Possible Future Trends in Residential Electricity Prices 2013-14 through 2015-16: Network Cost Drivers

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DISCLAIMER

This report has been prepared for the Australian Energy Market Commission (AEMC) as an input to a report it is preparing at the request of the Standing Council on Energy and Resources (SCER) on possible trends in residential electricity prices Australia in the three year period from 2013-14 to 2015-16.

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1. Executive Summary

1.1. Background

On 12 December 2012 the Australian Energy Market Commission (AEMC) received a request from the Standing Council on Energy and Resources (SCER) to prepare a report outlining possible future trends in residential electricity prices - and the drivers of those trends - in the states and territories of Australia for the three year period from 2013-14 to 2015-16, using 2012-13 as the basis of estimation.

SCER also asked that the report disaggregate prices into their component parts and provide commentary on a jurisdictional basis, as well as provide an aggregate, national summary. Specifically, the AEMC was asked to report on:

- Wholesale electricity costs;
- Transmission network costs;
- Distribution network costs;
- Retail costs (including margins);
- Costs associated with a carbon price;
- Renewable Energy Target costs (separating large and small schemes);
- Other costs associated with State, Territory or Australian Government specific policies and programmes (e.g. green energy programs and regulatory overheads); and
- Feed in tariff scheme costs.

Oakley Greenwood Pty Ltd was engaged to provide information on the trends and drivers that could be expected to affect distribution and transmission network costs over the period of interest, and therefore to also affect residential retail electricity prices.

1.2. Overview of scope

This report provides information on the trends and the key drivers of network costs in the following areas:

- Input costs, including
  - the cost of capital;
  - the cost of labour;
  - the cost of key materials; and
  - the influence of macroeconomic conditions.
- The extent of likely future augmentation and the impact of the age profile of network assets
- Changes in the level of residential demand, and possible changes in the structure of network pricing.

The AEMC asked that these investigations focus on network businesses that would experience regulatory determinations that could affect residential tariffs and prices within the 2013-14 to 2015-16 period. These businesses included:

- Energex
- Ausgrid

- Endeavour Energy
- Essential Energy
- ActewAGL
- TransGrid
- South Australia Power Networks
- Transend.

Reference to other businesses is made in several sections where that experience is relevant.

The information presented is drawn from publically available materials, primarily those published by the businesses and the Australian Energy Regulator (AER), and other third parties. No attempt has been made to predict or 'second guess' the content or impact of future regulatory or Rules changes.

Limited quantitative analysis was undertaken to assess the sensitivity of network charges to changes in the WACC and throughput.

1.3. Key findings

The table on the following page summarises the findings of the study and provides a general overview of the likely direction of changes in different variables assessed as part of this report, and their relative magnitude.

At this level of consideration it is not possible to be definitive regarding how the interplay of the key drivers and trends that impact network costs that were considered in this study will affect the level of network charges that will apply to residential electricity consumers over the course of the next three years. For example, whilst on the balance of probabilities there may be decreasing pressure on prices in the future as a result of reductions in the WACC and from lower augmentation capital expenditure programs, this is likely to be counteracted by input cost pressures relating to labour and materials, and more materially (at least for some businesses), increased replacement capital expenditure. Changes in energy consumption – both across this period, relative to forecast, as well as what is forecast to happen in the next regulatory control period – are also likely, on balance, to exert an upward pressure on price.

However, it is worth noting that any change in the WACC will tend to have a more significant impact on outturn prices than the same proportional change in any of the other components assessed in this study. This is because return on capital (which is calculated by applying the WACC to the business' regulated asset base) tends to represent the single largest component of a network business' revenue requirement.

Finally, however, it is important to note that:

- outcomes for individual network businesses will be a product of the balance of the specific values of each of these factors, detailed consideration of which was outside the scope of the present study, and the timing of their regulatory determinations (as the specific value of factors such as the WACC and materials cost escalators can change sufficiently within relatively short periods of time to make a material difference to price movements), and
- overall outcomes may be materially affected by changes to the Rules and the regulatory framework that are currently under consideration, particularly the proposed Distribution Network Pricing Arrangements Rule Change, and considerations regarding a change in the regulatory control mechanism from a Weighted Average Price Cap to a Revenue Cap. We have not sought to predict the outcomes of these considerations.

Likely direction and relative magnitude of various drivers of network costs on residential electricity price in the near future

Component	Likely direction of change	Comment
WACC	⬇	Given recent development in capital markets, on the balance of probabilities, future WACC decisions would be expected to be lower than the decisions that underpin the current prices of all of the businesses analysed in this report (this excludes any impact stemming from recent and pending Rule changes)
Labour Cost Escalators	⇧	While the most recent forecasts of labour cost escalators are lower than those that are embedded within the regulatory decisions affecting the current prices of the businesses analysed, they are still expected to exert some upward pressure on prices in the next round of regulatory reviews.
Materials Cost Escalators	⇧	Overall, there would appear to be a slight upside risk to the materials cost escalators over the evaluation period, although as highlighted in the body of the report, much will depend on the outlook for the Australian dollar.
Macroeconomic Conditions	-	The literature appears to be neither overly bearish nor bullish in relation to Australia's broader macro-economic outlook for the next few years. Therefore, based on currently available information, we consider that this is likely to have a neutral bearing on residential prices outcomes in the near term.
Augmentation Capital Expenditure	⬇	With demand forecasts easing, relative to those that were in place when the current regulatory reviews of the businesses were undertaken, the degree to which augmentation costs (excluding the impact of movements in labour and materials cost drivers) are likely to drive residential prices should reduce. Furthermore, pressure on expenditure forecasts as a result of changed levels of service (e.g., the move away from the existing deterministic n-2 reliability standard in the Sydney CBD) should reduce.
Replacement Capital Expenditure	⇧ to ⬆	On the balance of probabilities, we would expect there to be slight upward pressure on prices from increases in replacement levels over the next regulatory period. However, this pressure will vary significantly across the various network businesses.
Starting Price Changes due to difference between forecast and actual consumption outcomes	⇧ to ⬆	The majority of the networks have experienced outturn consumption that is materially lower than the levels on which their prices were developed, and, on present forecasts, several will have starting consumption levels in their next regulatory periods that will be below the actual levels of their first year consumption in the current regulatory period. This will exert upward pressure on prices.
Future price changes due to forecast consumption over next regulatory period	⇧ to ⬆	Because of the above, and despite annualised growth rates generally forecast to increase in the upcoming regulatory periods as compared to the outturn levels in the current regulatory periods, at least several of the networks are expected to experience levels in total sales over their coming regulatory periods that will be lower than those achieved in their current regulatory periods. This will tend to increase unit electricity prices.

2. Input cost trends

2.1. Objective

Oakley Greenwood has been asked to provide advice regarding likely trends in input costs and other factors that will affect the cost of network operations and augmentation. This section discusses a number of those input cost drivers, namely:

- the weighted average cost of capital;
- labour costs;
- materials costs; and
- the impact of broader macro-economic factors.

Our general approach has been to first discuss the key assumptions that underpinned the AER's decision for each business in relation to that key driver. We then review a selection of publicly available information from credible forecasting agencies to provide a qualitative description as to the likelihood of that particular driver increasing or decreasing in the next regulatory period.

We have also undertaken further analysis to assess the indicative impact on each businesses revenue requirement that would ensue from the AER adopting a WACC that was consistent with their most recent decision – namely the SP AusNet Transmission Draft Decision.

2.2. The weighted average cost of capital

2.2.1. Overview and review of recent decisions

The Weighted Average Cost of Capital (WACC) has the single biggest influence on outturn network prices in Australian regulatory regime. It can comprise anywhere up to 50% of the revenue requirement of a regulated network business[1].

The WACC reflects the AER's estimate of the cost of funds (equity and debt) that an efficiently run regulated network business needs in order to attract the debt and equity required to make investments in that network business. As a regulated network business commissions assets, their costs roll into that business' regulated asset base (RAB). The RAB is multiplied by the WACC in order to determine the return on investment that a business requires. *Ceteris paribus*, the lower the WACC or RAB, the lower will be the return on investment required by that network business in order to efficiently run its business, and therefore, the lower prices will be required to be.

The key input parameters that comprise the WACC are the:

- nominal risk free rate;
- debt Risk Premium;
- market risk premium;
- gearing levels; and
- equity beta.

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1 AER, *Better Regulation: Draft Rate of Return Guideline - Fact Sheet*, 30 August, 2013, p 1.

Whilst all are important, it is perhaps the nominal risk free rate that is most important, as it impacts both the debt risk premium and the equity risk premium. It is this parameter that has changed most materially in the last couple of years, which in turn has led to changes in the WACC that the AER has determined for regulated network businesses over that period.

Table 1 provides a summary of the key parameters underpinning the AER's decisions with regards to the allowed WACC for each of the respective businesses being evaluated, as well as its most recent electricity decisions, which have been for Powerlink, ElectraNet and its Draft Decision for SP AusNet's Transmission business.

Table 1: WACC decisions, by component (2009-2013)

Business	TransGrid[2]	NSW DNSP's[3]	ActewAGL[4]	Transend[5]	Energex[6]	SA Power Networks[7]	Powerlink[8]	ElectraNet	SP AusNet (Tx)[9]
Year Decision Made	(2009)	(2009)	(2009)	(2009)	(2010)	(2010)	(2012)	(2013)	(2013)
Risk-free rate (nominal)	5.86%	5.82%	4.29%	5.80%	5.64%	5.89%	4.17%	3.51%	3.54%
Expected inflation rate	2.47%	2.47%	2.47%	2.47%	2.52%	2.52%	2.60%	2.50%	2.50%
Debt Risk Premium	2.99%	3.00%	3.49%	3.01%	3.33%	2.98%	3.93%	3.18%	3.00%
Market risk premium	6.00%	6.00%	6.00%	6.00%	6.50%	6.50%	6.50%	6.50%	6.50%
Gearing	60%	60%	60%	60%	60%	60%	60%	60%	60%
Equity beta	1.00	1.00	1.00	1.00	0.80	0.80	0.80	0.80	0.80
Nominal pre-tax return on debt	8.85%	8.82%	7.78%	8.81%	8.98%	8.87%	8.10%	8.71%	6.55%
Nominal post-tax return on equity	11.86%	11.82%	10.29%	11.80%	10.84%	11.09%	9.37%	6.69%	8.74%
Nominal vanilla WACC	10.05%	10.02%	8.79%	10.00%	9.72%	9.76%	8.61%	7.50%	7.43%

2 AER, *Statement on updates for TransGrid transmission determination - March 2010*, p 1.

3 AER, *Statement on updates for NSW DNSPs distribution determination*, p 2.

4 AER, *Australian Capital Territory Distribution Determination 2009-10 to 2013-14 - Final Decision*, 28 April 2009, p xxi.

5 AER, *Statement on updates for Transend transmission determination*, p 1.

6 AER, *Queensland Distribution Determination 2010-11 to 2014-15 - Final Decision*, May 2010, p 267.

7 AER, *South Australia Distribution Determination 2010-11 to 2014-15*, May 2010, p 193.

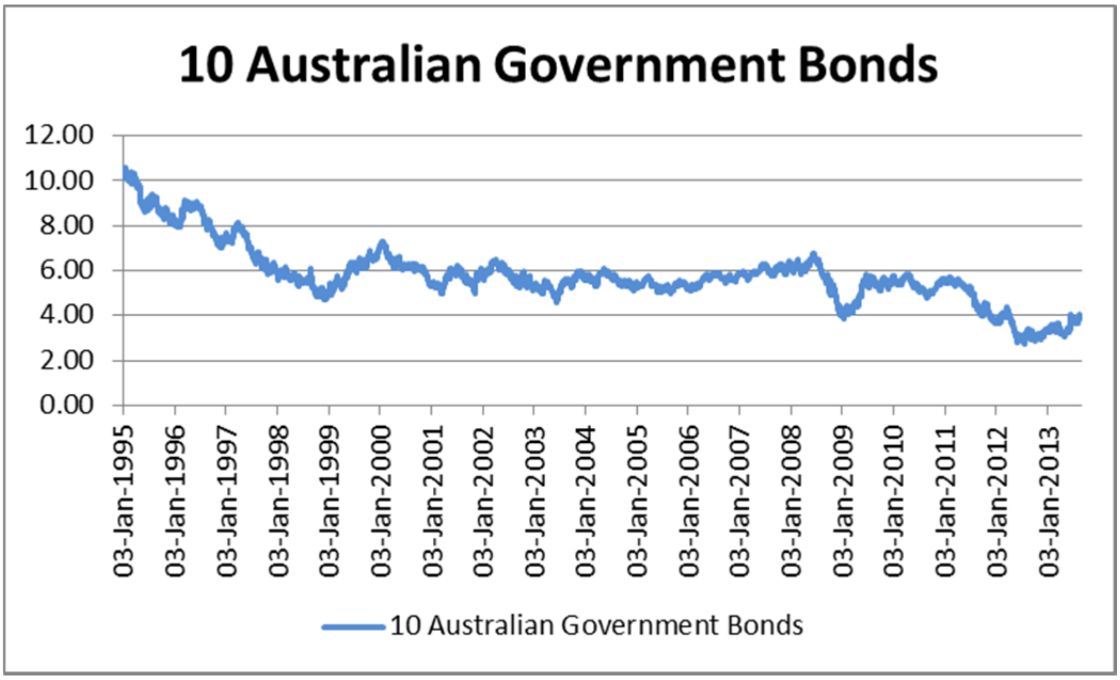
8 AER, *Final decision Powerlink Transmission determination 2012-13 to 2016-17*, April 2012, p 33.

9 AER, *Draft Decision SP AusNet Transmission Determination 2014-15 to 2016-17*, August 2013, p 24.

The AER adopts the prevailing yield on ten-year Commonwealth Government securities (CGS) averaged over a period which is as short and as close as practicably possible to the commencement of the regulatory period, to estimate a 10 year forward-looking risk-free rate. As the information in the table above indicates - particularly the most recent decisions for Powerlink and for SP AusNet's Draft Decision – it is this parameter that has been the key driver of the recent reductions in the allowed WACC for regulated businesses. This has been further reinforced by reductions in the equity beta. A countervailing influence has been a slight increase in the Market Risk Premium (MRP) in certain decisions.

The following graph illustrates the magnitude of the reduction in the yields on CGS over the longer term, with the lowest yield of 2.70% being recoded in July 2012 - which is less than 50% of the level it was when a number of the regulatory decisions were made, for example SAPN (5.89%) and the NSW DNSPs (5.82%).

Figure 1: Historic yields on ten-year government bonds



Source: *Reserve Bank of Australia - http://www.rba.gov.au/statistics/tables/index.html#interest_rates?accessed=2013-09-02-16-07-56*

However, as can be seen from the above graph, yields on long-term CGS have increased over the last six months, with this reflecting a rise in bond yields observed globally. In fact, the 10-year CGS yields reached an 18-month high of 4.04 per cent on the 24th of June, as "*speculation grew that the US Federal Reserve may taper its asset purchase program earlier than anticipated. Yields subsequently declined as this speculation abated and following the release of weaker-than-expected Chinese and domestic economic data*"[10].

Yields on long-term GCS are linked to the target cash rate – which is the overnight cash rate applicable to loans between financial intermediaries - as the target cash rate indirectly influences the term structure of interest rates in the whole economy, including the yields on long term CGS. As can be seen from the graph below, cash rates are at historically low levels.

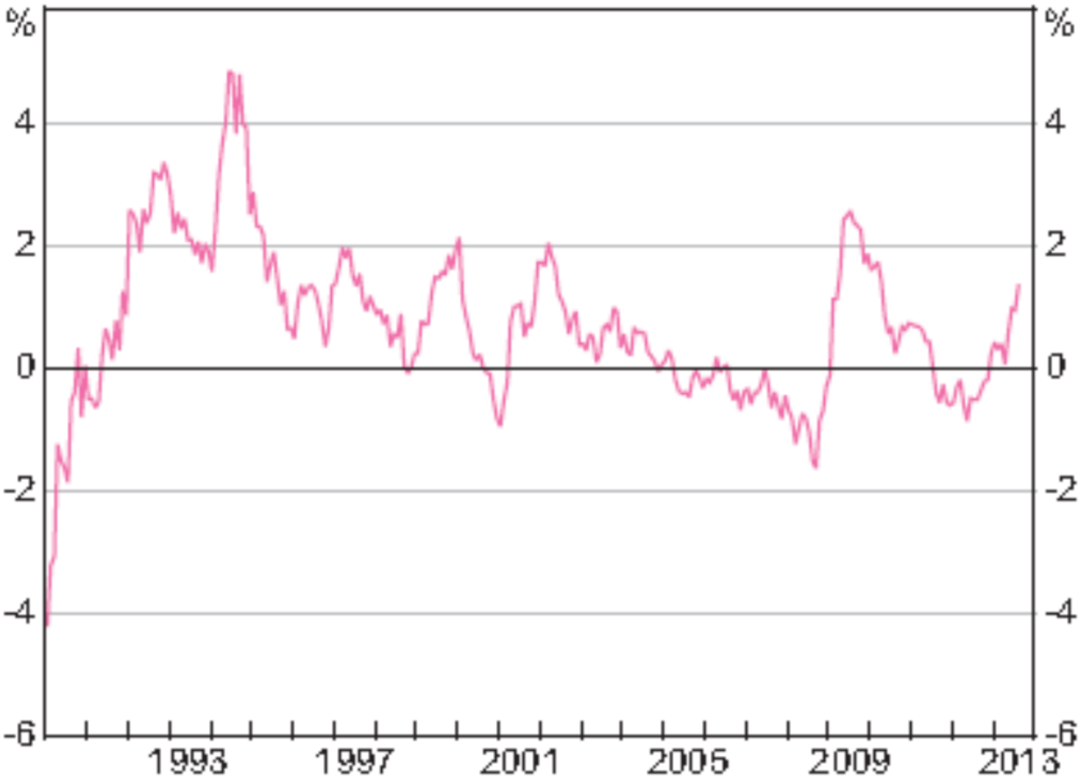
10 RBA, *Statement on Monetary Policy August 2013*, p 37.

Figure 2: Historic changes in the target cash rate

Source: *Reserve Bank of Australia - http://www.rba.gov.au/statistics/tables/index.html#content*

The other factor influencing the yields on long-term CGS is the slope of the yield curve. It generally slopes upwards as bond investors require higher interest rates to hold bonds of longer maturities. This is known as the liquidity or term premium. However, as shown in Figure 3, which has been reproduced from an RBA publication, the spread between the Australian ten-year bond yield and the cash rate has narrowed, except for the period around 2009, which was a manifestation of the impact of the Global Financial Crisis (GFC). This narrowing in the yield spread has primarily resulted from a fall in the long-term bond rate, and is likely to reflect the presence of more stable economic conditions and a structural decline in both inflation and inflation expectations. In short, this structural change has contributed to a reduction in the nominal risk free rate in the medium term, which, *ceteris paribus*, leads to lower WACC decisions.

Figure 3: Spread between ten-year bond yield and cash rate



Source: RBA - *The Australian Economy and Financial Markets Chart Pack* - October 2013

In summary, there is a confluence of factors that has driven long term bond yields to historically low levels over the last 18 months (although these yields have increased slightly in more recent times). As is seen by the AER's most recent decision - SP AusNet's Transmission Draft Decision (and other recent decisions such as the ElectraNet decision) - these lower long term bond yields are flowing directly through to lower WACC decisions. *Ceteris paribus*, if this trend continues (or even plateaus), it could be expected that future WACC decisions will reflect these otherwise lower financing conditions.

2.2.2. Possible impact of WACC on future electricity prices

Firstly, it should be noted that recent changes to the National Electricity Rules[11] are likely to lead to a number of changes in the way the AER (and businesses) seek to determine (argue) the appropriate rate of return applicable to regulated electricity businesses.

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11 These were announced in November 2012 by the Australian Energy Market Commission (AEMC).

For example, the AER's Rate of Return Guideline envisages that multiple methodologies, models and information may be used to inform their return on equity estimate. For example, it may be that various models are used to "*set the range of inputs into the CAPM foundation model*"[12] (the Sharpe-Lintner model) and "*assist in determining a point estimate within a range of estimates at the overall return on equity level*"[13]. We also note that the AER is proposing to materially change the way it calculates a regulated business' debt risk premium. More specifically, the AER states that it is "*proposing a gradual transition from using the current approach to a trailing average approach. The trailing average portfolio approach assumes that one-seventh of the debt portfolio is refinanced every year. The transition will occur over a period of seven years and will apply to all businesses*"[14]. The AER further states that this approach to the return on debt "*will more closely align with the efficient debt financing practices of regulated businesses. This should also lead to less volatile prices over time for consumers*"[15].

The purpose of this section of the report is not to speculate as to what the impact of the aforementioned changes might be; rather, we have sought to comment on the underlying components of the WACC, particularly the nominal risk free rate, which, as illustrated above, has in recent times, been the predominant driver of changes in the overall WACC.

To this end, we have reviewed a selection of publicly available forecasts of credible analysts/organisations with regards to forecasts of the cash rate and ten-year bond rate forecast, as shown in Table 2 below.

Table 2: Interest rate forecasts

Institution	Measure	Dec 2013	2014	2015
Westpac[16]	Cash rate forecast	2.25%	2.00%	NA
	10-year bond rate forecast	3.70%	3.40% (Mar) - 3.70% (Dec)	NA
NAB[17]	Cash rate forecast	2.50%	2.75%	NA
	10-year bond rate forecast	3.60%	4.50%	NA
CBA[18]	Cash rate forecast	2.50%	2.50% (June)	NA
	10-year bond rate forecast	3.60%	4.20% (June)	NA

12 AER, *Better Regulation: Draft Rate of Return Guideline - Fact Sheet*, 30 August, 2013, p 2.

13 Ibid.

14 Ibid.

15 Ibid.

16 Westpac, *Australia & NZ weekly*, week beginning 23 September 2013.

17 NAB, *Global and Australian Forecasts*, June 2013, p 10.

18 CBA, *CBA Australian Economic Forecasts*, August 2013, p 20 found at https://www.commbank.com.au/content/dam/commbank/corporate/research/publications/economics/forecasts-economic-financial/2013/300813-Forecasts_EcoFin.pdf.

The table indicates that there appear to be divergent views with regards to the forecast of ten-year nominal bond yields over the next 18 months – although this may be partially a function of different times at which these forecasts were made. Westpac appears more bearish with regards to the outlook for near term rates, relative to the NAB and CBA.

Whilst we are not in a position to opine as to which is the more “valid” forecast, there appears to be a consensus that even compared to near-term highs in nominal bond yields (e.g., levels around 4.00%), there is unlikely to be a material break-out on the upside over the coming 18 months.

More broadly, there is generally a correlation between the slope of the yield curve (measured by the spread) and expectations of future inflation and economic activity, with an upward-sloping (flat or inverted) yield curve interpreted as signalling stronger (weaker) real economic activity and inflation in the future.

Assumptions around future GDP growth would appear to be a predominant driver of each of the major banks rate forecasts – with Westpac forecasting (at the time of writing) GDP for calendar year 2014 at 2.3%, whereas the CBA and NAB are forecasting 2.9% and 2.8% for GDP in calendar year 2014. Consequently, CBA and NAB are also forecasting the largest increases in ten-year nominal bond yields. Again, we note that differences may also be partially a function of different timings as to when these forecasts were made.

The Reserve Bank of Australia (RBA), in its August *Statement of Monetary Policy*, states that[19]:

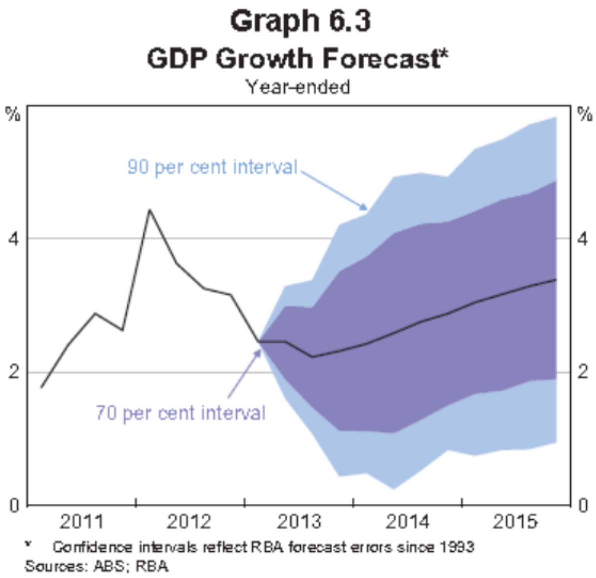
> *“GDP growth is expected to remain a little below trend at close to 2½ per cent through to mid 2014, before picking up to above-trend growth by the end of the forecast horizon as the global economy experiences above-trend growth and the stimulatory effects of the recent exchange rate depreciation and current low level of interest rates lead to an improvement in business conditions and so investment.”*

The RBA is forecasting year-average GDP growth in 2015 to be between 2.75 and 3.75 precent[20]. This is diagrammatically represented in the following graph [reproduced from the RBA’s August Statement on Monetary Policy].

19 RBA, *Statement on Monetary Policy August 2013*, p 54.

20 Ibid., p 55.

Figure 4: Forecast GDP

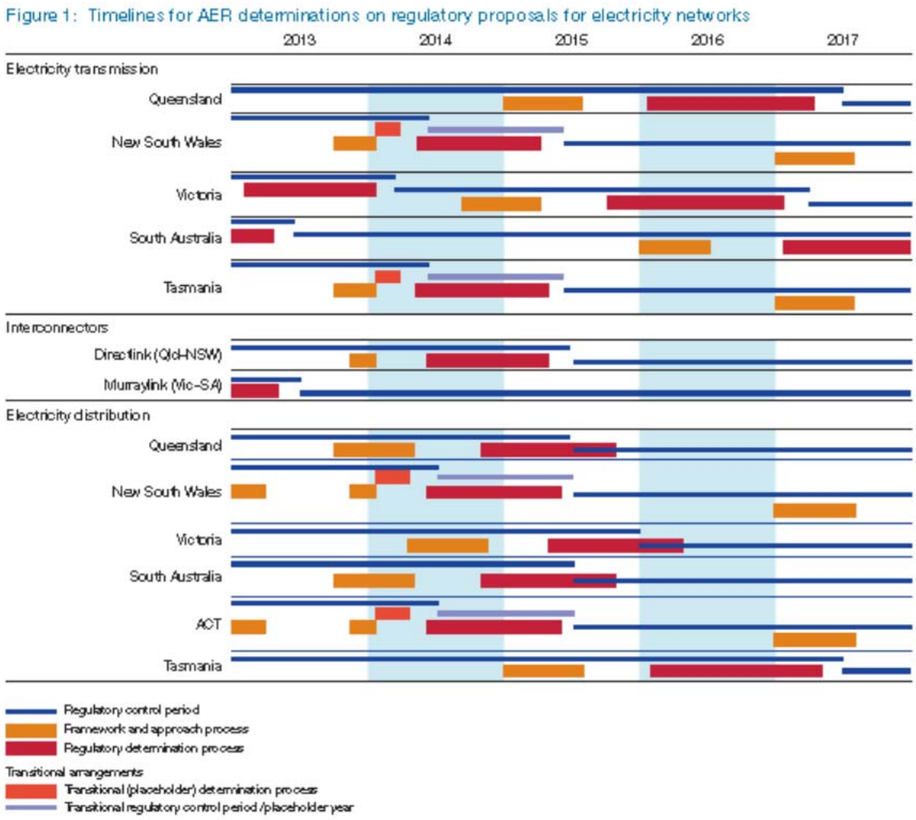


Source: "RBA - Statement on Monetary Policy August 2013, p 59"

The RBA's forecast of better than average GDP growth beyond the middle of 2014 reinforces the forecasts made by the major banks that there may, if anything, be upward pressure on nominal bond yields (relative to current levels) in the medium term.

