Nuttall Consulting

Regulation and business strategy

Report – Principle Technical Advisor

Aurora Electricity Distribution Revenue Review

A report to the AER

Final Report

11 November 2011

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Executive Summary

Background

The Australian Energy Regulator (AER) is assessing the regulatory proposal of Aurora Energy (Aurora) to determine its regulated revenue for the period 2012/13 to 2016/17.

Nuttall Consulting has been engaged by the AER to provide technical advice on the Aurora proposal. This engagement was focused on the capital expenditure (capex), but also included support and advice in relation to other technical matters on an “as needs” basis.

This report details our review and recommendations on capex (the capex review).

In undertaking our capex review, we have been mindful of the capital expenditure objectives, criteria, and factors provided in clause 6.5.7 of the National Electricity Rules (NER), which defines the basis and assessment approach for the DNSP’s capital expenditure forecasts.

Methodology

To undertake this review, we have used a number of different analysis and review approaches, which we consider are consistent with the requirements of the NER. These have included:

- benchmarking analysis of Aurora’s total capex with the capex of Distribution Network Service Providers (DNSPs) in the other National Electricity Market (NEM) states
- benchmarking analysis of specific components of Aurora’s capex with similar capex components of the Victorian DNSPs
- comparative analysis of Aurora’s capex unit costs
- age-based replacement modelling and benchmarking
- review of the policies, procedures, and forecasting methodologies associated with the capex forecast
- detailed review of a selection of project/program reviews.

Review findings and recommendations

Based upon the findings of our review (high-level and detailed), we do not consider that Aurora has adequately demonstrated that its overall proposed capex can be considered prudent and efficient.

This view is based upon the following specific findings:

- Our benchmark analysis of Aurora’s historical total capex against other NEM DNSPs has found that Aurora’s historical capex, when adjusted for scale and density, is similar to NSW levels and below Queensland levels. However, importantly, it is significantly above the Victorian levels, which we consider are a reasonable base to suggest an efficient level.

- Our benchmark analysis of Aurora's historical and forecast *reinforcement* capex against the other Victorian DNSPs has found that Aurora's capex is significantly above the Victorian DNSPs. This analysis has attempted to allow for the key driver of this capex: the growth in peak demand. Scale and density differences between DNSPs have also been accounted for. This analysis found Aurora's reinforcement capex to be approximately twice as high as the Victorian DNSP's historical and forecast levels.
- Similar benchmark analysis of Aurora's historical and forecast *non-demand driven* capex, adjusting for scale and density, has also found that Aurora's capex is significantly above the Victorian DNSPs. This analysis found Aurora's non-demand capex to be approximately 30% to 60% above the equivalent Victorian capex.
- Our replacement modelling has found that Aurora's forecast capex associated with asset replacement activities is in line with its historical asset lives. However, these lives are on average shorter than the asset lives we derived through the similar modelling we undertook for our review of the Victorian DNSP's regulatory proposals. When we adjusted the Aurora modelling for the average asset lives, the forecast was approximately half that proposed by Aurora.
- Our detailed reviews of a large number of projects and programs that underpin Aurora's proposal have found a number of matters where we consider the justification of the need for the project has not been adequately demonstrated, or the solution proposed is considered by us to be significantly greater in scope than is likely to be required. Furthermore, the AER has advised us of a revised load forecast that it may use to form its draft decisions. Our reassessment of the prudent timing of the projects under review, in light of this revised forecast, has found that, on average, projects will be deferred from the timings indicated by Aurora.

Taken together, we consider that the above is sufficient to justify that Aurora's capex proposal should be rejected.

One issue we have found, with regard to determining a substitute allowance, concerns capex that is not clearly required to maintain the performance of the network (i.e. reliability, safety, etc), but which we consider may result in net benefits in terms of reduced opex and improved reliability. In a number of circumstances, we found Aurora's planned projects to be primarily driven by these requirements.

Aurora has not provided sufficient information to allow us to determine with any accuracy what the opex and/or reliability benefits would be in these cases. It may be that the productivity improvement factored into its opex allowance should cater for these benefits, and as such, the capex should be allowed. We are not in a position to test this, as it relates more to the opex forecast, which is outside our scope. Furthermore, we are not sure how the AER intends to treat such capex projects, with regard to the appropriate capex, opex and reliability adjustments.

Therefore, to develop a substitute allowance, we have estimated the component of capex that we consider is directly required to maintain performance levels, and the additional component that we consider relates to efficiency and reliability benefits. To show the sensitivity of these findings to the AER's revised load forecast, we have calculated this allowance based upon both the Aurora and AER load forecasts.

We have used the findings of our detailed review to determine the appropriate adjustments to the total capex amount and define these two components.

It is worth noting that in forming these substitute amounts we have allowed for a proportion of non-network expenditure that Aurora proposed as a substitute for network expenditure. Appropriate amounts for the associated opex components of these programs will need to be made to the opex forecast. We have also allowed for capex associated with more general studies and trials of non-network initiatives where we considered the programs and costs seemed reasonable, but explicit substitutions of network expenditure were not made by Aurora. The AER will need to decide whether an allowance should be made for this type of component, and if so, what the best mechanism is for these types of cost.

Table ES1 below provides our estimate of the substitute amount, indicating these two components for both the Aurora and AER forecast.

Table ES1 - Overall capex allowance – compared to proposal

	Total capex ($ millions)					
	2012 - 2013	2013 - 2014	2014 - 2015	2015 - 2016	2016 - 2017	Total
Aurora capex	**76.6**	**78.1**	**75.6**	**71.6**	**73.6**	**375.6**
Nuttall Consulting (Aurora forecast)	**70.7**	**70.1**	**67.0**	**59.8**	**64.1**	**331.7**
Maintain	58.7	59.1	56.3	51.2	51.6	276.9
Efficiency benefit	12.0	11.0	10.7	8.6	12.5	54.8
Nuttall Consulting (AER forecast)	**70.3**	**69.7**	**66.6**	**60.1**	**63.9**	**330.6**
Maintain	58.1	58.2	55.4	50.5	51.1	273.3
Efficiency benefit	12.2	11.6	11.2	9.5	12.8	57.3

In total, this substitute allowance represents a 12% reduction to the Aurora capex proposal. However, the *efficiency benefit* component represents a further 15% reduction should the AER decide to remove this capex component rather than make adjustments to opex and reliability. The AER's load forecast results in a further reduction of 8% to the *maintain* component of reinforcement capex, but this represents only a 1% reduction to the overall *maintain* component.

1 Introduction

The Australian Energy Regulator (AER), in accordance with its responsibilities under the National Electricity Rules (NER), is to make a determination in 2012 associated with Aurora Energy Pty Ltd (Aurora), the Tasmanian Distribution Network Service Provider (DNSP).

As part of this process, Aurora has provided a regulatory proposal that, among other things, sets out its proposed revenue requirements for the next regulatory period, covering 2012/13 to 2016/17.

The AER is required to assess the regulatory proposal in accordance with the provisions of the NER. Nuttall Consulting has been engaged by the AER to provide technical advice on the proposal and provide a report of our findings and recommendations on these matters. This document represents the draft report commitment of this appointment.

1.1 Terms of reference

The complete terms of reference are contained in Appendix C.

The services required of the consultancy are summarised as:

- advice on the efficiency and prudency of the size, scope and timing of Aurora’s proposed capex allowances
- advice on the relationship of capex allowances to the respective drivers of capex
- advice on the efficiency and prudency of Aurora’s proposed capex allowances in relation to any capex-opex interactions and potential trade-offs between the forecasts of capex and opex
- advice on Aurora’s proposed reliability of supply targets for the 2012–2017 regulatory control period
- advice on the appropriateness of Aurora’s methods for determining its proposed capex allowances
- explanation of how the consultant’s advice is set against, and how the consultant’s recommended capex allowances satisfy, the requirements of the NEL and NER, in particular the capex and opex objectives and criteria in sections 6.5.6 and 6.5.7 of the NER
- where the consultant considers that Aurora’s capex and/or opex allowances do not satisfy the requirements of the NEL and NER, the consultant should recommend capex and opex allowances for Aurora for the 2012–2017 regulatory control period
- the reasons for the consultant’s advice, including details of the methods, techniques and any assumptions used to assess the efficiency of Aurora’s proposed capex and opex allowances should be advised.

The assignment was mainly focused on standard control capex. During the course of the review, the AER has also requested us to review some elements in alternative control capex and some matters associated with the base-line opex.

This report only details our review of capex (standard control and alternative control). Our review of the opex base-line items is contained in a separate report.

1.2 Structure of report

The report is structured as follows:

- Section 2 provides an overview of our methodology and its relationship with the requirements set out in the NER
- In section 3, we provide a summary of the review of historical expenditures. This review includes an assessment of the relative capex efficiency of the Victorian DNSPs, the relative efficiency of the individual DNSPs and an assessment of the accuracy of previous capex forecasts.
- Section 4 provides review of Aurora's unit costs
- In section 5, 6 and 7, we detail our review of capex across three broad categories: reinforcement, non-demand and non-system
- Section 8 provides an overall summary of our review findings and recommendations.
- Appendix A contains results from Nuttall Consulting's comparative analysis of the NEM DNSPs' capex, which are discussed in Section 3
- Appendix B contains summaries of our project reviews associated with reinforcement capex.
- Appendix C contains our review of targeted matters associated with alternative control capex.
- Appendix D contains our Terms of Reference.

2 Methodology

In this section we provide an overview of the methodology we have applied in reviewing Aurora's revenue proposal, in accordance with our terms of reference and the NER obligations.

In the section that follows, we highlight the techniques we have employed and the engagement with Aurora.

Following this, we summarise our appreciation of the most relevant NER obligations with regard to the AER's deliberations on the expenditure forecasts, and explain our methodology in the context of these obligations.

More detailed explanations of the specific analysis employed and its relationship to the NER obligations is provided in this report were it is relevant to the specific matters being considered.

