling investment, and a dummy variable taking the value of 1 from 1998-99 when the national electricity market commenced.

The driver variables were selected on the basis of 5-year-ahead out-of-sample forecasting performance, regression statistics (including R^2 and coefficient t-statistics) and obtaining sensible signs on the coefficients.

The average retail electricity price (lagged) is included as a driver variable as sales are known to be responsive to price changes. The price variable coefficient t-statistic indicates significance at the 1% level and the coefficient has the expected sign. Price elasticity changes with the price level and varies between -0.185 and -0.364 for the data set used to estimate the model. The elasticity estimated at the sample median is -0.236.

Residential sales are also found to be positively correlated with cooling degree days for the extended summer period running from 1 October to 31 March each financial year, and with an index based on the cumulative real value of South Australian dwelling investment. The level of new dwelling investment each year (including alterations and additions) adds to the stock of housing and so it is not surprising that the level of electricity sales grows over time with the cumulative level of housing investment. The coefficient on each of these variables has the expected sign and each is significant at the 1% level.

It is unclear why the dummy variable signalling the start of the national electricity market in December 1998 is statistically significant. This may signify a change in the way the underlying sales data was complied after the industry was restructured around this time or it may signify a change in consumer behaviour under the new market arrangements.

The preferred residential annual sales model also performs well in producing 5-year-ahead out-of-sample forecasts, with a MAPE for the 5 out-of-sample forecasts of 2.0%.

Desalination plant

AEMO's sales and demand forecasts have adopted similar assumptions to those used by ETSA Utilities in regard to electricity required to operate Adelaide's new desalination plant. In particular, the plant is assumed to be fully commissioned by 2012-13 with a peak load of 70 MW and an annual energy requirement of just over 300 GWh. This level of energy use assumes the plant operates with a capacity factor of 50%.

AEMO notes that ETSA Utilities' annual sales could be considerably greater than this if the desalination plant were to be operated with a capacity factor of 90% or so, which it should be quite capable of doing.

AEMO contacted SA Water in regard to the reasonableness of these forecasts and has been advised that studies have not yet been completed into the optimal level of operation of the plant or how this might vary with rainfall from year to year.

Annual public lighting sales model

Annual public lighting sales represent a relatively small component of total sales and a simple linear extrapolation has been used to develop AEMO's projections. Past trends indicate that sales increase at an annual average rate of around 2.6 GWh.

Annual water heating sales model

Electricity sold under the South Australian J tariff is used for heating water in storage tanks in residences and commercial premises. For customers with electric-boosted solar hot water units and heat pumps, electricity is used as a reserve heating source when the main source is inadequate to meet the customer's overall needs. The J tariff load is controlled in that timers attached to customers' meters determine when heating elements are switched on and off. The great majority of water heating occurs overnight. At the individual customer level, electricity use varies with ambient temperature and hot water usage.

This sector of the electricity sales market performed in a relatively stable and predictable manner throughout the 1990's, however, significant structural changes have been occurring since 2001-02. Although total customer numbers have been rising, total sales have fallen markedly, reflecting a decline in average usage per customer.

Part of the variation in average usage per customer reflects changes in the weather from year to year. However, it has not been possible to model this type of relationship in a meaningful way as reliable estimates of the number of customers are not available over a long period. The water heating sales forecasts therefore ignore short term weather influences and focus instead on the longer term drivers determining sales volumes. These longer term influences include demographic, economic and policy drivers.

Further details regarding AEMO's forecasting assumptions for the water heating load are provided in Attachment 1.

3.5 Distribution network peak demand forecasts

AEMO's distribution network peak demand forecasts for the base, high and low growth assumptions are set out in Table 5. The forecasts are consistent with the sales projections presented earlier, in that all of AEMO's forecasts are developed within a common modelling framework that simultaneously identifies both annual sales and peak demand levels.

The peak demand forecasts are presented on a probability of exceedence basis, as the actual peak observed in any year is dependent on prevailing weather conditions throughout summer and other random influences such as the timing and duration of hot spells and variability in underlying customer behaviour.

The peak demand forecasting methodology develops projections of the entire probability distribution of annual peaks for each year. These distributions have been used to identify the 90%, 50%, 10% and 2% PoE levels reported in Table 5. A 10% PoE forecast has a one-in-ten chance of being exceeded, while a 50% PoE forecast has a one-in-two chance of being exceeded.

Importantly, the peak demand forecasts also assume that the new Adelaide desalination plant is operating at its full capacity of 70 MW in 2012-13 and later years. It is possible, however, that SA Water may make this demand available under a demand management contract at times of peak demand on the distribution network in the southern suburbs.

Table 5: AEMO's peak demand forecasts to 2014-15 (MW)

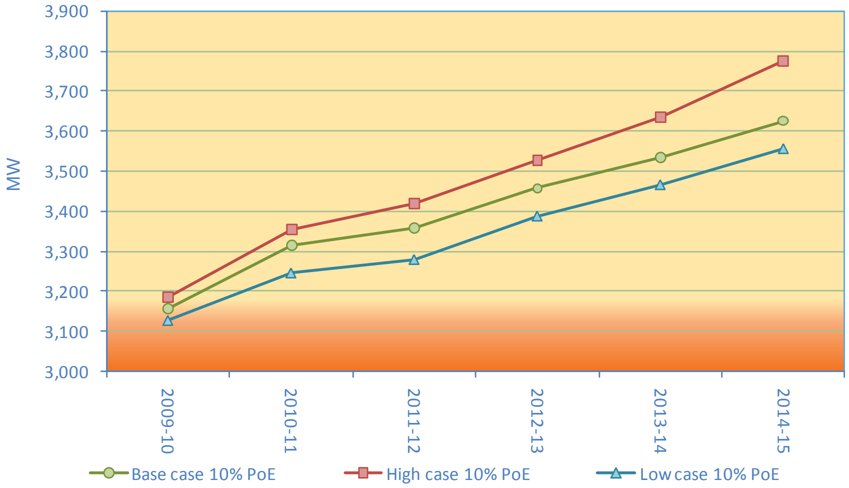
	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Base case						
90% PoE	2,756	2,885	2,928	3,017	3,085	3,165
50% PoE	2,946	3,095	3,138	3,227	3,295	3,385
10% PoE	3,156	3,315	3,358	3,457	3,535	3,625
2% PoE	3,326	3,485	3,538	3,637	3,725	3,825
High case						
90% PoE	2,776	2,925	2,978	3,077	3,175	3,305
50% PoE	2,976	3,135	3,188	3,297	3,395	3,525
10% PoE	3,186	3,355	3,418	3,527	3,635	3,775
2% PoE	3,346	3,525	3,588	3,697	3,815	3,965
Low case						
90% PoE	2,726	2,835	2,858	2,957	3,025	3,105
50% PoE	2,916	3,035	3,058	3,157	3,235	3,315
10% PoE	3,126	3,245	3,278	3,387	3,465	3,555
2% PoE	3,296	3,425	3,458	3,567	3,645	3,745

The base case 10% PoE demand level is projected to increase by 469 MW between 2009-10 and 2014-15, or 2.8% average annual growth. This is slightly less than the 2.9% average annual growth projected for total sales under the base case assumptions over the same period, reflecting the impact of the new desalination plant which is likely to have a better than average load factor.

The high growth economic assumptions show the 10% PoE peak demand level increasing by 589 MW over the six years to 2014-15, equating to an average annual increase of 3.5%. The low case assumptions show smaller growth of 429 MW over the period, or 2.6% average annual growth.

AEMO's base, high and low case 10% PoE peak demand forecasts to 2014-15 are compared in Figure 12.

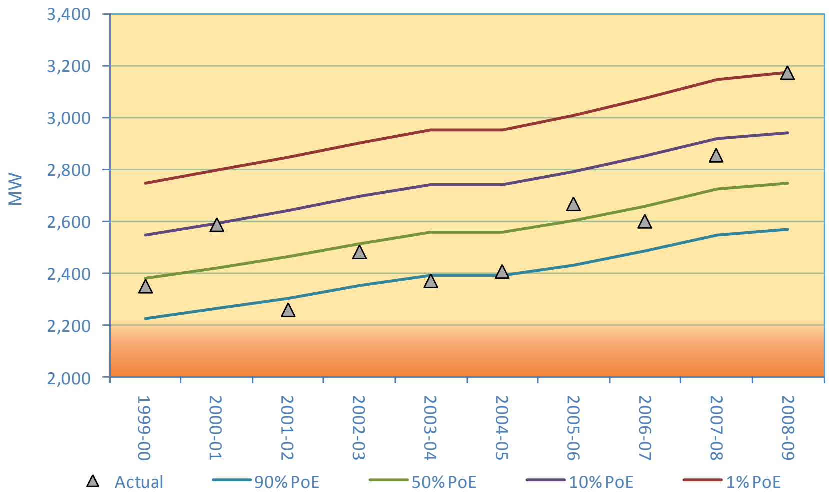
Figure 12: 10% PoE peak demand forecasts



3.6 Recent historic peak demand PoE outcomes

As part of the model validation process, Monash University identifies historic peak demand probability distributions. These distributions provide estimates of the PoE level of recent actual peak demand outcomes. Figure 13 shows the estimated 1%, 10%, 50% and 90% PoE levels for years since 1999-00 and actual peak demands for those years.

Figure 13: Historic distribution network peak demand and PoE levels



The 2008-09 summer peak is estimated to be a 1% PoE outcome, which is consistent with the extreme temperatures experienced during the January-February 2009 heatwave. That period saw a range of temperature variables in South Australia exceed one-in-fifty or one-in-one hundred year levels and completely new records were set in a number of areas.