As can be seen in Figure 5 on the following page, which has been reproduced from an AER publication, the majority of the businesses to be assessed as part of this study will be subjected to a Final Decision in early 2015. As such, it is the expected rates up until 2015 that are of most relevance.

Figure 5: Timelines for AER Determinations



Source: AER *Strategic Priorities and Work Program 2013-14*, p 17

Overall, based on the forecasts assessed as part of this assignment, we consider that even with slightly above average GDP being forecast in the medium term, which in turn may lead to slight upward pressure on nominal long term bond rates relative to current levels, the AER's future decisions with regards to the WACC are still likely be weighted to the downside, relative to what has been allowed for in the previous decisions of the businesses addressed in this report.

2.2.3. Quantitative assessment of the impact of a lower WACC on residential unit prices

To demonstrate the order of magnitude that a lower WACC decision *might* have on each of the businesses, Table 3 on the following page provides an indicative estimate of the impact on each business' revenue requirement, *if* the AER's most recent decision (being its SP AusNet Transmission Draft Decision) were adopted in future decisions.

Table 3: Indicative impact of a change in the WACC on revenue requirements

Business	Rate of return as a proportion of revenue requirement in final year of current regulatory period [A]	% reduction in rate of return from using SP AusNet Tx WACC [B]	Proportionate impact on revenue requirement [A]*[B]
TransGrid	67.00%	-26.1%	-17.50%
Ausgrid	61.00%	-25.8%	-15.70%
Essential	49.00%	-25.8%	-12.60%
Endeavour	53.00%	-25.8%	-13.70%
ActewAGL	38.00%	-15.5%	-5.90%
Energex	70.00%	-23.6%	-16.50%
Transend	58.00%	-25.7%	-14.90%
SA Power Networks	45.00%	-23.9%	-10.80%

Source: AER Final Decisions, Appeal Decisions and OGW analysis

The above table is indicative only. Invariably, not only will the calculated WACC deviate from that which has been assumed above, but also, the actual impact will be a function of the actual value of each business' RAB, which in turn is a function of their actual capital expenditure through this regulatory period (i.e., what is rolled into the RAB at the commencement of the next regulatory control period), as well as their forecast capital expenditure for the next regulatory control period. The calculated WACC also has a secondary effect on other components of the revenue requirement, for example, the benchmark tax liability.

In addition to the above, we were also asked by the AEMC to extend the above analysis, to also include the Victorian Distribution business.

Table 4: Indicative impact of a change in the WACC on revenue requirements – VIC DBs

Business	Rate of return as a proportion of revenue requirement in final year of current regulatory period [A]	% reduction in rate of return from using SP AusNet Tx WACC [B]	Proportionate impact on revenue requirement [A]*[B]
SP AusNet	52.81%	-23.8%	-12.60%
Citipower	58.75%	-21.7%	-12.70%
Powercor	48.40%	-21.7%	-10.50%
Jemena	46.18%	-28.1%	-13.00%
United Energy	43.17%	-21.7%	-9.40%

Source: AER Final Decisions, Appeal Decisions and OGW analysis

2.3. Labour cost escalators

2.3.1. Review of recent decisions

Regulated businesses have generally sought to incorporate into their operating and capital expenditure forecasts the impact of real increases in the cost of labour required to provide regulated electricity services.

The higher a business's real increase in labour costs is forecast to be, the larger their operating and capital expenditure forecasts will be, which, if accepted by the AER, flows through to higher network prices.

Like any other factor of production, an electricity business' labour costs are a function of the supply and demand fundamentals for the types of skills that are sought by electricity businesses. This will be a function of many complex, interrelated factors, for example, other industries' demand for the types of skills generally sought by electricity businesses; competition for labour between electricity businesses; and general economic conditions.

Table 5 the next page highlights the real labour cost escalation rates that the AER has approved as part of their Final Decisions for the regulated electricity businesses covered by this report. It also highlights their most recent decision (again, the SP AusNet Transmission Draft Decision), and highlights that expectations regarding real labour cost increases reached their peak in 2009/10 and 2010/11, with this reducing in subsequent years.

Table 5: Real labour cost escalators (%)

EGW Labour	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
TransGrid[21]	0.84	3.27	3.60	2.40	1.70	0.60	NA	NA
Ausgrid[22]	0.20	3.35	3.60	2.40	1.70	0.60	NA	NA
Essential[23]	-0.38	2.54	3.60	2.40	1.70	0.60	NA	NA
Endeavour[24]	1.38	3.35	3.60	2.40	1.70	0.60	NA	NA
ActewAGL[25]	2.42	2.50	3.60	2.90	2.50	1.50	NA	NA
Energex[26]	0.12	2.22	0.20	0.86	1.27	1.52	1.63	NA
Transend[27]	1.10	2.70	2.70	1.30	0.60	-0.30	NA	NA
SA Power Networks[28]	1.12	1.80	0.57	0.29	0.52	1.18	1.56	NA
SP AusNet (Tx)[29]	NA	NA	NA	NA	1.10	0.50	1.00	1.00

Source: AER Final Decisions

2.3.2. Possible impact of labour costs on future electricity prices

As highlighted in the section above, the most recent labour cost forecasts (that have been relied upon by the AER for the purposes of making regulatory decisions) indicate that there will be a slowing in labour cost pressures over the remainder of our evaluation period for electricity businesses, at least *in Victoria*. This is based on forecasts of the change in the Labour Price Index pertaining to employees in the Electricity, Gas, Water and Waste Services (EGWWS) sectors. *Ceteris paribus*, if this were to eventuate and be reflective of the outcomes in other jurisdictions, then this should dampen the impact that changes in this input cost has on end electricity prices.

21 AER, *Final decision TransGrid transmission determination 2009-10 to 2013-14*, 28 April 2009, p. 32.

22 AER, *Final Decision New South Wales distribution determination 2009-10 to 2013-14*, 28 April 2009, p.130.

23 Ibid.

24 Ibid., p. 131.

25 AER, *Final Decision Australian Capital Territory distribution determination 2009-10 to 2013-14*, 28 April 2009, p 61.

26 AER, *Final Decision Queensland distribution determination 2010-11 to 2014-15*, May 2010, p. 192.

27 AER, *Final Decision Transend Transmission Determination 2009-10 to 2013-14*, 28 April 2009, p. 167.

28 AER, *Final Decision South Australia distribution determination 2010-11 to 2014-15*, May 2010, p. 139.

29 AER, *Draft decision - SP AusNet 2014-15 to 2016-17*, August 2013, p. 58.

The underlying forecasts that were produced by Deloitte Access Economics for the AER's most recent Draft Decision also indicate that the *national* outlook for real labour cost growth in the utilities sector is even lower than that which has been forecast for SP AusNet in Victoria, with these being less than 1% for each of the remaining years of our evaluation period[30].

Forecasts developed by BIS Shrapnel for the purposes of supporting SP AusNet's recent Transmission regulatory submission indicate a slightly healthier picture of wage growth in the Utilities sector nationally, with real growth in the Labour Price Index for the Electricity, Gas and Water (EGW) sector ranging from 1.8% in 2014 to 2.6% in 2016[31]. We note that even at these levels, real wage cost increases would be less than what the AER has allowed in the existing prices of most of the regulated electricity businesses we are reviewing for this assignment.

Finally, we note that information from the RBA's most recent Statement of Monetary Policy indicates that this diminishment in labour cost pressure is not isolated to the Utilities sector, with the RBA observing that[32]:

> *"Softer conditions in the labour market have seen the pace of growth in wages decline to around its lowest rate in a decade. Combined with relatively strong growth of productivity, this has contributed to low growth of unit labour costs."*

Based on the information reviewed as part of this assignment, we consider that on balance, the AER is more likely than not to adopt a lower forecast of real labour cost escalators in the forthcoming regulatory reviews of the regulated electricity businesses that are being considered for the purposes of this assignment. This should temper the impact that this input cost driver has on future network price outcomes. Notwithstanding this, there is no evidence to suggest that real labour costs will *decline*, and therefore, this input cost parameter is still likely to exert some upward pressure on network prices in the forthcoming review periods, though this is likely to be less than in previous recent periods.

2.4. Materials cost escalators

2.4.1. Review of recent decisions

For each of the businesses reviewed as part of this engagement, the AER has incorporated explicit cost escalation forecasts for a number of key materials. These forecasts, weighted by the proportion of that material in each of the asset classes (e.g., conductors, transformers), have been used to forecast the real increase in the price of those asset classes over the regulatory period.

Materials cost escalators have also been used, in some cases, to forecast operating expenditure, although we note that their impact in this application has generally been less material than its impact on capital expenditure forecasts.

The key materials that the AER has historically assessed have been:

- aluminium,
- copper;

30 Deloitte Access Economic, *Forecast growth in labour costs in Victoria (Report prepared for the AER)*, 13 June 2013, p 69 (accessed from http://www.aer.gov.au/node/19819 on 5/09/2013).

31 BIS Shrapnel (for SP AusNet), *Real Labour Cost Escalation Forecasts to 2017 - Australia & Victoria*, November 2012, p iii (accessed from http://www.aer.gov.au/node/19819 on 5/09/2013).

32 RBA, *Statement on Monetary Policy August 2013*, p 2.

- iron ore; and
- crude oil.

The forecast escalator rates (in $AUD) approved by the AER as part of their Final Decisions' for each of the businesses are outlined in Table 6 through Table 9 below.

Table 6: Aluminium cost escalators (%)

Aluminium	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
TransGrid[33]	-17.34	-14.06	9.13	10.55	10.93	9.32	NA	NA
Ausgrid[34]	-17.34	-14.06	9.13	10.55	10.93	9.32	NA	NA
Essential[35]	-17.34	-14.06	9.13	10.55	10.93	9.32	NA	NA
Endeavour[36]	-17.34	-14.06	9.13	10.55	10.93	9.32	NA	NA
ActewAGL[37]	-17.34	-14.06	9.13	10.55	10.93	9.32	NA	NA
Energex[38]	-18.76	-6.96	23.00	-1.20	0.40	-2.62	-3.58	NA
Transend[39]	-17.3	-14.1	9.1	10.5	10.9	-9.3	NA	NA
SA Power Networks[40]	-18.76	-6.96	23.00	-1.20	0.40	-2.62	-3.58	NA
SP AusNet (Tx)[41]	NA	NA	NA	NA	-14.7	0.8	-5.4	-4.6

33 AER, *Final decision TransGrid transmission determination 2009-10 to 2013-14*, 28 April 2009, p 32.

34 AER, *Final Decision New South Wales distribution determination 2009-10 to 2013-14*, 28 April 2009, p 485.

35 Ibid.

36 Ibid., p 486.

37 AER, *Final Decision Australian Capital Territory distribution determination 2009-10 to 2013-14*, 28 April 2009, p 44.

38 AER, *Final Decision Queensland distribution determination 2010-11 to 2014-15*, May 2010, p 192.

39 AER, *Final Decision Transend Transmission Determination 2009-10 to 2013-14*, 28 April 2009, p 44.

40 AER, *Final Decision South Australia distribution determination 2010-11 to 2014-15*, May 2010, p 139.

41 AER, *Draft decision - SP AusNet 2014-15 to 2016-17*, August 2013, p 58.

Table 7: Copper cost escalators (%)

Copper	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
TransGrid[42]	-27.93	-10.83	2.06	2.46	2.32	1.96	NA	NA
Ausgrid[43]	-27.93	-10.83	2.06	2.46	2.32	1.96	NA	NA
Essential[44]	-27.93	-10.83	2.06	2.46	2.32	1.96	NA	NA
Endeavour[45]	-27.93	-10.83	2.06	2.46	2.32	1.96	NA	NA
ActewAGL[46]	-27.93	-10.83	2.06	2.46	2.32	1.96	NA	NA
Energex[47]	-27.33	17.42	20.03	-5.42	-4.19	-7.48	-8.63	NA
Transend[48]	-27.9	-10.8	2.1	2.5	2.3	-2.0	NA	NA
SA Power Networks[49]	-27.33	17.42	20.03	-5.42	-4.19	-7.48	-8.63	-27.33
SP AusNet (Tx)[50]	NA	NA	NA	NA	-7.9	-3.8	1.5	1.1

42 AER, *Final decision TransGrid transmission determination 2009-10 to 2013-14*, 28 April 2009, p 32.

43 AER, *Final Decision New South Wales distribution determination 2009-10 to 2013-14*, 28 April 2009, p 485.

44 Ibid.

45 Ibid., p 486.

46 AER, *Final Decision Australian Capital Territory distribution determination 2009-10 to 2013-14*, 28 April 2009, p 44.

47 AER, *Final Decision Queensland distribution determination 2010-11 to 2014-15*, May 2010, p 192.

48 AER, *Final Decision Transend Transmission Determination 2009-10 to 2013-14*, 28 April 2009, p 44.

49 AER, *Final Decision South Australia distribution determination 2010-11 to 2014-15*, May 2010, p 139.

50 AER, *Draft decision - SP AusNet 2014-15 to 2016-17*, August 2013, p 58.

Table 8: Steel cost escalators (%)

Steel	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
TransGrid[51]	16.27	-15.32	7.21	5.25	1.03	0.76	NA	NA
Ausgrid[52]	16.27	-15.32	7.21	5.25	1.03	0.76	NA	NA
Essential[53]	16.27	-15.32	7.21	5.25	1.03	0.76	NA	NA
Endeavour[54]	16.27	-15.32	7.21	5.25	1.03	0.76	NA	NA
ActewAGL[55]	16.27	-15.32	7.21	5.25	1.03	0.76	NA	NA
Energex[56]	7.09	-28.29	33.03	1.00	0.80	-2.29	-3.25	NA
Transend[57]	16.3	-15.3	7.2	5.2	1.0	0.8	NA	NA
SA Power Networks[58]	7.09	-28.29	33.03	1.00	0.80	-2.29	-3.25	NA
SP AusNet (Tx)[59]	NA	NA	NA	NA	-12.8	4.7	3.4	1.3

51 AER, *Final decision TransGrid transmission determination 2009-10 to 2013-14*, 28 April 2009, p 32.

52 AER, *Final Decision New South Wales distribution determination 2009-10 to 2013-14*, 28 April 2009, p 485.

53 Ibid.

54 Ibid., p 486.

55 AER, *Final Decision Australian Capital Territory distribution determination 2009-10 to 2013-14*, 28 April 2009, p 44.

56 AER, *Final Decision Queensland distribution determination 2010-11 to 2014-15*, May 2010, p 192.

57 AER, *Final Decision Transend Transmission Determination 2009-10 to 2013-14*, 28 April 2009, p 44.

58 AER, *Final Decision South Australia distribution determination 2010-11 to 2014-15,* May 2010, p 139.

59 AER, *Draft decision - SP AusNet 2014-15 to 2016-17,* August 2013, p 58.

Table 9: Crude oil escalators (%)

Crude Oil	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
TransGrid[60]	-18.33	-5.19	10.24	5.74	2.16	1.30	NA	NA
Ausgrid[61]	-18.33	-5.19	10.24	5.74	2.16	1.30	NA	NA
Essential[62]	-18.33	-5.19	10.24	5.74	2.16	1.30	NA	NA
Endeavour[63]	-18.33	-5.19	10.24	5.74	2.16	1.30	NA	NA
ActewAGL[64]	-18.33	-5.19	10.24	5.74	2.16	1.30	NA	NA
Energex[65]	-17.34	-3.69	25.80	-2.97	0.24	-1.74	-2.46	NA
Transend[66]	-18.3	-5.2	10.2	5.7	2.2	1.3	NA	NA
SA Power Networks[67]	-17.34	-3.69	25.80	-2.97	0.24	-1.74	-2.46	NA
SP AusNet (Tx)[68]	NA	NA	NA	NA	-5.9	9.9	-4.1	-4.2

To summarise, for the majority of businesses, the AER adopted negative cost escalators in the early years' of their regulatory period (except for steel), thus implicitly, the AER was assuming that the real cost of these materials would reduce. *Ceteris paribus*, this leads to lower capital expenditure forecasts. However, in most cases, this was more than offset by large positive cost escalators in the later years of the regulatory control period.

60 AER, *Final decision TransGrid transmission determination 2009-10 to 2013-14*, 28 April 2009, p 32.

61 AER, *Final Decision New South Wales distribution determination 2009-10 to 2013-14*, 28 April 2009, p 485.

62 Ibid.

63 Ibid., p 486.

64 AER, *Final Decision Australian Capital Territory distribution determination 2009-10 to 2013-14*, 28 April 2009, p 44.

65 AER, *Final Decision Queensland distribution determination 2010-11 to 2014-15*, May 2010, p 192.

66 AER, *Final Decision Transend Transmission Determination 2009-10 to 2013-14*, 28 April 2009, p 44.

67 AER, *Final Decision South Australia distribution determination 2010-11 to 2014-15*, May 2010, p 139.

68 AER, *Draft decision - SP AusNet 2014-15 to 2016-17*, August 2013, p 58.

2.4.2. Impact of exchange rates

The forecast exchange rate is also an important determinant of these real materials cost escalators, as these materials are generally priced in US dollars, and therefore need to be converted to $AUD based on an estimated exchange rate at the time of the Final Decision. Therefore, any forecast change in the exchange rate over the period will alter the underlying change in the price of that commodity when considered in $AUD terms. For example, if the $AUD is forecast to depreciate against the $US, this will, *ceteris paribus*, lead to *increases* in the materials cost escalator when measured in $AUD.

The following table outlines the AER's assumptions of forecast exchange rates for each of the businesses considered as part of this assignment.

Table 10: Exchange rates assumed by AER in its determinations[69]

Company	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16
TransGrid[70]	0.96	0.67	0.65	0.63	0.62	0.62	NA	NA
Ausgrid[71]	0.96	0.67	0.65	0.63	0.62	0.62	NA	NA
Essential[72]	0.96	0.67	0.65	0.63	0.62	0.62	NA	NA
Endeavour[73]	0.96	0.67	0.65	0.63	0.62	0.62	NA	NA
ActewAGL[74]	0.96	0.67	0.65	0.63	0.62	0.62	NA	NA
Energex[75]	0.744	0.856	0.721	0.738	0.725	0.728	0.738	NA
Transend[76]	0.96	0.67	0.65	0.63	0.62	0.62	NA	NA
SA Power Networks[77]	0.744	0.856	0.721	0.738	0.725	0.720	0.738	NA
SP AusNet (Tx)[78]	NA	NA	NA	NA	NA	NA	NA	NA

The forecast exchange rates adopted by the AER (as shown in Table 10 above) were materially lower than outturn exchange rate over this period, as shown in the table below.

69 The annual exchange rates shown for Energex and SA Power Networks differ from those shown for the other NSW businesses because of the difference in the timings of their determinations.

70 AER, *Final decision TransGrid transmission determination 2009-10 to 2013-14*, 28 April 2009, p 152.

71 AER, *Final Decision New South Wales distribution determination 2009-10 to 2013-14*, 28 April 2009, p 502.

72 Ibid.

73 Ibid.

74 AER, *Final Decision Australian Capital Territory distribution determination 2009-10 to 2013-14*, 28 April 2009, p 48.

75 AER, *Final Decision Queensland distribution determination 2010-11 to 2014-15*, May 2010, p 81.

76 AER, *Final Decision Transend Transmission Determination 2009-10 to 2013-14*, 28 April 2009, p 171.

77 AER, *Final Decision South Australia distribution determination 2010-11 to 2014-15*, May 2010, p 139.

78 AER, *Draft decision - SP AusNet 2014-15 to 2016-17*, August 2013, p 58.

Table 11: Actual historical exchange rates

Company	2008/09	2009/10	2010/11	2011/12	2012/13
$AUD to $US	$0.74	$0.88	$1.00	$1.04	$1.02

Source: RBA, OGW

Ceteris paribus, this reduces an electricity business' cost of procuring materials that are priced in $US terms, relative to what was assumed for the purposes of developing their pricing submissions[79].

2.4.3. Possible impact of materials costs on future electricity prices

To better understand how changes in future prices for aluminium, copper, steel and crude oil might impact on future electricity costs, we analysed recent historical price trends as well as forecast price trends, to ascertain the likelihood that a regulated business subject to an AER review over the study's evaluation period will need to factor in higher or lower prices for materials into their capital program (and to a lesser degree, their operating expenditure programs).

These historical and forecast commodity prices were obtained from three different sources:

- The World Bank (WB),
- The International Monetary Fund (IMF), and
- The Economist – Intelligence Unit (EIU).

The data collected was in nominal US dollars, and converted to Australian dollars, and converted into $2012. We then took the median commodity price forecast of the three sources[80]. The information in the following paragraphs is in $AUD.

- **Aluminium:** Between 2008/09 and 2012/13, aluminium prices fell from $2,475/tonne to $1,933/tonne (a fall of approximately 22%), on the back of a falling oil price and strengthening Australian dollar[81]. Aluminium prices in 2013/14 are forecast to increase by approximately $300/tonne. Aluminium consumption is forecast to increase, with this being driven, by amongst other things, substitution away from copper, mainly in the wiring and cable sectors (copper prices are now more than four times higher than aluminium prices, whereas the two were similar in price prior to the 2005 boom). Aluminium prices are forecast to increase to $2,470/tonne by 2015/16.

79 Note: Actual outcomes will be a function of a number of other interrelated factors, including a business' hedging strategies, as well as the underlying changes in the commodity in $US terms.

80 As there was only 1-2% difference between two of the price forecasts, the median was used, whereas the use of the mean would have skewed the data by the outlier.

81 http://oilprice.com/Metals/Commodities/Falling-Oil-Prices-Causing-Temporary-Drops-In-Aluminum.html (accessed on 6/09/2013).

- **Copper:** After reaching peaks of over $9,000/tonne in 2008 the price of copper fell sharply at the end of that year as a result of the global economic crisis[82]. The price in 2009 was down to $7,657/tonne. Since then the price has staged a steady recovery with the result that the price rose in each subsequent quarter to reach $9,153/tonne by 2010/11. Copper demand expanded by 4.7% in 2012, up from 1.4% the year before, with China's demand increasing 11.7%, up from 7.2% in 2011. High copper prices are said to have induced a wave of new mines and expansions of existing ones that are expected to come on-stream soon. Copper stocks at the London, New York and Shanghai exchanges (combined) were up 95% in May 2013 compared to the year before[83]. Copper prices are forecast to increase by approximately $1,300/tonne over the next three years as a result.
- **Iron ore (proxy for steel):** Iron ore is a basic ingredient in the production of steel and is generally viewed as a cyclical commodity, sensitive to changes in global economic conditions. Between 2008/09 and 2010/11, the price of iron ore increased by almost 50%, from $119/tonne to $174/tonne. The following two years saw iron ore prices fall by $48/tonne as China's appetite for iron ore (which consumes over half of global iron ore output) weakened with slowing steel demand from the construction sector, pushing down prices for the steel-making ingredient nearly 30%[84]. Iron ore prices are forecast to increase by approximately $11/tonne over the next three years, to $138/tonne in 2015/16.
- **Crude oil:** Historically, crude oil prices increased approximately 8% between 2008/09 and 2012/13, from $92/bbl to $100/bbl. More recently, oil prices have fallen from a high of $108/bbl in 2010/11. Over the next three years, it is forecast to increase a further $14/bbl.

Table 12 on the following page presents historical and forecast changes in the relevant materials costs. Figure 6, which follows the table, presents the same information in a graph.

82 http://www.icf.at/en/6448/raw_material_price_trends.html (accessed on 6/09/2013).

83 Ibid.

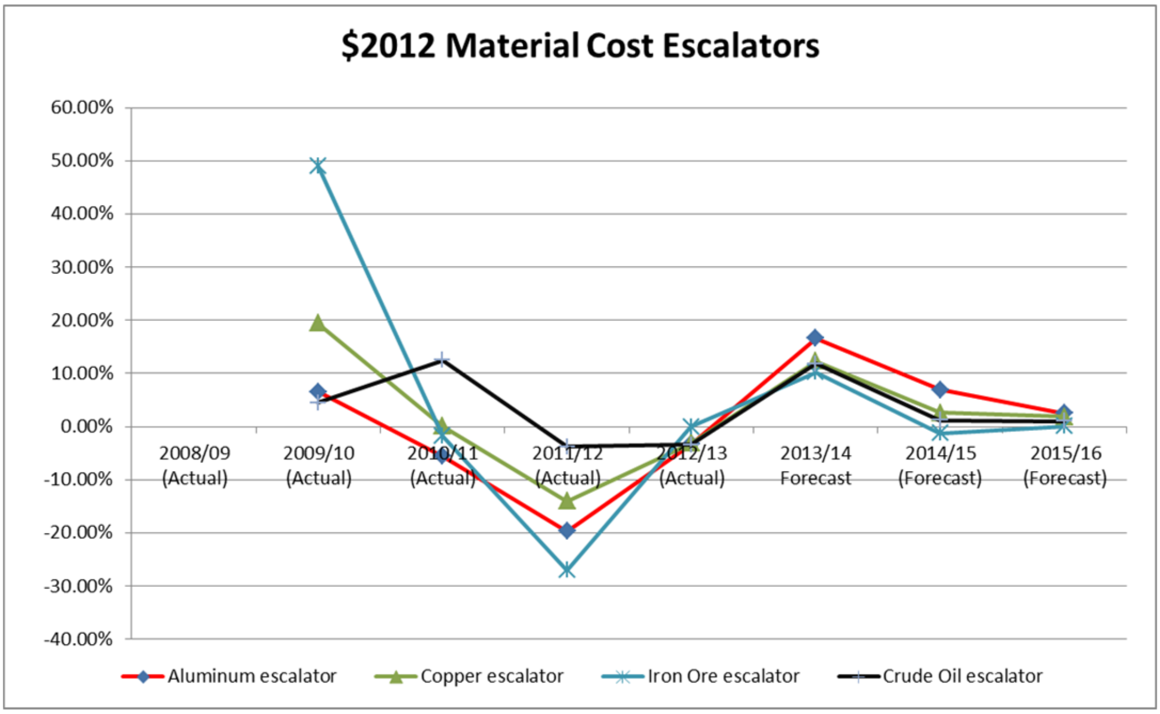
84 http://www.reuters.com/article/2011/10/26/us-ironore-idUSTRE79P1BB20111026 (accessed on 6/09/2013).