2.1 Methodology

Our analysis of the capex Aurora has forecast in the next regulatory period has involved:

- benchmarking analysis of Aurora's total capex with the capex of DNSPs in the other NEM states
- benchmarking analysis of specific components of Aurora's capex with similar capex components of the Victorian DNSPs
- unit cost comparative analysis
- age-based replacement modelling, and benchmarking
- review of policies, procedure, and forecasting methodologies associated with the capex forecast
- the detailed review of a selection of project/program reviews.

In undertaking our review, we have been mindful of the capital expenditure objectives, criteria, and factors provided in clause 6.5.7 of the NER, which defines the requirements associated with the assessment of a DNSP's capital expenditure forecast for the following regulatory period.

The Nuttall Consulting review process has entailed a desktop review of the Aurora's proposals and supporting information. In undertaking this review, we held a number of meetings with the Aurora to discuss its capex proposal and the supporting material. We have also requested additional information from Aurora to aid our understanding and considerations of its capex programs.

The initial phase of our review involved a high-level appraisal of Aurora's proposal and supporting information. Based upon this review, the AER and Nuttall Consulting agreed a set of targeted projects and programs for more detailed review.

The structure of the Nuttall Consulting review is aligned with the capex categories defined by the AER in its regulatory information notice (RIN) to Aurora. The categories covered by our review include:

- reinforcement
- reliability and quality maintained (RQM)
- regulatory obligations
- reliability and quality maintained (RQI)
- non-system general (including IT and other assets).

For reasons discussed further in Section 6, we have reviewed RQM, regulatory obligations and RQI together.

In parallel with the Nuttall Consulting review of capex, the AER and its other consultants have reviewed other elements of Aurora's proposal. The parallel reviews that are relevant to the Nuttall Consulting review of capex include:

- Aurora's demand forecasts
- "business as usual" opex
- opex step-changes
- labour and material inflation on the capex forecasts
- Aurora's overheads included the capex forecast
- Aurora's capex allocated to the customer initiated category
- reliability and the service target performance incentive scheme.

The outcomes of the above reviews will need to be considered by the AER as to their potential impact on the capex allowances recommended in this report.

2.2 Relationship to NER

The key requirements defined in the NER that guide our approach to reviewing capital and operating expenditure are the capital expenditure *objectives*, *criteria* and *factors* set out in section 6.5.7 of the NER. In the context of our review, these can be summarised as follows:

NER capital expenditure objectives

The **objectives** define the technical outcomes that a DNSP's expenditure forecast should achieve. This is largely to meet the expected future demand for relevant services, such that these services and the integrity of the infrastructure that supports them, are maintained, and all obligations on Aurora are complied with.

These objectives can be measured and tracked historically by Aurora and predicted in the future, and may include:

- compliance with power quality obligations, such as the reliability standards defined in the Tasmanian Electricity Code
- compliance with safety and environmental obligations
- maintaining existing levels of reliability, both with regard to the provision of customer services and asset integrity
- maintaining existing safety levels or the risks associated with safety.

With regard to our review, determining whether expenditure meets the NER objectives is analogous to assessing whether there is a *need* for some activity by Aurora.

Within our methodology, determining whether expenditure is required to meet the NER objectives is, to some degree, implicitly allowed for within the benchmarking analysis we have undertaken as part of this review. More importantly, a specific component of the detailed project reviews we have undertaken explicitly considers whether there is an identified need for the project (or some alternative), and this need is in accordance with the NER objectives.

NER capital expenditure criteria

The AER must be satisfied that an expenditure forecast that achieves the objectives reasonably reflect defined **criteria**. These criteria broadly define that the forecast must be prudent and efficient, and allow for realistic expectations in demand and cost inputs.

We understand that this can be interpreted to mean that Aurora's expenditure forecast should reflect the most appropriate options to achieve the objectives, and the costs of these options should reflect their efficient delivery.

Much of our review is aimed at testing whether Aurora's forecast can be considered prudent and efficient. This includes the high level analysis we have undertaken, including:

- capital expenditure analysis and benchmarking
- replacement capital expenditure modelling and benchmarking
- unit cost benchmarking.

Similar to achieving the NER objectives, such analysis, to some degree, implicitly allows for the selection of the appropriate option and its efficient delivery.

Prudency and efficiency has also been assessed within the detailed reviews of specific projects and programs, and associated forecasting methodologies. In these reviews, following the establishment of a need, the range of options considered to address the need (including non-network options) and the rationale to select the preferred option has been assessed. Following this, the efficient cost for the preferred option has been assessed.

NER capital expenditure factors

The **factors** define the various matters that the AER must have regard to when determining whether it is satisfied that the expenditure forecast reflect the criteria.

Our approach addresses most of these factors, as summarised in the table below.

Table 1 Relationship of our approach to NER expenditure factors

	NER factors	Comments
1)	Information in or accompanying the proposal	Our approach has included a detailed review of the relevant sections in the proposal and associated supporting information.
2)	Submissions received	In accordance with our terms of reference, our approach has not considered submissions by other parties to the AER at this time.
3)	Analysis undertaken by/for AER and published before determination is made in final form	This report details the various forms of analysis we have undertaken. A public version will be provided that is in a form suitable for publications. Analysis has included: • Expenditure analysis and trending • Replacement modelling • Cost benchmarking • Qualitative and quantitative assessments of forecasting methodologies, projects and programs. Associated spreadsheets of the above analysis can be provided to the AER as required.
4)	Benchmark expenditure that would be incurred by an efficient DNSP over the period	Our approach has included a number of forms of analysis that could be characterised as benchmarking, including: • Capex comparative analysis with other DNSPs, covering: ○ Total capex ○ Reinforcement capex ○ Non-demand capex • Replacement capex benchmarking • Unit cost comparative analysis against other DNSP costs.
5)	Actual and expected expenditure of the DNSP during any preceding periods	Our approach has explicitly considered actual and expected expenditure in the current and preceding periods. This is most notable in: • Expenditure analysis and trending, • Replacement benchmarking, which has considered historical replacement expenditure and associated lives and unit costs.
6)	Relative prices of	Our approach has only considered cost inputs at a reference

	NER factors	Comments
	operating and capital inputs	year. We understand that the AER will conduct a review of input cost escalations. The AER's findings in this regard should be able to be used to adjust our recommendations.
7)	Capex/opex substitution possibilities	Our approach inherently considers capex/opex substitution possibilities through the detailed project review. These reviews have considered options to address needs, including the substitution of opex to defer capital projects, or capital projects to remove the need for opex. Furthermore, our forecast methodology reviews has assessed how this has been considered when Aurora has prepared its forecast.
8)	Whether total labour costs included in opex and capex forecasts are consistent with incentives provided by STPIS	We understand that the AER will undertake much of the analysis associated with Service Target Performance Incentive Scheme.
9)	Extent that the forecasts are referable to a related party	We understand that the AER will consider this matter.
10)	The extent the DNSP has considered and made provision for efficient non-network alternatives	Our approach has inherently considered non-network alternatives through the detailed project reviews. These reviews have considered the range of options to address identified needs, including non-network options. Furthermore, our review of the forecast methodology has assessed how this matter has been considered by Aurora, including the process and assumptions it has applied to determine a reasonable expectation of non-network opportunities.

3 DNSP expenditure analysis

The following section discusses the high-level quantitative analysis we have undertaken on Aurora's historical capex. This analysis includes an assessment of the relative capex efficiency of Aurora's capex against other NEM DNSPs (termed benchmarking here), and the assessment of the accuracy of the previous capex forecasts and the variation from trend of Aurora's capex forecasts for the next period.

Following this we provide a summary of the results of our analysis and discuss the findings. A more detailed listing of the benchmark results is provided in appendix A.

Finally, we provide some views on similar benchmarking studies that have been provided by Aurora as part of its proposal.

It is worth noting at the outset that, while we consider that the results of our high-level benchmarking analysis are reasonably compelling, these results have not been used to set expenditure targets directly. Rather, the primary purpose of the benchmarking has been to gauge the overall level of efficiency of Aurora compared to other NEM DNSPs, and in turn, inform the in-depth review of targeted matters.

3.1 Benchmarking background

Formalised benchmarking studies are now used by businesses around the world. Benchmarking is a key component of continuous improvement and embedded in international standards for asset management[1] and business process management. Almost every Australian electricity network business has been involved in detailed national and international benchmarking exercises[2].

We understand that the AER (and the ACCC) are well aware of the different forms of benchmarking, their roles in setting prices or revenue, their pro and cons, and their general data requirements for robust analysis. We also note that these matters, particularly in the context of Total Factor Productivity (TFP) forms of benchmarking, have been the subject of much recent activity by various stakeholders, including the AER[3]. As such, these matters are not covered here[4]. This background section introduces the form of capex analysis we have performed and then discussed the key elements of the analysis that we consider most relevant to benchmarking the capex of electricity distribution businesses in general, and gauging Aurora's capex in particular.

[1] PAS 55 – Asset management standard, ISO 55000 Asset Management standard.
[2] http://www.umsgroupeurope.com/Contents/Files/IGBC%20Program%20Overview%202011.pdf.
[3] For example, see the recent "Review into the Use of Total factor Productivity for the Determinations of Prices and Revenues" conducted by the AEMC – available on the AEMC website.
[4] We do note that benchmarking paper provided by Aurora provides a good summary of some of these benchmarking methodologies: AE062 - Benchmark Economics Report (Benchmarking).pdf, p16

The form of benchmarking analysis we have applied uses ratio type analysis, based on technical principles to achieve comparability between DNSPs. This approach is consistent with analysis undertaken in previous reviews for the AER and state electricity regulators, the experience of Nuttall Consulting, and the information made available by Aurora.

To appreciate the form of our analysis, it is first important to discuss a key aim of benchmarking, which is to allow comparisons between DNSPs. The phrase "comparing apples with apples" is a regular occurrence when discussing benchmarking. Every company is different from its peers in one way or another. It is important to understand these differences when conducting a benchmark study so that they can be accounted for or, at least, recognised.