3.7 Description of AEMO's peak demand forecasting models

AEMO's South Australian peak demand forecasting models have been developed in conjunction with Monash University over a number of years and build upon earlier demand forecasting research sponsored by the ESIPC.

The modelling framework, which is described in detail in Monash University's report on distribution network forecasts for AEMO, has been used in past years to prepare electricity forecasts for South Australia's Annual Planning Report and the Statement of Opportunities.

Monash University's modelling framework has a number of components:

- Linear regression models are used to forecast the annual (average) level of sales using economic and climate driver variables.
- Non-parametric models are used to forecast standardised demand levels for each of the 48 half hourly trading intervals in a day using half hourly temperatures at two sites near Adelaide and various calendar and time of year variables.
- These models are used in conjunction with the specified economic scenarios and 1,000 simulated temperature traces to simulate half hourly electricity demand traces for each year being forecast.
- Adjustments are made to the simulated temperature traces to capture the effects of climate change.
- Model residuals (adjusted for bias) are re-sampled and added to forecast demand traces as part of the simulation process to capture the unexplained or random component of demand.
- Annual peak demands and energy volumes are identified for each simulated load trace and used to create probability distributions for the variables being forecast. The forecasts for various PoE levels are then identified from these distributions.
- Post model adjustments are applied to reflect the impact of energy efficiency policies or any large new loads. Adelaide's new desalination plant has been treated in this way in developing the distribution network forecasts and it is not included in the forecasts shown in Monash University's report to AEMO.

Monash University's usual demand forecasting framework has been adapted in several ways to meet the specific needs associated with preparing forecasts for the distribution network. In particular:

- The models are usually used to forecast overall South Australian electricity demand, whereas the peak demand variable being forecast for this report is total distribution network demand (being the sum of all of ETSA Utilities' transmission connection point loads adjusted to add back load curtailment activity and embedded generation). Monash University's models were re-estimated using historic connection point load data for the period 1 July 1999 to 30 June 2009.

- Monash's usual models are used to develop probabilistic forecasts of South Australia's total annual energy volume. However, AEMO's work for the AER requires annual sales forecasts split by customer sector. This requirement has been met by developing sector-specific annual sales models and using the output of these models, adjusted for network losses, as the annual component of the modelling framework.

Monash University's report to AEMO describing its South Australian distribution network demand and energy forecasts has been provided to the AER as a supporting document to this report.

4. AEMO's forecasts using ETSA Utilities' assumptions

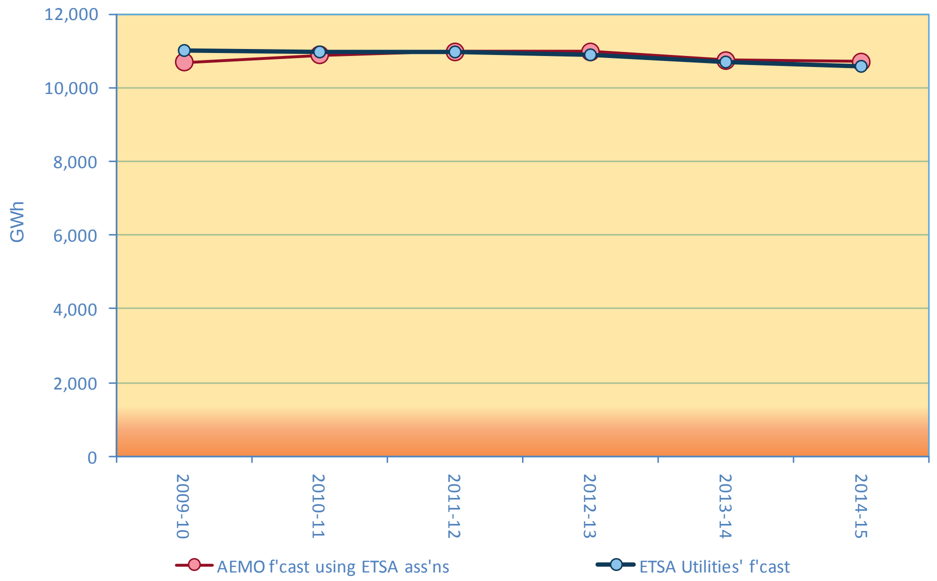
This section of the report compares ETSA Utilities' sales and demand forecasts with a set of forecasts prepared by AEMO using ETSA Utilities' economic and related assumptions, including its assumptions in relation to energy efficiency effects.

This comparison provides an indirect evaluation of the underlying forecasting models relied upon by ETSA Utilities. If AEMO's models produce similar electricity forecasts to ETSA Utilities' electricity forecasts when ETSA Utilities' macroeconomic assumptions are applied, it is reasonable to conclude that the models work in a broadly similar fashion for all practical purposes, regardless of how ETSA Utilities' models are actually constructed.

4.1 Customer sales forecasts

Figure 14 compares ETSA Utilities' total sales forecasts, as submitted in its Regulatory Proposal, with forecasts prepared by AEMO using the same macroeconomic outlook and energy efficiency effects assumed by ETSA Utilities. There is a small difference of 2.8% between the forecasts for the 2009-10 year. The forecasts are almost identical for the remaining years to 2014-15, with differences ranging between +/-1%. ETSA Utilities' sales forecasts show average annual growth of minus 0.7% between 2009-10 and 2014-15. In comparison, AEMO's forecasts using ETSA Utilities' assumptions show average annual growth of 0.0% over this period.

Figure 14: Comparison of sales forecasting model outputs



AEMO is satisfied that its own sales forecasting models and the models relied upon by ETSA Utilities operate in a broadly similar manner for all practical purposes, regardless of how ETSA Utilities' models are actually constructed. Significant differences between the sales forecasts submitted by ETSA Utilities and AEMO's sales forecasts based upon KPMG's economic outlook therefore reflect differences in the input assumptions (including post model adjustments) rather than underlying modelling differences.

Table 6 provides a more detailed comparison of the components of the two sets of forecasts.

Table 6: Detailed components of sales forecasting model output (GWh)

	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Business						
AEMO f'cast using ETSA ass'ns	6,491.9	6,603.9	6,742.0	6,748.8	6,655.6	6,695.7
ETSA Utilities' forecast	6,728.9	6,716.1	6,778.4	6,733.2	6,657.1	6,696.0
Residential						
AEMO f'cast using ETSA ass'ns	3,497.9	3,473.3	3,421.3	3,359.8	3,278.3	3,241.0
ETSA Utilities' forecast	3,556.4	3,465.5	3,392.6	3,304.5	3,214.9	3,130.2
Water heating						
AEMO f'cast using ETSA ass'ns	591.9	535.9	483.8	432.7	382.7	333.9
ETSA Utilities' forecast	591.9	535.9	483.8	432.7	382.7	333.9
Public lighting						
AEMO f'cast using ETSA ass'ns	113.9	116.8	119.6	122.6	125.7	128.8
ETSA Utilities' forecast	113.9	116.8	119.6	122.6	125.7	128.8
Desalination plant						
AEMO f'cast using ETSA ass'ns	0.0	143.0	215.0	307.0	307.0	307.0
ETSA Utilities' forecast	0.0	143.0	215.0	307.0	307.0	307.0
Total sales						
AEMO f'cast using ETSA ass'ns	10,695.6	10,872.9	10,981.7	10,971.0	10,749.4	10,706.4
ETSA Utilities' forecast	10,991.1	10,977.3	10,989.5	10,900.0	10,687.5	10,595.9

4.2 Distribution network peak demand forecasts

ETSA Utilities' Regulatory Proposal includes peak demand forecasts for individual transmission connection points as well as peak demand forecasts for the distribution network as a whole. The Regulatory Proposal does not, however, attempt to reconcile the two sets of forecasts prepared by ETSA Utilities.

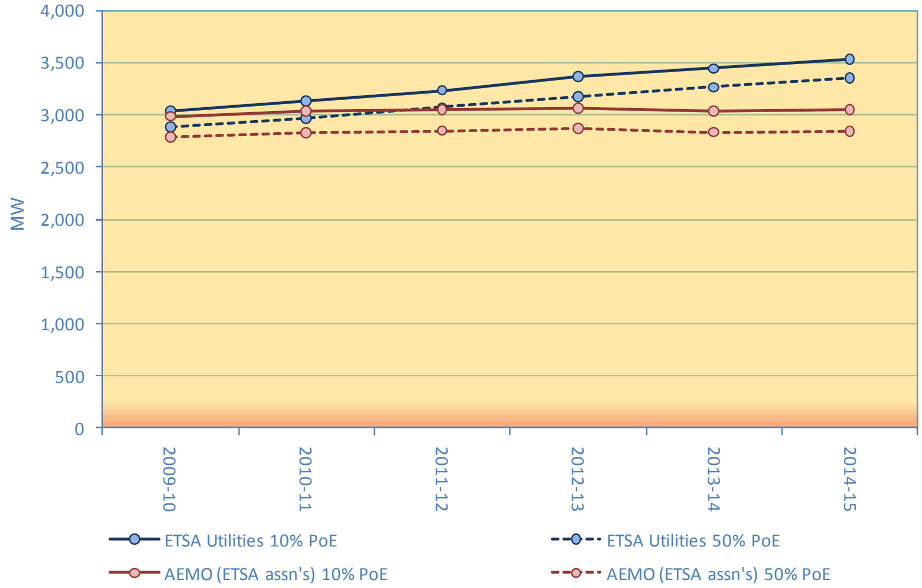
In the following section of this report, AEMO presents a reconciliation of its own distribution network peak demand forecasts with ETSA Utilities' transmission connection point peak demand forecasts. This section of the report compares the overall distribution network peak demand forecasts submitted by ETSA Utilities with equivalent forecasts prepared by AEMO using ETSA Utilities' input assumptions.