Table 12: Actual/forecast change in material costs ($AUD 2012)

Material	2008/09 (Act)	2009/10 (Act)	2010/11 (Act)	2011/12 (Act)	2012/13 (Act)	2013/14 (For)	2014/15 (For)	2015/16 (For)
Aluminium (2012/13 AUS$/tonne)	$2,475	$2,638	$2,490	$1,999	$1,933	$2,254	$2,410	$2,470
Aluminium escalator		*6.57%*	*-5.61%*	*-19.73%*	*-3.31%*	*16.63%*	*6.92%*	*2.48%*
Aluminium cumulative escalator		*6.57%*	*0.60%*	*-19.25%*	*-21.92%*	*-8.94%*	*-2.64%*	*-0.23%*
Copper (2012/13 AUS$/tonne)	$7,657	$9,148	$9,153	$7,865	$7,618	$8,550	$8,772	$8,932
Copper escalator		*19.47%*	*0.05%*	*-14.07%*	*-3.14%*	*12.24%*	*2.59%*	*1.83%*
Copper cumulative escalator		*19.47%*	*19.53%*	*2.71%*	*-0.51%*	*11.66%*	*14.56%*	*16.65%*
Iron Ore (2012/13 AUS$/tonne)	$119	$177	$174	$127	$127	$140	$138	$138
Iron Ore escalator		*49%*	*-2%*	*-27%*	*0%*	*10%*	*-1%*	*0%*
Iron Ore cumulative escalator		*49%*	*46%*	*7%*	*7%*	*18%*	*16%*	*16%*
Crude Oil (2012/13 AUS$/b)	$92	$96	$108	$104	$100	$112	$113	$114
Crude Oil escalator		*4.45%*	*12.44%*	*-3.82%*	*-3.43%*	*11.81%*	*1.16%*	*0.94%*
Crude Oil cumulative escalator		*4.45%*	*17.45%*	*12.97%*	*9.09%*	*21.96%*	*23.38%*	*24.54%*

Source: The World Bank; The International Monetary Fund; The Economist – Intelligence Unit; OGW analysis

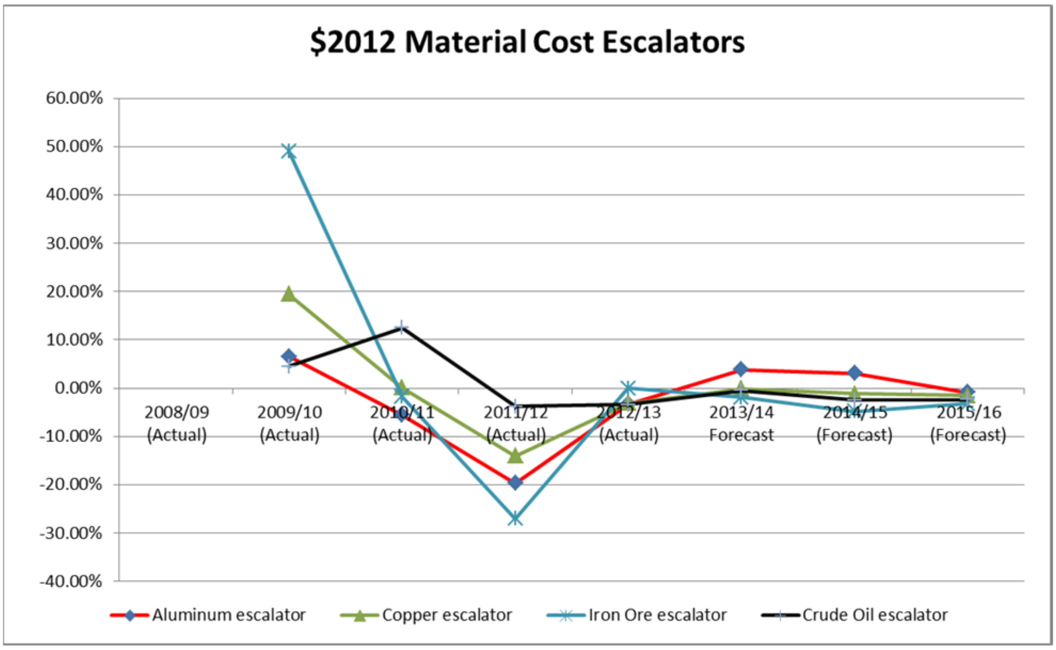
Figure 6: Real materials cost escalators



Source: The World Bank; The International Monetary Fund; The Economist - Intelligence Unit; OGW analysis

We note for completeness, that much of the forecast increase in materials cost stems from the forecast depreciation of the exchange rate over that evaluation period. *Ceteris paribus*, if the exchange rate were to continue at parity, only aluminium would be forecast to increase in real $US terms over the evaluation period. This is diagrammatically represented in Figure 7 on the following page.

Figure 7: Materials Cost Escalators excluding the impact of forecast changes in the exchange rate



Source: The World Bank; The International Monetary Fund; The Economist - Intelligence Unit; OGW analysis

Overall, on the balance of probabilities, it is likely that materials cost, when measured in $AUD, will increase in real terms over the evaluation period, although as highlighted in the above graph, much will depend on the outlook for the $AUD. Interestingly, despite the outturn $USD/$AUD exchange rate differing materially from the AER's assumptions for virtually every business, the forecast change in each of the materials does not appear to have diverged materially from outturn changes, which, *ceteris paribus*, would indicate that there is unlikely to be a material risk of unit rates for different asset classes differing materially to what was otherwise forecast as part of the current price determinations[85].

2.5. Macro-economic drivers

Each of the aforementioned input cost drivers are affected by broader macro-economic conditions affecting state economies, the national economy, and the world economy. For example, labour cost escalators may be different across states, depending on the broader economic conditions within and affecting each state. The WACC – and in particular the risk free rate – is particularly influenced by national economic conditions and expectations, whilst commodity prices are predominately influenced by global economic conditions.

However, beyond the impact on the specific input cost drivers discussed in previous sections of this report, macro-economic factors influence electricity price outcomes via their impact on the amount of electricity that is forecast to be demanded by customers, and the amount of energy that is forecast to be consumed by customers.

In particular, *ceteris paribus*, strong macro-economic conditions are likely to be (positively) correlated with increased consumption of electricity and increased demand for electricity, particular in the non-residential segment – although we would not wish to overstate this relationship.

In the case of the former, any increase in the amount of energy consumed will, *ceteris paribus*, lead to lower unit prices, where an electricity business adopts a tariff structure that charges based on electricity throughput (which most do). In the case of the latter, any increase in the amount of electricity demanded will lead to higher demand forecasts for that business, which will in most cases lead to a higher level of forecast capital expenditure being required which may (but may not) put upward pressure on prices[86].

As was highlighted earlier in this report, the RBA has indicated in its most recent *Statement of Monetary Policy* that it expects GDP growth to pick up to above-trend growth by 2015. More specifically, it is forecasting year-average GDP growth in 2015 to be between 2.75 and 3.75 precent.

Despite this, our view is that the literature is neither overly bearish nor bullish in relation to Australia's broader macro-economic outlook for the next few years. Therefore, based on currently available information, this is likely to have a neutral bearing on future prices outcomes.

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85 That is, that the unit rates for different asset classes would need to be "reset", as a result of a substantial difference between forecast materials cost escalators and actual materials cost escalators.

86 There are a number of other factors that will determine the extent to which higher forecasts of demand impact upon a business' capital expenditure forecasts, including the existing levels of spare capacity that a business has in its network, and whether demand increases are actually occurring in areas that are subject to capacity constraints.

3. Augmentation and licence driven reliability improvements

3.1. Objective

The objective of this section of the report is to provide high level qualitative advice to the AEMC with regards to the likely direction of future augmentation for each of the distribution businesses analysed as part of this report. A second-order objective is to highlight how licence-driven reliability improvement capital expenditure may change in the next regulatory periods within each jurisdiction of interest.

3.2. Overview

In undertaking this high level, qualitative assessment, we have reviewed a number of publically available sources of information, including, but not limited to:

- The businesses' Regulatory Proposals,
- AER Draft and Final Decisions,
- The businesses' Network Development Plans,
- The National Electricity Forecasting Report (NEFR),
- The businesses' Annual Pricing Proposals, and
- Ad hoc, recent, publicly available submissions/statements made by individual distribution businesses.

The extent to which we have placed reliance on any individual source was dependent on the scale and scope of information that was able to be derived from that source.

It should be noted, however, that to some extent the augmentation costs reported by the networks and discussed in this section will have been affected by movements in materials costs. This section discusses augmentation costs as reported by the networks; we have not disaggregated the effects of changes in materials costs discussed in the previous section.

3.3. Ausgrid

In its June 2008 Regulatory Proposal, Ausgrid (then Energy Australia) stated that its capital requirement for 2009-14 was $8.66 billion ($2008-09).

The key components of this capital program pertaining to augmentation and licence driven changes in reliability were:

- Its Sydney CBD Area Plan, which contributed $612 million ($2008-09), and was to provide for two new zone substations (which represented a 40% increase) and was "*to meet load growth and the N-2 design criteria licence condition*[87]";
- Increased capacity in the 11kV system, which contributed $698 million ($2008-09), and was to restore capacity in line with the Design, Reliability and Performance (DRP) licence conditions; and
- Other 'Area Plans', which contributed $2,894 million ($2008-09), and was for 42 new zone substations and retirement of 32 zone substations[88].

87 EnergyAustralia, *Regulatory Proposal*, June 2008, p 8.

At the time, Ausgrid indicated in its Regulatory Proposal that they expected 37 zone & subtransmission substations to be over their firm rating[89]. Further, Ausgrid stated that[90]:

> *"…. approximately 11 percent of assets that currently experience loading outside the criteria as set in the Design, Reliability and Performance (DRP) licence conditions, and on average 11 percent of zone substations and subtransmission substations are older than designed life."*

Ausgrid's Regulatory Proposal was premised on average peak demand growth of 2.8 percent.[91]

Whilst the AER's Final Decision for Ausgrid included a reduction in the business' expenditure allowance from the $8.66 billion originally proposed to around $6.6 billion ($2008-09), the aforementioned figures illustrate the overall contribution that augmentation related capital expenditure (and licence compliance driven expenditure) contributed to Ausgrid's overall capital expenditure requirements.

We reviewed Ausgrid's 2012/13 Electricity System Development Review (ESDR) to assess the extent to which it indicated the likely magnitude of Ausgrid's augmentation program over the next regulatory control period. The ESDR indicates that around 3% (or 9) of Ausgrid's zone substations are expected to reach loadings where investment will be triggered within the next 5 years – a period that not only covers this current regulatory control period, but the first two years of the next regulatory period. We note that this needs to be considered in light of the fact that another 19 (around 8%) of Ausgrid's zone substations are expected to have loadings that equal, or exceed their "secure capacity" over the period to 2018/19. Another 3% of zone substations are expected to be loaded to levels that very nearly reach "secure capacity" levels.

Another broader observation is that Ausgrid's expected feeder loadings (33kV, Sub transmission) do not appear to be likely to trigger large scale augmentations, at least within the early years of the next regulatory control period.

Whilst it is difficult to draw definitive conclusions from reviewing the ESDR in isolation, it would appear that Ausgrid's extensive capital program in this regulatory control period may have alleviated a number of the constraints on its network.

To complement this analysis, we also undertook a high level analysis of how forecasts of summer peak demand have changed since Ausgrid's current regulatory determination was made. In summary, since the 2009 regulatory determination process, there has been a significant downward revision in the forecasts of summer peak demand in NSW. For example, the latest NEFR (2013) states that[92]:

> *"The 10% POE MD is forecast to increase from 2013-14 to 2022-23 at an annual average rate of 1.0% under the medium scenario, compared to 1.1% in the 2012 NEFR."*

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88 It should be noted that that Ausgrid's Area Plans were discussed but did not entirely separate the impact of several drivers, including peak demand growth, aged replacement and capex required to meet the demands associated with new customer connections. To the extent that the sources used have discussed the drivers consistently across time, our estimates of the total impact of changes in capex requirements will be broadly correct even if we cannot always accurately disaggregate the magnitude of the impact to its component parts.

89 Ibid., p 46.

90 EnergyAustralia, *Regulatory Proposal*, June 2008, p 3.

91 Ibid., p 42.

92 AEMO, *National Electricity Forecasting Report - 2013*, p 4-1.

This compares to Ausgrid's assumption of an average per annum growth in peak demand of 2.8 percent over the current regulatory period. It is noted that caution needs to be drawn in directly comparing these figures, as there is likely to be a difference between the rate at which peak demand is growing in the Ausgrid distribution area as compared to the state as a whole. To test this further, we assessed forecasts that were provided by AEMO back in 2010 to assess whether there had in fact been an overall decline in forecast demand across NSW. In the 2010 Electricity Statement of Opportunities, AEMO forecasted that in NSW, the[93]:

> *"summer 10% POE MD is projected to increase over the next 10 years at an annual average rate of 2.3% under the medium growth scenario."*

What this illustrates is that since the time at which Ausgrid developed its Regulatory Proposal, there has been a substantial reduction in the overall forecasts of summer peak demand in NSW – from 2.3% per annum in 2010, to 1.0% per annum in 2013. Overall, one would expect that the factors that have driven such reductions would be fairly evenly distributed across NSW; therefore, one could assume that if Ausgrid were to forecast its demand growth now, it would be materially lower than what they forecast in 2009.

Over the longer term, a lower growth should translate into lower augmentation capital expenditure requirements. However, there are two factors that will influence the timing and magnitude of such a reduction. The first is the fact that growth in peak demand may not be equally distributed geographically across the distribution area; the second is that the headroom available between peak demand and capacity limits may not be equally distributed across the local asset areas of the network. Depending on how factors co-vary by local network area will have material impacts on the timing with which a lower peak demand growth rate will translate in lower capital expenditure requires for the network business..

This appears to have been confirmed by a submission made by the NSW DNSPs to the Productivity Commission's Draft Report into Electricity Network Regulatory Frameworks, where they stated that[94]:

> *"We concur with the Commission's assessment that peak demand growth has slowed over the past two to three years. To this end, meeting peak demand growth is unlikely to be a primary driver of investment moving forward. Dealing with greenfield and brownfield residential and business growth and replacement of ageing assets will be the focus of NSW DNSP future capital investment programs".*

In addition to the above, we would expect that the capital expenditure requirements to support the achievement of the N-2 design criteria licence condition would reduce materially in the next regulatory period. In particular, it is our understanding from the information available that the "*N-2 design criteria licence condition*" has to be achieved by 2014[95] – which is within Ausgrid's current regulatory control period. A similar observation applies to the large expenditure on the 11kV Network Development Plan, which, according to Ausgrid is[96]:

93 AEMO, *2010 Electricity Statement of Opportunities for the National Electricity Market*, p 45.

94 NSW DNSPs, *Response to Productivity Commissions Draft Report - Electricity Network Regulatory Frameworks*, 23 November, 2012.

95 For example, on page 4 of its 2008 Regulatory Proposal, Ausgrid states "*these licence conditions must be achieved for all existing assets by 2014 which effectively brings forward some future investment in capacity into the 2009-14 period*".

96 EnergyAustralia, *Regulatory Proposal*, June 2008, p 69.

"made up of a catch-up compliance portion of $439 million and an ongoing compliance portion of $259 million which will continue beyond the period at this level to keep pace with underlying load growth".

3.4. Essential Energy

In its Regulatory Proposal, Essential Energy (then Country Energy) stated that[97]:

> *"Peak demand, particularly summer peak demand, is a principal driver of growth related capital expenditure."*

It further stated that[98]:

> *"The average annual rate of growth in summer and winter peak demand for the whole of the network is expected to be 3.0 per cent and 1.8 per cent per annum respectively under the base growth scenario over the period to 2013-14."*

This led to it forecasting $1.4 billion of augmentation related capital expenditure over the regulatory control period – or around 43% of its total system capital expenditure forecast, or 35% of its total capital expenditure forecast[99]. In short, it represented by far and away the most significant contributor to Essential Energy's capital expenditure forecasts at the time.

In its Final Decision, the AER accepted Essential Energy's revised demand forecasts, which were virtually exactly the same as the 3.0% outlined in the original Regulatory Proposal.

As was outlined in the previous section for Ausgrid, there has been a significant downward adjustment in expectations as to how summer peak demand will change in the future. If these expectations remain unchanged until the commencement of the next regulatory determination process, it would be reasonable to expect that Essential Energy would adopt materially lower forecasts of peak demand growth for its next regulatory proposal as compared to those used in its current one. Whilst the extent to which lower demand forecasts leads to lower augmentation capital expenditure forecasts is a function of, amongst other things, the spatial aspects of that growth (i.e., where growth occurs, and in particular, the extent to which it is more or less concentrated in areas where the existing distribution network is constrained), on the balance of probabilities, this should, if anything, lead to lower augmentation forecasts than the current regulatory control period. Again, this has been broadly confirmed by the NSW DNSPs in their submission to the Productivity Commission's *Draft Report into Electricity Network Regulatory Frameworks*.

Ideally, we would confirm this by reviewing Essential Energy's Electricity System Development Review; however, this document was not available on their website at the time this report was prepared.

97 Country Energy, *Regulatory Proposal 2009-2014*, 2 June 2008, p 84.

98 Ibid.

99 Non-system capex was a higher proportion of total capex in Essential Energy's case than for any of the other distribution businesses. Further inspection revealed that its costs in this area were predominantly associated with vehicles and secondarily, IT.

3.5. Endeavour Energy

In its 2008 Regulatory Proposal, Endeavour Energy (then Integral Energy) forecast that its maximum system (peak) demand was forecast to grow annually at 3.6% over the 2009 regulatory control period[100]. Endeavour Energy forecast that it would spend around $1.35 billion ($2008/09) over the 2009 regulatory control period[101] on growth capital expenditure forecasts. In addition, Endeavour Energy forecast that it would spend around $403 million ($2008/09) complying with the NSW DRP Licence Conditions, which imposed a "*significant requirement for network augmentation on NSW DNSPs*[102]". This latter requirement equated to "*9 transmission substations, 43 sub-transmission feeders, 27 zone substations and 478 distribution feeders …. over the 2009 regulatory control period*[103]". Overall, this represented around 66% of Endeavour Energy's forecast total system capital expenditure over the period, or 59% of its forecast total capital expenditure over the period. In short, augmentation related capital expenditure, as well as the need to comply with more onerous licence requirements, were by far and away the largest driver of Endeavour Energy's forecast capital expenditure requirements.

Whilst Endeavour Energy revised its capital expenditure program as part of its response to the draft decision, the proportions stayed at similar levels[104], and the AER made no material change to this revised forecast in its Final Decision[105].

Endeavour Energy's most recent *Electricity System Development Review* (2012) provides a detailed description of the zone substations that are expected to exceed capacity limitations within a five year period. It is indicates that for around 20% of its zone substations / transmission substations, forecast peak load in 2016 will exceed current firm/ cyclic rating. This indicates that based on the demand forecasts underpinning Endeavour Energy's ESDR, its network is still generally highly utilised.

Notwithstanding this, we note the information that has previously been referred to in the Ausgrid and Essential Energy sections of this report, namely that the most recent forecasts of growth in summer peak demand have been reduced materially relative to those assumed as part of the 2009 Regulatory Proposal. This also applies for Endeavour Energy, who assumed an annual growth rate of 3.6% over the 2009 regulatory control period. On the balance of probabilities, this should, if anything, lead to lower augmentation forecasts than the current regulatory control period. Again this has been broadly confirmed by the NSW DNSPs in their submission to Productivity Commission's *Draft Report into Electricity Network Regulatory Frameworks*.

Overall, we consider that if:

- forecast demand growth continues at currently forecast levels, and
- capital expenditure driven by the need to comply with Licence Requirements regarding reliability does undergo the large reduction that seems likely,

100 Integral Energy, *Regulatory Proposal to the Australian Energy Regulator 2009 to 2014*, 2 June 2008, p 66.

101 Ibid., p 112.

102 Ibid., pp 117 and 118.

103 Ibid.

104 For example, augmentation and compliance, as a proportion of total proposed capital expenditure was around 55%.

105 AER, *Final decision - New South Wales distribution determination 2009-10 to 2013-14*, 28 April 2009, p 145.

the combined effect will be to place material downward pressure on Endeavour Energy's future augmentation-related capital expenditure programs.

3.6. ActewAGL

ActewAGL's proposed augmentation related capex was $76.5 million over the regulatory period[106]. The business proposed a similar amount in its Revised Proposal, and the AER, in its Final Decision, accepted those forecasts[107], subject to them being updating with revised input cost escalators. We estimate that this reduced ActewAGL's augmentation program by around 7.5%, which, if applied to ActewAGL's original augmentation forecasts, reduces its allowance to around $71 million over the regulatory period.

ActewAGL's original demand forecasts were 1.9% per annum[108]. It reduced these forecasts to 0.6% per annum in its Revised Proposal[109]. In doing so, it stated that it had[110]:

> *"reviewed the forecasts in light of the significant revisions to economic growth forecasts and CPRS implications outlined above. The revised system demand in 2013/14 is 5 per cent lower in summer and 6 per cent lower in winter when compared with the original forecast. This reflects the impact of the downward revision of the economic growth forecasts for the ACT, together with the impact of higher prices resulting from the CPRS."*

As part of its Final Decision, the AER accepted the lower demand forecasts that ActewAGL provided in its Revised Proposal. However, based on information contained on page 34 of ActewAGL's Revised Proposal, it appears that whilst the reduction in ActewAGL's demand forecasts deferred augmentation *within* the regulatory control period, it did not change the magnitude of the program materially over the entire regulatory period.

We note that in its original Regulatory Proposal, ActewAGL stated that[111]:

> *"An important implication of ActewAGL Distribution's relatively small size is that major network augmentations have a significant step impact on total capital expenditure. This is apparent in the capital expenditure forecasts presented in chapter 7. While no new zone substations were built during the 2004-09 regulatory period, two new zone substations and a major substation augmentation will be required during the 2009-14 regulatory period. These zone substation projects, along with the required southern supply point augmentation, are major drivers of the forecast increase in augmentation capital expenditure <u>from $13.9 million in the current regulatory period to $76.5 million for the 2009-14 period.</u>" [Emphasis added]*

106 ActewAGL, *Regulatory Proposal to the Australian Energy Regulator*, June 2008, p 126.

107 Based on information contained on page 34 of ActewAGL's revised proposal (January, 2009), the reductions in demand deferred augmentation within the regulatory control period, however, it did not change the overall magnitude of the program materially.

108 AER, *Final decision Australian Capital Territory distribution determination 2009-10 to 2013-14*, 28 April 2009, p 27.

109 Ibid.

110 ActewAGL, *Revised Regulatory Proposal to the Australian Energy Regulator*, January 2009, p 43.

111 ActewAGL, *Regulatory Proposal to the Australian Energy Regulator*, June 2008, p 12.

Whilst any network business' augmentation program is, to a degree, "lumpy", ActewAGL's comments above highlight that this is an even larger issue for its business, as a result of its relatively small size. This limits the ability to overlay high level drivers of network augmentation expenditure, for example, changes in state-wide demand, on ActewAGL's network and then infer outcomes.

In lieu of this, we sought to review ActewAGL's key long-term planning document, namely its "Network Ten Year Augmentation Plan". Unfortunately, we were not able to locate this document on the ActewAGL website. However, as part of its 2009 Regulatory Proposal, ActewAGL cited the following key outcomes from its Network Ten Year Augmentation Plan[112]:

> *"The sub-transmission lines have sufficient capacity to cope with load growth in the foreseeable future under the current operational regime.*
>
> *Most zone substations have adequate capacity to cope with the current summer and winter peak load. However, demand at five zone substations will exceed their two-hour emergency ratings within ten years. Zone substation demand forecasts are provided in chapter 5. New zone substations and zone substation expansion are required to cope with the demand increase.*
>
> *The 11kV distribution network has been able to meet the maximum demand in all parts of the network under normal operational conditions. However an increasing number of feeders have reached or exceeded feeder firm ratings in summer. Network capacity augmentations and network reconfigurations will continue to be required to address the distribution network capacity shortage."*

For context, it is noted that at the time of its last regulatory proposal, ActewAGL only had 11 zone substations[113], therefore, the information above indicates that at the time it prepared its Network Ten Year Augmentation Plan it considered that five of the 11 zone substations were expected to breach their two-hour emergency rating thresholds during the next 10 years. In another part of its Regulatory Proposal, ActewAGL states that its augmentation criteria for zone substations is that the "*load should not exceed two-hour emergency rating of the substation*"[114].

Overall, based on the information outlined above, we consider that on the balance of probabilities, it is likely that ActewAGL's augmentation related expenditure will likely increase, but not to the extent that may be indicated by the ratio above (5 zone substations out of 11). We base this on two assumptions: (1) that expenditure on the southern supply point augmentation will cease in the next period, which in turn will offset any increases in expenditure required on zone substation augmentation; and (2) that the lower levels of demand forecast by ActewAGL in their Revised Proposal are more likely to be reflective of future demand forecasts than the forecasts that underpinned their original proposal, which in turn should relieve pressure on their network, thus potentially delaying the need to augment a number of those zone substations.

3.7. Energex

Based on Energex's Regulatory Proposal for 2010-2015, its augmentation related capital program was expected to be driven by a number of influences, including:

112 ActewAGL, *Regulatory Proposal to the Australian Energy Regulator*, June 2008, p 105.

113 Ibid., p 10.

114 Ibid., p 102.

- the delivery of the 'Electricity Distribution for Service Delivery in the 21st Century' (EDSD)[115] security compliance program throughout the 2010-15 regulatory control period[116];
- reliability enhancements arising from the EDSD Review, with the codification of Minimum Service Standards (MSS) and Guaranteed Service Levels (GSL) in the Queensland Electricity Industry Code (EIC) under the Electricity Act 1994[117]; and
- a forecast increase in peak demand of 4.36 per cent per annum[118].