There are thirteen DNSPs operating in the NEM. This potentially provides twelve similar companies to Aurora for this benchmarking study. There are number of different factors that may affect the most appropriate peers to gauges Aurora's expenditure against.

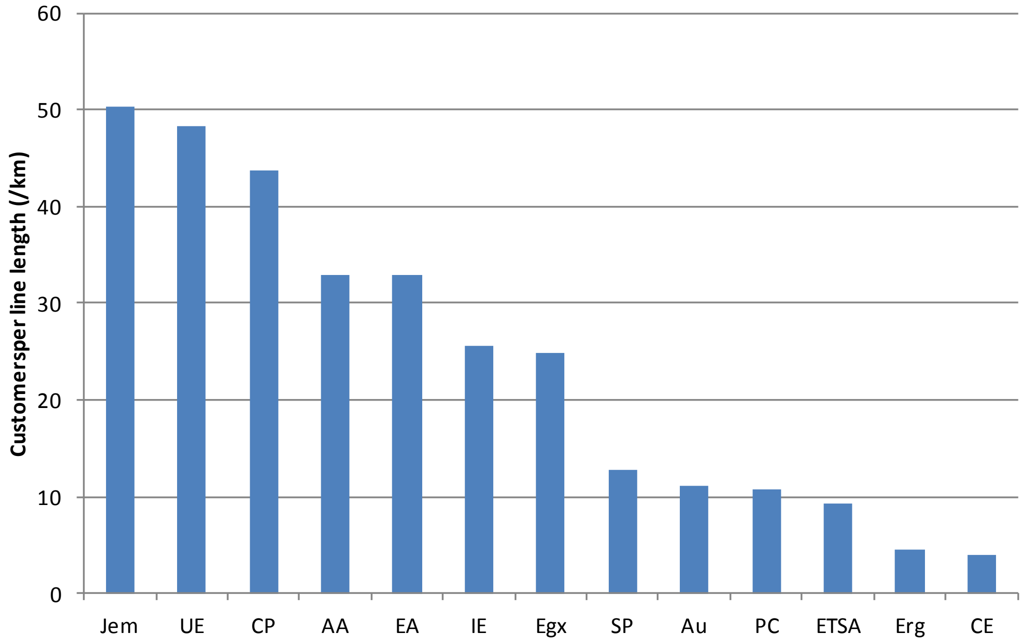
Firstly, Aurora services the complete state of Tasmania. This suggests that one way of comparing Aurora would be to compare it to the state-wide metrics for the other NEM states. In NSW this would include the combined metrics of Ausgrid, Endeavour Energy and Essential Energy[5]. In Queensland this would include the combined metrics of Energex and Ergon Energy.

Secondly, Aurora is a relatively small DNSP by Australian standards and there are good arguments for considering the scale of the network. On this basis, the peers for Aurora would include CitiPower, Jemena and Actew.

Thirdly, Aurora services a highly rural service territory. This can affect the costs to provide services to customers, as travel times increase, accessibility diminishes, and the volume of assets required to service each customer (e.g. the number of poles) increases. Conversely, highly urbanised DNSPs may have higher proportions of underground assets, which can be more costly (per km) to install and replace. Figure 1 highlights that Aurora has a relatively low customer density (customers per km of line). The peers for Aurora, in terms of this density parameters, are those with equivalent rural territories, most notably Powercor, SP AusNet, Ergon Energy and ETSA.

[5] Previously named EnergyAustralia, Integral Energy, and Country Energy respectively.

Figure 1- Customer density[6]



From the simple review above, it is clear that there are a number of aspects of Aurora and its service territory that differ from all other DNSPs in some way or other. This differentiation is experienced by all companies that seek to undertake benchmarking and is overcome through:

1. the use of multiple measures and comparisons to provide a more complete perspective
2. the assessment of the benchmark outcomes against the particular operating environment faced by the business.

We have used both these features within our approach. In this regard, using a number of capex metrics, our approach benchmarks Aurora against the state averages, against all NEM DNSPs and against rural network peers. This broad based approach allows for the peer group issues discussed above to be individually assessed.

The key features of this approach, and their relevance to assessing Aurora's capex are as follows:

- the range of output measures
- normalisation for density
- the appropriate time period to assess capex.

These are discussed in turn below.

[6] Legend: AA – Actew/AGL, AGLE – Jemena (formerly AGL and Alinta), Au – Aurora Energy, CE – Country Energy, CP – CitiPower, EA – EnergyAustralia, Egx – Energex, Erg – Ergon Energy, ETSA – ETSA Utilities, IE – Integral Energy, PC – Powercor, SP – AP AusNet, UE – United Energy

3.1.1 Output measures

Benchmarking approaches will typically seek to compare the cost or number of inputs against the volume of outputs. In the case of our analysis, the input is capex. The output measure, to some degree, reflects the scale of the DNSP, whether by asset volume, asset value or some form of customer service volume.

We have identified five output measures for the comparison with capex. The measures used by Nuttall Consulting are:

- per asset value (dollar value of the regulated asset base)
- per customer (based on number of active connections)
- per km of line (length of overhead and underground lines)
- per energy delivered (measured in giga-watt hours)
- per maximum demand on the network (measured in mega-watts).

There are advantages and disadvantages associated with each of the above measures. Table 2 summarises some of the key benefits and issues with each of the identified measures.

Table 2 - Capital benchmarking measures

Measure	Advantages	Disadvantages
Asset value	• New assets acquired at common rates • Regulatory defined value • Incorporates different voltage systems (e.g. the ownership, or not, of subtransmission)	• Consistency of initial asset base • Consistency of depreciation • Jurisdictional capital requirements (e.g. planning standards)
Customer	• Clearly defined value • Consistent with reliability statistics • Directly relates to customer revenues/bills	• Favours urban and CBD businesses with more customers per asset • Does not discriminate between large and small customers (e.g. hospital and domestic) • Does not recognise different voltage ownerships • Reporting of unmetered supplies and temporary supplies may vary
Km of line	• Clearly defined value • Consistently reported • Reflective of underlying assets • Incorporates different voltage systems (e.g. the ownership, or not, of subtransmission)	• Favours rural DNSPs with fewer assets per km of line • Does not account for number of circuits or line type (e.g. three phase, single phase, SWER) • Requires accurate measurements and reporting systems.
Energy delivered	• Strong link with customer revenues • Annually reported and audited • Recognises link with thermal constraints for rural lines	• Does not recognise different customer load profiles (i.e. peakier profiles require more assets) • Does not recognise different voltage ownerships
Maximum demand	• Directly related to capital construction and asset base (with exception of rural lines)	• Does not recognise thermal design limitations that impact most rural lines • Does not recognise different voltage

Measure	Advantages	Disadvantages
	• Recognises average customer load profile • Annually reported and audited • Allows recognition of distribution generation	ownerships. • Does not recognise pockets of high and low demand growth.

Based on the above table, the use of a single capex measure to compare businesses is not considered sufficiently robust. As discussed above, any single measure will be subject to external factors that cannot be easily accounted for. For this reason, we have used all five measures when comparing capex in order to gain a more robust picture of overall capex performance.

It is worth noting that the above measures do not directly consider the differences in network ownership between transmission and distribution businesses. The ownership of sub-transmission assets is addressed later when discussing the results of the analysis.

3.1.2 Normalisation for density

Normalisation is another means of adjusting or accounting for inherent differences between businesses.

When comparing capex at an individual company level there are factors that significantly impact expenditure and influence the value of the benchmark. As discussed above, one of the most significant of these factors is the relative density of the areas serviced by the DNSP.

A good example of the density issue is represented by the distance between each customer in a rural or remote setting. The DNSP is required to install and maintain additional poles and other network assets to convey electricity between each customer. In contrast, a single electricity pole in an urban setting may have multiple services to customers. As such, two DNSPs with seemingly similar capex per output measure (e.g. $ per customer) may have significantly different cost imposts to service the average customer, depending on the relative density of customers.

One way of considering the relative density is to take account of the number of customers per km of overhead or underground distribution line. In the case of our analysis, we have identified that the rural/urban nature of the business is a key contributor to the overall capex requirement. This view is supported by many international studies and by the consultants reviews provided by Aurora[7].

Therefore, within our approach we use the number of customers per kilometre of line[8] to gauge this effect for each of the five output measures. This parameter is a proxy for the density of the network. For the purposes of this study, we refer to this as “customer density”.

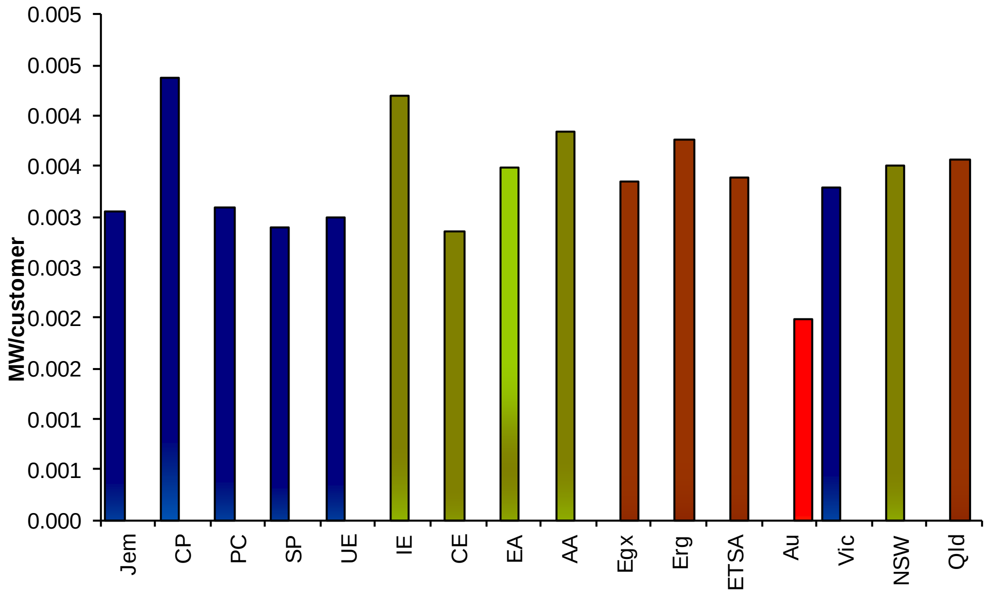
[7] AE062 - Benchmark Economics Report (Benchmarking).pdf, p39.