ETSA Utilities' distribution network peak demand forecasts do not cover the entire network, but exclude "major price sensitive customers" and the controlled water heating load, whereas AEMO's forecasts include all customers connected to the distribution network.

In comparing the two sets of forecasts, AEMO has therefore adjusted ETSA Utilities' forecasts to include all customers connected to the network. In particular, AEMO has applied an upward adjustment of around 170 MW, plus the assumed peak demand of the new desalination plant, to each of ETSA Utilities' forecasts to place them on a comparable footing. The value of 170 MW reflects the diversified peak demand of major price sensitive customers referred to in the Regulatory Proposal documentation. AEMO has not made any adjustment to add back the water heating load as this will be very small at the time of peak demand.

Figure 15 compares ETSA Utilities' (adjusted) 10% and 50% PoE peak demand forecasts with AEMO's model outputs when the same input assumptions and efficiency effects are used.

Figure 15: Comparison of peak demand forecasting model outputs



This comparison indicates that significant differences exist between AEMO's models and the peak demand forecasting models relied upon by ETSA Utilities. In particular:

- ETSA Utilities' 10% PoE peak demand forecast in 2014-15 is almost 500 MW, or 16%, higher than AEMO's equivalent forecast;

- AEMO's forecasts show the 10% PoE level of demand rising by 0.4% on average each year between 2009-10 and 2014-15, which is broadly in line with AEMO's annual average sales growth of 0% over this period;
- in comparison, ETSA Utilities' forecasts show the 10% PoE demand level rising by 3.1% on average each year, which is quite different from the average annual decline of 0.7% which ETSA Utilities has forecast for its total sales volumes during the same period.

Insufficient detail is available to AEMO to comment in depth on the underlying peak demand modelling approach used by ETSA Utilities and the reasons for the differences in the forecasts noted above. However, the following general observations may be made in relation to the models.

- AEMO's South Australian forecasts are developed within a common modelling framework which has been designed to ensure consistency between its sales and peak demand forecasts. It is unclear how ETSA Utilities' sales and peak demand forecasts relate to one another.
- The peak demand forecasting models used by ETSA Utilities apportion historic demand observations between an estimated "base load" component and a residual "temperature sensitive" component and each is projected forward separately using different driver variables. Monash University's modelling approach is similar but not identical, in that the annual average level of demand is projected forward using economic, climate and price variables, while the temperature sensitive component is modelled as the ratio of demand in any half hour to the average level.
- ETSA Utilities' models use forecasts of air conditioner sales as a driver variable, while Monash University has found that the stock of air conditioning is not a significant explanatory variable, given that other more (statistically) significant variables are included in their models. ETSA Utilities' forecasts therefore include an extra layer of uncertainty, in that air conditioner sales must be forecast as an intermediate step within the overall forecasting process.
- A key part of AEMO's ongoing South Australian forecasting methodology development involves extensive analysis of the performance of its past forecasts. As part of this process, Monash University developed new techniques for evaluating its forecasts, including methods to evaluate the accuracy of the projected probability distributions generated through the demand simulation processes. The supporting documentation provided with ETSA Utilities' Proposal indicates that its consultant has attempted to apply a similar evaluation methodology to its own South Australian models, however the documentation as provided suggests that Monash's evaluation techniques have not been interpreted correctly. In particular, Monash has proposed comparing the forecast and actual distribution of weekly peak demands falling within a particular summer as a measure of model accuracy. Importantly, each of these weekly peaks comes from a common probability distribution applying to that

particular summer. ETSA Utilities' consultant, in evaluating its South Australian models, has instead analysed the modelled PoE level of annual peaks occurring over a number of different summers. Each of these peaks come from a different probability distribution which is unique to each year. While this type of analysis is useful in its own right, and is undertaken as a part of Monash's regular review of its models, the correct way to proceed with such an evaluation is to compare the pattern of outcomes with probabilities derived from the binomial distribution. This has not been done by ETSA Utilities' consultant, and in any event, is a quite different evaluation technique to that developed and used by Monash University. It is therefore unclear to AEMO if the model validation techniques used by ETSA Utilities' consultant are reliable in the context of its South Australian forecasts.

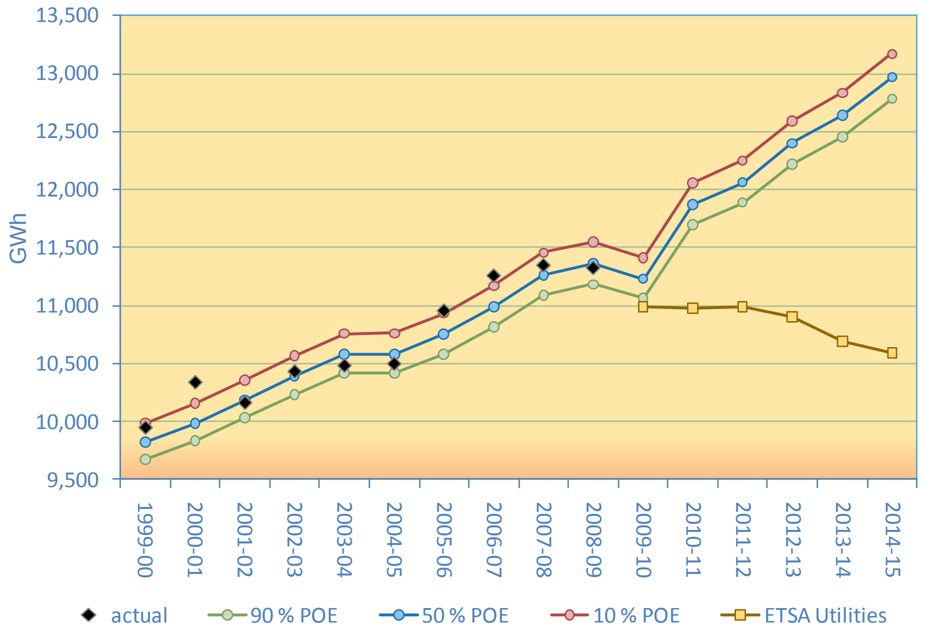
5. Comparison of AEMO's and ETSA Utilities' forecasts

This section of the report compares AEMO's and ETSA Utilities' annual sales and network-wide peak demand forecasts and presents a reconciliation of AEMO's peak demand forecasts with the individual connection point forecasts submitted by ETSA Utilities.

5.1 Annual sales forecasts

Figure 16 compares AEMO's 10%, 50% and 90% PoE sales forecasts using KPMG's base case economic assumptions with ETSA Utilities' total annual sales forecasts to 2014-15. The figure also shows past actual sales and associated PoE levels estimated by AEMO.

Figure 16: Total distribution network annual sales



The two sets of forecasts show a materially different outlook to 2014-15:

- ETSA Utilities' total sales forecast for the 2014-15 year is 2,374 GWh (18.3%) lower than AEMO's base case 50% PoE forecast for that year; and
- ETSA Utilities' forecasts imply average annual growth of -0.7% between 2009-10 and 2014-15 compared with AEMO's forecasts for growth of 2.9% over this period.

As reported in the previous section, these differences largely reflect the use of different economic assumptions (including assumptions in respect of energy efficiency savings) rather than effective underlying modelling differences.

Table 7 compares the major components of ETSA Utilities' and AEMO's total sales forecasts.

Table 7: Components of total sales forecasts (GWh)

	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	AVE ANN GROWTH %
Business							
AEMO high	7,030.0	7,519.5	7,703.5	7,960.5	8,308.8	8,767.4	4.5
AEMO base	6,935.7	7,367.9	7,515.8	7,727.7	7,960.9	8,255.9	3.5
AEMO low	6,819.7	7,164.1	7,250.0	7,494.2	7,738.6	8,005.9	3.3
ETSA Utilities	6,728.9	6,716.1	6,778.4	6,733.2	6,657.1	6,696.0	-0.1
Residential							
AEMO high	3,542.4	3,626.7	3,619.1	3,667.1	3,687.3	3,741.4	1.1
AEMO base	3,541.4	3,624.2	3,617.3	3,668.4	3,691.1	3,743.3	1.1
AEMO low	3,537.0	3,611.9	3,569.7	3,611.0	3,617.7	3,667.5	0.7
ETSA Utilities	3,556.4	3,465.5	3,392.6	3,304.5	3,214.9	3,130.2	-2.5
Water heating							
AEMO high	638.5	616.1	595.0	575.0	556.1	538.2	-3.4
AEMO base	636.7	613.9	592.4	571.9	552.5	534.1	-3.5
AEMO low	636.2	613.3	591.6	571.0	551.4	532.8	-3.5
ETSA Utilities	591.9	535.9	483.8	432.7	382.7	333.9	-10.8
Public lighting							
AEMO high	116.0	118.6	121.3	123.9	126.6	129.2	2.2
AEMO base	116.0	118.6	121.3	123.9	126.6	129.2	2.2
AEMO low	116.0	118.6	121.3	123.9	126.6	129.2	2.2
ETSA Utilities	113.9	116.8	119.6	122.6	125.7	128.8	2.5
Desalination plant							
AEMO high	0.0	143.0	215.0	307.0	307.0	307.0	na
AEMO base	0.0	143.0	215.0	307.0	307.0	307.0	na
AEMO low	0.0	143.0	215.0	307.0	307.0	307.0	na
ETSA Utilities	0.0	143.0	215.0	307.0	307.0	307.0	na
Total sales							
AEMO high	11,326.9	12,024.0	12,253.8	12,633.6	12,985.8	13,483.2	3.5
AEMO base	11,229.8	11,867.6	12,061.8	12,398.9	12,638.0	12,969.4	2.9
AEMO low	11,108.9	11,650.9	11,747.5	12,107.1	12,341.3	12,642.4	2.6
ETSA Utilities	10,991.1	10,977.3	10,989.5	10,900.0	10,687.5	10,595.9	-0.7

Significant differences exist in the business sales and residential sales forecasts, reflecting the different economic outlook and efficiency effects assumed by ETSA Utilities. The majority of the differences relate to differences in the economic outlook.