The first two of those, in combination, accounted for over $2.1 billion ($2009-10) of Energex's proposed $6.4 billion ($2009-10) capital expenditure program[119]. In the third component, growth in demand growth was the predominant driver of Energex's $2.6 billion ($2009-10) growth driven capital expenditure program[120]. In total, these components made up 73.4% of Energex's forecast capital program.

These assumptions were tempered slightly in the AER's Final Decision. For example, demand was reduced to 3.8% per annum, which in turn was the primary driver of reduced allowance for this capital expenditure category – in the order of $270 million ($2009-10).

With regards to those costs that were premised on reliability enhancements and the delivery of the EDSD, we would expect, on the balance of probabilities, that they will diminish materially in the next regulatory control period. This is not to say that there will not be higher costs than would have otherwise been faced to maintain those now higher levels of service; however, it would be our expectation that the majority of the costs required to move the underlying standard up that higher level will have been incurred in the current regulatory period.

With regards to augmentation related costs, there is *prima facie* evidence to suggest that if anything, there may be diminished pressure on Energex's future growth capital expenditure, with lower demands being forecast in the QLD region in the future, relative to that which was assumed in its current Final Decision. In particular, we note that AEMO, in its most recent NEFR (2013) indicates that:[121]

> *"Queensland's MD (10% probability of exceedance, or POE) is expected to increase by an annual average of 3.2% over the 10-year outlook period under the medium economic growth scenario, with the biggest increase occurring in the first half of the outlook period due to the revised timing of LNG projects."*

However, caution needs to be exercised when assessing the impact on Energex's forecast growth capital expenditure in the next period, for a number of reasons, including:

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115 On page 196 of its Regulatory Proposal, Energex states that "*The EDSD Review recommended ENERGEX adopt planning processes that apply a deterministic 'N-1' planning philosophy to sub-transmission feeders and bulk supply and zone substations. A revision of the security planning guidelines for the practical application of the 'N-1' approach is currently being considered by the technical regulator. ENERGEX has based the capital expenditure forecast included in this Regulatory Proposal on the revised security planning guidelines*"

116 Energex, *Regulatory Proposal for the period July 2010 - June 2015*, July 2009, p 6.

117 Ibid.

118 Ibid., p 16.

119 Ibid., p 19.

120 Ibid.

121 AEMO, *National Electricity Forecasting Report - 2013*, p vi.

- in the 2012 NEFR, under the medium scenario, this figure was a full 1% lower, at 2.2% per annum, which indicates potential volatility in this forecast;
- the driver of the increase between the 2012 and 2013 NEFR forecasts is due to the revised timing of LNG projects, which we consider are likely to impact more upon Ergon Energy's network than Energex's network; and
- mapping to spatial demand forecasts, which means that the "raw" growth rate in demand is, as discussed earlier, but one of the factors that drives a business' augmentation program (i.e., where the growth occurs and the level of spare capacity within the network both matter).

To test this further, we reviewed Energex's *Network Management Plan* for 2012/13 to 2016/17. We note that Energex is forecasting that:

- only 1 out of its approximately 40 Bulk Supply Substation will exceed its required security of supply standard in the first two years of the next regulatory control period – compared with 15 back in 2007/08[122], which was the last forecast of this type made before, and therefore was almost certainly used in formulating, Energex's proposal for the 2010-2015 regulatory period; and
- only around 9 of its approximately 230 zone substations will not meet their required security of supply levels in the first two years of the next regulatory control period – compared with 109 back in 2007/08[123].

Further, our review of Energex's *Network Management Plan* does not indicate to us that there is likely to be a material upswing in the volume of augmentations that Energex needs to complete at a feeder level during the next regulatory control period.

In summary, collectively, this information indicates to us that on the balance of probabilities, the volume of augmentation-related capital expenditure and work required to meet enhanced reliability-related licence conditions that Energex will need to undertake in the next regulatory control period is likely to be smaller than what was proposed, and accepted by the AER, for the current period. .

3.8. SAPN

In its 2009 Regulatory Proposal, SAPN (then ETSA Utilities) proposed to invest around $775 million ($2009/2010) on the extension and augmentation of its existing network to meet peak demand growth. This represented around 33% of SAPN's $2.3 billion total forecast capital expenditure program.

A key input to this was SAPN's forecast that maximum demand would increase by 3.0% per annum[124].

In its Final Decision, the AER provided a total capital expenditure allowance of $1.587 billion ($2009-10), whilst making only relatively minor reductions in SAPN's demand driven allowance. This increased the proportion of augmentation-related capital expenditure in SAPN's overall approved capital expenditure program to, we estimate, over 45%, making it by far and away the largest contributor to SAPN's final capital expenditure allowance.

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122 Energex, *Regulatory Proposal for the period July 2010 - June 2015*, July 2009, p 113.

123 Ibid.

124 AER, *Draft decision South Australia Draft distribution determination 2010-11 to 2014-15*, 25 November 2009, p xvii.

In its most recent network development plan, SAPN is forecasting an overall increase in demand of around 2.5% per annum[125]. This is not materially different to the growth rate that was accepted by the AER as part of its final decision (which was 2.4%)[126]. A high level review of SAPN's most recent *Electricity System Development Plan* (2012) indicates a number of broad constraints across its region that will need to be addressed over the next few years.

More broadly, in our review, we discovered a consolidated forecast that SAPN had provided of its forecast augmentation program into the next regulatory control period. This was provided in an Appendix to the business' 2012 pricing proposal (April 2012).

Figure 8: Consolidated Forecast of SAPN's Growth Related Capital Expenditure ($000's 2010/11)

Asset class	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Subtransmission	24,005	63,482	84,114	32,871	25,648	25,055	37,227	45,765	37,290	80,278	92,514
Zone substations	23,246	28,588	45,255	52,440	50,829	46,444	44,139	47,867	30,079	26,530	31,021
HV network	33,182	16,172	18,537	16,253	19,484	19,174	16,524	16,720	16,964	16,446	16,558
Distribution substations	77,383	28,844	30,159	28,820	29,977	30,189	31,066	31,713	32,481	33,390	34,471
LV network	17,357	7,148	7,299	7,118	7,228	7,362	7,585	7,749	7,943	8,173	8,447
Services	14,833	3,508	3,368	3,331	3,272	3,387	3,395	3,404	3,414	3,426	3,441
LV Network & Services	32,190	10,656	10,667	10,449	10,500	10,750	10,980	11,153	11,358	11,600	11,888
Total standard control	**190,006**	**147,741**	**188,733**	**140,834**	**136,438**	**131,612**	**139,936**	**153,218**	**128,172**	**168,244**	**186,453**

Source: SAPN, *Pricing Proposal - Appendix E - Distribution Tariffs Long Run Marginal Cost Methodology*, April 2012

In that document, SAPN states that[127]:

> *The forecast for the 2010-15 regulatory control period is the same as that provided to the AER in ETSA Utilities' regulatory proposal and accepted by the AER in its Decision for the 2010-15 regulatory control period. The forecast from 2015-20 has been estimated by ETSA Utilities' planners in the course of developing longer term strategic options for the development of the network.*

Notwithstanding this, we note that as SAPN provided this forecast in support of its LRMC calculation, it may not have been subjected to the same level of internal scrutiny as would a forecast provided for the purposes of a regulatory review process. Therefore, caution should be exercised when drawing definitive conclusions from it. Nonetheless, the result are consistent with the broader evidence presented that SAPN does not, at this stage, expect its augmentation program to materially reduce in the next regulatory control period, in fact, the information provided above indicates that SAPN was, in April 2012, expecting an increase of approximately 4.1% in its augmentation program in the 2015-2020 regulatory period as compared to the amount allowed in the 2010-2015 period.

However, we note that the forecasts underpinning its most recent network development plan (around 2.5% per annum) and the AER's final decision (2.4%) both materially exceed the 2012 NEFR's forecast growth rate for South Australia of 0.8% per annum, and the most recent 2013 NEFR's forecast growth rate for South Australia of 0.0% per annum. We assume that this is also the case with the forecasts provided in support of the LRMC calculation in 2012.

125 SA Power Networks, *Electricity System Development Plan 2012*, p 5.

126 We note that this materially exceeds both the 2012 National Electricity Forecasting Report's forecast growth rate for South Australia of 0.8% per annum, and the most recent 2013 National Electricity Forecasting Report's forecast growth rate for South Australia of 0.0% per annum.

127 SAPN, *Pricing Proposal - Appendix E - Distribution Tariffs Long Run Marginal Cost Methodology*, April 2012, p 5.

If the growth rates outlined in either the 2012 or the 2013 NEFRs were to eventuate, one would expect this would lower SAPN's future augmentation program, notwithstanding the issues around the spatial distribution of growth, and whether growth is disproportionately focused on areas that are already capacity constrained.

3.9. TransGrid

In its original regulatory proposal of May 2008 TransGrid forecast that it would need $1,663.5 million ($2008) to meet the need to augment its network over the 2009-2014 regulatory period, and another $287.4 million ($2008) for easements associated with those augmentation projects. These costs represented 63.2% and 10.9% respectively of its total forecast capital expenditure of $2,663.5 million ($2008)[128] for the period.

Subsequently, in August 2008, TransGrid provided the AER with an updated version of its capex proposal following the release of its 2008 Annual Planning Report (APR). The revision was undertaken due to new information regarding:

- revisions that had been made by NEMMCO to various economic assumptions relevant to forecasting, and
- greater certainty associated with the Munmorah power station, due to the NSW Government committing to keeping the power station running until 2013.

Based on that revised information, TransGrid proposed total capital expenditure over the regulatory period of $2,549.8 million ($2008), of which $1,549.5 million and $292.7 million were forecast to be spent on augmentation and associated easements representing 60.8% and 11.5% of total forecast capex[129].

TransGrid identified three major drivers of the need for augmentation:

- Growth in peak demand, which TransGrid forecast in its original Regulatory Proposal would grow at an annual average rate of 2.5% in summer and 2.0% in winter over the regulatory period;
- NSW jurisdictional requirements that require TransGrid to "plan and develop its transmission network on an 'n-1' basis", which means that "unless specifically agreed otherwise by TransGrid and the affected DNSP or major directly-connected end-use customer, there will be no inadvertent loss of load (other than load which is interruptible or dispatchable) following an outage of a single circuit (transmission line or cable) or transformer, during periods of forecast high load"[130].
- The need to provide for connection of generation assets, based on a probabilistic assessment of potential generation development paths for New South Wales (though there was no capex proposed for this category in the current regulatory period.

It is also worth noting that, all up, TransGrid expected that it would experience a 24% increase in the value of its asset base during the regulatory period, including the addition of about 900km of new high voltage transmission lines and 18 new substations[131].

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128 TransGrid, *Meeting customer needs for transmissions services: TransGrid Revenue Proposal 1 July 2009 - 30 June 2014*, 31 May 2008, p 73.

129 Ibid., p 46.

130 Ibid., p 53.

131 Ibid., p 5.

Figure 9 below compares TransGrid's original updated capex proposal, by expenditure category, with the AER's draft decision and TransGrid's revised proposal.

Figure 9: Comparison of TransGrid's updated original capex proposal with the AER draft decision and TransGrid's revised proposal ($2008 millions)

Capex by Category	Revenue Proposal	Draft Decision	Revised Proposal
Augmentation	1,549.5	1,453.7	1,550.1
Property & Easements	292.7	280.2	285.1
Replacement	508.4	449.3	483.8
Security/ Compliance	42.1	41.1	41.7
Support the business	157.3	152.1	154.8
Total	**2,549.8**	**2,376.5**	**2,515.5**

Source: TransGrid, *Meeting customer needs for transmissions services: TransGrid Revised Revenue Proposal 1 July 2009 - 30 June 2014*, January 2009, p 46

In its Final Decision, the AER reduced TransGrid's capex allowance to $2,405.1million ($2008-09), a reduction of $144.7 million from TransGrid's updated original capex proposal and $110.4 million from TransGrid's revised capex proposal of $2,515.5 million ($2008)[132]. This represented reductions of 5.7% and 4.4% respectively.

In doing so, the AER did not provide a detailed breakdown of the reductions made to each of the expenditure categories listed in Figure 9 above, but rather expressed its reductions as a series of different types of adjustments, as shown in Table 13 below.

Table 13: Adjustments made in AER's Final Decision to TransGrid's revised capex proposal

Adjustment	Amount ($2008 million)
Adjustments resulting from detailed project review	-36.6
Adjustment to cost accumulation process	-62.2
Adjustment to cost estimation risk factor	-6.5
Adjustment to cost estimating factors	-5.1
Total adjustments	-110.4

Source: AER, "*Final Decisions: TransGrid transmission determination 2009-10 to 2013-14*", 28 April 2009, pp 45.

The categories used do not readily allow them to be apportioned to augmentation versus other categories of capital expenditure. However, the projects in which AER identified possible reduction through detailed project reviews were augmentation projects. The cost accumulation process is the other significant category and is likely to apply to all categories of capital expenditure proportionally. Using this simplification, it is possible to estimate that the AER reduced TransGrid's proposed augmentation capex by about $75 million ($2008), or about 4.8%.

132 AER, *Final Decisions: TransGrid transmission determination 2009-10 to 2013-14*, 28 April 2009, pp 44- 45.

In its Transmission Annual Planning Report (TAPR) TransGrid identified:

- 6 augmentation projects that had completed the regulatory process (i.e., relate to constraints identified in either TransGrid's 2009-14 Regulatory Determination or a subsequent TAPR) but have not progressed to the point where they can be considered committed,
- 5 augmentation projects associated with constraints that are expected to emerge within a five year planning horizon, and
- 6 constraints expected to emerge within a five-year planning horizon but for which no firm proposal for augmentation has as yet been identified.

The TAPR does not provide any estimate of the cost of these projects[133], which means that it is not possible to directly compare the augmentation capex projected for the next five years with that proposed (or approved) for the current regulatory period.

However, we may be able to infer the likely relativity of the augmentation capex in TransGrid's upcoming determination process with that of its previous one by considering the following:

- The forecast average annual growth in summer seasonal peak demand that TransGrid put forward and the AER accepted in the July 2009 – June 2014 regulatory period was 2.5%. By contrast, the average annual growth rate for summer seasonal peak demand for the July 2014 – June 2018 period is slightly less than 1.0% at 50POE and just over 1.0% at 10POE in the medium NEFR forecast[134].
- Other circumstantial evidence comes from the fact that the addition of a 330kV line from Dumaresq to Lismore – the third largest augmentation project proposed by TransGrid in the 2009-14 regulatory period -- is cited in AEMO's 2012 National Transmission Network Planning report as not being needed before 2017-18. In TransGrid's original regulatory proposal it was expected to be in service in 2011-12[135].

Therefore, on the balance of evidence, we think it is unlikely that TransGrid's augmentation capex proposal for the July 2014 – June 2018 period will be an increased amount as compared to that proposed for the present regulatory period. However, if some of the assets that were originally forecast to be required in the current regulatory period are deferred into the upcoming period, this will reduce the amount by which augmentation capex might fall in the next period based solely on the change in forecast growth in peak demand.

3.10. Transend

In its original Revenue Proposal for the 2009 – 2014 period Transend described its proposed capital expenditure program as being significantly higher than in the previous period. It identified the following as the drivers of that increase:

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133 Certainly the 11 projects other than those that have been identified in earlier TAPRs or the Regulatory Proposal have not progressed to a point where even an indicative pricing would be appropriate as a number of alternatives exist for each of these constraints.

134 See Table 4-2 in AEMO, *2013 National Electricity Forecasting Report*, 2013, p 4-4.

135 TransGrid, *Meeting customer needs for transmissions services: TransGrid Revenue Proposal 1 July 2009 - 30 June 2014*, 31 May 2008, p 74.

- *growth in demand creating the need for transmission system augmentations and seven new connection sites* [Transend used an average annual demand growth rate of 2.2% that was provided by NIEIR][136];
- *the network performance requirements set out in the Electricity Supply Industry (Network Performance Requirements) Regulations 2007, which drive reliability augmentations; and*
- *continuation of the current asset renewal program to sustain transmission system performance and the reliability of electricity supply*[137].

Figure 10 below shows Transend's original capex proposal for the 2009 – 2014 regulatory period.

Figure 10: Transend capital expenditure as proposed in its original 2009 – 2014 Revenue Proposal ($2008 – 09 millions)

Category	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Augmentation	70.8	82.7	29.4	16.1	28.6	**227.6**
Connection	31.5	35.0	37.0	16.5	1.7	**121.8**
Land and easements	0.0	0.0	0.0	10.5	10.3	**20.9**
Asset renewal	29.8	39.4	25.7	62.4	69.3	**226.6**
Physical security/compliance	5.1	2.0	2.4	0.8	0.4	**10.7**
Inventory/spares	9.6	0.4	0.5	0.2	1.0	**11.7**
Operational support systems	4.6	4.8	3.2	3.6	6.1	**22.3**
Total network	**151.4**	**164.2**	**98.3**	**110.2**	**117.5**	**641.6**
Information technology	2.7	5.1	3.6	4.0	5.9	**21.3**
Business support	3.9	4.1	4.5	4.3	1.0	**17.8**
Total non-network	**6.6**	**9.2**	**8.2**	**8.3**	**6.9**	**39.1**
Total	**158.0**	**173.4**	**106.5**	**118.5**	**124.3**	**680.7**

Source: Transend, *Transend Transmission Revenue Proposal for the Regulatory Control Period 1 July 2009 to 30 June 2014*, 30 May 2008, p 86

As can be seen, augmentation comprises the single largest category of capex (though replacement is virtually the same size), and it should be noted that at least some of the 'land and easement' category will be associated with augmentation projects as well. 'Connection' is another similar category, as it relates to capital expenditure associated with growth (in terms of customer numbers and peak demand, in most cases).

136 Ibid., 71.

137 Transend, *Transend Transmission Revenue Proposal for the Regulatory Control Period 1 July 2009 to 30 June 2014*, 30 May 2008, p 57.

In its Draft Decision, the AER reduced Transend's total proposed capex by $65.4 million ($2009-09). Most of this ($50.1 million) was associated with renewal capex. The other two categories of adjustment were associated with:

- the use of escalation factors ($10.6 million), and
- augmentation and easement projects ($4.8 million)[138].

The former affects all capital expenditure, while the latter only affects the two categories named. Applying the proportion of augmentation capex to total capex (in the first case) and the proportion of augmentation capex to augmentation and easement capex (in the second case) suggests that the AER's draft decision would have reduced Transend's augmentation capex proposal by $7.75 million ($2008-09) or 3.4%.

It is Revised proposal, Transend re-categorised a project that was listed as contingent in its original Revenue Proposal to the augmentation category, but this was rejected by the AER in its Final Decision[139].

In its Final Decision the AER also noted that several submissions had questioned the demand forecast that Transend had used in its original and revised Revenue Proposals. Although the AER agreed that there was some merit in the argument that the Global Financial Crisis might dampen demand from the path forecast by Transend in the first half of 2008, it also noted that forecast demand constituted the primary driver for only $158.8 million (23.2%) of Transend's total proposed capex. In addition, of that, the AER found that:

- $95.6 million (13.9% of all capex) was related to connection requests from Aurora Energy which Transend is required to address under clause the NER;
- $49.2 million (9.2%) was required because the forecast demand would lead to breach of the Tasmanian network performance requirements, to which Transend is obligated to comply; and
- $14 million (2.0 per cent of all capex) related to a particular augmentation project, which the AER found to be justified given the demand forecast for the particular area and relevant jurisdictional network planning requirements.

The AER also noted that Transend categorised several projects that might be needed due to high demand as contingent rather than *ex-ante* projects, and that this also served to reduce the sensitivity of the its proposed capex to changes in demand.

As a result, the AER did not change these portions of Transend's capex proposal from that of its Draft Decision[140].

Transend's 2013 Annual Planning Report (APR) forecasts winter peak demand to grow at an average annual rate of 1.26% over the 2013 -2028 period[141], which is materially less than the 2.2% included in their forecast for the current regulatory period. Their figures show that this is also the rate they forecast to pertain in the upcoming regulatory period 2014 2019[142].

138 AER, *Final Decision: Transend Transmission Determination 2009-10 to 2013-14*, 28 April 2009, p 20.

139 Ibid., pp 28 - 33.

140 Ibid., pp 24 - 28.

141 Transend Networks, *2013 Annual Planning Report*, 2013, pp 40 - 43.

142 Ibid., see Figure A1.2, p 150 for the medium forecast at 10 POE.

In addition, the 2013 APR identifies 12 augmentation projects that are proposed to meet constraints that are expected to develop within the network over the course of the upcoming regulatory period. The estimated cost of those projects is $98.5 million ($2013)[143].

Based on these considerations we think it is probable that Transend's augmentation capex proposal for the upcoming regulatory period is likely to be no more than it was for the current period and possibly less.

143 Ibid., pp 75 – 114.

4. Asset replacement

4.1. Objective

The objective of the following section is to provide high-level qualitative advice to the AEMC with regards to the likely direction of future replacement expenditure for each of the businesses analysed in this report.

4.2. Overview

Forecasting replacement expenditure is a very complex task for electricity network businesses. Most businesses model replacement levels having regard to the probability and consequence of failure, with this being compared under different options (in particular, a "do nothing" option). The outturn results of such modelling allow businesses to decide whether to continue to operate an individual asset or entire asset class in the same manner as it has been doing, refurbish an individual asset or entire asset class, change the maintenance/inspection practices for an individual asset or entire asset class, or replace an individual asset or entire asset class.

Both the probability and consequence of failure are inherently complex parameters to forecast. They will be a function of, amongst other things:

- The condition of the asset – as the condition of an asset deteriorates, the probability of failure increases;
- The age of an asset – as an asset/asset class ages, the probability of failure generally increases[144];
- Environmental factors – such as the exposure of assets to conditions that can affect its useful life or potential for early/catastrophic failure; dust-prone areas are an example of the first environment factor, while cyclone-prone areas are examples of the latter condition;
- The location of the asset – the location of an asset may impact upon the consequence of failure, for example, the failure of an asset that causes a fire in a high-risk bushfire region will have a higher consequence of failure, *ceteris paribus*, than the same asset failure in a low risk bushfire region; and
- The customer density/type affected by a failure to that asset – an asset that services a large number of customers, or customer's that place a higher value on electricity services, will, *ceteris paribus*, have a higher consequence of failure relative to an asset that has fewer customers, or customers that place a lower value on electricity services.

Given the uncertainty around the above parameters, it is impossible to draw definitive conclusions with regards to the levels of replacement expenditure required by different businesses from publicly available information on its own. This is further complicated by the fact that the value of these parameters may change over time; for example, the value that customers place on lost load may change over time, and the probability and consequence of starting a bushfire may change over time, both of which would impact on a business' replacement decisions.

144 This comment applies primarily to assets approaching the end of their useful lives; not assets that are in other phases of their lifecycle (e.g., mid-life).

Therefore, as a blunt measure of a business' likely future replacement requirements, we have reviewed information with regards to the age profile of assets, as well as the weighted average age of assets, to assess the likelihood of a business' replacement expenditure increasing or decreasing in the next regulatory period. This reflects the fact that despite businesses not making actual replacement decisions on the basis of asset age, asset age, particularly the age of a large population of assets, is a critical factor influencing *long term* replacement plans.

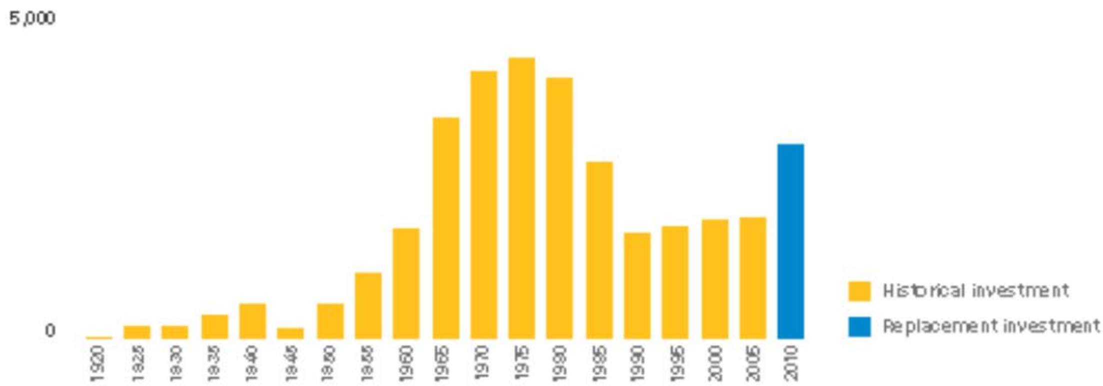
We reiterate that this is a blunt tool, and is a necessary simplification of what is an otherwise, very complex decision.

Further, as in the case of augmentation costs, this section discusses replacement costs as reported by the networks. We have not disaggregated the effect of any change in materials costs.

4.3. Ausgrid

The following diagram outlines the Ausgrid's system asset age profile at the time of their last regulatory submission.