[8] Length of overhead and underground electricity circuits of all network voltages, excluding services.

There are a number of other possible density proxies that could be used. The operating expenditure benchmark report provided by Aurora provides sound reasoning for the use of a density proxy of the network maximum demand per kilometre of line (MW/km).

Regression analysis of this proxy provides a strong relationship with the DNSP expenditure data.[9] However, Nuttall Consulting is concerned that the network demand per customer for Aurora is inconsistent with other DNSPs and we have not been able to determine the cause for this. Figure 2 highlights that Aurora has the lowest system demand on a per customer basis.

Figure 2 – System demand per customer[10]



It is also possible to use measures of energy delivered per km of line (GWh/km) as a proxy for network density.

It would seem logical to consider the use of service territory (measured in square kilometres) as an input to measuring density (for example; customers per square km). However, this has proven problematic due to difficulties in measuring areas of the territory that are unserviceable such as lakes, deserts, parks, swamps, mountain areas, etc.

For these reasons, plus it is more readily understandable to the general public, we have elected to use only the customer density proxy.

It is important to note that many other factors that can influence capex, including the general level of energy and demand growth, the age of the existing asset base, significant weather events such as a cyclone, and individual state regulations. Each of these factors

[9] AE062 - Benchmark Economics Report (Benchmarking).pdf, p36.

[10] Legend: AA – Actew/AGL, AGLE – Jemena (formerly AGL and Alinta), Au – Aurora Energy, CE – Country Energy, CP – CitiPower, EA – EnergyAustralia, Egx – Energex, Erg – Ergon Energy, ETSA – ETSA Utilities, IE – Integral Energy, PC – Powercor, SP – AP AusNet, UE – United Energy

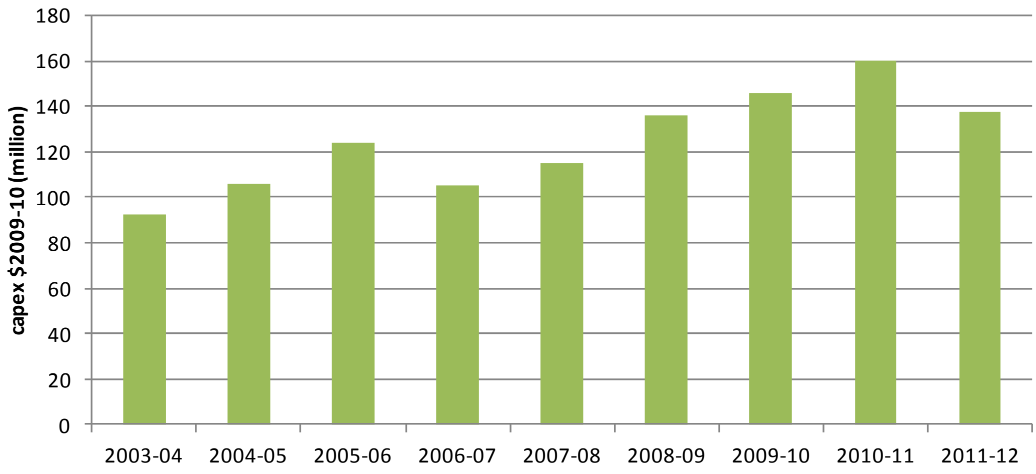
may result in changes to capex that are beyond the immediate control of a DNSP and lead to differences between DNSPs.

We have not attempted to normalise for these factors in the analysis presented in this section; however, the relevance of these factors to Aurora's specific circumstances are discussed below and considered further to some degree through the more detailed reviews of the specific capex categories.

3.1.3 The appropriate time period to assess capex

Our analysis of capex uses a five-year average for each measure. Capex can vary considerably from year to year for a number of factors. The following chart (Figure 3) of Aurora's recent capex highlights this variability.

Figure 3 – the variability of Aurora's recent capex



We consider that a five-year average is appropriate for the purposes of our analysis as it mitigates individual yearly fluctuations and aligns with the typical regulatory period[11]. The variability of operating expenditure on a year-to-year basis is not as significant as it is for capex and this may allow for shorter time periods.

3.2 Actual expenditure levels

The high-level capex information submitted by Aurora has been compared against recent expenditures in Victoria, NSW and Queensland electricity distribution businesses. Figure 4 shows the average level of capex[12] for the last 5 years for each state compared with the number of customers serviced in each area.

[11] It is noted that Aurora's current regulatory period is 4.5 years. We do not consider that this should materially affect the results presented here.

[12] Capital expenditure excluding customer contributions and metering.

Figure 4 - Capex as a percentage of customer numbers

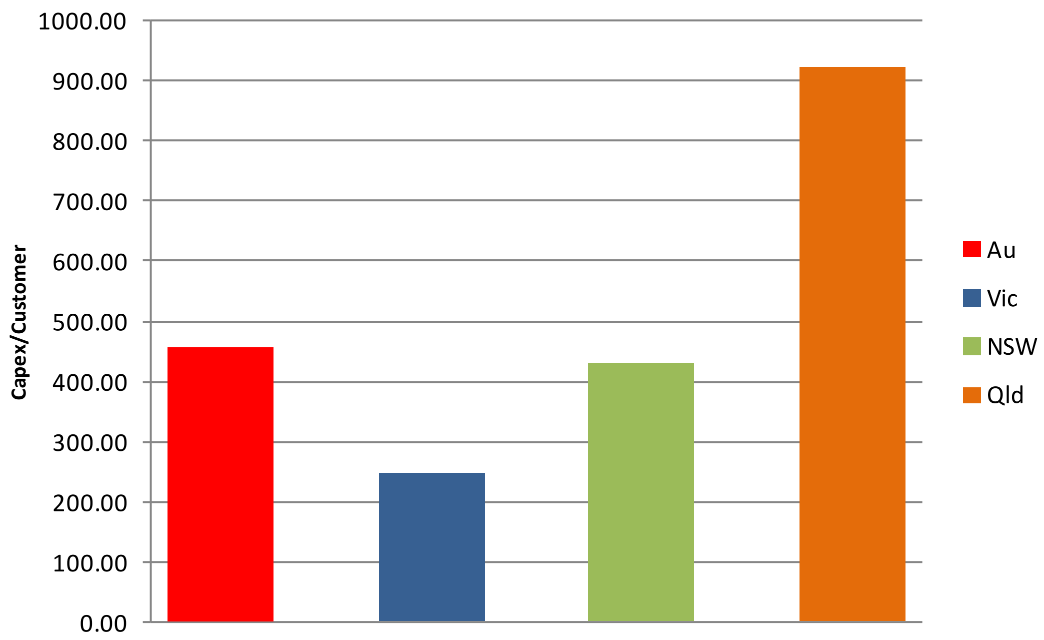
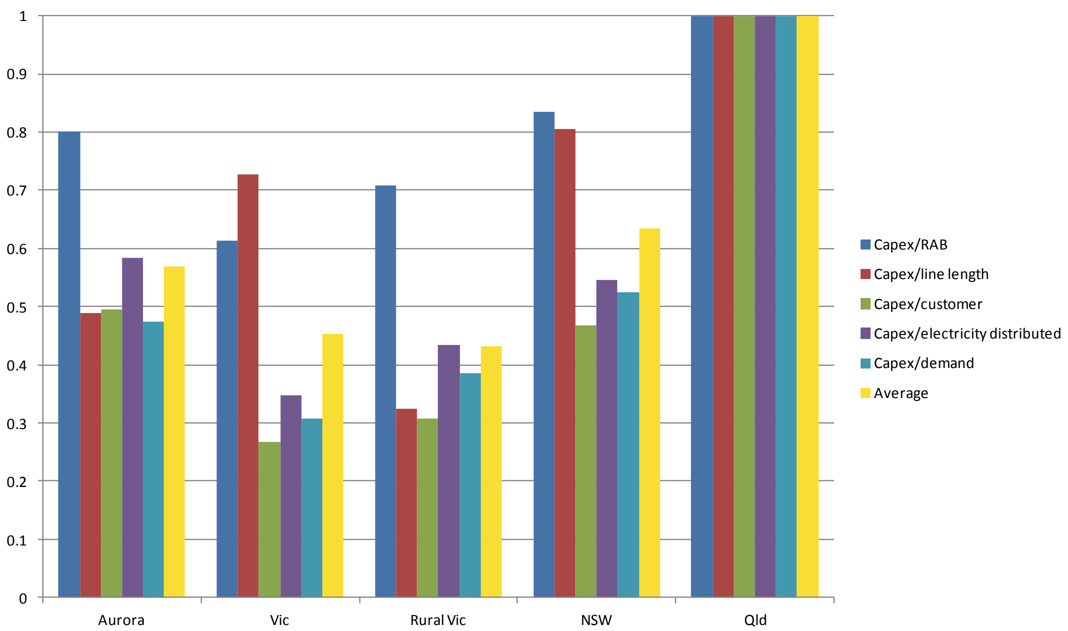


Figure 5 summarises each of the five output measures in a single chart. The individual measures have been calibrated within a 0 to 1 scale (with the highest company ranked as 1) to allow for more direct comparison. An average figure has also been added to this chart to simplify the comparison.