- AEMO's business sector forecasts show average annual growth of 3.5% to 2014-15 compared with ETSA Utilities' forecasts which show average growth of -0.1%.
- AEMO's residential sector sales forecasts show average annual growth of 1.1% compared with ETSA Utilities' average growth rate of -2.5%.

Smaller but material differences are also apparent in the water heating forecasts.

AEMO's water heating sales forecasts are based on a model which reasonably replicates historic sales and customer numbers over the past five years. This period has seen significant structural change in this market sector as customers' preferences have switched towards gas and solar-electric water heating units. AEMO's historic model identified a slower effective rate of replacement of electric storage heaters and higher average consumption of electricity than assumed by ETSA Utilities in preparing its forecasts. AEMO's model assumes these recently observed parameters continue to apply in the future, with the result that AEMO's sales forecasts are somewhat higher than ETSA Utilities' forecasts. ETSA Utilities' forecasts effectively assume a break with recent trends and accelerating structural change in this market sector, as reflected in the following comparative growth rates:

- annual growth during the 12 years to 2001-02 averaged around 0.8%;
- growth during the 6 years to 2008-09 averaged around -2.6%;
- AEMO's forecasts show growth averaging -3.5% to 2014-15; and
- ETSA Utilities' forecasts show growth averaging -10.8% to 2014-15.

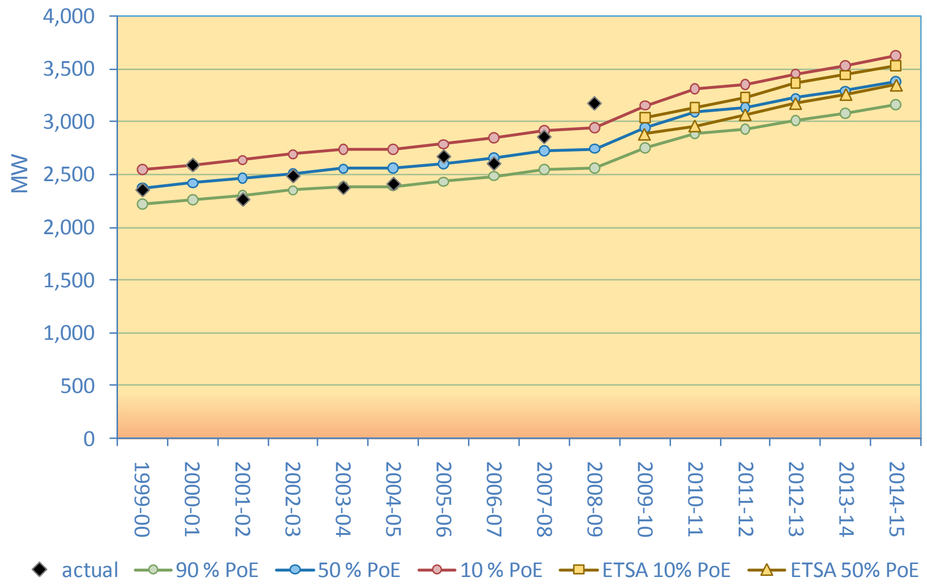
AEMO's sales forecasts regarding the desalination plant and public lighting are similar to ETSA Utilities' forecasts.

Considerable uncertainty surrounds the energy requirements of the desalination plant and AEMO has adopted ETSA Utilities' assumptions for this plant in the absence of clearer advice from SA Water. It is quite feasible that energy used by the desalination plant could be almost double that shown in the forecasts, which assume a load factor of only 50% for the plant.

5.2 Network wide peak demand forecasts

Figure 17 compares AEMO's 10%, 50% and 90% PoE base case peak demand forecasts with ETSA Utilities' 10% and 50% PoE forecasts. The figure also shows past actual peak demand and PoE levels estimated by AEMO. ETSA Utilities' forecasts have been adjusted by AEMO to include major price sensitive customers and the desalination plant, both of which are excluded from the demand forecasts reported in ETSA Utilities' submission.

Figure 17: Distribution network peak demand levels



AEMO's and ETSA Utilities' network-wide peak demand forecasts are reasonably close for most years throughout the forecast period, which is surprising given the very different economic assumptions underlying the two sets of forecasts. As indicated in the previous section, AEMO's demand forecasting models produce quite different peak demand forecasts compared with ETSA Utilities' forecasts when ETSA Utilities' macroeconomic assumptions are used as driver variables for AEMO's models.

- AEMO's 10% PoE demand forecast for the 2014-15 summer is 93 MW above ETSA Utilities' forecast. There is a smaller difference of 33 MW at the 50% PoE level.
- ETSA Utilities' 10% PoE forecasts show compounding growth of 3.1% between 2009-10 and 2014-15 compared with AEMO's forecasts which show growth of 2.8%.

Table 8: Comparison of 50% and 10% PoE peak demand forecasts (MW)

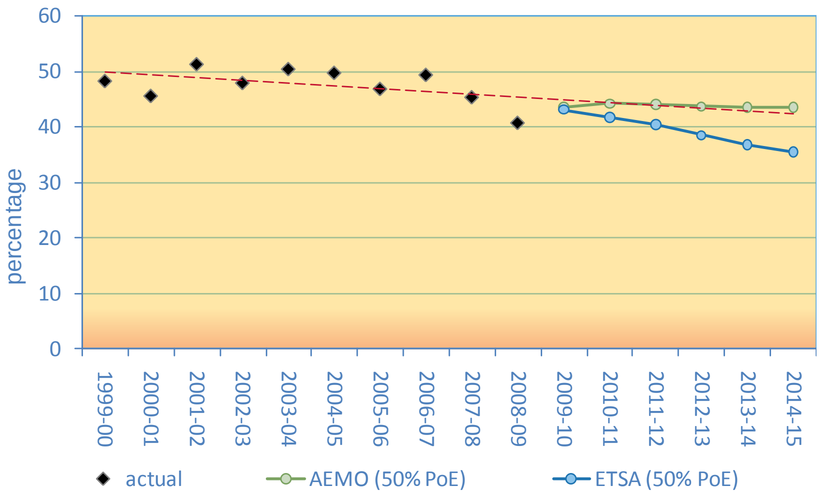
	AEMO 50 % POE	AEMO 10 % POE	ETSA 50% POE	ETSA 10% POE	50% POE VAR'N	10% POE VAR'N
2009-10	2,946	3,156	2,886	3,036	-60	-120
2010-11	3,095	3,315	2,965	3,135	-130	-180
2011-12	3,138	3,358	3,071	3,235	-67	-123
2012-13	3,227	3,457	3,178	3,367	-49	-90
2013-14	3,295	3,535	3,264	3,444	-31	-91
2014-15	3,385	3,625	3,352	3,532	-33	-93
Ave annual growth (%)	2.8	2.8	3.0	3.1		

5.3 Distribution system load factor

The system load factor is the ratio of average demand to peak demand expressed as a percentage. As well as indicating the intensity of use of the network, the load factor also provides an indication of the relative growth of the summer peak compared to growth of annual sales. A falling load factor indicates that peak demand is rising more quickly than sales, which has tended to be the experience in South Australia over the past decade or so.

Figure 18 shows the actual South Australian distribution network load factor for each of the ten years to 2008-09 and the load factors implied by AEMO's and ETSA Utilities' annual sales and 50% PoE peak demand forecasts to 2014-15. (50% PoE values are used because these represent the median expectation and will more closely reflect the typical experience over a number of years.) The figure also shows the linear trend-line associated with past actual load factors. Loads associated with the desalination plant have been excluded from the derivation of the projected load factors.

Figure 18: Actual and projected distribution system load factors



AEMO's sales and demand forecasts imply that the load factor will continue to fall in the future substantially in line with the trend rate of decline observed since 1999-00. In comparison, ETSA Utilities' forecasts show the load factor falling much more quickly to be around 20% (or 8 percentage points) below trend by 2014-15. Given that AEMO's and ETSA Utilities' peak demand forecasts for 2014-15 are broadly in line with one another, this difference is largely attributable to the lower level of annual sales forecast by ETSA Utilities.

5.4 ETSA Utilities' connection point peak demand forecasts

As part of a pre-lodgement review of ETSA Utilities' spatial demand forecasting processes for the AER, AEMO (then the ESIPC) advised that it is not in a position to comment directly on individual connection point peak demands, but instead would conduct an indirect evaluation by considering if ETSA Utilities' connection point peak demand forecasts are consistent with AEMO's network-wide peak demand projections.

The evaluation recognises that the level of peak demand on any individual connection point may be greater than its contribution to the network-wide peak due to diversity in the timing of loads. For example, loads in predominantly industrial areas are likely to peak earlier in the afternoon than loads in predominantly residential areas. The overall system-wide peak may occur at a different time to individual peaks on different parts of the network.

A diversity factor represents the ratio of demand at a particular connection point at the time of the network-wide peak to the outright peak demand occurring at that point. The diversity factor will be unity if the connection point peaks at the same time as the system, and less than unity if it peaks at a different time.