Figure 11: Ausgrid system asset age profile – replacement cost (FY09 $m real)



Source: EnergyAustralia, *Regulatory Proposal*, June 2008, page 8

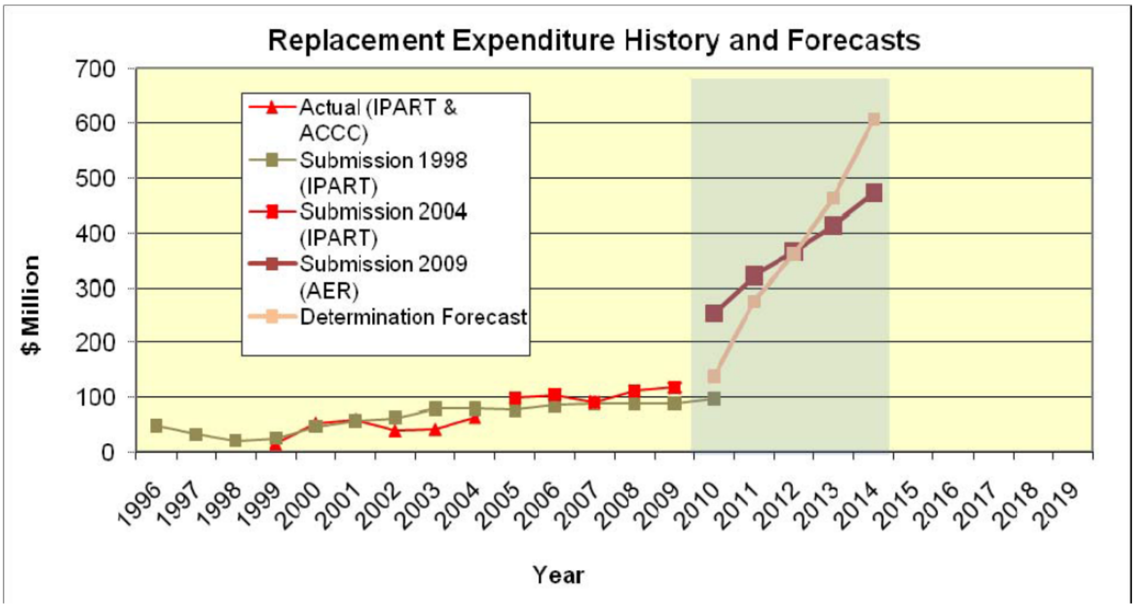
The table indicates that much of Ausgrid's network (measured in terms of replacement cost) was constructed in 1960s through to the 1980s – with much smaller investment occurring both immediately preceding and after these periods. A natural by-product of this type of lumpiness in the original investment in the network is that replacement expenditure will also be lumpy. This lumpiness is not likely to cause replacement expenditure to vary materially year-on-year or even from one regulatory period to the next. Rather, it is more likely to lead to material variations that characterise different decades or spans of even longer time periods.

If we assume that a network business' weighted average asset life is around 45 years, even without the benefit of hindsight, one would not have been surprised that Ausgrid was seeking to increase its replacement levels from around 2010 onwards, given the large increase in Ausgrid's installed replacement cost in the period 1965-1970 period. Extending this analysis, Ausgrid' System Asset Age Profile [reproduced above] indicates that expenditure increased even further throughout the 1970's and early 1980s, which *ceteris paribus*, would indicate that the fundamental drivers of long term replacement plans are, if anything, increasing.

This point is broadly reinforced by Ausgrid in a submission it wrote to the "*Directions paper on AER/EUC rule change proposals*".

The following diagram is an excerpt from that submission. It illustrates Ausgrid's historic levels of replacement.

Figure 12: Ausgrid replacement expenditure



Source: Ausgrid, *Submission Directions paper on AER/EUC rule change proposals*, 16 April 2012, Attachment A

In that submission, Ausgrid points to the fact that replacement expenditure over the 1990s to 2000s was less than $100 million a year, on an asset base which would cost around $30 billion to re-build[145]. Ausgrid notes in another section of that submission that assuming a 42 year life, it should require a continual renewal of around $700 million.

Having regard to the above, Ausgrid contends in that document that[146]:

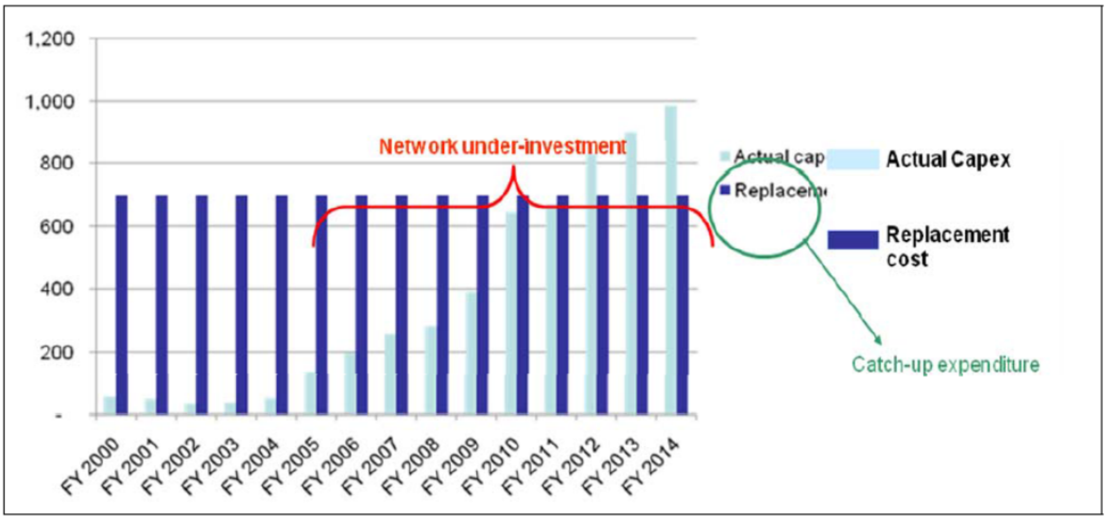
> *"the level of replacement should have been higher in the late 1990's to 2000. A more sustainable allowance would have gradually increased the value of the RAB (and prices) thereby avoiding the price shock that ensued from a period of under-investment.*

Ausgrid used the information in Figure 13 to demonstrate the extent to which this benchmark level of replacement expenditure was not achieved over the majority of the last 15 years.

145 This figure is also quoted on page 3 of Ausgrid's 2009 Regulatory Proposal.

146 Ausgrid, *Submission Directions paper on AER/EUC rule change proposals*, 16 April 2012, Attachment A.

Figure 13: Ausgrid replacement expenditure compared to "benchmark" levels



Source: Ausgrid - "*Submission Directions paper on AER/EUC rule change proposals*", 16 April 2012, Attachment A

Ausgrid also provided evidence as to how recent increases in investment have led to improvements in customer service levels[147].

Figure 14: How investment has led to improvements in customer service levels

Indicators	Improvement
Average number of blackouts from equipment failure	The average number of blackouts from equipment failure has been cut by about 12% between 2003/04 to 2010/11.
Failures of major substations	In 2001 there were eight significant failures at major substations. Last year, there were two major failures.
11kV feeder above rating capacity	In 2005, there were 108, 11 kV feeders over rating capacity in Sydney and the Central Coast. Now there are 44.
Pole failures	In 2001, there were 45 poles failures. Last year, there were 13.
Average failures of rural power lines	The average number of blackouts caused by rural power lines has been cut in half over the same period.
Maintenance costs	Maintenance costs have reduced by 4 per cent.

Source: Ausgrid, *Submission Directions paper on AER/EUC rule change proposals*, 16 April 2012, Attachment A

147 Ausgrid did not explicitly link these improvements to replacement asset expenditure, and indeed, such a claim would be extremely difficult to substantiate definitively. Investment of different types – including augmentation, replacement and reliability – can all contribute to observed improvements in service.

Having regard to the above information, we consider that Ausgrid's premise that there is a relationship at a broad level between the annual levels of replacement expenditure required by a network business; the weighted average asset life of a business; and the replacement cost of a business; is reasonable at a *general* level. However, we would note that if age is used as a guide to assessing long term replacement requirements, it should reflect the original investment cycle undertaken by the business. This would mean that long term forecast replacement requirements will fluctuate up or down depending on which part of the investment/replacement cycle a business is in, which in turn will depend on the original investment cycle undertaken by the business. Therefore, a more appropriate measure of replacement cost to underpin such an analysis is the *cumulative replacement cost* – that is, the cumulative replacement cost of the network at the point in time 45 years ago (or broadly within this age range).

Notwithstanding this, we note that Ausgrid's age profile indicates that if anything, it may be facing a period of even higher investment than it would when looked at on average. This reflects the large increase in asset investment in the mid-1960s through to the mid-1970s.

To further test this, we estimated the proportion of the AER's Final Decision that relates to asset renewal/replacement capex. This equated to around $580 million per annum[148], or $2.9 billion over the regulatory period. This is below the $700 million quoted previously by Ausgrid, which we note is an average, and does not reflect the original investment profile. Prima facie, this indicates that Ausgrid may be expecting replacement expenditure in the next regulatory control period to increase relative to existing levels.

Complementing this high level analysis is a more practical observation that a robust, efficient replacement expenditure program for a distribution network, is unlikely to be subject to significant year-on-year volatility. Rather, it should be developed as a program of works over an extended period of time. This means that the replacement program for an asset class with a large fleet should be subjected to strategic renewal, possibly in advance of large portions of the population reaching the end of their useful life, where the economic cost of failure is high. This simply reflects a prudent approach to managing the cost, and risk, around such a replacement program. In this context, we would therefore not expect Ausgrid's proposed replacement program, which was broadly accepted by the AER, to suddenly reduce materially in the next regulatory period, relative to what has been allowed for by the AER in this regulatory period. This may also work to temper the upside risk as well, as some expenditure may have implicitly been brought forward as a result of this type of assessment.

Furthermore, whilst Ausgrid appears to have improved upon a number of service attributes (as indicated in Figure 14 above), the outcomes do not suggest that Ausgrid has increased levels of service to a point of 'saturation' (i.e., which would have been a possible conclusion in the event that increased expenditure was not seen to improve customer service[149]). Where such saturation is indicated it may provide a high-level indication of the effective ceiling on cost-efficient replacement expenditure, at least in the near term.

148 To do this, we reduced Ausgrid's Revised Proposal level of asset renewal/replacement of $3,063.5 million, or $612 million per annum (p 121 of the AER's Final Decision), by the proportionate reduction attributable to cost escalators in that Final Decision – being $373.3 million / $7,050.4 million = 5.2% (p 144).

149 It should also be noted that such an outcome may also indicate that replacement expenditure is required to counteract what would have otherwise been an underlying degradation in service levels.

Finally, Ausgrid makes a number of statements in its 2009 Regulatory Proposal to the effect that even considering its proposed replacement expenditures, it expects increased levels of replacement in the following regulatory period. For example, it states that[150]:

> *"The Replacement Plan incorporates a significant increase in expenditure on distribution assets, particularly in distribution substations and low voltage cables. Despite this increase in expenditure, the average age of distribution equipment will continue to increase over the 2009-14 period. Figure 5.1 shows that the weighted average age of assets in the distribution mains group increases from 28.22 to 31.47 years over the period. If no investment was made the average age at the end of the period would be 33.22 years. <u>EnergyAustralia expects that replacement expenditure on the distribution system will increase substantially from 2014</u>." [Emphasis added]*

Having regard to the above, it is our view that the above evidence indicates that on the balance of probabilities, Ausgrid is likely to seek even larger underlying levels of replacement in the next regulatory control period, relative to those that were forecast (and accepted by the AER) in the existing regulatory control period.

4.4. Essential Energy

In its 2008 Regulatory Proposal, Essential Energy (then Country Energy) forecast asset renewal requirements to be around $163 million per annum for the current regulatory control period[151]. It proposed a similar allowance in its Revised Proposal. After adjusting for the changes made by the AER to cost escalators in the Final Decision (around 3%[152]), this allowance reduces to around $158 million per annum.

Essential Energy state in their Regulatory Proposal that[153]:

> *"The weighted average age across all asset classes is around 27 years. Around 33 per cent of Country Energy's existing asset base (by replacement cost) was installed during the 1950s and 1960s, and around 18 per cent (by replacement cost) was installed over 45 years ago. It is expected that on average 1 per cent of all assets will reach the end of their nominal engineering lives each year over the next regulatory control period."*

This is illustrated in the figure below, which is reproduced from Essential Energy's Regulatory Proposal.

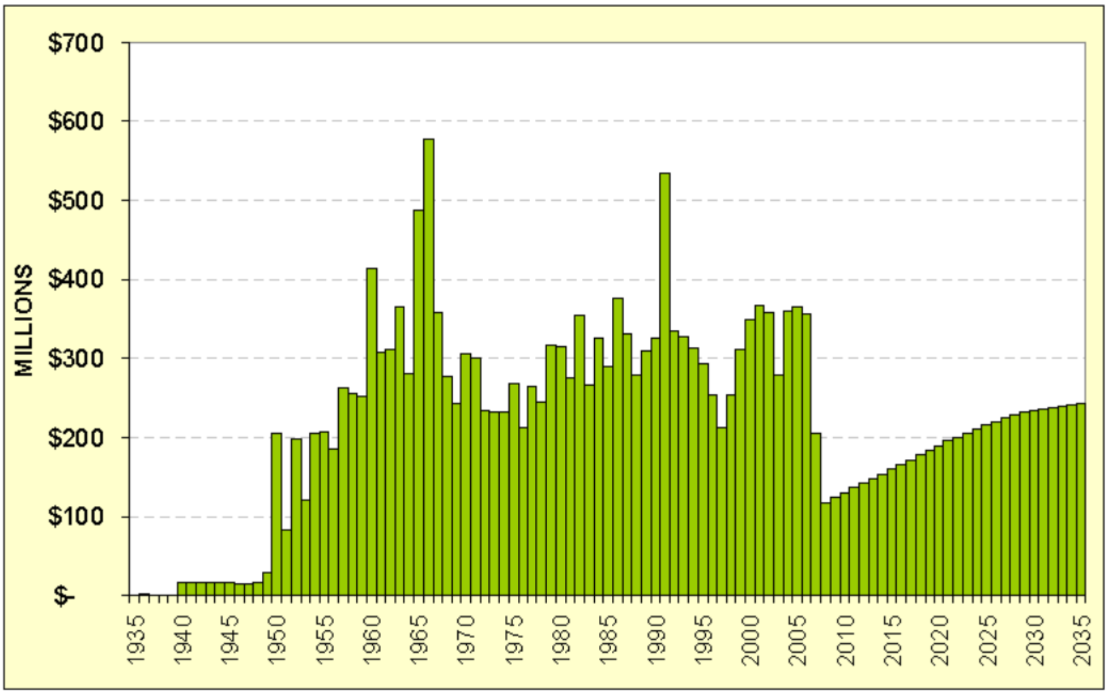
150 EnergyAustralia, *Regulatory Proposal*, June 2008, p 64.

151 Country Energy, *Regulatory Proposal 2009-2014*, 2 June 2008, p 107.

152 From Table 7.16 on p 163 of the AER's Final Decision.

153 Country Energy, op cit., p 110.

Figure 15: Overall age and replacement profile for Essential Energy



Source: Country Energy, *Regulatory Proposal 2009-2014*, 2 June 2008, page 109

Essential Energy also states that[154]:

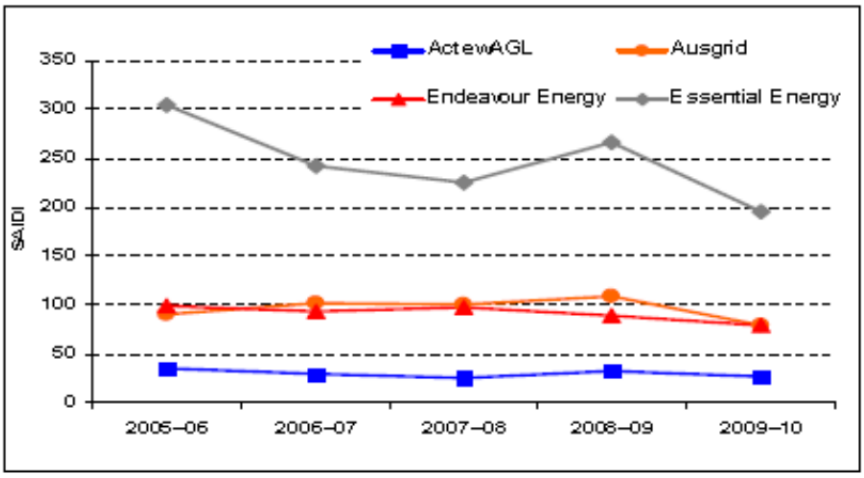
> *"The age based replacement model provides an annual replacement expenditure requirement that averages around 1 per cent of the total asset replacement cost per annum over the regulatory period. This amount is significantly below the 2 per cent long term average expenditure required to replace all assets over an implied weighted average asset life of 50 years."*

154 Country Energy, *Regulatory Proposal 2009-2014*, 2 June 2008, p 109.

Interestingly, it would appear that apart from a number of "spikes" in investment in individual years around 1958, in 1963-1966, and again in 1991, Essential Energy's original investment program has been fairly constant (in replacement cost terms) since the mid-1950s. This is particularly noticeable when compared with Ausgrid's replacement cost distribution, which forms more of a "bell curve". In and of itself, prima facie, this indicates that unless a large backlog of replacement is being created as a result of current replacement levels (i.e., current levels are less than what is required, based on the underlying fundamentals of the network), the replacement program that Essential Energy proposed in this regulatory period should be broadly consistent (in real terms) with what they will require in future regulatory periods[155]. That said, we note Essential Energy comment that it expects that "*on average 1 per cent of all assets will reach the end of their nominal engineering lives each year over the next regulatory control period*", and that this is "*significantly below the 2 per cent long term average expenditure required to replace all assets over an implied weighted average asset life of 50 years*". Taken together, this may indicate that efficient deferral of replacement has been adopted by Essential Energy in this regulatory period (and possibly in previous periods), which may contribute to a backlog of replacement that will need to be "caught up" with at some point in the future. A broad uplift in replacement in the next regulatory period is reflected in the figure above.

The figure below indicates that Essential Energy's levels of service, a proxy measure for which is the system average minutes off supply per customer, had declined over the period leading up to its last Regulatory Proposal, although they were at relatively high levels in comparison to the two other DNSPs in NSW[156].

Figure 16: Average unplanned minutes off supply per customer, 2005-10



Source: AER, *ACT and NSW Electricity Distribution Network Service Providers Performance Report for 2009-10*, November 2011, page viii[157]

155 This assumes that there has not been any major advancement in technology, which would otherwise lead to the efficient extension of asset lives, nor has there been any material change in the consequence of failure (i.e., that neither the consequence of bushfire nor the value of lost load has increased materially).

156 There are numerous factors that need to be considered when comparing Essential Energy's performance to that of other distribution business, for example, topography, customer density and mix of asset types.

157 Whilst the Comparative Performance Reports list this as being "Average minutes off supply", the text in support of the graph indicates that it is "unplanned" minutes off supply.

According to Essential Energy's Annual Reports, the normalised SAIDI figure increased in 2010/11 and 2011/12, with these being reported as 238 minutes[158] and 237 minutes respectively[159]. Based on this information, we don't consider there to be a material risk that Essential Energy is approaching a point of "saturation" with regards to the level of service that it delivers to its customers, which in turn might indicate that it had reached a ceiling on its replacement expenditure program at least in the near-term future.

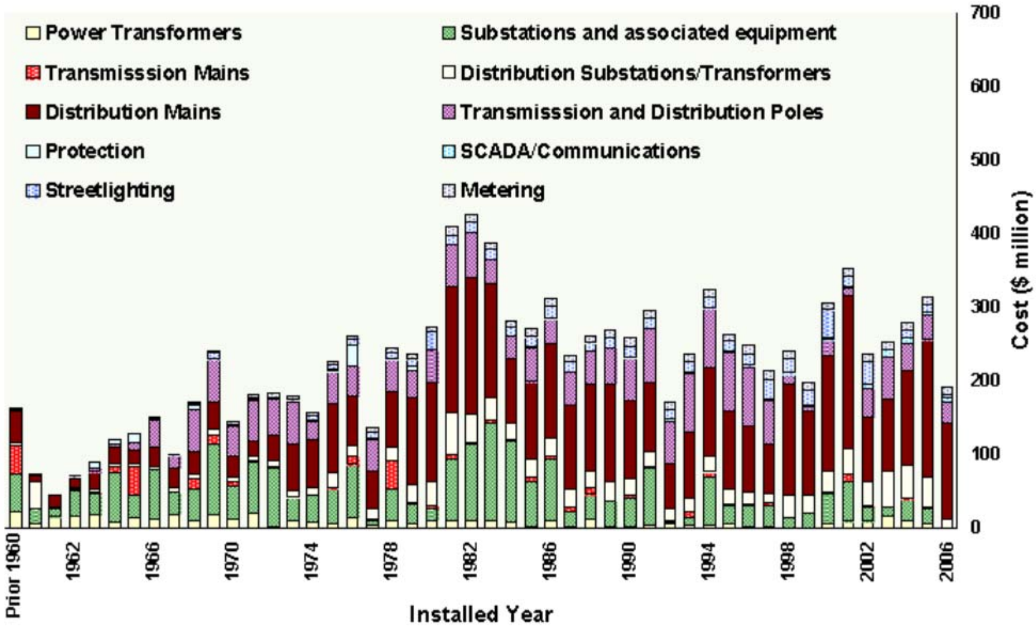
Having regard to the above, it is our view that the evidence above indicates that, on the balance of probabilities, Essential Energy may seek larger underlying levels of replacement in the next regulatory control period, relative to this regulatory control period. However, we doubt that this would be of the same magnitude (in percentage terms) as any change in Ausgrid's replacement program, due to the different original installation profile underpinning the development of each business' network.

4.5. Endeavour Energy

In its 2008 Regulatory Proposal, Endeavour Energy (then Integral Energy) forecast asset renewal requirements to be around $784 million[160] over the current regulatory period, or $156 million per annum. It proposed a similar allowance in its Revised Proposal. The AER only made a slight adjustment to this in its Final Decision.

Endeavour Energy also provided a snapshot of the age profile of its asset base at the time of its 2008 Regulatory Proposal.

Figure 17: Network assets – installed cost profile (2006/07$)



Source: Integral Energy, *Regulatory Proposal,* 2 June 2008, p 35

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158 Essential Energy, *Annual Report 2010-2011*, p 25.

159 Ibid., p 4.

160 Integral Energy, *Regulatory Proposal*, 2 June 2008, p 10.

In a number of spots throughout the Regulatory Proposal, Endeavour refers to the age of its assets. Two cases in point are[161][162]:

- *…a significant number of Integral Energy power transformers were installed before the 1970s. During the 1990s many of these critical network assets reached an age at which they would require replacement in the following decade. This is illustrated by the power transformer age profile shown in Figure 3.10, which indicates that almost half of power transformers are greater than 36 years old; and*
- *Experience indicates that most zone and transmission substations have an effective service life of between 45 and 55 years….Nearly a third of Integral Energy's zone and transmission substations are now at, or are close to, replacement age: 25 are 45 years or older, and an additional 70 will reach 45 years within the next 10 years. The age of these assets presents Integral Energy with a significant renewal challenge.*

Looking at Endeavour Energy's original investment program (as reflected in its installed cost profile in the Figure above), it appears that Endeavour Energy exhibited a fairly constant network investment program (in terms of replacement cost) from the late 1960s through to the late 1970s, with a large step up from then on. Using a 45 year average asset life, this indicates that Endeavour Energy would be facing a similar proportion of assets (in replacement cost terms) approaching the end of their useful life in the next regulatory period as it did in this regulatory control period, but with material upside risk in the following regulatory period.

We also note from Figure 16 above that Endeavour Energy's SAIDI, which is considered a barometer for the general level of health of the network, has fluctuated between about 80 minutes and 100 minutes between 2005/06 and 2009/10. In 2010/11 it was 72 mins[163], and in 2011/12, it was 82 mins[164]. Consistent with our observations for Essential Energy, we don't consider there to be a material risk that Endeavour Energy is approaching a point of "saturation" with regards to the level of service that it delivers to its customers – which in turn may provide high level evidence of their being a ceiling on its replacement expenditure program in the future.

Having regard to the above, it is our view that the above evidence indicates that on the balance of probabilities, Endeavour Energy may seek some underlying increase in replacement levels in the next regulatory control period, relative to this regulatory control period. However, we doubt that this would be to the same magnitude (in percentage terms) as any change in Ausgrid's replacement program.

161 Ibid.

162 Ibid., p 114.

163 Endeavour Energy, *Annual Performance Report 2010/11*, p 6.

164 Ibid.

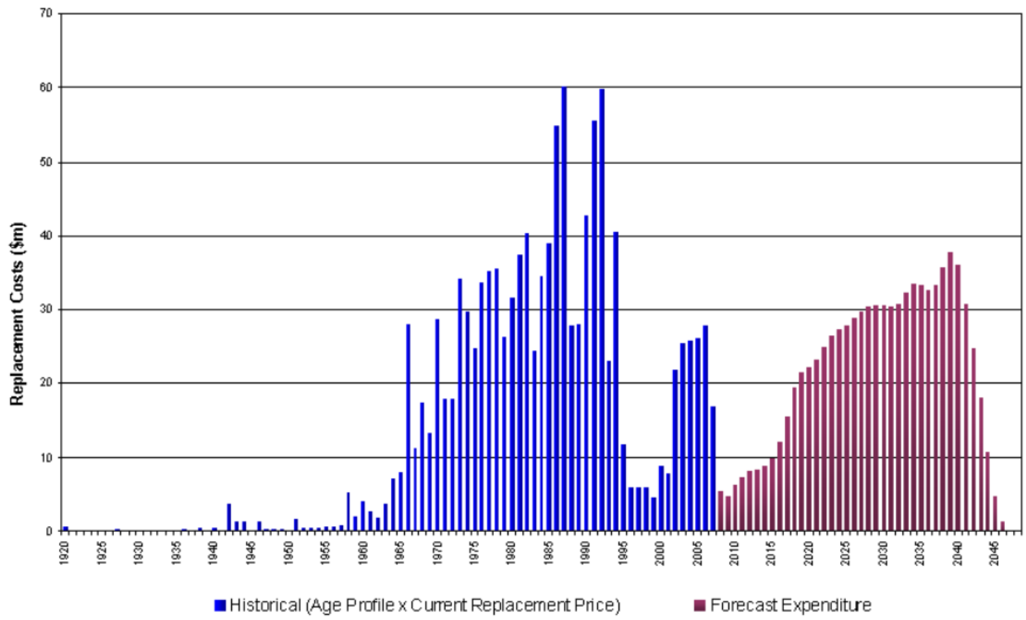
4.6. ActewAGL

In its Regulatory Proposal, ActewAGL proposed to spend $98.6 million ($2008/09) on "Asset renewal/replacement"[165] over the regulatory period or around $20m per annum. By far the largest contributor to this replacement program was ActewAGL's 'pole replacement and reinforcement program', at $51.1 million[166]. In describing this program, ActewAGL indicated that it estimated that 5,492 poles would be replaced in the 2009-14 regulatory period. It is worth noting that is out of a population of approximately 53,000 power poles, the majority of which (approximately 39,000) are wooden[167]. ActewAGL also stated that "*almost half of the poles in the network are untreated natural round wood poles which are particularly susceptible to deterioration of their structural integrity over time*[168]".

ActewAGL proposed a similar capital program in its Revised Proposal, and the AER, in their Final Decision, accepted these forecasts, subject to updating them for the latest input cost escalators. We estimate that this reduced ActewAGL's replacement program by around 7.5%, which if applied to ActewAGL's original forecasts, would reduce its allowance to around $91 million over the regulatory period.

In its Regulatory Proposal, ActewAGL provided the following figure showing the timing of its original network investment (in replacement cost terms), and their forecast expenditure.