Figure 5 – Summary of capex ratios



The comparison of capex at the state level allows for the inclusion of rural, urban and CBD areas to be considered in total. Aurora services the central business district of Hobart and

Launceston as well as the urban and rural areas of Tasmania. The state-wide benchmarks allow for these areas to be compared in aggregate. However, Tasmania is less densely populated than the Northern states, so Nuttall Consulting has also compared Aurora with DNSPs with a similar customer density in the following section.

The Queensland ratios were the highest in each category and therefore set the maximal levels for the comparison. On average, Victoria reported the lowest ratios, or highest levels of capital efficiency. The NSW businesses and Aurora were, on average, placed in the middle of the field of measures.

The Victorian results are consistent with the recent findings of the AER that the Victorian DNSPs are operating at an efficient level of capital. The AER's recent draft determination for Victoria noted that "*Overall this trend analysis, together with comparative benchmarking of Victorian DNSPs with DNSPs in other jurisdictions, shows that Victorian DNSPs compare very favourably to those in other states. This means that the revealed costs of the Victorian DNSPs are a sound base for determining the starting point for evaluating their regulatory proposals*".[13]

Nuttall Consulting considers that the Victorian average represents an efficient base for the comparison of capex. Further detail on this position is provided in the following sections. The relative expenditure comparisons for NSW and Queensland DNSPs are not considered to represent an efficient base for the purposes of this review. The reasons that these DNSPs are not considered to represent an efficient base include:

- previous pricing reviews identified significant levels of capex required to meet changes in state planning and reliability standards
  - NSW Government's Design, Reliability and Performance (DRP) licence conditions
  - compliance with the minimum service standard requirements under the Queensland Electricity Industry Code
- significant demand growth in NSW and Queensland
- the AER's reviewer "was not able to say definitively that the NSW DNSPs' own capital costs … are efficient in all respects"[14] although it accepted them as sufficiently so for the purpose of the previous NSW review
- one-off events such as Tropical Cyclone Larry (Ergon Energy).

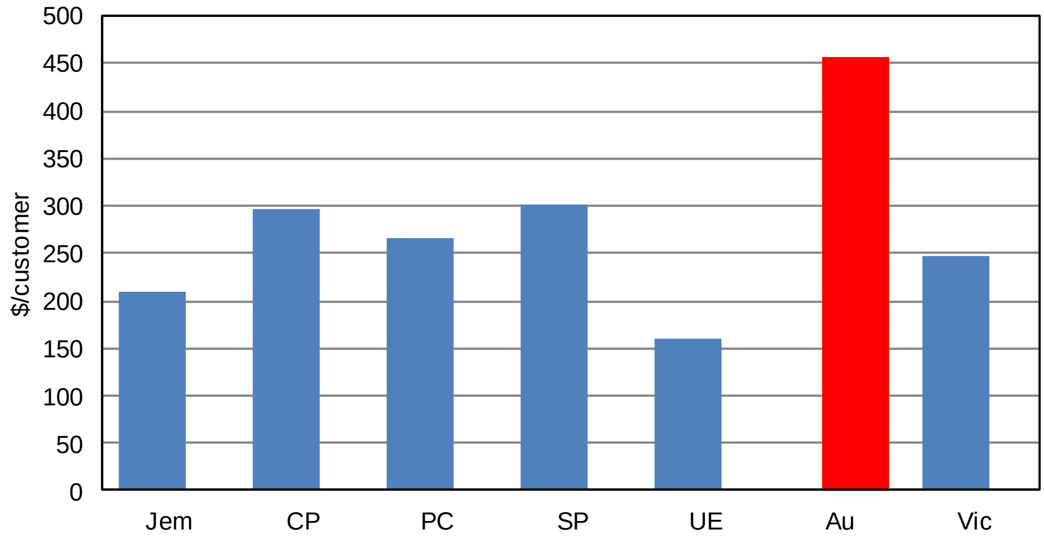
It is clear than many of the factors identified above are outside the direct control of the respective DNSPs. For these reasons is it not appropriate to utilise the NSW and Queensland DNSPs as reference points when seeking to determine efficient capex.

The following chart (Figure 6) provides a comparison of the capex/customer ratio for Aurora and each of the Victorian DNSPs. The average Aurora capex per customer for the

[13] Draft decision, Victorian electricity distribution network service providers, Distribution determination 2011–2015, June 2010, AER, pVII.
[14] Draft decision - New South Wales draft distribution determination, 2009–10 to 2013–14, 21 November 2008, P129, AER.

last 5 years is higher than the Victorian (5 DNSP) average and higher than each of the individual Victorian DNSP 5-year averages.

Figure 6 - Capex per customer



Aurora's overall capex levels appear high when compared against the Victorian average. Table 3 compares Aurora against the Victorian average for each of the 5 output measures. The table also provides a direct comparison with the rural Victorian DNSPs of Powercor and SP AusNet.

Table 3 – Aurora capex measures compared against Victorian average

Measure	Aurora-Victoria comparison	Aurora-Rural Victoria comparison
Capex/RAB	30%	13%
Capex/line length	-33%	51%
Capex/customer	86%	61%
Capex/electricity distributed	68%	35%
Capex/demand	54%	23%
Average	**41%**	**37%**

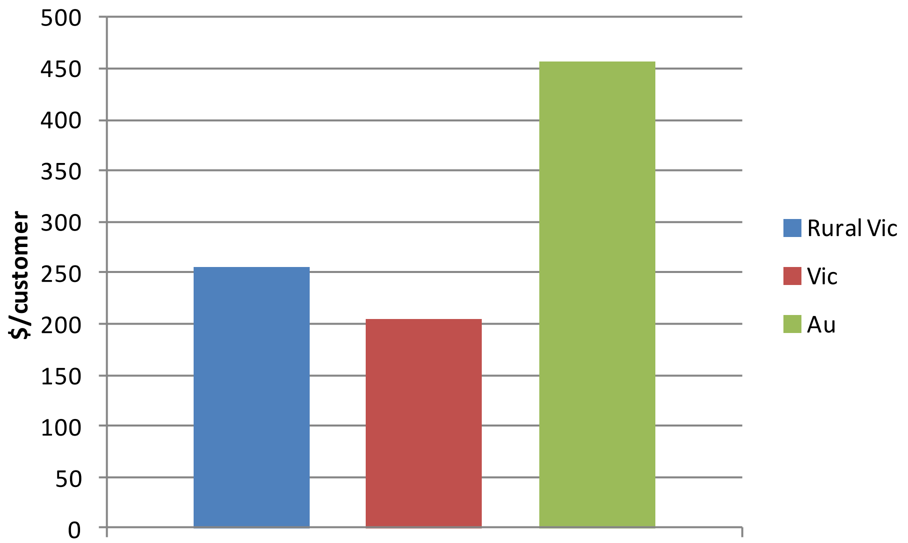
The above table highlights that the Victorian DNSPs appear to have a much higher level of capital efficiency than that of Aurora. Aurora has a lower capex per km of line than the Victorian average; however, it is behind Victoria in all other measures. Even when compared to the rural Victorian DNSPs (SP AusNet and Powercor), Aurora does not appear as the most efficient.

The line length measure is heavily influenced by the ratio of long rural lines being serviced by a DNSP. In this measure, Aurora performs better than the CBD and urban DNSPs, but not as well as the rural Victorian DNSPs. Rural and remote lines are typically significantly cheaper to construct and replace due to their simple designs and longer distances between customers. Powercor and Aurora both have an average of 11 customers per kilometre of line. SP AusNet has an average of 13. Aurora ranks as less efficient than both SP AusNet and Powercor when capex is compared on the “per km of line” output measure. The impact of customer density is further discussed in the following chapter.

Aurora varies from the majority of mainland DNSPs in terms of sub-transmission assets. The majority of Tasmanian assets that are commonly identified as sub-transmission are owned and operated by Transend, the Tasmanian Transmission Network Service Provider (TNSP). Aurora is responsible for considerably fewer sub-transmission assets than most mainland DNSPs. This has an impact on many of the cost measures that would be typically used to assess the performance of the network.

For example, the percentage value of sub-transmission assets[15] in Victoria is 15%, while the value of sub-transmission assets in Tasmania is 2%. When the expenditures and values associated with sub-transmission are removed from the performance comparison data, the Aurora position appears even less efficient than before. This is highlighted in Figure 7 below.

Figure 7 - Capex per customer (sub-transmission excluded)



The above comparisons has been undertaken for different comparison measures including the number of customers served, length of overhead and underground lines, energy delivered and maximum system demand. Again, Aurora is placed as the least capital efficient in each of these measures with the exception of the "per km of line" measure.

This range of measures would seem to suggest that the overall Tasmanian levels of capex as revealed for the last 5 years are not efficient when compared with Victoria.

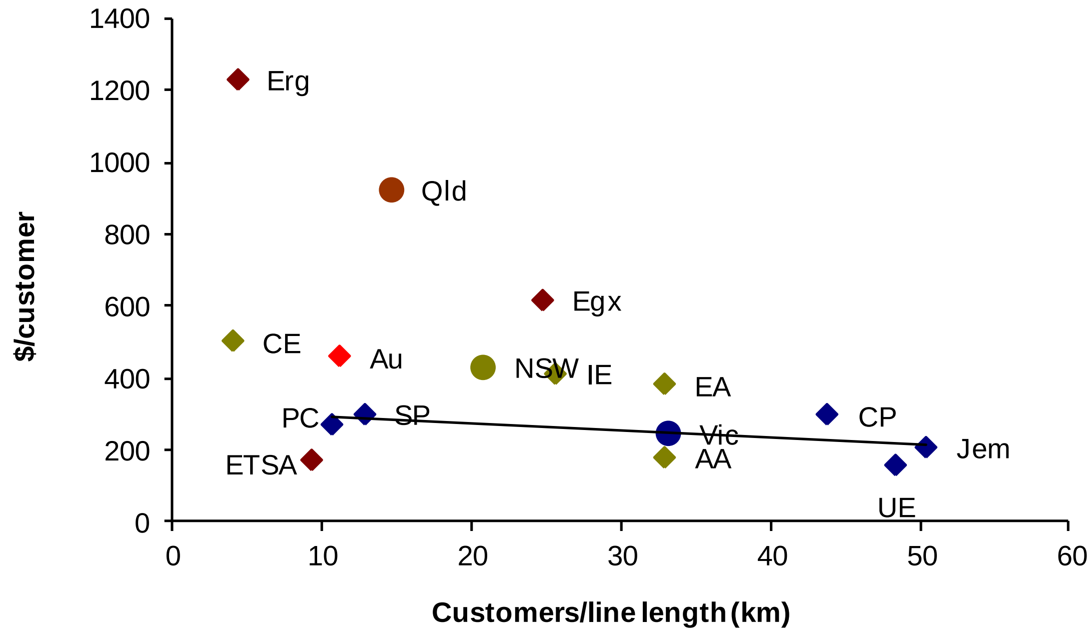
[15] As a proportion of total network assets.