Estimated diversity factors from the 2008-09 summer heatwave period have been applied to ETSA Utilities' connection point peak demand forecasts and the sum of these adjusted demands compared with AEMO's peak demand forecasts. This comparison provides an indication of whether the connection point forecasts in aggregate are broadly consistent with AEMO's peak demand forecasts. The evaluation assumes that recently observed diversity factors remain unchanged in the future.

The 2008-09 summer was exceptional in that the network-wide peak on 29 January is estimated to have been approximately a 1% PoE outcome. This type of outcome is expected only once in every one hundred years on average and has not been seen before in the South Australian electricity data available to AEMO.

Diversity factors are likely to change with the extremity of the level of demand - progressively higher system-wide demands during heatwaves are driven in part by the convergence of diversity factors towards unity. Accordingly, AEMO has identified two sets of diversity factors to conduct its evaluation:

- one set has been derived from connection point loads observed at the time of the 1% PoE system-wide peak on 29 January. As these diversity factors are associated with a very low PoE level of demand, they have been used to compare ETSA Utilities' spatial forecasts with AEMO's 2% PoE peak demand forecasts (1% PoE forecasts are not available);
- a second set of diversity factors has also been identified for 10% PoE demand conditions and used to compare ETSA Utilities' forecasts with AEMO's 10% PoE peak demand forecasts. Demand was very near to the 10% PoE level on a number of occasions throughout the 2008-09 summer. AEMO has used the average diversity factor observed during the afternoons of 29 and 30 January and on 6 February when network-wide demand was within several MW's of the 10% PoE level.

Figure 19: Connection point demands and 10% PoE network demand forecasts

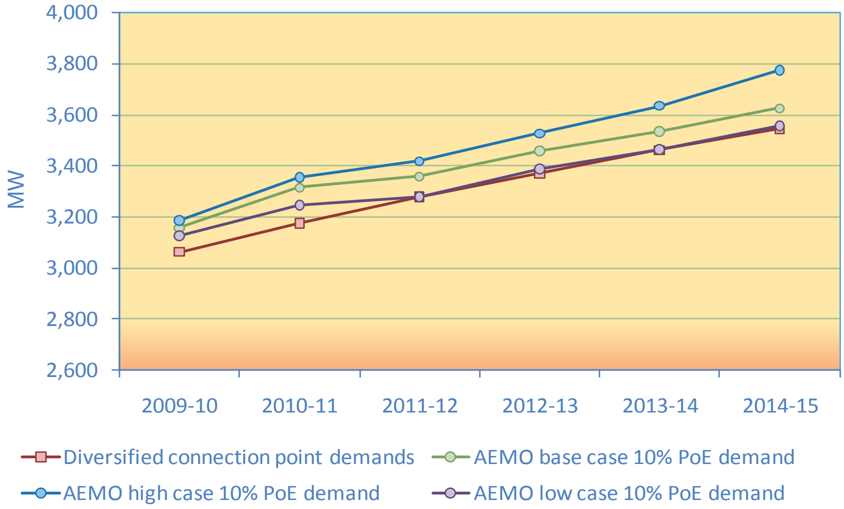


Figure 19 indicates that the connection point forecasts, adjusted for diversity experienced at the 10% PoE demand level, are broadly consistent with AEMO's peak demand forecasts and lie towards the bottom of the high-low range predicted under the three economic scenarios developed by KPMG. The adjusted connection point forecasts are around 90 MW on average below AEMO's base case 10% PoE forecasts. AEMO considers this to be a tolerable discrepancy and within the range of error that might be associated with inherent variability of load diversity across various points within the network.

Figure 20: Connection point demands and 2% PoE network demand forecasts

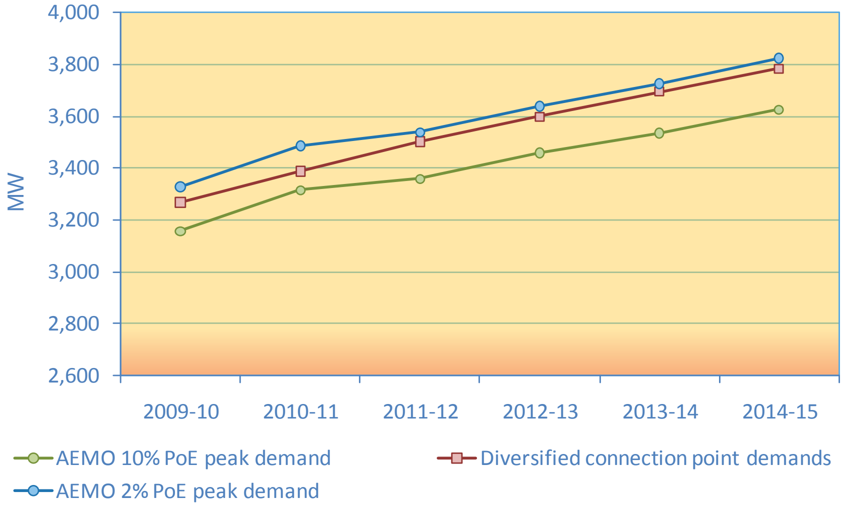


Figure 20 presents a similar comparison, this time between AEMO's 2% and 10% PoE base case forecasts and ETSA Utilities' connection point forecasts after adjusting for diversity factors observed at the time of the 1% PoE peak demand event on 29 January. This chart is interesting in that it indicates that the network may be able to cope with system-wide peak demands near to the 2% PoE level under certain circumstances. (Indeed, the network connection points were able to withstand the 1% PoE State-wide demand level seen on 29 January 2009.) However, this does not necessarily imply that the network is being constructed to a 1% or 2% PoE planning standard. Rather, it implies that a system-wide 2% PoE demand level, when driven by convergence of diversity which occurs under widespread extreme temperature conditions such as observed on 29 January 2009, should be able to be accommodated by the network.

Figure 19 indicates that the adjusted connection point forecasts are consistent with AEMO's 10% PoE peak demand forecasts. AEMO also conducted a pre-lodgement review of ETSA Utilities' data sources and approach to compiling its spatial demand forecasts at three different levels within the distribution network and its approach to reconciling these forecasts with one another. This was a sound approach that offered a self-checking mechanism to ensure the forecasts are internally consistent with one another and that consistent data had been used in the preparation of the forecasts. AEMO therefore concludes that ETSA Utilities' connection point peak demand forecasts are reasonable.

Attachment 1 – AEMO's annual sales models

This attachment describes in detail the annual sales models and related data used to develop AEMO's sales forecasts for this report. These models were provided to Monash University for incorporation into its overall demand forecasting and simulation processes and replaced the usual annual component of Monash's modelling framework. This approach was necessary as the AER requires sales forecasts by customer sector, which are not normally available as part of the modelling output from Monash's models.

Annual sales and peak demand associated with Adelaide's new desalination plant have been treated separately in developing the forecasts shown in the body of the report and are not covered in the following material.

5.5 Annual model structure

A key requirement of the Distribution network forecasts being prepared for the AER is to identify annual sales volumes by customer category. These forecasts are required in addition to peak demand forecasts for the overall distribution network.

It is also a requirement that both annual sales and peak demand forecasts are prepared on a consistent basis, ideally through use of a single modelling framework to project forward both sales and peak demand levels within the same framework.

Monash's forecasting work undertaken to date uses an annual model which only identifies aggregated sales across all customer types and includes network losses. This framework satisfies the requirement that sales and peak demand forecasts be prepared on a consistent basis but does not provide separate sales forecasts for different customer categories.

The purpose of this attachment is to specify the alternative modelling structure that has been used by Monash and which meets both requirements. This has been achieved by replacing Monash's existing annual model with four separate annual models for the following components of customer sales.

- Annual business sales
- Annual residential sales
- Annual water heating sales
- Annual public lighting sales

Appropriate adjustments are also made in respect of distribution network losses. These and other post model adjustments are described in section 5.7.

The annual average demand level (in GW) used in the half hourly component of Monash's model is the sum of the (loss adjusted) annual sales forecasts from each of the above four models converted to a half hourly average value for the year.

The four annual sales models are described in the following sections. An algebraic summary of the model is shown in section 5.8.

Annual business sales model

The annual business sales model is an OLS regression based on data for years 1989-90 to 2008-09. The driver variables include the SA average retail electricity price (lagged by one year) and two components of industry gross value added (GVA). The driver variables were selected on the basis of 5-year-ahead out-of-sample forecasting performance, regression statistics (R^2 and coefficient t-statistics) and obtaining sensible signs on the coefficients. The historic data and modelling results are summarised in the flowing table and figure.