Figure 18: ActewAGL distribution weighted age profile (excluding pole replacement)



Source: ActewAGL, *Regulatory Proposal to the Australian Energy Regulator*, June 2008, p 114

Further, ActewAGL stated that[169]:

165 ActewAGL, *Regulatory Proposal to the Australian Energy Regulator*, June 2008, p 126.

166 Ibid., p 148.

167 Ibid.

168 Ibid.

169 Ibid., p 113.

> *"the majority of ActewAGL Distribution's electricity network assets were installed over the period from 1965 onwards, with the largest proportion installed during the period 1985-95. While a small amount of targeted refurbishment took place over time, the portfolio of assets continued to accumulate and progressively age. As the portfolio of assets progressively reach the end of their service life, it will become necessary to allocate an increasingly larger amount of capital expenditure for asset refurbishment and replacement purposes. It should be noted that this modelling has been done primarily on the basis of asset age, nominal asset life and the statistical distribution of expected lives for various asset categories."*

The following table – reproduced from ActewAGL's Regulatory Proposal – outlines the average age of its network at the time of the submission, relative to the expected life.

Figure 19: ActewAGL distribution average asset age by category

Asset category	Weighted average age (2007/08)	Average expected life
Sub-transmission overhead lines	28.88	50
Sub-transmission underground	5.00	50
Zone substations	26.11	47
Distribution substation	23.92	41
Distribution underground	22.57	50
Distribution poles	31.00	43
Distribution overhead lines	22.48	50
Distribution other	22.29	31
Total weighted average system age	**24.88**	**-**
Total weighted average system life	-	46

Source: ActewAGL, *Regulatory Proposal to the Australian Energy Regulator*, June 2008, p 114

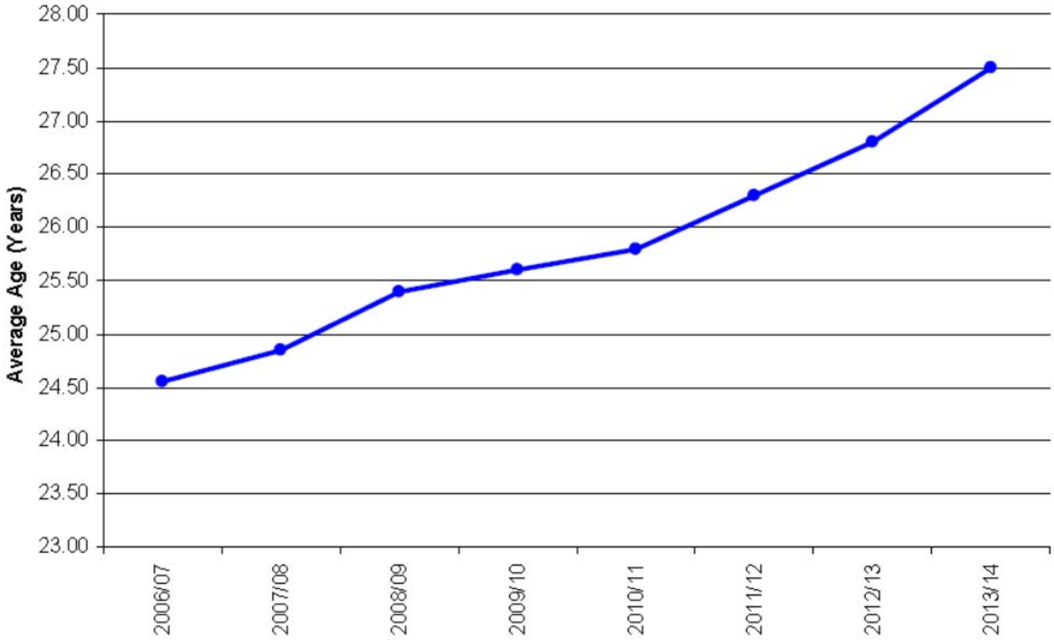
For clarity, ActewAGL stated that[170]:

> *"It must be noted that the average ages and lives shown above are not numerical averages, but are weighted by the replacement cost (RC) value of each asset category"*

Finally, ActewAGL provided the following figure in its Regulatory Proposal. The figure shows the impact undertaking the capital works program outlined in its Regulatory Proposal will have on its weighted average age.

170 Ibid., p 115.

Figure 20: Forecast weighted average age of network



Source: ActewAGL, *Regulatory Proposal to the Australian Energy Regulator*, June 2008, p 114

It can be seen that the weighted average age increases to around 27.5 years over this regulatory period (assuming the proposed capital expenditure program is approved).

Based on the SAIDI outcomes documented by ActewAGL in their Regulatory Proposal[171] - which show that its average SAIDI over the period 2002/03 to 2006/07 was nearly 82 minutes[172]- there is little evidence to suggest that ActewAGL had reached a point of saturation with regards to the level of service it was providing customers at the time of its Regulatory Proposal.

In summary, the evidence provided by ActewAGL in its original Regulatory Proposal indicates that the weighted average age of its network is slightly over half of its weighted average useful life, which indciates that, if anything, it is likely to be on the upward phase of its replacement investment program. Further, its original investment profile indicates that investment in the network increased continuously year on year throughout the 1970's, which should broadly flow through to the profile of replacement expenditure around 45 years later. The evidence presented also indicates that the capital works program proposed by ActewAGL in its last Regulatory Proposal (which was predominately accepted by the AER) would still lead to a slight increase in the weighted average age of its network. It also indicates that a significant proportion of its replacement expenditure was related to its "pole replacement and reinforcement program", and that this was expected to lead to about 10% of poles being replaced in the 2009-14 regulatory period.

171 Ibid., p 38.

172 We note that this figure conflicts with figures presented in the graph earlier in our report. Those earlier figures were sourced from the AER's Comparative Performance Report, whilst the aforementioned average figure is sourced from ActewAGL's Regulatory Proposal. We consider the latter a more authoritative source of information. We also note that we were unable to obtain more up-to-date SAIDI information for ActewAGL in the time available.

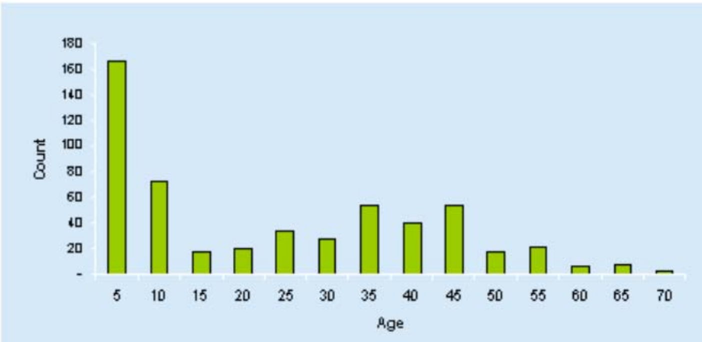
Ceteris paribus, having regard to the above information, we consider that on the balance of probabilities, it is likely the ActewAGL will propose larger replacement/renewal expenditures in the next regulatory control period than it did for the current regulatory control period.

4.7. Energex

In its 2009 Regulatory Proposal, Energex forecast asset renewal requirements to be around $1,165 million ($2009-10)[173] over the current regulatory period, or $233 million per annum. Whilst the AER's Final Decision does not specify the exact allowance for replacement, it appears that there was no material change to Energex's proposed program, as in its Final Decision, the AER made no explicit reduction to Energex's replacement capital expenditure allowance, although they did reduce its overall capital expenditure allowance for changes in cost escalators. This represented an around 4% reduction[174]. Applying this to Energex's original forecasts reduces their per annum allowance to around $223 million.

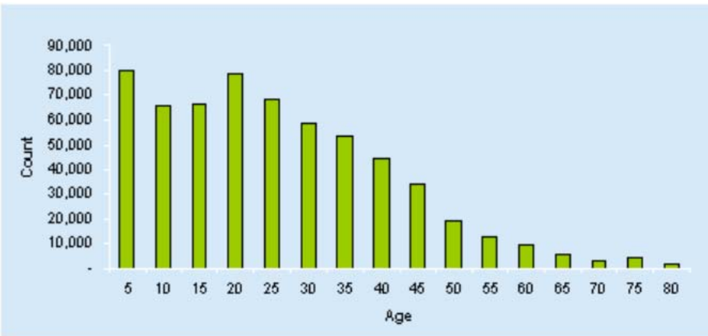
In its regulatory proposal, Energex provides a snapshot of the age of 3 key asset categories.

Figure 21: Age profile of power transformers



Source: Energex, *Regulatory Proposal for the period July 2010 - June 2015*, July 2009, p 41

Figure 22: Age profile of poles

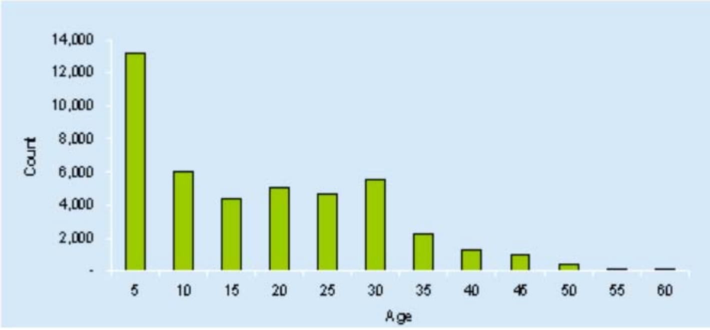


Source: Energex, *Regulatory Proposal for the period July 2010 - June 2015*, July 2009, p 41

173 Energex, *Regulatory Proposal for the period July 2010 - June 2015*, July 2009, p 19.

174 This is based on information on page 139 of the AER's Final Decision.

Figure 23: Age Profile of Distribution Transformers



Source: Energex, *Regulatory Proposal for the period July 2010 - June 2015*, July 2009, p 42

It also provides information with regards to the standard lives for system assets, and the remaining life of those assets, as at July 2010.

Figure 24: Standard lives and remaining life (as at July 2010)

Assets categories	Standard life	Remaining life
System assets		
OH sub-transmission lines	51	36
UG sub-transmission cables	45	33
OH distribution lines	45	29
UG distribution cables	60	47
Distribution equipment	35	26
Substation bays	45	32
Substation establishment	58	31
Distribution substation switchgear	45	27
Zone transformers	50	41
Distribution transformers	41	30
Low voltage services	35	30
Metering	25	11
Communication – pilot wires	29	19

Source: Energex, *Regulatory Proposal for the period July 2010 - June 2015*, July 2009, p 235

In explaining the above table, Energex states[175]:

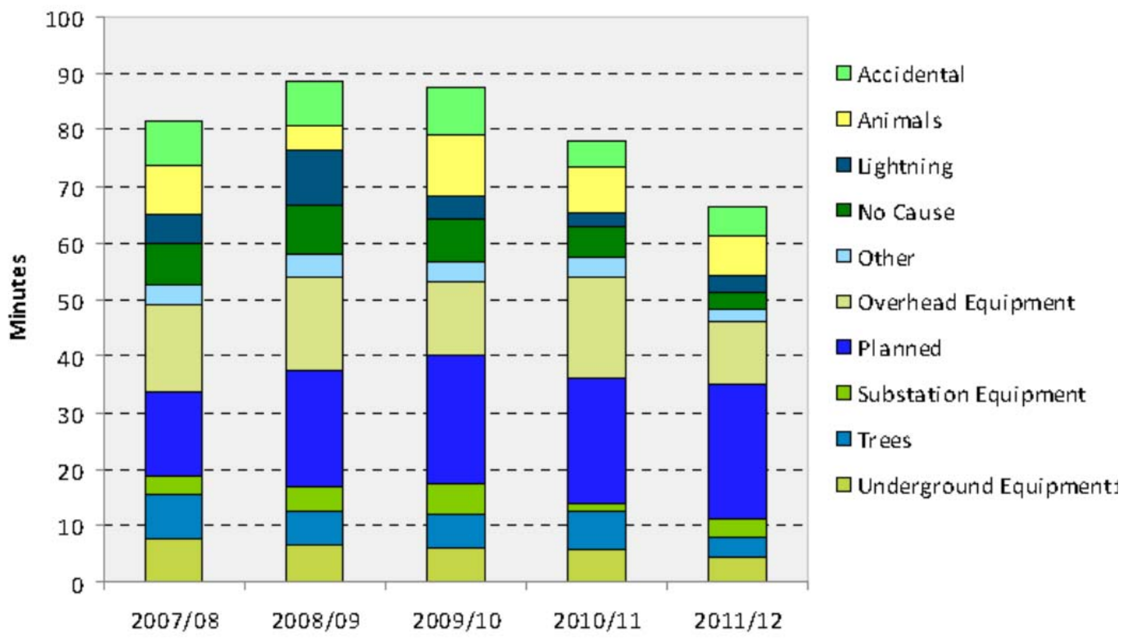
> *"ENERGEX has adopted the standard lives (i.e. the anticipated life of a new asset at the time of commissioning) and the estimated remaining lives as per its fixed asset register. These lives are based on ENERGEX's informed knowledge and understanding of how the assets perform over time and will be used within its distribution system, and the expected life associated with the type of usage".*

175 Energex, *Regulatory Proposal for the period July 2010 - June 2015*, July 2009, p 235.

Based on the asset age information outlined above, it appears that the remaining lives of virtually all of Energex's asset classes are over 50% of the standard life – that is, on average, the lives of assets in each asset class have not yet reached half of their standard life. Prima facie, this would indicate to us that Energex is unlikely to be facing a forward looking replacement program that is driven by an overly ageing asset base[176].

Figure 25 and Figure 26 below provide a snapshot of Energex's reliability performance – split out between urban and rural. They also provide a breakdown of the underlying drivers of that performance.

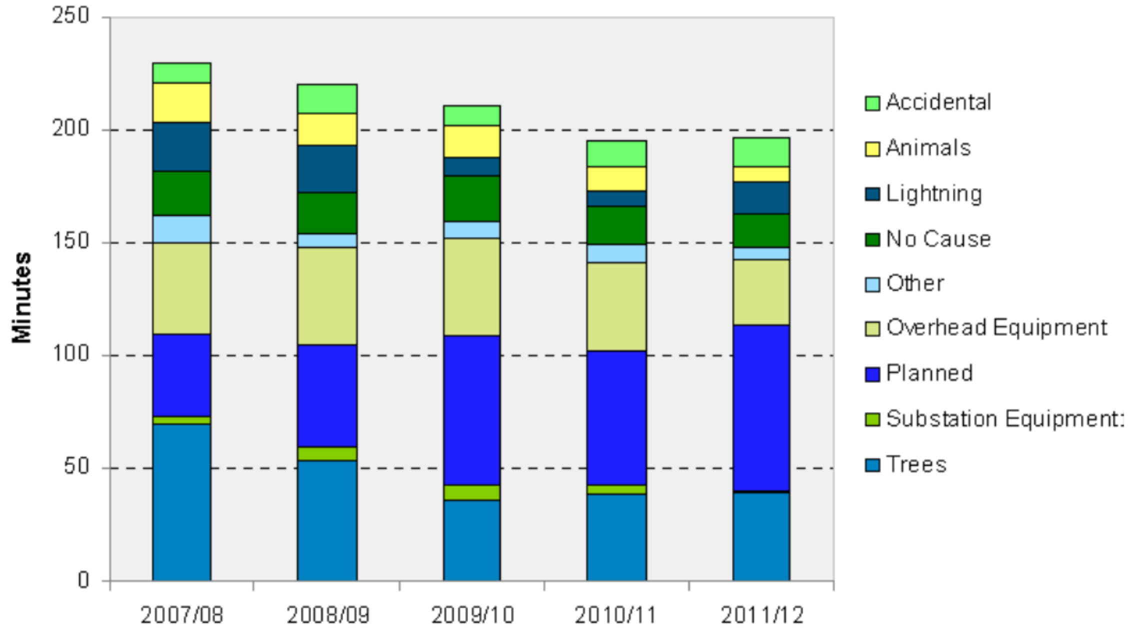
Figure 25: Causes of urban SAIDI



Source: Energex, *Network Management Plan - 2012/13 to 2016/17*, Final, 31 August 2012, p 85

176 However, it is noted that that the average remaining lives will have changed as a result of the replacement program that Energex has adopted over the current regulatory control period.

Figure 26: Causes of rural SAIDI



Source: Energex, *Network Management Plan - 2012/13 to 2016/17*, Final, 31 August 2012, p 86

The predominant driver of SAIDI outcomes in urban areas is planned maintenance. Overhead equipment is the largest asset related cause of SAIDI outcomes. The predominant drivers of SAIDI outcomes in rural areas are planned maintenance and vegetation (trees). It is the reduction in vegetation related causes that has been the predominant driver of reductions in SAIDI over the 2007/08 to 2011/12 period. Asset related issues do not appear to represent a substantial driver.

Based on this information, whilst we don't consider that Energex is approaching a point of "saturation" with regards to the level of service that it delivers to its customers, asset related failures do not appear to be either a predominant driver of SAIDI outcomes, not is there a noticeable trend increase being driven by asset related drivers. We should note for completeness that SAIDI outcomes are not the only impact of failure (e.g., bushfire risk is another); however, it does provide a picture of whether there is a change in the trend of failure causes.

Combined with the fact that on average, the lives of Energex's assets in each asset class had (at the time of the last Regulatory Proposal) not yet reached half of their standard life, we think that on the balance of probabilities, Energex is less likely to seek material increases in its replacement expenditure program than other businesses reviewed as part of this report.

4.8. SAPN

In its Regulatory Proposal, SAPN (then ETSA) proposed to spend around $466 million on asset replacement over five years, or $93 million per annum[177]. SAPN also cautioned at the time that[178]:

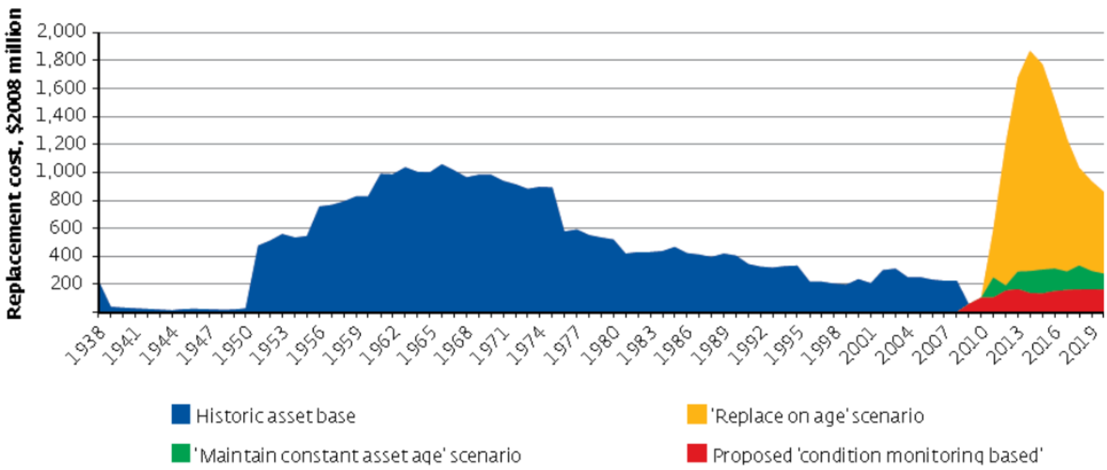
177 ETSA Utilities, *Regulatory Proposal 2010-2015*, 1 July 2009, p 15.

178 Ibid., p 19.

> *"..although aged asset replacement will increase significantly over the next regulatory control period, it will still be insufficient to arrest the increase in average asset age, moving from 36 years to 39 years over the next regulatory control period. We will rely on increasing condition monitoring of aged assets to enable such deferral without significantly increasing risk or placing reliability performance in jeopardy. Ultimately, levels of asset replacement will require significant further increases in future regulatory control periods".*

In support, SAPN produced the following graph in its Regulatory Proposal:

Figure 27: Asset age profile and proposed replacement expenditure



Source: ETSA Utilities, *Regulatory Proposal 2010-2015*, 1 July 2009, p 19.

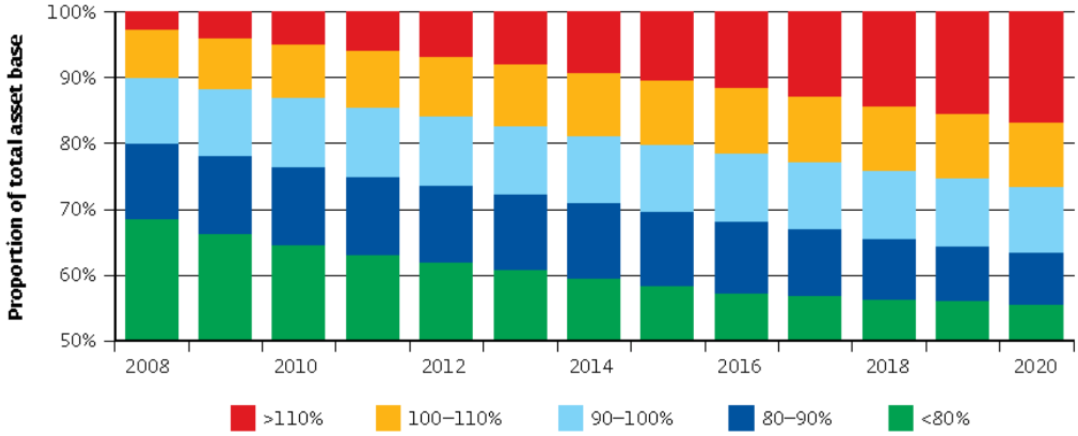
Taken on face value, this indicates that much of the network was (in replacement cost terms) constructed in the 1950s and 1960s and is thus approaching 50-60 years of age. It also indicates that SAPN considers that if a 'replace on age' approach were to be adopted, a significant 'catch-up' in replacement capex would be required over the next 10 years to replace assets already over age.

SAPN states that the average age of the network assets in 2009 was 36 years, meaning that approximately 12% of the network assets then in service had already exceeded their design lives to some extent, and, in the absence of an accelerated replacement program[179], a further approximately 8% of assets could be expected to exceed their design lives by the end of the then upcoming regulatory period.

This is illustrated in Figure 28 below.

179 Ibid., p 28.

Figure 28: SAPN's projected proportion of assets exceeding design life



Source: ETSA Utilities, *Regulatory Proposal 2010-2015*, 1 July 2009, p 107

It should be noted that in its Draft Decision, the AER reduced SAPN's proposed replacement capex by $227 million ($2009-10)[180]. In response, SAPN's revised asset replacement forecasts resulted in an increase in total capex of approximately $91 million ($2009-10) compared with the draft decision[181]. In its Final Decision, the AER reduced SAPN's proposed asset replacement capex by $93 million ($2009-10)[182]. In summary, this appears to have reduced SAPN's capital expenditure that is explicitly classified as replacement to around $239 million, or less than $50 million per annum.

As a broad observation, we note that this allowance is around a third (or even less) of the allowance provided by the AER to most other distribution businesses analysed in this report, including Endeavour Energy, who appears to have a younger asset base (measured in replacement cost terms), similar customer numbers, less kilometres of line[183], a smaller service area[184], and therefore, a lower customer density[185].

We note that SAPN's performance levels showed a general improvement between 2005/06 and 2007/08, however since then, there would appear to be a slight deterioration in this outcome (although it is difficult to tell because of the small time series, and the impact of the large increase in 2010/11).

180 AER, *Draft decision South Australia Draft distribution determination 2010-11 to 2014-15*, 25 November 2009, p 146.

181 AER, *Final decision South Australia distribution determination 2010-11 to 2014-15,* May 2010, p 80.

182 Ibid., p 88.

183 ETSA Utilities, *Regulatory Proposal 2010-2015*, 1 July 2009, p 28; and Integral Energy, *Regulatory Proposal*, 2 June 2008, p 29.

184 Ibid.

185 We should stress that this should not be seen as a criticism of Endeavour Energy. Rather, it simply reflects a high level comparison of two network business that have broadly equivalent customer numbers.

Figure 29: Total state-wide duration of interruptions (minutes) for SAPN

Source: ESCOSA, *2011/12 Annual Performance Report - Electricity Distribution Network*, p 3

Overall, based on the information outlined above, we consider that on the balance of probabilities, it is likely that SAPN will propose a replacement program that exceeds the capital expenditure allowance that was accepted by the AER in its Final Decision.

4.9. TransGrid

In its original Regulatory Proposal for the 2009 – 2014 period TransGrid proposed a capital expenditure of $493.4 million ($2008) on replacement projects, which represented 18.8% of its total capex proposal. The company submitted an updated proposal four months after its original proposal based on updated information from NEMMCO (regarding its economic assumptions), and the NSW government (regarding the fact that the Munmorrah generation plant would continue to operate). In its updated capital expenditure proposal replacement projects increased to $508.4 million ($2008) or 19.9% of the revised total capex of $2,549.5 million.

In its original regulatory proposal TransGrid stated that it

> *"takes a proactive approach in assessing and monitoring the 'well-being' of the assets it manages. This involves taking into consideration a number of factors about the condition of the assets, ongoing serviceability, NER requirements for reliability, comparison to practices used by other TNSPs, safety and the environment in which it operates. The output from this assessment forms the input to the Network Asset Management Plan."*[186]

186 TransGrid, *Meeting customer needs for transmissions services: TransGrid Revenue Proposal 1 July 2009 - 30 June 2014*, 31 May 2008, p 64.