Observation: The overall level of capex in Tasmania as revealed in the previous 5 years is not demonstrably efficient.

3.2.1 Australia-wide comparison

Figure 8 shows the capex spent[16] per customer for each of the NEM DNSPs.

Figure 8 - capex per customer[17]



The above chart highlights that the Victorian DNSPs are consistently at the lower level of the chart, along with ETSA and Actew. The trend line on the above graph represents the Victorian average, which is considered to be the efficient base.

The above benchmark has been undertaken for the five output measures (refer appendix A). The Victorian DNSPs placed as relatively capital efficient in most of these measures. Aurora was consistently higher than the Victorian levels in all of these measures.

In aggregate, the above charts suggest that the revealed capex of the Victorian DNSPs for the last 5 years is relatively efficient and that the Aurora level of capex is not currently at an equivalent efficient level.

Observation: The individual Victorian DNSPs appear reasonably efficient when compared to interstate DNSPs, while Aurora is not as efficient.

[16] Reported capex for last 5 years in $2011.

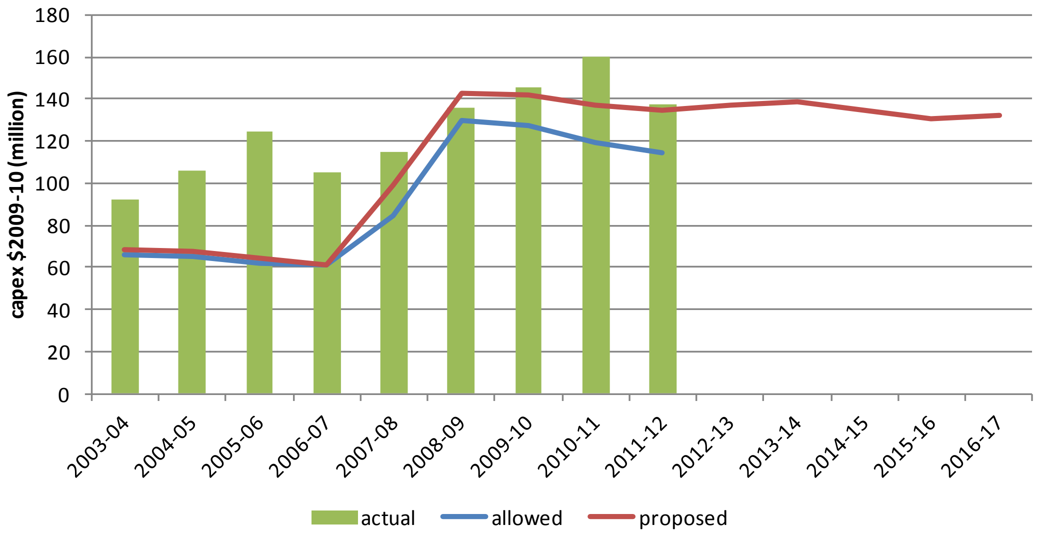
[17] Legend: AA – Actew/AGL, AGLE – Jemena (formerly AGL and Alinta), Au – Aurora Energy, CE – Country Energy, CP – CitiPower, EA – EnergyAustralia, Egx – Energex, Erg – Ergon Energy, ETSA – ETSA Utilities, IE – Integral Energy, PC – Powercor, SP – AP AusNet, UE – United Energy

3.3 Forecasting accuracy

This section considers the overall accuracy of the Aurora forecasts for the current and previous regulatory periods. The accuracy of the Aurora forecasting processes is a key consideration when reviewing forecasts for the next regulatory period.

Figure 9 provides the actual, forecast and allowed capex for Aurora since 2003/04.[18]

Figure 9 – Aurora capex



The above chart highlights the variations between the capex proposed by Aurora and the actual levels of capex that were incurred. This variability is highlighted in the following chart.

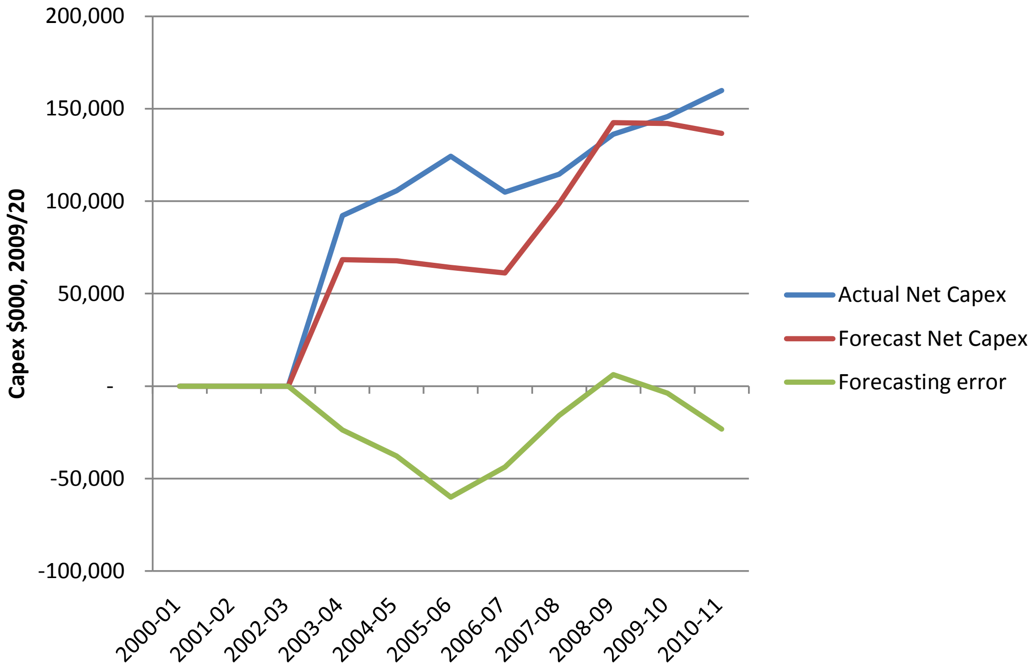
The average level of forecasting accuracy for Aurora over the last 8 years is 23%. This means that actual expenditures are on average 23% more than the expenditures proposed by the DNSP at the commencement of the last two Regulatory Control Periods[19].

Figure 10 shows the annual degree of forecasting error as a percentage of the overall annual expenditure.

[18] Aurora Energy did not provide data for 2002/03.

[19] Using actual expenditure as the baseline and measured in absolute terms.

Figure 10 - Forecasting (actual vs forecast capex)



This level of forecasting inaccuracy is quite high; although it appears that the accuracy of the forecasts has improved in the current period. The forecasting error in the current period[20] is 9% compared with an average error rate of 24% in the previous period[21].

In general, Aurora has under-forecast compared to actual capex. The exception to this trend is 2008/09 where the forecast was 5% greater than actual expenditure in that year.

The reasons for the general level of overspend are not clearly evaluated in the Aurora submission. There are a number of items identified at the sub-category capex level that are stated to have contributed to variations from expected expenditure, but these are not discussed in detail or quantified.

This assessment of forecasting accuracy is based on the actual expenditure incurred by Aurora. This assessment is not intended to suggest that the actual level of expenditure represents the overall efficient level or expenditure. It is equally possible that the forecast levels are closer to representing the efficient base than the actual expenditures.

The Aurora proposal identifies a large number of new forecasting processes that are supported by independent review. Some examples of this include:

- The system demand level forecast is derived from that prepared independently by the National Institute of Economic and Industry Research (NIEIR).
- Aurora's energy consumption forecasts were prepared by Aurora and reviewed by ACIL Tasman on the basis of analysis and assumptions made on a range of factors used to develop Aurora's demand forecasts.

[20] Based on the first 3 years of actual data and a forecast for 2010/11 and measured in absolute terms.
[21] Noting that data for 2000/01, 2001/02 and 2002/03 has not been provided by Aurora Energy.

- Aurora's forecast of customer numbers for the period 2011/17 has been prepared by ACIL Tasman.
- Development of capex forecasts through Aurora's new or updated management plans.

Observation: Aurora has consistently forecast lower levels of expenditure than have actually been incurred, although there is a significant level of variability in the level of forecast inaccuracy. Aurora has significantly revised the processes for developing regulatory forecasts.

3.4 Review of Aurora benchmarking

Aurora has provided two independent benchmarking reviews of expenditure. The following section provides a summary of these reviews and their applicability to the Nuttall Consulting review of Aurora's proposed capex.

3.4.1 Parsons Brinckerhoff Capex and Opex Benchmarking Study[22]

Aurora commissioned Parsons Brinckerhoff Australia Pty Ltd (PB) to "benchmark Aurora's proposed capex and opex against its historical requirements and wider industry experience".

As part of this study, the PB review included an assessment of the unit costs used by Aurora to prepare its expenditure forecasts. Our discussion of this component of the PB study is contained in Section 4.3. The following discusses the remainder of the PB study.