Table 9: Business sales model – historic data 1989-90 to 2008-09

	DEPENDENT VARIABLE		DRIVER VARIABLES		
	Business sales GWh	Log Business sales (variable used in model)	Yr-1 SA Price cents/kWh (07-08 prices)	Manufacturing GVA $m (06-07 prices)	Other GVA (excl Agric, Mining, Manuf, Dwell Inv) $m (06-07 prices)
1989-90	4,476.407	8.40658	16.879	8,028.000	26,422.000
1990-91	4,521.648	8.41663	15.883	7,970.000	26,621.000
1991-92	4,475.150	8.40630	15.347	7,694.000	25,878.000
1992-93	4,659.018	8.44656	15.744	7,781.000	26,320.000
1993-94	4,834.134	8.48346	15.426	8,069.000	27,384.000
1994-95	5,182.890	8.55312	14.633	8,232.000	28,529.000
1995-96	5,188.048	8.55411	13.435	8,380.000	29,609.000
1996-97	5,125.833	8.54205	12.807	8,603.000	30,610.000
1997-98	5,383.238	8.59105	13.213	8,915.000	31,416.000
1998-99	5,632.859	8.63637	13.235	9,148.000	32,953.000
1999-00	5,910.479	8.68448	13.183	9,231.000	34,304.000
2000-01	6,077.546	8.71236	12.901	9,384.000	35,127.000
2001-02	6,148.900	8.72403	13.930	9,464.000	36,882.000
2002-03	6,321.303	8.75168	14.336	9,646.000	38,336.000
2003-04	6,370.454	8.75943	14.613	9,552.000	39,959.000
2004-05	6,449.851	8.77181	14.767	9,237.000	40,285.000
2005-06	6,654.583	8.80306	14.396	8,926.000	41,299.000
2006-07	6,906.877	8.84027	13.839	8,758.000	42,582.000
2007-08	6,909.608	8.84067	13.292	8,591.000	43,894.000
2008-09 est	6,964.441	8.84857	13.640	8,108.282	45,335.136

Figure 21: Business sales model – regression results and coefficients

Multiple R	0.9917			
R Square	0.9834			
Adjusted R Square	0.9803			
Standard Error	0.0218			
Observations	20.0000			
	df	*SS*	*MS*	*F*
Regression	3.0000	0.4491	0.1497	316.1146
Residual	16.0000	0.0076	0.0005	
Total	19.0000	0.4567		
	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	7.8602407	0.1379792	56.9668420	0.0000000
Yr-1 SA Price 07-08 cents/ kWh	-0.0133754	0.0053896	-2.4817231	0.0245601
Manuf GVA	0.0000306	0.0000103	2.9602982	0.0092109
Other GVA (ex Ag, Mng, Man, Dw)	0.0000206	0.0000010	21.5900202	0.0000000

SA average retail electricity price (lagged) is included as a driver variable as sales are known to be responsive to price changes. The t-statistic for the price variable coefficient is significant at the 2.5% level and the coefficient has the expected sign. Price elasticity changes with the price level and varies between -0.170 and -0.224 for the historic data set used to develop the model. The value estimated at the sample median is -0.188.

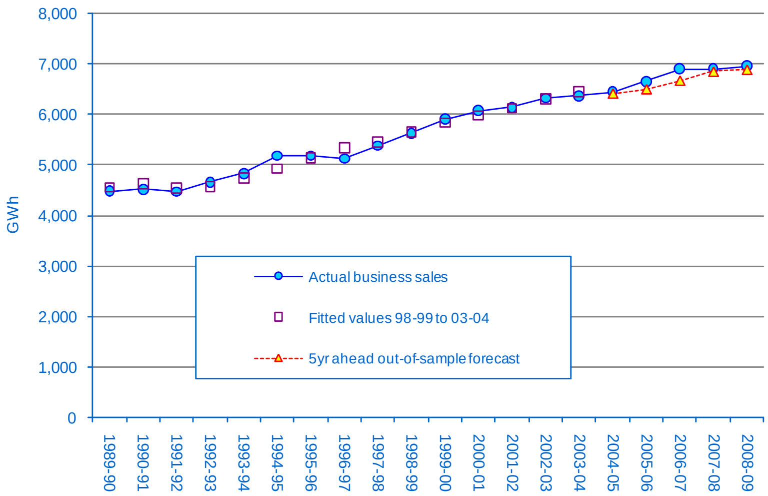
Two industry GVA variables are included as this provides a more focussed measure of business sector activity compared with broader-based GSP data. This approach allows the model to distinguish between activity in different industry sectors.

- Manufacturing sector GVA is included as this sector is believed to be more electrically intense than some other sectors and is unlikely to grow as quickly in the near term as some other sectors.
- GVA aggregated across all other industrial sectors – with the exclusion of those noted below – is included to capture the relationship between electricity demand and non-manufacturing activity. These sectors are generally less electrically intense than manufacturing and may grow more quickly than manufacturing in the near term.
- Mining sector GVA is not included as most mining loads are supplied by electricity generation sources which are not connected to the distribution network.
- Agricultural sector GVA is not included as this varies from year to year with commodity price movements and weather conditions.
- GVA attributable to the ownership of dwellings is not included as this is more closely related to residential sector electricity use.

The coefficients on the two industry GVA driver variables have the expected sign and the t-statistics indicate they are significant. The relative size of the coefficients is as expected, with sales being more responsive to manufacturing GVA than other industrial activity.

The preferred model performs well in producing 5-year-ahead out-of-sample forecasts, as shown in the figure below. The MAPE for the 5 out-of-sample forecasts is 1.6%.

Figure 22: Business sales model – out-of-sample forecasting performance



Annual residential sales model

The residential sales model is a simple OLS regression based on annual data for years 1989-90 to 2008-09. The driver variables include the SA average electricity price (lagged by one year), cooling degree days for the extended summer period 1 October to 31 March, an index value based on the cumulative level of real dwelling investment, and a dummy variable taking the value of 1 from 1998-99 when the national electricity market commenced.

The driver variables were selected on the basis of 5-year-ahead out-of-sample forecasting performance, regression statistics (including R^2 and coefficient t-statistics) and obtaining sensible signs on the coefficients.

The historic data and modelling results are summarised in the flowing table and figure.

Table 10: Residential sales model – historic data 1989-90 to 2008-09

	RESIDENTIAL SALES EXCLUDING HOT WATER GWH	YR-1 SA PRICE CENTS/ KWH (07-08 PRICES)	EXTENDED SUMMER CDD (18.5)	CUMULATIVE DWELLING INVESTMENT INDEX	MARKET START DV
1989-90	2,354.339	16.879	533.100	10,449.000	0
1990-91	2,379.710	15.883	535.500	12,983.000	0
1991-92	2,318.519	15.347	416.775	15,425.000	0
1992-93	2,468.985	15.744	430.700	18,024.000	0
1993-94	2,386.092	15.426	371.425	20,855.000	0
1994-95	2,569.474	14.633	545.300	23,354.000	0
1995-96	2,575.722	13.435	419.600	25,412.000	0
1996-97	2,762.717	12.807	481.475	27,554.000	0
1997-98	2,844.500	13.213	476.525	30,000.000	0
1998-99	3,000.700	13.235	560.475	32,590.000	1
1999-00	3,108.100	13.183	588.000	35,657.000	1
2000-01	3,357.500	12.901	734.600	38,106.000	1
2001-02	3,075.700	13.930	241.550	40,896.000	1
2002-03	3,180.600	14.336	530.300	44,158.000	1
2003-04	3,221.600	14.613	511.000	47,857.000	1
2004-05	3,176.200	14.767	436.075	51,716.000	1
2005-06	3,430.600	14.396	581.950	55,596.000	1
2006-07	3,527.479	13.839	671.325	59,664.000	1
2007-08	3,637.888	13.292	679.300	63,698.000	1
2008-09 est	3,590.566	13.640	546.200	67,714.080	1

Figure 23: Residential sales model – regression statistics and coefficients

Multiple R	0.9929			
R Square	0.9859			
Adjusted R Square	0.9821			
Standard Error	59.7412			
Observations	20.0000			
	df	*SS*	*MS*	*F*
Regression	4.0000	3741185.7709	935296.4427	262.0608
Residual	15.0000	53535.0830	3569.0055	
Total	19.0000	3794720.8540		
	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	2671.7778706	237.1630140	11.2655756	0.0000000
Yr-1 SA Price 07-08 cents/ kWh	-50.7664181	14.2146852	-3.5714064	0.0027842
Ext Sum CDD 18.5	0.5842929	0.1329777	4.3939171	0.0005232
Cum Dwel Inv	0.0158894	0.0014909	10.6575571	0.0000000
Market start DV	231.3358239	49.1069089	4.7108610	0.0002787

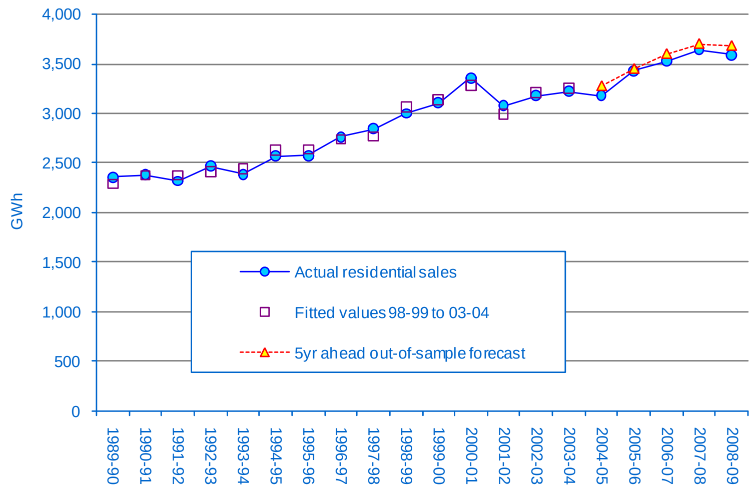
SA average retail electricity price (lagged) is included as a driver variable as sales are known to be responsive to price changes. The price variable coefficient t-statistic indicates significance at the 1% level and the coefficient has the expected sign. Price elasticity changes with the price level and varies between -0.185 and -0.364 for the data set used to estimate the model. The elasticity estimated at the sample median is -0.236.

Residential sales are also found to be positively correlated with cooling degree days for the extended summer period running from 1 October to 31 March each financial year, and with an index based on the cumulative real value of SA dwelling investment. The level of new dwelling investment each year (including alterations and additions) adds to the stock of housing and so it is not surprising that the level of sales grows over time with the cumulative level of investment. The coefficient on each of these variables has the expected sign and each is significant at the 1% level.