The company prepares 5- and 30-year versions of its Asset Management Plan. According to the company this allows "short term maintenance requirements to be best managed while taking the long term issues into consideration."[187]

Its replacement efforts are is organised in two streams:

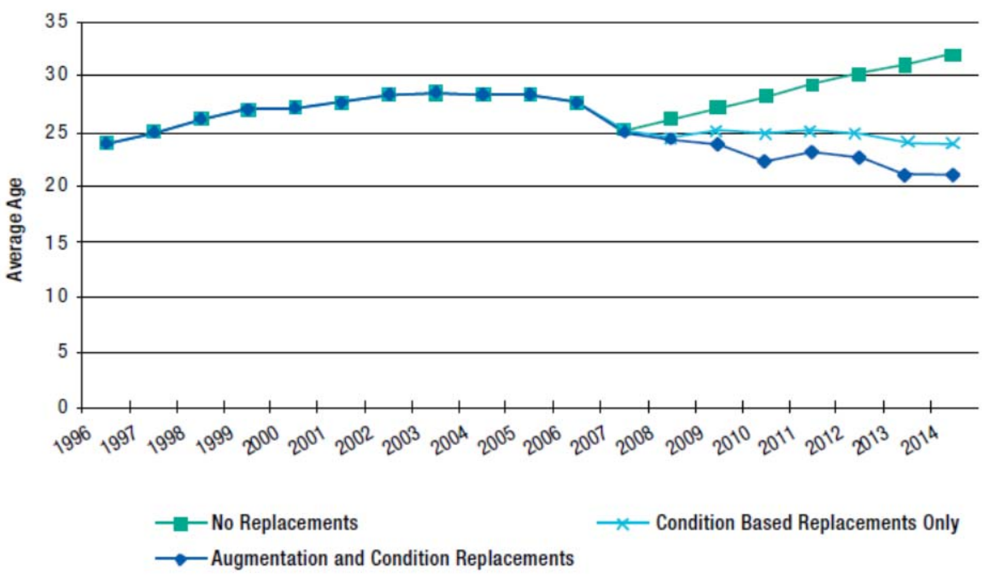
> *"Project based asset replacement occurs for significant refurbishments of specific parts of the transmission system, such as substation renewals, transmission line reconstructions, replacement transformers and capacitor banks, substation control rooms and telecommunication systems. This work is non-routine and is site specific.*
>
> *Program based asset replacements, such as replacing circuit breakers or protection relays, is performed in a systematic way throughout the transmission system by type of equipment."*[188]

In regard to the age of its assets TransGrid noted that:

> *"The majority of the transmission network in NSW was built between the 1950s and 1980s. Over 40% of transmission lines and 35% of substations and switching stations were commissioned in the 1960s or earlier. These are the types of assets that are the focus of the asset replacement program."*[189]

It also provided information on the impact of its proposed replacement capex program on the age of several classes of its assets as shown in Figure 30.

Figure 30: TransGrid average transformer age



Source: TransGrid, *Meeting customer needs for transmissions services: TransGrid Revenue Proposal 1 July 2009 - 30 June 2014*, 31 May 2008, p 67

187 Ibid.

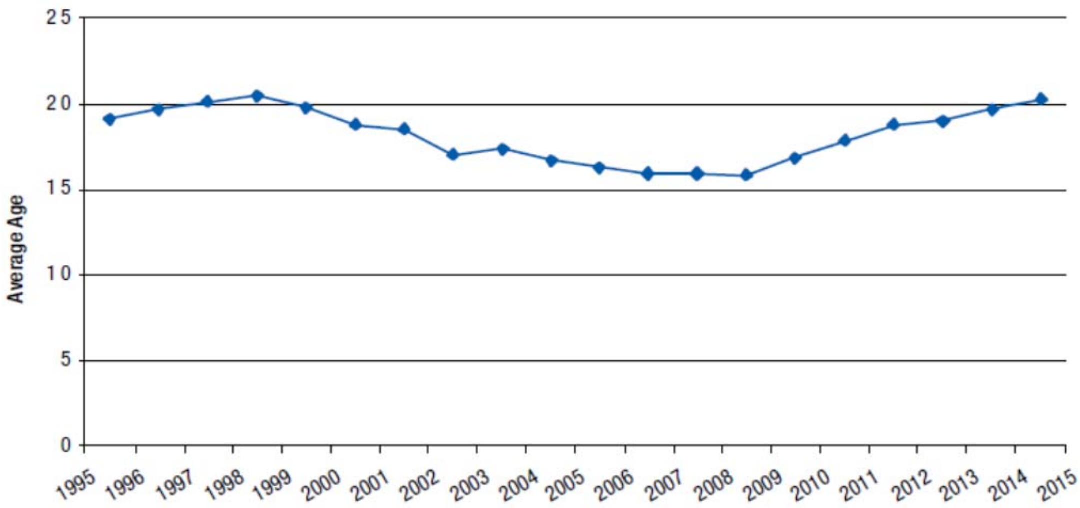
188 Ibid., pp 64 & 66.

189 Ibid., p 66.

It is worth noting that in a study undertaken for its 2007 Transmission Asset Management Plan, SP AusNet identified that the average age of transmission transformers in Australia was approximately 29 years, indicating that TransGrid's transformers are probably of about average age (or slightly younger).

Figure 31 below presents similar information regarding the age of TransGrid's circuit breakers.

Figure 31: TransGrid average circuit breaker age



Source: TransGrid, *Meeting customer needs for transmissions services: TransGrid Revenue Proposal 1 July 2009 - 30 June 2014*, 31 May 2008, p 68

As can been seen, TransGrid's proposed replacement program was anticipated to have only a marginal impact on the average age of these two classes of assets (information was not presented on other asset classes in TransGrid's original regulatory proposal).

However, TransGrid also reported quite good service levels in the 2003 – 2007 period. In each of the following service performance areas

- transmission line availability
- reactive plant availability
- loss-of-supply events greater than
  - 0.05 system minutes
  - 0.25 system minutes
- average unplanned outage restoration time

TransGrid reported meeting or exceeding its service targets on average over the period, if not in every year for every service area[190]. In one area:

- transformer availability

TransGrid's performance was below standard, but that was reported to primarily be the result of the capital works program[191].

190 Ibid., pp 99 - 106.

Based on these results, we do not think it is likely that TransGrid will increase replacement capex in order to improve service performance, but it would seem reasonable to expect that it will likely seek to maintain its replacement capex at present levels in order to continue to manage average asset age and protect service performance levels.

4.10. Transend

As noted in section 3.10, Transend proposed $226.6 million ($2008-09) in capital expenditure for 'asset renewal' during the current regulatory period, which was only very marginally less than it proposed for augmentation projects.

Transend described its renewal effort as "a long-term program that comprises a combination of targeted asset replacements and substation redevelopment projects that are critical to sustaining transmission system performance and the reliability of electricity supply to customers"[192]. It also noted that its proposed renewal expenditure was a continuation of the comprehensive asset renewal program that was already in progress during the then current regulatory control period (i.e., 2004 - 2009). In that period, asset renewal expenditure totalled $202 million.

Transend also stated that the primary drivers of asset renewal are asset condition, asset performance and technical obsolescence, and that it had "comprehensive condition assessment and performance monitoring regimes in place that provide a detailed understanding of the condition and performance of its assets"[193]. Other factors that can result in the replacement of assets, but which were identified in the Revenue Proposal as separate capex categories included the availability of spare parts/equipment and product support; physical security; technical, safety and environmental compliance; and the availability and requirements of operational support systems[194].

In its Draft Decision the AER reduced Transend's capex allowance related to renewal projects by $50.1 million ($2008-09). The primary reasons given by the AER for this reduction were:

- economic assessment and financial evaluation that was inadequate for project option and timing analysis
- inadequate documentation of inputs to the analysis in some cases
- inadequate attention to deferral opportunities through maintenance[195].

In its Revised Revenue Proposal, it provided additional information and sought to reinstate almost all of its originally proposed replacement capex. In its Final Decision the AER rejected these revisions and therefore the reduction of $50.1 million was retained[196]. This reduced the average annual capex allowed for replacements at a bit over $35 million.

191 Ibid.

192 Transend, *Transend Transmission Revenue Proposal for the Regulatory Control Period 1 July 2009 to 30 June 2014*, 30 May 2008, p 89.

193 Ibid., p 65.

194 Ibid.

195 AER, *Draft decision: Transend transmission determination 2009-10 to 2013-14*, 21 November 2008, pp 101 - 109.

196 AER, *Final Decision: Transend Transmission Determination 2009-10 to 2013-14*, 28 April 2009, p 41.

Transend did not provide information on the age profile of its assets in either its original Revenue Proposal or in its more recent 2013 Annual Planning Report (APR). As such, that information is not available to inform our qualitative assessment of the likely direction of Transend's asset replacement capex proposal for the upcoming regulatory period.

However, we note that the Tasmanian Treasury undertook a valuation of the Transend system in 2003 for the purpose of setting its regulatory asset base (RAB)[197], and that the opening RAB for the 2009 – 2014 regulatory period was set at just under $1 billion ($2008-09)[198]. Assuming that the network is approximately halfway through its average asset life of 45 to 50 years, an annual replacement spend of about $40 million would be indicated. Given that this is relatively close to the annual amounts that Transend has requested and been granted over the past two regulatory periods, we would expect that this amount will not change materially in Transend's upcoming revenue proposal.

197 Department of Treasury and Finance, *Transend Networks Pty Ltd: Valuation of Transmission Assets*, August 2003, p 1.

198 AER, *Final Decision: Transend Transmission Determination 2009-10 to 2013-14*, 28 April 2009, p 18.

5. Changes in demand

5.1. Objective

The objective of this section is to:

- review recent trends in household consumption patterns (including the effects of rooftop solar PV and government energy efficiency programs) for their impact on forecast throughput and average unit prices, and
- provide an order of magnitude estimate of the impact that a change in residential consumption might have on a distribution business' unit prices.

The latter component focuses on the NSW Distribution businesses – Ausgrid, Essential Energy and Endeavour Energy - and the Victorian Distribution businesses- SP AusNet, Citipower, Powercor, Jemena and United Energy.

5.2. Background

The extent to which a change in energy consumption impacts upon network charges is primarily a function of three issues:

- The proportion of a business' revenue requirement that is generated from energy variable (throughput) charges (relative to say fixed charges or capacity charges);
- The form of price control under which the business operates; and
- Whether the impact on consumption was forecast by the regulated business as part of their pricing submission.

In the case of the former, the more a business relies on variable charges, the more a change in consumption will impact upon their revenue recovery. At the extreme, if a business relies exclusively on the levying of variable charges to recover its revenue requirement then it will be fully exposed to changes in consumption. By contrast, if a business relies exclusively on fixed charges to recover its revenue requirement, it will not be impacted at all.

The extent to which a change in consumption impacts unit prices versus shareholder returns will be a function of the form of price control that is adopted by that business, as well as whether the consumption change was forecast by the business.

With regards to the form of price control, regulated businesses operate under either a Revenue Cap or a Weighted Average Price Cap (WAPC). If a business operates under a Revenue Cap, it means that its revenues are capped (in NPV terms) for the entire regulatory control period, no matter what level of sales occurs. Under a WAPC, a business' revenues are a function of their sales volume. In this case, if a business forecasts the change in energy consumption as part of their pricing submission, then this would lead to changes in their energy forecasts, which, *ceteris paribus*, will lead to overall unit prices increasing or decreasing in order to compensate them for the gained/lost revenue associated with that forecast change in consumption. If they do not forecast the impact, it is the shareholder that bears the loss/increase in revenue that stems from the changed levels of consumption for that regulatory control period, with this then being "reset" in the following regulatory period based on new demand forecasts and revenue requirement levels. The above outcomes do not occur under a Revenue Cap; rather it is always the customer that is exposed to the effect of this volume risk on price.

Each of the Victorian distribution businesses has historically, and continues to, operate under a WAPC. This is the same for the NSW DNSP's (at least for their current regulatory control period). This means that any *forecast* reduction (increase) in sales that is accepted by the AER in a Final Decision will flow through to higher (lower) unit prices for the network business in question. However, we note that the AER's current position is to adopt a Revenue Cap form of price control for the NSW distribution businesses in the forthcoming regulatory control period[199]. It is unclear if the AER will also seek to implement a Revenue Cap for the Victorian businesses in their next regulatory review process.

As alluded to above, a move to a Revenue Cap will automatically mean that any change in revenue caused by a change in throughput will lead to changes in unit prices, although it is noted that the timing of this will be dependent on whether the business forecasts the change or not[200]. In short, consumers bear the revenue risk associated with changes in volume under a Revenue Cap.

5.3. Likely trends in residential electricity consumption and impact on average price and pricing

5.3.1. Overview

Electricity consumption in the residential sector has changed significantly in the recent past. From the second half of the 90s and into the first half of the first decade of the 2000s, electricity consumption continued to increase at a moderate rate, but was overshadowed by increases in peak demand due largely to the increased penetration and average installed capacity of refrigerative air conditioning. This tended to reduce the annual system load factors of most network businesses, resulting in upward pressure on unit electricity prices.

Toward the end of the last decade, however, electricity consumption actually declined, as shown in Figure 32 below. Key drivers of that decline included decreased economic activity due to the GFC, which primarily affected non-residential electricity users, but had spill-over effects into the residential sector through increased unemployment and decreased confidence; significant increases in electricity prices, which were caused by a variety of factors[201]; government subsidies, feed-in tariffs and falling prices for rooftop PV systems; and subsidies for energy efficiency measures.

Figure 32 also shows that AEMO is now forecasting a return to growth, though at a relatively modest rate. It also shows the underlying trend of decreasing per-customer consumption (for all but large industrial consumers) that accelerated at the time of the GFC is continuing despite the return to growth in overall consumption.

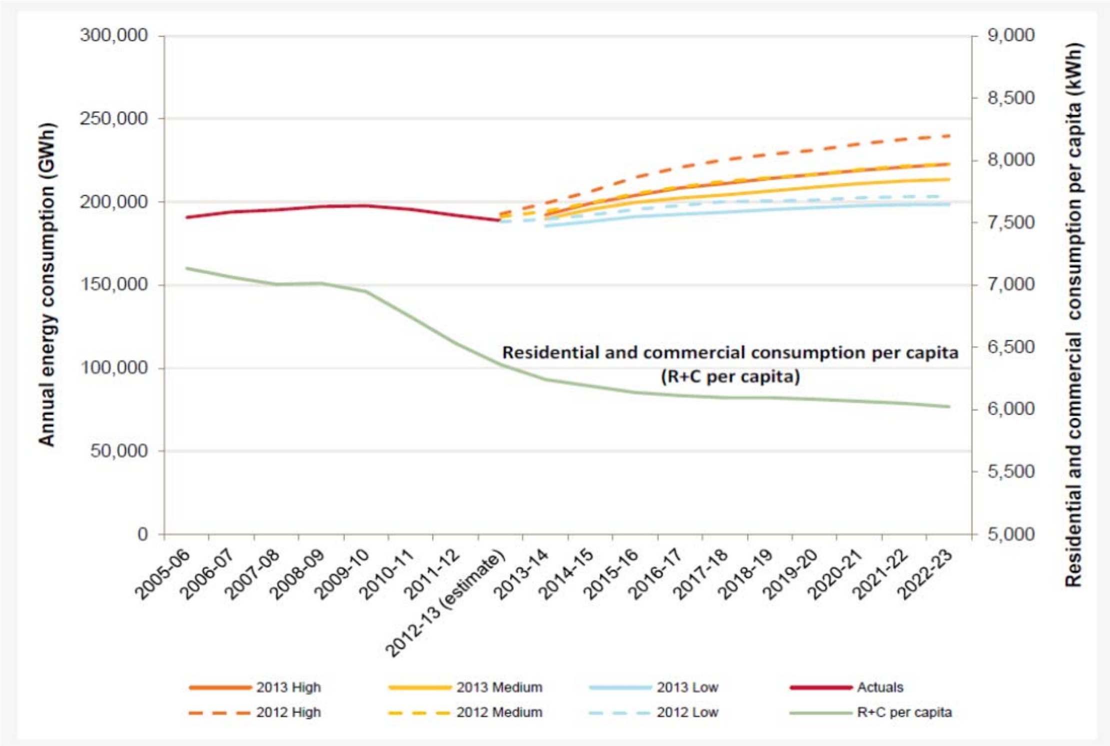
199 AER, *Stage 1 Framework and approach paper Ausgrid, Endeavour Energy and Essential Energy*, March 2013, pp 48 - 57.

200 For example, if a business, operating under a Revenue Cap, did not forecast the change in consumption, then, *ceteris paribus*, the revenues that they receive in the first year will vary to required levels due to that change in consumption. However, this gained/lost revenue will be recovered/given back to customers through higher/lower prices in future years of the regulatory control period. Moreover, the Revenue Cap formula is designed to ensure that the business is indifferent, in NPV terms, to the timing of revenue recovery.

201 Price pressures included: various government policies focussing on renewable energy and energy efficiency whose costs were recovered through levies on electricity consumption; the impact of the reductions in sales that those policies caused and that put upward pressure on network per-unit prices; and the need for significant investment in some jurisdictions for increased network reliability or the replacement of aged network assets.

The paragraphs following Figure 32 look into these trends on a regional basis in order to explore implications for the impact of observed and forecast changes in consumption on networks prices, and in turn, retail electricity prices for residential customers.

Figure 32: NEM electricity consumption (GWh) 2005-06 through 2022-23



Source: AEMO, *2013 National Electricity Forecasting Report*, 2013, p 2-2

5.3.2. Trends in residential demand by jurisdiction

Queensland

Figure 33 on the following page provides information about electricity consumption in Queensland from 2008-09 through 2019-20.

Figure 33: Queensland electricity consumption (GWh) 2008-09 to 2019-20

Timeframe		Total	R+C	R+C as % of Total	R+C per capita (kWh)	PV	EE	Effect of PV+EE on R+C
Actual	2008-09	49,768	38,347	77.1%	8,853	7	-	-0.02%
	2009-10	50,647	39,023	77.0%	8,861	40	-	-0.10%
	2010-11	48,871	37,479	76.7%	8,414	157	-	-0.42%
	2011-12	48,900	37,456	76.6%	8,272	469	-	-1.25%
	Average annual growth rate	-0.44%	-0.59%		-1.68%	186.03%		
Base	2012-13 (estimate)	49,543	37,434		8,093	1,023	304	
Forecast	2013-14	50,087	37,872	75.6%	7,893	1,221	872	-5.5%
	2014-15	55,278	38,814	70.2%	7,799	1,309	1,164	-6.4%
	2015-16	58,889	39,805	67.6%	7,763	1,396	1,538	-7.4%
	2016-17	60,767	40,756	67.1%	7,740	1,493	1,828	-8.1%
	2017-18	61,517	41,656	67.7%	7,726	1,599	2,154	-9.0%
	2018-19	62,528	42,660	68.2%	7,734	1,735	2,476	-9.9%
	2019-20	63,625	43,727	68.7%	7,737	1,900	2,799	-10.7%
Expected annual growth rates	Current regulatory period	2.49%	0.70%		-1.51%	52.83%	N/A	
	Upcoming regulatory period	1.56%	1.90%		-0.07%	6.35%	12.71%	

Source: AEMO, 2013 NEFR

Key points to note are that:

- While residential/commercial and total electricity consumption declined slightly on an annualised average basis over the years 2008-09 through 2011-12, both are expected to return to an annual increasing pattern from 2012-13 through 2017-18.
- Growth over the current regulatory period is expected to be significantly stronger in the large industrial sector, whereas growth in the residential/commercial sectors is expected to be less than 1% on an annualised basis. The strong growth in the large industrial sector is driven by three LNG projects that are expected to come on line in 2013-14. In the upcoming regulatory period (which commences in July 2015), by contrast, consumption in the residential/commercial sector is expected to grow at a marginally faster rate than that of the large industrial sector.
- The combined effects of the take-up of PV and energy efficiency measures are expected to reduce consumption in the residential/commercial sectors by approximately 6.4% from what it otherwise would have been by the end of the current regulatory period and by approximately 10.7% by the end of the next regulatory period. These trends contribute to the year-on-year decreases that are forecast for per-capita consumption in the residential/commercial sector through 2020.

In its Final Decision regarding Energex's 2010 – 2015 regulatory determination period the AER adopted an annual electricity growth rate of 3.60%[202], which means that, on present state-wide forecasts, Energex will not achieve the level of sales volume assumed in its price setting, and therefore will not fully recover the revenue required to cover it costs and provide its allowed commercial return. However, because Energex operates under a Revenue Cap, the effect of revenue shortfalls will have been addressed through price adjustments during the regulatory period. However, as those adjustments are made one to two years in arrears, some of that adjustment will carry forward into the upcoming regulatory period. Those adjustments will tend to put upward pressure on Energex's prices in the first year or two of the next regulatory period (i.e., 2015-16 and 2016-17).

The lower growth rate forecast for the upcoming regulatory period could also put additional upward pressure on per-unit distribution charges, assuming all factors relating to the business' costs and tariff structure remain unchanged. In this regard, it is useful to note that growth is forecast to be higher in the residential/commercial sectors than for larger industrial customers. To the extent that sectoral-specific growth rates are used in setting the per-unit charges levied to the various customer segments, this would result in a smaller impact on charges to the residential/commercial sectors than if their growth rate had been below that of the total load for the state.

It should be noted however, that

- The information presented in **Error! Reference source not found.** is for Queensland as a whole. While it is not possible to determine how much Energex's actual consumption has differed from the growth rate predicted for the current regulatory period state-wide, Energex will almost certainly not have experienced the state-wide rate of growth in consumption by large industrial customers, given that none of the three large industrial projects that are driving that growth are located in the Energex distribution service area. However, Energex may have received a higher proportion of the state-wide growth in residential/commercial consumption than suggested by the state-wide average. However, and regardless of why, if outturn growth in the Energex service area is lower during the current regulatory period than forecast it will result in a lower starting point for sales in the upcoming regulatory period which, *ceteris paribus*, will put upward pressure on per-unit charges in the upcoming regulatory period.
- While a change in total electricity sales (consumption) will affect average unit prices under a Revenue Cap, the distribution business has flexibility (within limits) in to allocate that change to the average unit prices charged to different tariff classes (and the components of the tariff charged to each tariff class).

As a result, it is not possible to be definitive about the effect of changes in total and residential class consumption on the per-unit charges that Energex is likely to levy on its residential customers in the 2015 to 2020 regulatory period, though on the balance of evidence we think that an upward impact is more likely than a downward one.

New South Wales

Figure 34**Error! Reference source not found.** provides information about electricity consumption in New South Wales from 2008-09 through 2019-20.

202 AER, *Final decision: Queensland distribution determination 2010-11 to 2014-15*, May 2010, p xviii.

Figure 34: NSW electricity consumption (GWh) 2008-09 to 2019-20

Timeframe		Total	R+C	R+C as % of Total	R+C per capita (kWh)	PV	EE	Effect of PV+EE on R+C
Actual	2008-09	74,781	58,371	78.1%	7,900	3	-	-0.01%
	2009-10	74,522	58,204	78.1%	7,783	22	-	-0.04%
	2010-11	74,308	57,934	78.0%	7,671	197	-	-0.34%
	2011-12	71,782	56,019	78.0%	7,340	457	-	-0.82%
	Annualised average growth rate	-1.02%	-1.02%		-1.82%	253.39%		
Base	2012-13 (estimate)	68,834	55,253		7,164	659	425	
Forecast	2013-14	69,363	55,331	79.8%	7,103	836	1,225	-3.7%
	2014-15	69,574	55,477	79.7%	7,050	1,011	1,656	-4.8%
	2015-16	69,646	55,450	79.6%	6,975	1,208	2,196	-6.1%
	2016-17	70,012	55,804	79.7%	6,945	1,430	2,613	-7.2%
	2017-18	70,565	56,334	79.8%	6,936	1,674	3,074	-8.4%
	2018-19	71,344	57,093	80.0%	6,954	1,935	3,536	-9.6%
	2019-20	71,925	57,666	80.2%	6,945	2,210	3,998	-10.8%
Expected annual growth rates	Current reg period	-1.42%	-1.01%		-1.81%	107.58%	N/A	
	Upcoming reg period	0.50%	0.58%		-0.27%	13.86%	16.38%	

Source: AEMO, 2013 NEFR

Key points to note are that:

- While residential/commercial and total electricity consumption declined slightly on an annualised average, state-wide basis over the years 2008-09 through 2011-12, they are expected to return to annualised increases from 2012-13 through 2017-18.
- However, forecast consumption across the state for the current regulatory period (2009 - 2014) is still forecast to be negative both in total and for the residential/commercial sector.
- This trend is forecast to reverse in the upcoming regulatory period (2014-15 to 2018-19), resulting in very modest growth in sales to both larger industrial customers and the residential/commercial sector.
- However, total consumption and consumption in the residential/commercial sectors in 2014-15 (the first year of the new regulatory period) will still be below what they were in 2009-10 (the first year of the current regulatory period).
- The combined effects of the take-up of PV and energy efficiency measures are expected to reduce consumption in the residential/commercial sectors by approximately 3.7% from what it otherwise would have been by the end of the current regulatory period and by approximately 9.6% by the end of the upcoming regulatory period. It should be noted that these figures do not include the impact of NSW's Energy Savings Scheme, meaning that (a) the impact of energy efficiency in the forecast and on the per-capita usage of residential/commercial sector customers may be marginally conservative, and (b) forecast consumption may be marginally optimistic.

In its Final Decisions regarding the revenue proposals of the NSW network businesses the AER adopted the following annual electricity growth rates for the 2009 -2014 period:

- Ausgrid: -0.10%[203]
- Endeavour Energy: 0.70%[204]
- Essential Energy: 0.50%[205]
- TransGrid: 0.80%[206]

Because the growth numbers in **Error! Reference source not found.** above are on a state-wide basis it is not possible to say exactly how the outturn consumption in each of the distribution service areas compared with the growth rate assumptions that underpinned their average price calculations. However, given the disparity in the forecast state-wide outturn of (-1.42%) from the approved forecast numbers (which ranged from -0.1% to +0.7%) it is highly likely that outturn consumption will prove to be less than forecast for all three businesses. Because they are regulated (at least currently) under a Weighted Average Price Cap, any shortfall in revenue recovery that results over the current regulatory due to lower than forecast consumption will be borne by the distribution businesses (and their shareholder).

On the basis of the current forecast, consumption in the initial year of the upcoming regulatory period is expected to be lower in total and in regard to the residential/commercial sector in than the initial year of the current regulatory period. In addition, state-wide growth (at 0.5% in total and 0.58% for the residential/commercial sector) suggests that total consumption over the upcoming period is likely to be lower in total than in the current regulatory period[207]. In combination these factors will, *ceteris paribus*, put upward pressure on per-unit prices – and this is the case whether they continue to be regulated under a WAPC or are moved to a Revenue Cap.

On the balance of these considerations, we would expect that the changes in demand that have been experienced and are forecast will put upward pressure on per-unit network charges in the upcoming regulatory period in NSW.

South Australia

Figure 35 provides information about electricity consumption in South Australia from 2008-09 through 2019-20.

203 AER, *Final Decision: New South Wales distribution determination 2009-10 to 2014-15*, 28 April 2009, pp 112-113, 115.

204 Ibid., pp 88 - 89, 115.

205 Ibid., pp 84 - 85, 115.

206 AER, *Draft decision: TransGrid transmission determination 2009-10 to 2013-14*, 31 October 2008, pp 38 – 40. The AER did not comment further on TransGrid's energy forecast in its Final Decision.

207 It is worth noting that, on the basis of the AEMO 2013 NEFR, state-wide consumption by the *end* of the upcoming regulatory period (2018-19) will still be below where it was at the *beginning* of the current regulatory period (2009-10).