The PB report identifies the capex trend based on the last 5 years of capex, and highlights that this trend is $300 million above the capex forecast by Aurora.

The PB report also provides a series of benchmarks using similar comparators to those referred to in section 3.1.1 of this report. The capex comparators used in the PB report are:

- Capex
- Capex/customer
- Capex/kilometre
- Capex/RAB
- Capex/MW

The PB report uses these comparators to rank Aurora against eleven other DNSPs based on forecast expenditure. The results of the PB benchmarking are a positional ranking of Aurora against the eleven selected DNSPs. The resultant rankings are as follows:

[22] Capex and Opex Benchmarking Study - March 2011, Parsons Brinckerhoff Australia Pty Ltd

Table 4 – PB Capex Rankings

Description	Position
Capex	2 of 12
Capex/customer	8 of 12
Capex/kilometre	5 of 12
Capex/RAB	6 of 12
Capex/MW	6 of 12

The PB conclusions based on the benchmarking of capex are as follows[23]:

- *"Aurora's forecast system capex is generally aligned with, or below industry expectations when normalised using a range of comparators.*
- *However, we note that the lower than average benchmarking results compared to other distribution networks may indicate potential underinvestment in the capex forecast."*

With the exception of "capex", the comparators used by PB are consistent with the approach adopted by Nuttall Consulting. In our opinion, the direct comparison of capex alone is not a useful benchmark, as the scale of the network is directly related to the level of efficient capex. The comparison of capex divided by an appropriate numerator (e.g. customers, kilometres of line, RAB, energy or demand) allows for companies of different scales to be compared.

The PB report identifies that Aurora is performing at an average level within the industry. It does not appear to explicitly state that this indicates that the forecast capex of Aurora can be considered prudent and efficient; however, it could be easy for a reader to infer this. In fact, as noted above, the reader could easily consider that the analysis supports a view that Aurora is under investing. This is clearly different to the view we have formed from our similar analysis.

We have number of concerns with the PB study, which we consider may explain this different position.

Firstly, a number of the approaches adopted by PB in the capex analysis vary from approaches typically adopted in Australian regulatory reviews. Most notably, we consider that the use of forecast expenditure as a base for benchmarking is not a reliable approach due to the variability inherent in forecast expenditures. For example, over the last 8 years, Aurora has on average spent more than it had originally forecast. On the other hand, the Victorian DNSPs have tended to underspend on their forecast. In addition, the current regulatory regime is an incentive-based regime, based upon an ex ante capex allowance and a roll in of actual capex, as such DNSPs are motivated to outperform the regulatory

[23] Ibid p11.

forecasts. As such, it should be the outworking of the regime (i.e. the actual expenditure) that should be considered to be the best guide to efficient costs.

Secondly, we do not consider that the PB study adequately discusses the exogenous factors, identified in section 3.2 of this report, including cyclones, state reliability standards, high levels of growth, etc. We believe that these factors are important when deciding how well a DNSP compared to the others. Given some of the matters we have noted that have resulted in significantly greater cost drivers in NSW and Queensland, we would expect this issue to be drawn out when forming conclusions.

Thirdly, given the different operating circumstances of the DNSPs and the different exogenous factors, we do not consider that an ***average*** position of all NEM DNSPs can be considered a reliable indicator of the ***efficient*** capex. The National Electricity Rules specifically identify "efficient" capex as an criteria for determining allowable revenue. Unless all firms are very similar, the efficient level will not be the same as the average level. Such an indicator of efficiency should be based upon those DNSPs that appears to be at the lower end across the various comparators with consideration given to appropriate peers and exogenous impacts.

Finally, given the points above, we do not agree that it is reasonable to imply that as Aurora's capex forecast is "approximately $300m below expectations based on the longer term trend"[24] and is at an average position compared to other DNSPs then it may be under investing. We consider that a far more thorough review would need to be undertaken to draw that conclusion. As will be shown later, both our high-level and detailed analysis has not found any evidence for this at the aggregate level.

Based upon the above, we do not consider that the PB study conflicts with our analysis presented in this section or the other findings we present later.

3.4.2 Benchmark Economics - A comparative analysis: Aurora's Network cost structure

Aurora commissioned a report by Benchmark Economics[25] for the review of operating expenditure. This report provided detailed analysis of some of the key drivers of costs within a DNSP. The report also identifies a number of factors that are outside the direct control of the DNSP and provides some analysis of how these factors can be taken into account.

The Benchmark Economics report is focussed on operating expenditure, as such we do not consider its findings are directly relevant to our analysis presented in this section. However, there are some references to capex and a benchmarking methodology that we consider relevant for further consideration. We believe that these broadly support the approach we have applied.

Firstly, the Benchmark Economics report uses load density (as measured in MW per km of line) to account for the inherent cost differences between urban and rural locations. This

[24] Ibid piii.

[25] A comparative analysis: Aurora Energy's Network cost structure, May 2011, Benchmark Economics.

measure is similar to the customer density measure used in our analysis. The reason for this choice has been discussed in more detail in section 3.1.2 above.

Secondly, when assessing the potential for trade-offs between operating and capital expenditure, the Benchmark Economics report notes that "(w)e find the regulated capital expenditure allowance in 2009 and 2013-15 for Aurora is in line with its business conditions and industry trend investment levels. Accordingly, we accept that capital expenditure does not include any off-set for higher/lower operating and maintenance expenditure."[26] This finding that capex is in line with the industry trend supports the Nuttall Consulting findings that Aurora is an average performer, and not necessarily one of the most efficient. The overall statement however conflicts with our findings, and views expressed by Aurora, that there *are* projects included in the capex forecast that should result in opex reductions. Examples of these projects will be discussed later when discussing the findings of our detailed reviews.

Thirdly, the Benchmark Economics report goes on to note that "(t)he mandated changes were not insignificant; DNSPs in NSW received capex increases ranging from 25 to 50 per cent of regulated expenditure; comparisons against expenditures for these networks would be misleading if these step changes were included."[27] This finding is also consistent with our position that the out-turn expenditures in NSW cannot be considered as the efficient base due to the enhanced reliability requirements put in place by the NSW government.

Finally, the Benchmark Economics report identifies that "the ratio of expenditure to the RAB is not considered suitable for efficiency comparisons"[28]. The report correctly identifies asset age, rates of depreciation, and asset condition result in often large differences in the RAB and that single indicators can only provide credible comparisons if the businesses are identical.

While this is correct, similar issues apply for any measure that can be used to compare and contrast DNSP expenditures at a high level. It is for these reasons that our analysis uses a range of five high-level output measures to provide an overview of relative efficiency, rather than rely on a single measure. The Benchmark Economics report also utilises a range of high-level measures to avoid the inaccuracies of an individual measure. The advantages and disadvantages of the different measures are discussed in section 3.1.1 above.

3.5 Summary

This section has considered the historical expenditures of Aurora. These expenditures have been compared against other DNSPs and states in the National Electricity Market. The section also reviews the overall accuracy of the forecasts from previous capex proposals and considers the implications for this review.

[26] Ibid – p3
[27] Ibid – p25
[28] Ibid – p30

In summary, the observations from this section are:

- The overall level of capex in Tasmania as revealed in the previous 5 years appears less efficient than Victoria overall and the Victorian peer companies of SP AusNet and Powercor, relatively similar to that of NSW, and overall more efficient than Queensland.
- Aurora appears overall less efficient than each of the Victorian DNSPs, including the rural DNSPs (SP AusNet and Powercor).
- Aurora has consistently forecast lower levels of expenditure than have actually been required, although there is a significant level of variability in the level of forecasting accuracy.
- The capex forecasts for the next regulatory control period are significantly above the actual expenditure trendline. Capex categories that represent the greatest contribution to these increases are reinforcement, new customer connection and load movement, reliability and quality maintained, and non-system general IT.
- The independent benchmarks commissioned by Aurora indicate an average level of overall performance when Aurora is compared to other Australian DNSPs.

4 Review of unit costs

In this section we discuss our review of the unit costs Aurora has used to prepare its forecast for network capex.

Due to time and data limitations, we have not attempted to undertake a detailed forensic analysis of the inputs and assumptions Aurora has used to develop the various unit costs. Instead we have undertaken a two stage review process, involving:

- the review of the methodology Aurora has applied to develop its unit costs
- a high-level comparative study of a selection of the unit costs used by Aurora against unit costs that have been used and accepted in the previous Victorian DNSP revenue decision.

We consider that this approach is reasonable given these limitations. In this regard, we consider the approach we have applied provides a reasonable guide to whether Aurora's unit costs can be considered inefficient in comparison to the unit costs of those DNSP that have been found to the lowest cost by the AER previously. That said, with more time and better data, we consider that a more robust approach could be undertaken that provides more accurate benchmark unit costs. The AER may wish to consider this matter further for future DNSP determinations.

In this section, we first discuss our review of the methodology. Following this we present the findings of our comparative analysis. Finally, we discuss a similar independent comparative study that has been provided by Aurora to support its proposed capex.

4.1 Methodology

The Aurora capex forecasts have been developed using a set of unit rates for key tasks and projects. The methodology for developing the unit rates varies based on the scope and repeatability of the task. To this end, Aurora has developed four categories of unit rates, as follows:

A Type	'A type' capex projects are significant or major projects with a single identified scope. These projects require design and are identified as a discrete item in the Program of Works. Aurora reports that all capex 'A types' have been calculated via a desk-top design using Aurora's work estimation tool (WASP). A Network Services designer estimated the component task costs (labour, materials, contractors and other) using the provided scope. Material costs associated with the project are estimated using historical costs associated with similar work, sourced from job packs contained within WASP. Direct work hours are allocated by skill set and are derived using a combination of similar historic projects and designer knowledge. Direct labour hours and labour rates form the labour component of the unit rate.
B type	These unit rate types are based on an annual scope for each work category and typically involve high work volumes, low complexity and require no design involvement. The unit rates have been calculated by obtaining actual historic volumes, time and material cost data from WASP. Using the historical actual average labour hours from WASP the labour rates for the new period are applied and weighted average material costs are assumed.
C type	Aurora's C type scopes relate to work which is unable to be provided by Aurora's Network Services division and is subsequently outsourced. Project costing estimates have been developed using a number of data sources, these include historic actual costs and vendor quotes.
D type	D type work is generally relatively low in dollar value and complexity, but high in volume. This work type has a single scope for a particular category or work program, and an allowance for tasks that will occur during each forecast year. The costs, time and historical percentage of skill set mix for each job is based on reviewing approximately 19,000 "work packs" and analysis of the recorded mix of skill sets for each of the cost categories. A "work pack" is the scoping document that is issued to the field crew for construction, and the data is retained in Aurora's Works Management System (WASP). For example a task description "Replace low LV conductors" has allowed for the works to be done, without specifically naming locations.