It is unclear why the dummy variable signalling the start of the national electricity market in December 1998 is statistically significant. This may signify a change in the way the underlying sales data was complied after the industry was restructured around this time or it may signify a change in consumer behaviour under the new market arrangements.

The preferred residential annual model also performs well in producing 5-year-ahead out-of-sample forecasts, as shown in the following figure. The MAPE for the 5 out-of-sample forecasts is 2.0%.

Figure 24: Residential sales model – out-of-sample forecasting performance



Annual public lighting sales model

Annual public lighting sales represent a relatively small component of total sales and a simple linear extrapolation has been used to develop AEMO's projections. Past trends indicate that sales increase by an average of 2.6 GWh annually. The recent historic data and base case projected sales levels are shown in the following figure. Table 11 summarises the forecasts.

Figure 25: Annual public lighting sales

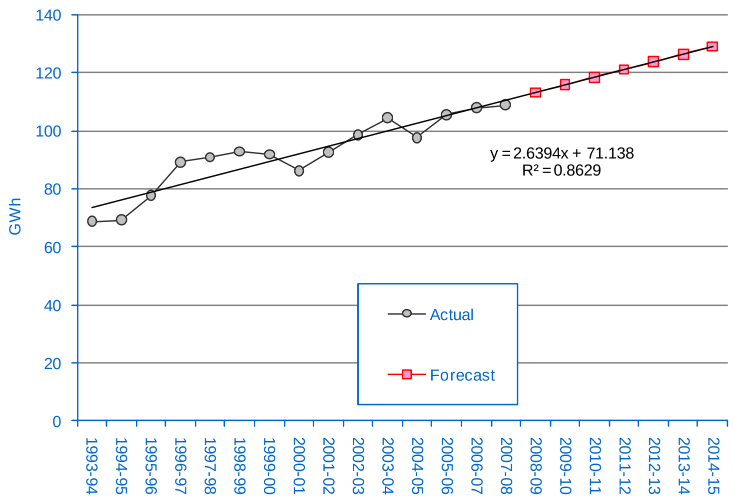


Table 11: Annual public lighting sales (GWh)

	AEMO BASE	AEMO HIGH	AEMO LOW	ETSA
2009-10	116.003	116.003	116.003	113.880
2010-11	118.642	118.642	118.642	116.780
2011-12	121.281	121.281	121.281	119.620
2012-13	123.920	123.920	123.920	122.590
2013-14	126.559	126.559	126.559	125.720
2014-15	129.198	129.198	129.198	128.830

Annual water heating sales model

Electricity sold under the South Australian J tariff is used for heating water in storage tanks in residences and commercial premises. For customers with electric-boosted solar hot water units and heat pumps, electricity is used as a reserve heating source when the main source is inadequate to meet the customer's overall needs. The J tariff load is controlled in that timers attached to customers' meters determine when heating elements are switched on and off. The great majority of water heating occurs overnight. At the individual customer level, electricity use varies with ambient temperature and hot water usage.

This sector of the electricity sales market performed in a relatively stable and predictable manner throughout the 1990's, however, significant structural changes have been occurring since 2001-02. Although total customer numbers have been rising, total sales have fallen markedly, reflecting a decline in average usage per customer.

Part of the variation in average usage per customer reflects changes in the weather from year to year. However, it has not been possible to model this type of relationship in a meaningful way as reliable estimates of the number of customers are not available over a long period. The water heating sales forecasts therefore ignore short term weather influences and focus instead on the longer term drivers determining sales volumes. These longer term influences include demographic, economic and policy drivers.

Growth of total customer numbers is supported by a rising population and the formation of new households. Advice from SA State Government policy advisers and historic market shares suggest that between 40% and 50% of new households choose some form of electric water heating. These are almost all electric boosted solar units, or to a smaller extent heat pump units, as opposed to traditional electric storage units. This trend is supported by recently introduced building standards and subsidies available to customers installing solar water heating units. As these new customers are added to the pool of existing customers, average usage per customer falls. Electric boosted solar units are estimated to use around 750 kWh of electricity annually, compared with average usage of 2,641 kWh across all customers during 2004-05 and 2005-06. There is also evidence that the proportion of newly formed households choosing electric water heating units has been declining in recent years as more customers elect for gas water heating and new households are formed in apartments rather than stand alone residences.

Changes are also occurring within the stock of existing customers as traditional electric storage units reach the end of their life and must be replaced. Only a very limited number of these replacements are on a like-for-like basis. Assuming a 20 year average life, around five percent of the existing stock moves to a more efficient form of water heating each year. Some customers change to gas units, while many find it economical to choose electric boosted solar units as much of the necessary plumbing is already in place. This change within the stock of existing customers is also reducing the overall average level of customer sales.

Conservation and efficiency policies, as well as demographic changes, are also working to reduce the average level of sales per customer. In particular, the trend towards smaller average household sizes and adoption of water saving devices such as low-flow shower heads will continue to drive down average hot water usage and the total heating load. The drought and associated public calls to conserve water is also likely to have had an effect on sales levels.

AEMO's modelling of the water heating load has keyed off the level of sales and customers in 2004-05. The following assumptions have been applied to project forward the number of customers and average electricity use to forecast total electricity sales.

Five percent of existing customers, commencing with the actual number of customers in 2004-05, are assumed to require some form of replacement water heater each year. Five percent of these are assumed to reinstall a traditional electric storage unit. The stock of existing customers falls to around 155,000 by 2017-18. We assume average per customer usage commences at 2,641 kWh in 2005-06 (which is the average level for 2004-05 and 2005-06) and falls by 0.5% each year thereafter, reflecting ongoing efficiency improvements.

For 2005-06, we assume that 85% of the existing customers requiring a replacement unit elect for an electric boosted solar unit, with the remainder choosing gas. We also assume the 85% share falls progressively by 0.5% each year, so that by 2017-18 only 79% of those requiring a replacement unit choose an electric solar unit. Average electricity use of 750 kWh annually is assumed for this group in 2004-05, with a 0.5% improvement in efficiency each year.

Base, high and low case projections of household formation are used to estimate new customer numbers. We assume 46% of new households formed in 2005-06 choose an electric boosted solar unit, with this share declining by 0.5% in each subsequent year. Again, average electricity use of 750 kWh annually is assumed for this group in 2004-05, with a 0.5% improvement in efficiency each year.

AEMO's base, high and low case forecasts and ETSA's forecasts are tabulated below.

Table 12: Annual water heating sales forecasts (GWh)

	AEMO BASE	AEMO HIGH	AEMO LOW	ETSA
2009-10	636.690	638.456	636.150	591.910
2010-11	613.923	616.109	613.276	535.860
2011-12	592.352	594.991	591.566	483.810
2012-13	571.916	575.039	570.958	432.730
2013-14	552.524	556.120	551.398	382.720
2014-15	534.122	538.181	532.832	333.870

5.6 Economic forecasts

Annual sales and peak demand forecasts are required for four different economic scenarios. Three of these (AEMO base, high and low cases) are based on economic forecasts provided by KPMG Econtech. These forecasts were used by jurisdictional planning bodies to develop electricity forecasts for each NEM region for the *2009 Statement of Opportunities* and each region's *Annual Planning Report*. The fourth scenario is based on the economic assumptions used by ETSA Utilities' to develop electricity forecasts for its Regulatory Proposal 2010-15 for the AER.

Economic forecasts are required for the following variables which appear in the annual sales models described in the previous section:

- SA average retail electricity price (business and residential models)
- Manufacturing sector GVA (business model)
- Other sectors GVA (business model)
- Cumulative dwelling investment (residential model)

The climate variable included in the residential sales model is simulated by Monash as part of the modelling process. Annual sales volumes for public lighting and water heating are taken directly from the tabulated forecasts shown earlier.

For the purposes of forecasting water heating sales and public lighting sales Monash has used the values shown in Table 11 and Table 12.

The economic forecasts for the business and residential models are shown in Table 13.

Table 13: Economic assumptions for business and residential annual models

	YR-1 SA PRICE 07-08 CENTS/ KWH	MANUF GVA	OTHER GVA (EX AG, MNG, MAN, DW)	CUM DWEL INV
		AEMO BASE CASE		
2009-10	15.123	7,281.544	46,793.646	71,800.294
2010-11	14.321	7,706.917	48,605.290	76,101.044
2011-12	15.401	7,883.291	50,039.831	80,750.742
2012-13	15.425	7,984.298	51,280.646	85,797.874
2013-14	16.025	8,782.136	51,971.872	90,909.327
2014-15	16.040	9,546.479	52,653.841	96,137.333
		AEMO HIGH CASE		
2009-10	15.123	7,328.052	47,380.424	71,863.575
2010-11	14.365	7,599.614	49,778.315	76,400.651
2011-12	15.481	7,761.465	51,465.786	81,120.276
2012-13	15.518	8,029.753	52,713.845	86,012.957
2013-14	16.153	9,264.327	53,425.164	91,073.928
2014-15	16.188	10,391.383	54,431.587	96,486.961
		AEMO LOW CASE		
2009-10	15.123	7,175.040	46,131.527	71,517.934
2010-11	14.261	7,693.719	47,224.795	75,121.951
2011-12	15.793	7,983.355	48,402.916	78,942.427
2012-13	15.859	8,190.505	49,774.153	83,473.202
2013-14	16.751	8,997.547	50,756.897	88,448.178
2014-15	16.772	9,749.647	51,343.253	93,501.719
		ETSA UTILITIES		
2009-10	13.93	7,049.179	43,123.452	71,977.002
2010-11	14.02	7,032.841	44,039.624	76,174.309
2011-12	14.79	7,124.614	45,409.876	80,405.194
2012-13	15.95	6,983.305	46,416.585	84,847.623
2013-14	17.48	6,832.853	46,963.629	89,254.513
2014-15	18.35	6,774.565	47,903.619	93,789.203

5.7 Annual sales forecasts and post model adjustments

Post model adjustments are applied to AEMO's South Australian business sector and residential sector annual sales forecasts to reflect energy efficiency measures that are considered not to be reflected in trends in the historic data. Adjustments are not applied to the water heating or public lighting annual sales forecasts.