Figure 35: SA electricity consumption (GWh) 2008-09 to 2019-20

Timeframe		Total	R+C	R+C as % of Total	R+C per capita (kWh)	PV	EE	Effect of PV+EE on R+C
Actual	2008-09	13,686	11,668	85.3%	7,257	8	-	-0.07%
	2009-10	13,621	11,818	86.8%	7,275	27	-	-0.23%
	2010-11	13,729	11,516	83.9%	7,044	67	-	-0.58%
	2011-12	13,372	11,195	83.7%	6,793	253	-	-2.26%
	Average annual growth rate	-0.58%	-1.03%		-1.64%	136.72%		
Base	2012-13 (estimate)	13,144	10,888		6,555	497	84	
Forecast	2013-14	12,753	10,509	82.4%	6,281	583	245	-7.9%
	2014-15	12,598	10,410	82.6%	6,171	630	332	-9.2%
	2015-16	12,429	10,298	82.9%	6,055	671	440	-10.8%
	2016-17	12,355	10,225	82.8%	5,963	716	515	-12.0%
	2017-18	12,345	10,214	82.7%	5,908	765	611	-13.5%
	2018-19	12,410	10,278	82.8%	5,896	818	704	-14.8%
	2019-20	12,493	10,359	82.9%	5,890	886	796	-16.2%
Expected annual growth rates	Current reg period	-1.70%	-2.00%		-2.61%	56.59%	N/A	
	Upcoming reg period	0.10%	0.12%		-0.55%	5.71%	12.60%	

Source: AEMO, 2013 NEFR

Key points to note are that:

- Residential/commercial and total electricity consumption declined by 1.03% and 0.58% respectively from 2008-09 through 2011-12, but are forecast to show further declines by the end of the current regulatory period.
- These trends are expected to reverse in the upcoming regulatory period to very marginal positive growth rates of 0.1% state-wide and 0.12% in the residential/commercial sectors.
- However, total consumption and consumption in the residential/commercial sectors in 2015-16 (the first year of the new regulatory period) will still be below what they were in 2010-11 (the first year of the current regulatory period).
- The combined effects of the take-up of PV and energy efficiency measures are expected to reduce consumption in the residential/commercial sectors by approximately 9.2% from what it otherwise would have been by the end of the current regulatory period and by approximately 16.2% by the end of the upcoming regulatory period. It should be noted that these figures do not include the impact of the South Australia Residential Energy Efficiency Scheme, meaning that (a) the impact of energy efficiency in the forecast and on the per-capita usage of residential/commercial sector customers may be marginally conservative, and (b) forecast consumption may be marginally optimistic.

In its Final Decision regarding ETSA Utilities' (now South Australia Power Networks - SAPN) revenue proposal for the 2010 to 2015 period, the AER adopted a growth rate of -0.70%[208]. On the basis that growth over the period is currently forecast to have been -1.70% overall and -2.0% in the residential/commercial sectors, SAPN will not achieve the level of sales volume assumed in its price setting, and therefore will not fully recover the revenue required to cover it costs and provide its allowed commercial return. Because the business operates under a WAPC form of regulatory control, the shareholders of the business will bear these revenue shortfalls.

It is also worth noting that on the basis of the present forecast:

- consumption in the initial year of the upcoming regulatory period is expected to be lower in total and in regard to the residential/commercial sector in than the initial year of the current regulatory period, and
- total consumption over the upcoming period is likely to be lower in total than in the current regulatory period, given the fact that total consumption in the *last* year of the upcoming regulatory period (2019-20) is forecast to be lower than actual consumption in the first year of the current regulatory period (2010-11).

On the basis of these considerations, we would expect that the changes that have taken place and are forecast to take place over the next several years, will put upward pressure on the per-unit prices that SAPN charges residential/commercial (and other) customers.

Tasmania

Figure 36 on the following page provides information about electricity consumption in South Australia from 2008-09 through 2019-20.

208 AER, *"Final decision: South Australia distribution determination 2010-11 to 2014-15"* May 2010, p 67.

Figure 36: Tasmania electricity consumption (GWh) 2008-09 to 2019-20

Timeframe		Total	R+C	R+C as % of Total	R+C per capita (kWh)	PV	EE	Effect of PV+EE on R+C
Actual	2008-09	10,979	5,503	50.1%	10,957	0	-	-0.01%
	2009-10	10,877	5,313	48.8%	10,482	2	-	-0.05%
	2010-11	10,934	5,044	46.1%	9,887	6	-	-0.12%
	2011-12	10,540	4,951	47.0%	9,667	12	-	-0.24%
	Average annual growth rate	-1.01%	-2.61%		-3.08%	135.69%		
Base	2012-13 (estimate)	10,247	4,770		9,291	38	37	
Forecast	2013-14	10,574	4,672	44.2%	9,061	54	108	-3.5%
	2014-15	10,462	4,502	43.0%	8,682	66	147	-4.7%
	2015-16	10,227	4,273	41.8%	8,194	78	195	-6.4%
	2016-17	10,181	4,229	41.5%	8,194	92	233	-7.7%
	2017-18	10,205	4,252	41.7%	8,194	106	273	-8.9%
	2018-19	10,344	4,387	42.4%	8,194	121	314	-9.9%
	2019-20	10,428	4,469	42.9%	8,194	136	355	-11.0%
Expected annual growth rates	Current reg period	-0.56%	-2.54%		-2.87%	85.42%	N/A	
	Upcoming reg period	-0.23%	-0.52%		-1.15%	12.86%	16.46%	

Source: AEMO, 2013 NEFR

Key points to note are that:

- Residential/commercial and total electricity consumption declined by 2.61% and 1.01% respectively from 2008-09 through 2011-12, but by the end of the current regulatory period some recovery is expected. State-wide consumption is expected to recover to an overall decline of -0.56% and residential/commercial sector consumption to show a more marginal improvement to -2.54%.
- Further improvement is forecast for the upcoming regulatory period, with state-wide consumption still negative, but the annualised rate improving to -0.23%. An even larger improvement in the residential/commercial sector is forecast with the growth rate there improving to -.0.52%.
- However, total consumption and consumption in the residential/commercial sectors in 2014-15 (the first year of the new regulatory period) will still be below what they were in 2009-10 (the first year of the current regulatory period).
- The combined effects of the take-up of PV and energy efficiency measures are expected to reduce consumption in the residential/commercial sectors by approximately 3.5% from what it otherwise would have been by the end of the current regulatory period and by approximately 9.9% by the end of the upcoming regulatory period.

In its Final Decision regarding Transend's revenue proposal for the current regulatory period, the AER stated that it had accepted the energy sales forecast Transend provided in its 2008 Transmission Annual Planning Report. We were unable to find a copy of this document on either the AER or Transend websites, and therefore cannot compare actual and forecast consumption figures for this regulatory period to the forecast that underpinned the development of Transend's current per-unit prices. However, because Transend's revenue is subject to a Revenue Cap, the effect of any shortfall in revenue will have been addressed through price adjustments during the regulatory period. However, as those adjustments are made one to two years in arrears, some of any such adjustment (if needed) will carry forward into the upcoming regulatory period.

By contrast, the fact that total consumption and consumption in the residential/commercial sectors are forecast to be lower in every year of the upcoming regulatory period than they were in the corresponding years of the current regulatory period suggests that Transend will have fewer sales in total in the upcoming regulatory period than they are forecast to have in the current one. All other things being equal, this will put upward pressure on per-unit prices, though because Transend's tariff generally accounts for about 12% of Tasmanian residential retail electricity prices[209], the overall impact of this upward pressure will be relatively modest.

5.3.3. Trends in distribution pricing

The previous section assessed the impact of likely changes in demand on the per-unit prices charged by network businesses under the assumption that other key factors remain unchanged.

Important factors that can change are the costs incurred by the network business, which will affect the amount of revenue the business needs to recover through its tariffs, and the structure of its pricing, which will determine the overall importance of energy sales for revenue recovery. Under the Rules, network businesses have a degree of flexibility in how it allocates costs to different classes of customers (such costs need to fall between the cost of serving that class of customers on a standalone basis and on a marginal basis as part of the rest of the customer base), and how they structure the tariffs for any particular customer class.

Tariff structures will determine the degree to which the network business is depending on energy sales to recover its costs. At one extreme, if a network business' tariff was only comprised of a charge for electricity consumed, it would be 100% dependent on electricity sales for recovering its costs. At the other extreme, if a network business charged customers entirely on either their maximum demand – or on a fixed cost per month – it would be entirely indifferent to annual energy sales. In fact, no network businesses operate at either extreme. However, with regard to residential and small commercial customers, cost network businesses obtain the majority of their revenue from their charge on energy sales[210].

As discussed previously, under a WAPC, sales above the forecast will result in additional profit for the network business, and sales below forecast create losses. While the effect is the same under a Revenue Cap, the regulatory mechanism adjusts for such over- and under-recoveries.

209 Transend, *Transend Transmission Revenue Proposal for the Regulatory Control Period 1 July 2009 to 30 June 2014*, 30 May 2008, p 173.

210 For example, almost 80% of the revenue received from residential customers in NSW comes from charges on energy consumption. In Victoria the proportion is in the low 90%s.

In times of strong or at least reliable sales growth, network businesses may perceive that there is significant opportunity in energy-based revenue recovery (though as noted above, this will be more relevant to networks under a WAPC than those under a Revenue Cap). By contrast, in time of decreasing demand – and particularly volatility in demand – energy-based pricing will be riskier with regard to revenue recovery, and increased reliance on other parts of the tariff may provide more certainty of adequate revenue recovery.

There are three basic ways in which reliance for revenue recovery on marginal energy sales can be reduced:

- Increasing the fixed charge (this is the charge that the customer charged on a daily, monthly or quarterly basis) – Customers tend to be negative about these charges as they cannot be avoided (except by totally disconnecting from the grid), and regulators and policymakers also often oppose these charges for the same reason and in some cases because they reduce the value of energy efficiency or conservation to the consumer and therefore do not promote environmental policies aimed at reducing greenhouse gas emissions through reduced electricity consumption.
- Increasing the charge on the first block of electricity consumption and decreasing it (at least relatively) on subsequent blocks – Most of the network electricity tariffs for residential customers apply a lower price to the first block of electricity consumed in a billing period and a higher price to subsequent blocks. This structure has equity benefits, in that it provides a lower price for low energy users, which can be advantageous for disadvantaged groups, and environmental benefits, in that its higher price on subsequent blocks provides a stronger price signal for energy efficiency and conservation. Increasing the price on first block electricity consumption is likely to have some of the advantages (from the perspective of increasing the certainty of revenue recovery) of increasing the fixed charge because electricity use in the first block is likely to be more inelastic than consumption in subsequent blocks.
- Increasing charges for instantaneous demand (either system coincident peak demand or the customer's anytime maximum demand) – While this basis for charging is generally considered to be more reflective of the costs imposed by the customer (or customer class) on the network, it requires that customers have meters that are capable of reading and recording demand. Such meters are more expensive than meters that just record electricity usage, and size of residential customers' bills have historically not been large enough to justify this expense. "Smart meters" can record demand and therefore would support the use of demand-based pricing for residential customers, but the installation of such meters on a mass scale for residential customers being served by the distribution business we have assessed as part of this assignment is unlikely in the period of interest in this study (i.e., by July 2016). This reinforces the use of either of the other two approaches discussed above.

As noted in the dot points above, changes to network tariffs for residential customers are likely to be limited in the near term to increasing either (or both) the fixed charge and/or first-block electricity charges. In fact, there is evidence that such changes are being pursued by a number of the networks.

Figure 37 below shows the changes in Energex's 8400 tariff, which is the general non time-of-use tariff for residential customers.

Figure 37: Energex single rate tariff by component 2010-11 to 2013-14

Component		2010-11	2011-12	% change	2012-13	% change	2013-14	% change	2010-11 to 2013-14
Fixed ($/day)	Distribution	0.22063	0.27	22.4%	0.28	3.7%	0.360	28.6%	63.2%
	Transmission	0.05409	0.06	10.9%	0.07	16.7%	0.079	12.9%	46.1%
	Total NUoS	0.27472	0.33	20.1%	0.35	6.1%	0.439	25.4%	59.8%
Electricity (c/kWh)	Distribution	6.680	7.353	10.1%	8.728	18.7%	10.247	17.4%	53.4%
	Transmission	1.331	1.471	10.5%	1.472	0.1%	1.700	15.5%	27.7%
	Total NUoS	8.011	8.824	10.1%	10.200	15.6%	11.947	17.1%	49.1%

Source: Energex Annual Pricing Proposals for the years cited

As can be seen in all years but one – and over the period as a whole – per-cent increases in the fixed component of the tariff have been higher than those on the variable (electricity) component.

SAPN's recent proposed tariff changes are shown in Figure 38 below.

Figure 38: SAPN's proposed residential tariff changes for 2013-14

Tariff component	2012-13	2013-14	% change
Fixed charge ($pa)	94.43	101.74	7.7%
Block 1 usage (c/kWh)	8.135	9.247	13.7%
Block 2 usage (c/kWh)	10.726	12.049	12.3%
Block 3 usage (c/kWh)	12.76	14.334	12.3%
Block 4 usage (c/kWh)	12.76	14.334	12.3%

Source: SA Power Networks, *Annual Pricing Proposal 2013-2014*, 24 May 2013, p 34

The component that was subject to the highest increase was first-block electricity use, which is likely to be relatively inelastic to price changes. The increase on the fixed component of the tariff was significantly lower, but this was due to a side constraint in the allowed pricing. As SAPN explained, the increase of $7.32 was "the maximum . . . permitted by the $10 pa side constraint for small customers after allowing for a $2.68 pa metering charges increase"[211]. SAPN also stated that for the remainder of the current regulatory period it expected that relative movement in the charging parameters of the residential flat rate tariff would include increases on the fixed charge and no material change to the energy components[212].

In terms of where the networks would like to go with their pricing, their statements regarding 'network pricing strategy' are pretty clear. Here is what SAPN stated in its 2013-14 Annual Pricing Proposal:

> *SA Power Networks has a pricing strategy that will, within the limitations of metering arrangements and efficient tariff structures, signal the costs associated with increased demand placed on the network, including the use of air conditioning.*
>
> *Consistent with the network tariff objectives outlined in section 5.2, SA Power Networks' network tariff strategy aims to:*
>
> - *Attain revenue sufficiency under the Weighted Average Price Cap;*
> - *Signal the long run marginal cost of supply through its network tariffs;*

211 SA Power Networks, *Annual Pricing Proposal 2013-2014*, 24 May 2013, p 34.

212 Ibid., p 33 - see Table 15 on p 33 of the SA Power Network document.

- *Improve cost reflectivity and reduce revenue variability by reducing the reliance on usage based tariff components where appropriate;*
- *Pass on the cost of ElectraNet's transmission services to customers; and*
- *Explore tariff based demand management opportunities, including voluntary capacity based tariffs.*[213]

Similarly for Endeavour Energy:

Endeavour Energy's network tariff strategy aims to:

- *Constrain average distribution price increases to no more than the rate of inflation for (at least) the next six years;*
- *Reflect the role of networks in providing capacity;*
- *Align the largely fixed costs of the network and revenues;*
- *Signal the costs of using the network at peak times;*
- *Provide outcomes that recognise the impacts that pricing decisions have on our customers;*
- *Pass through the full cost of TransGrid's transmission services and preserve transmission price signals where possible; and*
- *Explore tariff based demand management opportunities, including voluntary time of use tariffs, and tariffs that target network constraints on a locational basis.*[214]

And finally, a selection of statements from the "Pricing Strategy" section of Energex's most recent Annual Pricing Proposal:

- ***Move towards fixed charges comprising [a} greater percentage of tariffs --*** *In the absence of demand and capacity charge elements, based on typical usage profiles, a fixed charge can be used to reflect the typical capacity requirement of a SAC Non-Demand [residential] customer. Moving towards an increase in the proportion of tariffs comprised of fixed charges will improve the cost-reflectivity of providing network for small customers.*
- ***Capacity and/or demand charges for small customers --*** *Demand charges are well established and accepted as components of network tariffs for large customers. In the medium to long term, Energex will look at progressively rolling out demand and/or capacity based tariffs for small business and, eventually, residential customers.*

  Additionally, in the long term, Energex is considering locational tariffs to assist in managing localised peak demand on the network and various tariffs (including ToU and capacity-based tariffs) with Dynamic Peak Pricing (DPP) elements. Further consideration of the inclusion of DPP elements in tariffs will be informed by the outcomes of the recently completed Reward Based Tariff (RBT) Trial.[215]

213 Ibid., p 30.

214 Endeavour Energy, *Direct Control Services Annual Pricing Proposal 2013/14*, 20 April 2013, p 36.

215 Energex, *"ricing Proposal 1 July 2013 to 30 June 2014*, 30 April 2013, p 49 - 50.

As these quotes make clear, the networks see demand/capacity based charging as the appropriate goal in the longer term, but realise that progress toward that is constrained in the near terms due primarily to limitations of current metrology.

Therefore, in the near term, it is likely that tariff adjustments will move toward:

- higher fixed charges, with the magnitude of movement limited by pricing side constraints, (and in some cases political considerations), and
- time-of-use tariffs (TOU), as a means for improving cost-reflectivity (and possibly as a step toward demand-based pricing).

As indicated in several of the pricing proposals, networks will be experimenting with a variety of voluntary tariff designs to determine their take-up and impact of load, demand and revenue.

Higher fixed charges will tend to put downward pressure on per-unit variable charges, but have the potential in times of decreasing consumption to actually increase average bills.

The effect of TOU tariffs on per-unit charges should be neutral but in fact will depend on the specifics of the TOU pricing design. It is also worth noting that in the near term, it is more likely that assignment to TOU tariffs for residential customers will be voluntary rather than mandatory.

In summary, therefore, we would expect that a significant proportion of the effects of changes in demand over the timeframe of interest in this study will be expressed in terms of changes in both the fixed charge and the variable charge.

However, it should be recognised that a Rule Change Request has been initiated by the Standing Council on Energy and Resources (SCER) which could change the basis on which network tariffs are to be developed. A Final Determination on this matter is expected in November 2014. Depending on the outcome of the Determination, it could affect network pricing proposals at the end of the timeframe being considered in this report.

5.4. Quantitative estimate of the impact of changes in consumption on residential unit prices

OGW undertook scenario modelling to estimate the order of magnitude impact that a change in energy consumption might have on the variable prices that distribution businesses charge their residential customers.

We note that an implicit assumption underpinning this assessment is that either:

- the change in consumption being modelled is forecast accurately by a distribution business operating under a WAPC, and thus, the revenue impacts associated with that change in consumption will be borne by end customers, and not the shareholders of the business; or
- the business operates under a Revenue Cap, and thus, the revenue impacts associated with that change in consumption will automatically be borne by end customers.

Another implicit assumption is that any change in the amount of revenue generated due to a change in consumption will be recovered from the customer class who has caused that change in consumption to occur. For the purposes of our modelling, we have therefore assumed that all changes in revenue received from residential customers are reflected in a change in the unit price faced by residential customers.

Finally, our analysis implicitly assumes that the business does not make any material changes to their residential tariff structures (e.g., they do not materially move away from the use of variable charges to recover revenue requirements), or that there is any rebalancing of the recovery of revenue from one customer class to another over the next regulatory period. As was discussed in the previous section, this may not necessarily be the case.

To model the impacts, we have:

- Created three energy consumption scenarios:
  - Low sustained positive growth = 1% increase in residential consumption throughout the period;
  - Low sustained negative growth = 1% decrease in residential consumption throughout the period; and
  - High sustained negative growth = 3% decrease in residential consumption throughout the period.
- We have estimated the proportion of revenue that is generated from throughput for each business being analysed. We did this by estimating an average residential bill for each business, using its posted DUoS tariffs[216] and an average consumption of 4500 kWh[217], and then calculating the proportion of the average bill that is generated from variable charges; and
- We multiplied the percentage changes under each energy consumption scenario by the proportion of revenue generated from variable charges, to estimate the overall change in average residential *variable* prices.

The following table outlines the results of this analysis.

Table 14: Estimated impact of change energy consumption on variable prices

Scenario	AusGrid	Endeavour	Essential	SP AusNet	Citipower	Powercor	Jemena	United Energy
1% increase in residential consumption	-0.81%	-0.80%	-0.71%	-0.95%	-0.92%	-0.91%	-0.94%	-0.92%
1% decrease in residential consumption	0.81%	0.80%	0.71%	0.95%	0.92%	0.91%	0.94%	0.92%
3% decrease in residential consumption	2.43%	2.40%	2.14%	2.84%	2.77%	2.74%	2.82%	2.77%

Source: OGW analysis

To convert this into an average bill impact (as opposed to the impact on variable prices), the aforementioned percentage change in variable prices needs to be multiplied by the proportion of the average bill that is driven by variable charges. The results of this are outlined in the table below.

216 We had to use Network Use of System (NUoS) tariffs for Endeavour Energy and Essential Energy, as we were unable to find published information on as to the Distribution (DUoS) component of their tariffs.

217 This is a broad estimate of the average consumption of a residential customer without electric hot water. We acknowledge that each business' average consumption will be different, and also, that a certain proportion of customers will have electric hot water, which in turn will increase their overall consumption. *Ceteris paribus*, this latter issue would, if included, increase the proportion of a residential customer's bill that is recovered from variable charges, which in turn increases the percentage impact on unit prices that a change in consumption has. This is not considered to be material, given the overall amount of consumption attributable to hot water, and the fact that in most cases, this usage is charged at much lower, off peak rates.

Table 15: Estimated impact of change energy consumption on the average residential bill

Scenario	AusGrid	Endeavour	Essential	SP AusNet	Citipower	Powercor	Jemena	United Energy
1% increase in residential consumption	-0.66%	-0.64%	-0.51%	-0.89%	-0.85%	-0.84%	-0.88%	-0.85%
1% decrease in residential consumption	0.66%	0.64%	0.51%	0.89%	0.85%	0.84%	0.88%	0.85%
3% decrease in residential consumption	1.97%	1.91%	1.52%	2.68%	2.55%	2.51%	2.65%	2.55%

Source: OGW analysis

For completeness, we note that there may also be an impact on the Transmission Use of System (TUoS) charges that are incorporated into the Network Use of System charges (NUoS) that are levied by distribution businesses. We consider that this is likely to represent a much smaller impact that what is presented above for distribution, as transmission represents a much smaller proportion of NUoS charges than does DUoS, which, *ceteris paribus*, means that the impact on final unit prices will be proportionately reduced (assuming that the fixed/variable split for TUoS tariffs is the same as DUoS).

6. Conclusions

The following table provides a general overview of the likely direction of changes in different variables assessed as part of this report.

Table 16: Likely direction and relative magnitude of various drivers of network costs on residential electricity price in the near future

Component	Likely direction of change	Comment
WACC	🡻	Given recent development in capital markets, on the balance of probabilities, future WACC decisions would be expected to be lower than the decisions that underpin the current prices of all of the businesses analysed in this report (this excludes any impact stemming from recent and pending Rule changes)
Labour Cost Escalators	⇧	While the most recent forecasts of labour cost escalators are lower than those that are embedded within the regulatory decisions affecting the current prices of the businesses analysed, they are still expected to exert some upward pressure on prices in the next round of regulatory reviews.
Materials Cost Escalators	⇧	Overall, there would appear to be a slight upside risk to the materials cost escalators over the evaluation period, although as highlighted in the body of the report, much will depend on the outlook for the Australian dollar.
Macroeconomic Conditions	-	The literature appears to be neither overly bearish nor bullish in relation to Australia's broader macro-economic outlook for the next few years. Therefore, based on currently available information, we consider that this is likely to have a neutral bearing on residential prices outcomes in the near term.
Augmentation Capital Expenditure	🡻	With demand forecasts easing, relative to those that were in place when the current regulatory reviews of the businesses were undertaken, the degree to which augmentation costs (excluding the impact of movements in labour and materials cost drivers) are likely to drive residential prices should reduce. Furthermore, pressure on expenditure forecasts as a result of changed levels of service (e.g., the move away from the existing deterministic n-2 reliability standard in the Sydney CBD) should reduce.
Replacement Capital Expenditure	⇧ to 🡹	On the balance of probabilities, we would expect there to be slight upward pressure on prices from increases in replacement levels over the next regulatory period. However, this pressure will vary significantly across the various network businesses.
Starting Price Changes due to difference between forecast and actual consumption outcomes	⇧ to 🡹	The majority of the networks have experienced outturn consumption that is materially lower than the levels on which their prices were developed, and, on present forecasts, several will have starting consumption levels in their next regulatory periods that will be below the actual levels of their first year consumption in the current regulatory period. This will exert upward pressure on prices.
Future price changes due to forecast consumption over next regulatory period	⇧ to 🡹	Because of the above, and despite annualised growth rates generally forecast to increase in the upcoming regulatory periods as compared to the outturn levels in the current regulatory periods, at least several of the networks are expected to experience levels in total sales over their coming regulatory periods that will be lower than those achieved in their current regulatory periods. This will tend to increase unit electricity prices.

Note: Unfilled arrows (e.g.,⇧) represent small expected changes; filled arrows (e.g.,🡻) represent larger expected changes.

In totality, it is impossible to say with any certainty whether or not these different components in aggregate are more or less likely to lead to price increases or decreases in the future. For example, whilst on the balance of probabilities there may be decreasing pressure on prices in the future as a result of reductions in the WACC and from lower augmentation capital expenditure programs, this is likely to be counteracted by input cost pressures relating to labour and materials, and more materially (at least for some businesses), increased replacement capital expenditure. Changes in energy consumption – both across this period, relative to forecast, as well as what is forecast to happen in the next regulatory control period – are also likely, on balance, to exert an upward pressure on price.

However, it is worth noting that any change in the WACC will tend to have a more significant impact on outturn prices than the same proportional change in any of the other components assessed in this study. This is because return on capital (which is calculated by applying the WACC to the business' regulated asset base) tends to represent the single largest component of a network business' revenue requirement.

Finally, however, it is important to note that:

- outcomes for individual network businesses will be a product of the balance of the specific values of each of these factors, detailed consideration of which was outside the scope of the present study, and the timing of their regulatory determinations (as the specific value of factors such as the WACC and materials cost escalators can change sufficiently within relatively short periods of time to make a material difference to price movements), and
- overall outcomes may be materially affected by changes to the Rules and the regulatory framework that are currently under consideration, particularly the proposed Distribution Network Pricing Arrangements Rule Change, and considerations regarding a change in the regulatory control mechanism from a Weighted Average Price Cap to a Revenue Cap. We have not sought to predict the outcomes of these considerations.