Adjustments are made by AEMO in respect of the following efficiency/energy saving policies:

- the Australian Government's policy to phase out incandescent lights; and
- the rising penetration of small scale rooftop solar PV units.

These adjustments are applied so as to reduce annual sales volumes prior to calculating the average demand levels used in the half hourly demand model. The required efficiency adjustments are tabulated below.

Table 14: Post model adjustments for annual sales forecasts (GWh)

	BUSINESS SECTOR MODEL				RESIDENTIAL SECTOR MODEL			
	Base	High	Low	ETSA	Base	High	Low	ETSA
2009-10	3.470	3.517	3.412	0.000	35.744	35.751	35.714	142.700
2010-11	7.375	7.527	7.171	0.000	65.510	65.546	65.340	232.600
2011-12	11.291	11.573	10.891	0.000	94.971	95.008	93.974	316.400
2012-13	15.486	15.953	15.018	0.000	126.376	126.341	124.764	393.400
2013-14	19.952	20.824	19.395	0.000	157.945	157.813	155.351	470.400
2014-15	24.842	26.381	24.090	0.000	191.550	191.469	188.309	539.400

The sector-specific annual sales models described above utilise annual sales data measured at customer meters, whereas Monash's half hourly demand forecasting models require data measured at the boundary between the transmission and distribution network, as this is the basis required to produce the Distribution network peak demand forecasts. Therefore a further adjustment is required to adjust the annual sales forecasts in respect of network losses. In particular, the aggregated level of annual sales, adjusted for the efficiency measures noted above, are multiplied by a loss factor of 1.06179 before determining the average demand level used in the half hourly models.

Monash's models also produce forecasts of the total annual sales volumes which are dependent on the simulated level of summer cooling degree days. This variable influences the annual residential sales forecasts. As such, annual sales forecasts are produced for 10%, 50% and 90% PoE levels.

5.8 Model summary

The annual sales model in consolidated form is described in the following equation.

$$DAve_t = \frac{DAnn_t}{17520}$$

$DAve_t$ *is annual ave demand for financial year* t; *this vaule is used in the half hourly model*

$$DAnn_t = 1.06179 * (BS_t - BPMA_t + RS_t - RPMA_t + WH_t + PL_t)$$

Where:

BS_t = *annual business sales for financial year* t*, as described by model in* Figure 21

$BPMA_t$ = *post model adjustment for business sales forecasts, as shown in* Table 14

RS_t = *annual residential sales for financial year* t*, as described by model in* Figure 23

$RPMA_t$ = *post model adjustment for residential sales forecasts, as shown in* Table 14

WH_t = *annual water heating sales for financial year* t*, as reported in* Table 12

PL_t = *annual public lighting sales for financial year* t*, as reported in* Table 11

Attachment 2 – Sales forecasts by extended tariff categories

This attachment shows tables which apportion AEMO's total sales forecasts across tariff categories proposed by ETSA Utilities. The residential sales figures include the water heating load. Unmetered sales and business sales have been allocated across tariff categories using the same proportions assumed by ETSA Utilities. Business sales include the desalination plant load.

Table 15: Base case sales forecasts by tariff category (GWh)

	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
24 hour Unmetered	11.8	12.0	12.3	12.6	12.8	13.1
12 hour Unmetered	104.2	106.6	109.0	111.3	113.7	116.1
Other Unmetered	0.0	0.0	0.0	0.0	0.0	0.0
Residential	4,178.1	4,238.1	4,209.7	4,240.3	4,243.6	4,277.4
Bus 1 Rate	856.3	756.1	612.2	629.3	650.6	673.9
Bus 2 Rate	1,679.5	1,500.9	1,237.3	1,273.4	1,318.0	1,367.1
kVA LV Demand	2,131.1	2,718.3	3,221.3	3,316.2	3,433.2	3,561.9
HV Bus 2 Rate	0.0	0.0	0.0	0.0	0.0	0.0
kVA HV Demand <1000kVA	0.0	0.0	0.0	0.0	0.0	0.0
kVA HV Demand Obsolete	80.0	85.3	87.0	89.5	92.7	96.2
kVA HV Demand	886.2	945.0	963.4	991.8	1,026.7	1,065.3
kVA Zone S/Sta	687.2	707.1	705.8	710.5	711.7	728.3
kVA Sub/Tran	615.4	798.3	903.9	1,023.9	1,035.0	1,070.2
MP 1-ph 1 Rate	0.0	0.0	0.0	0.0	0.0	0.0
MP 1-ph & CL and/or OP	0.0	0.0	0.0	0.0	0.0	0.0
MP multi-ph direct	0.0	0.0	0.0	0.0	0.0	0.0
MP multi-ph direct with CL	0.0	0.0	0.0	0.0	0.0	0.0
MP 3-ph CT	0.0	0.0	0.0	0.0	0.0	0.0
MP Type 1-4 legacy	0.0	0.0	0.0	0.0	0.0	0.0
EDS Type 6 QR	0.0	0.0	0.0	0.0	0.0	0.0
Total sales	**11,229.8**	**11,867.6**	**12,061.8**	**12,398.9**	**12,638.0**	**12,969.4**

Table 16: High case sales forecasts by tariff category (GWh)

	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
24 hour Unmetered	11.8	12.0	12.3	12.6	12.8	13.1
12 hour Unmetered	104.2	106.6	109.0	111.3	113.7	116.1
Other Unmetered	0.0	0.0	0.0	0.0	0.0	0.0
Residential	4,180.9	4,242.8	4,214.1	4,242.2	4,243.4	4,279.6
Bus 1 Rate	868.0	771.4	627.1	647.6	677.9	714.2
Bus 2 Rate	1,702.3	1,531.2	1,267.3	1,310.3	1,373.5	1,448.8
kVA LV Demand	2,160.1	2,773.1	3,299.5	3,412.3	3,577.6	3,774.7
HV Bus 2 Rate	0.0	0.0	0.0	0.0	0.0	0.0
kVA HV Demand <1000kVA	0.0	0.0	0.0	0.0	0.0	0.0
kVA HV Demand Obsolete	81.1	87.0	89.1	92.1	96.6	101.9
kVA HV Demand	898.2	964.0	986.8	1,020.5	1,069.9	1,128.9
kVA Zone S/Sta	696.5	721.4	722.9	731.1	741.6	771.8
kVA Sub/Tran	623.7	814.4	925.8	1,053.6	1,078.6	1,134.1
MP 1-ph 1 Rate	0.0	0.0	0.0	0.0	0.0	0.0
MP 1-ph & CL and/or OP	0.0	0.0	0.0	0.0	0.0	0.0
MP multi-ph direct	0.0	0.0	0.0	0.0	0.0	0.0
MP multi-ph direct with CL	0.0	0.0	0.0	0.0	0.0	0.0
MP 3-ph CT	0.0	0.0	0.0	0.0	0.0	0.0
MP Type 1-4 legacy	0.0	0.0	0.0	0.0	0.0	0.0
EDS Type 6 QR	0.0	0.0	0.0	0.0	0.0	0.0
Total sales	**11,326.9**	**12,024.0**	**12,253.8**	**12,633.6**	**12,985.8**	**13,483.2**

Table 17: Low case sales forecasts by tariff category (GWh)

	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
24 hour Unmetered	11.8	12.0	12.3	12.6	12.8	13.1
12 hour Unmetered	104.2	106.6	109.0	111.3	113.7	116.1
Other Unmetered	0.0	0.0	0.0	0.0	0.0	0.0
Residential	4,173.1	4,225.1	4,161.2	4,182.0	4,169.1	4,200.3
Bus 1 Rate	842.0	735.6	591.2	611.0	633.1	654.2
Bus 2 Rate	1,651.4	1,460.2	1,194.8	1,236.4	1,282.6	1,327.2
kVA LV Demand	2,095.5	2,644.5	3,110.5	3,219.8	3,340.9	3,458.0
HV Bus 2 Rate	0.0	0.0	0.0	0.0	0.0	0.0
kVA HV Demand <1000kVA	0.0	0.0	0.0	0.0	0.0	0.0
kVA HV Demand Obsolete	78.7	83.0	84.0	86.9	90.2	93.4
kVA HV Demand	871.3	919.3	930.2	962.9	999.1	1,034.2
kVA Zone S/Sta	675.7	687.9	681.5	689.9	692.5	707.0
kVA Sub/Tran	605.1	776.6	872.8	994.1	1,007.2	1,038.9
MP 1-ph 1 Rate	0.0	0.0	0.0	0.0	0.0	0.0
MP 1-ph & CL and/or OP	0.0	0.0	0.0	0.0	0.0	0.0
MP multi-ph direct	0.0	0.0	0.0	0.0	0.0	0.0
MP multi-ph direct with CL	0.0	0.0	0.0	0.0	0.0	0.0
MP 3-ph CT	0.0	0.0	0.0	0.0	0.0	0.0
MP Type 1-4 legacy	0.0	0.0	0.0	0.0	0.0	0.0
EDS Type 6 QR	0.0	0.0	0.0	0.0	0.0	0.0
Total sales	**11,108.9**	**11,650.9**	**11,747.5**	**12,107.1**	**12,341.3**	**12,642.4**