To prepare the expenditure forecasts, Aurora has developed a spreadsheet model that takes the inputs of labour rates and overtime, the unit rates described above and work volumes. Overheads are also apportioned by the model.

In principle, we consider the process Aurora has applied to develop its unit costs to be reasonable. However, the reasonableness of the output unit costs depends very much on the reasonableness of the inputs and associated assumptions. In some cases, these inputs appear to be estimates and rounded costs.

The reasonableness of the output unit costs is considered further through our comparative study discussed below.

4.2 Unit costs comparative assessment

To assess the reasonableness of the unit costs Aurora has used to prepare its capex forecast, we have undertaken an assessment of a selection of these unit costs by comparing them against similar unit costs, made available to us by the AER, from the recent regulatory proposals of the Victorian DNSPs.

It is important to note at the outset that rigorous unit cost benchmarking requires detailed knowledge of the scope of the works that the unit cost is to cover. This is important to ensure an "apples with apples" comparison is occurring. There are significant limitations with our understanding of the detailed scope that is covered by the unit costs of Aurora and the Victorian DNSPs. Therefore, such benchmarking has not been attempted. Instead, we have conducted a pseudo-quantitative review where we assess whether the unit costs appear reasonable in the context of the range of unit costs applied by the other DNSPs.

The unit cost categories assessed have been selected from the proposed program of works, to ensure a large portion of Aurora's proposed capex is captured. In many cases, due to different possible scopes, the unit cost categories cover a range of individual unit costs.

The findings of this assessment for each of the unit cost categories reviewed is provided below.

Table 5 Unit cost comparison summary findings

Unit cost category	Summary of review findings
EDO fuses	The unit cost assumed by Aurora is at the low end of the range of the Victorian unit costs.
Service replacement	The service replacement unit cost is around that assumed by the Victorian DNSPs. However, it is much higher than the amount allowed by the AER to cover the planned replacement programs proposed by the Victorian DNSPs. As such, it may be that the Aurora cost is appropriate for its reactive replacement but above that relevant for an efficiently targeted and delivered proactive program.
Overhead line	Aurora has used a range of unit costs to develop replacement, upgrade and construction costs to cover overhead conductor and line developments.

Unit cost category	Summary of review findings
	Aurora's replacement unit costs appear to be higher than similar costs used by the Victorians. Most notably, its unit costs associated with its copper and steel replacement programs are higher than those allowed for similar programs being proposed by SP AusNet and Powercor. Its unit costs assumed for line upgrades on the other hand, in general, appear to be similar to those allowed by the AER.
Distribution substations	Aurora uses a range of unit costs for various distribution substation ratings, and whether it is pole or ground mounted. Aurora's unit costs for pole mounted substations is in line with the unit costs assumed by the Victorian DNSPs. Aurora's unit costs for the larger ground mounted substations appear much higher than the Victorian DNSPs. However, it is clear that these unit costs do not includes the relevant switchgear and associated equipment costs. Allowing for these, the Aurora unit costs seem reasonable.
Pole replacements	Pole replacement costs can vary significantly depending on the type of pole. Aurora has used a single average unit cost for its pole replacements. The Victorian DNSPs had a broad range for the similar average unit cost. Aurora's unit cost is at the upper end of this range, but is below its two closest peers (by density), SP AusNet and Powercor.
Underground cable	Aurora has a range of unit costs to cover cable replacement and installation. Its unit costs for HV and sub-transmission cables appear to be in line with the Victorian DNSPs, with only one DNSP using a significantly lower unit cost. In the case of LV CONSAC cable replacements, which form a significant portion of the forecast replacement capex on cables, Aurora's unit cost appears to be higher than the majority of Victorian DNSPs. Most notably, this is much higher than the unit costs used by the urban DNSPs. However, we understand that it is in urban areas where Aurora is undertaking a targeted replacement program. In these circumstances we would expect a very significant uplift to cover brownfield issues associated with the replacements[29]. It is assumed that these are not allowed for in the very low unit costs of the urban Victorian DNSPs. Given this, we consider Aurora's unit cost

[29] For example, in residential areas they may be significant cost increases to account for street trees, driveway reinstatement, allowing for other services in the proximity, etc.

Unit cost category	Summary of review findings
	is high, but not clearly unreasonable.
Zone substation transformers	The unit costs for transformers can vary significantly with the rating of the transformer. Aurora's unit costs assumed for transformer replacements and installations are broadly in line with the unit costs used by the Victorian DNSP for similar rated transformers.

The broad finding of this assessment is that the unit costs used by Aurora are generally in line with the range of unit costs used by the Victorian DNSPs. However, in a few cases, Aurora's unit costs appear to be much higher than the Victorian DNSPs. This is most notable for:

- planned service replacements, where the unit cost allowed by the AER for similar replacement were in the order of 50% of Aurora's unit cost
- conductor planned replacement costs for the copper and steel replacement programs, where the unit cost allowed for similar replacements were in the order of 60-80% of Aurora's unit cost.

It is important to note that for these categories, it is not clear whether this is due to Aurora actually having unit costs that could be considered inefficient or this is simply a unit cost that is higher than Aurora will incur.

Furthermore, the implications of this on our overall review findings depends very much on the methodology used to develop the forecast. For example, it is clear that, although Aurora has a detailed bottom-up program of works largely assuming volumes and unit costs, it has also applied a top-down adjustment to ensure the total capex is at a level it considers appropriate. As such, any adjustment of the unit costs must also consider the prudency of the volumes and the overall capex needs.

Therefore, the relevance of these findings has been considered further in the reviews of the capex categories, which are discussed later.

4.3 PB unit cost analysis

As discussed in Section 3.4.1, PB undertook a similar unit costs comparative study using its own unit costs.

The PB report discusses a series of "unit cost" comparators based on the "top ten proposed projects or programs". The majority of these programs are not relevant to the capex categories that are the subject of the Nuttall Consulting review. Only four unit costs reviewed are relevant to this review. These unit costs and PB's broad findings are as follows:

Pole replacements	Aurora's unit costs were below PB's average, but Aurora's removal of more costly complex replacements may place an adjusted unit cost closer to the average.
Install pole mounted transformers	Aurora's unit costs were above PB's average, but within the range of unit costs reviewed.
HV copper conductor replacements	Aurora's unit costs were below PB's average.
Meter installation replacement	Aurora's unit costs were "in line with industry averages".

The PB assessment did not cover sufficient categories to say whether its findings are broadly in line with ours. Furthermore, as discussed above, the unit rates identified by the PB report can cover an extensive range of replacement activities and associated costs. The report does not provide any detailed discussion on its definitions for these unit cost benchmarks and also provides no sources or other company data to support its findings. On this basis it is not possible to determine the validity of the PB analysis. This is not to say that the findings are not valid, just that they cannot be validated on the information provided.

It is clear however that the main difference to our findings relates to HV copper conductor replacements, where PB found this to be in line with industry averages but our analysis suggested it could be too high. On this matter, using the range of PB's unit costs quoted in its report, we note that the Aurora unit cost is still 40% greater than PB's lower limit – which is more in line with the AER's allowances for SP AusNet and Powercor conductor replacement programs.

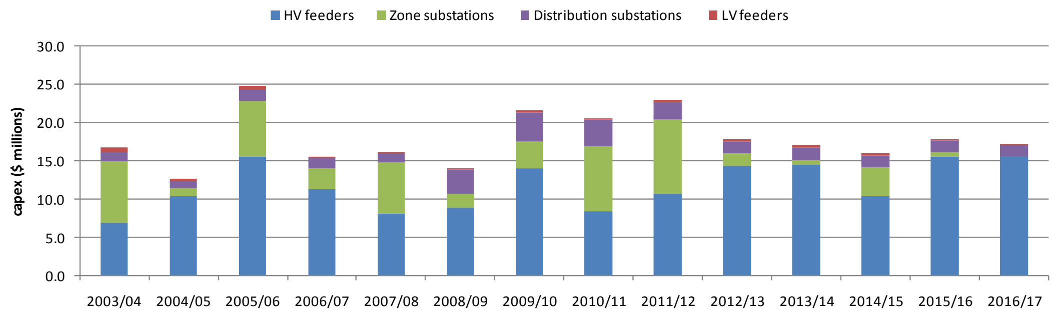
Given this, we do not consider that our analysis is too dissimilar to PB's; rather our interpretation of the findings differ. Furthermore, noting the further discussion on the proposed conductor program provided in section 6.3.3.2, where we have broadly accepted the proposed allowance for conductor replacements, we do not consider this difference is significant.

5 Reinforcement expenditure

5.1 Introduction

This section discusses our review of capex that has been allocated by Aurora to the "Reinforcement" capex categories. Figure 11 below shows a stacked chart of this capex within the four RIN sub-categories: zone substation, HV feeder, distribution substations and LV feeders.

Figure 11 Overview of reinforcement capex by network category



The chart indicates the following:

- The majority of expenditure is associated with HV feeders, particularly in the next period. Smaller portions are associated with zone substation and distribution substation augmentations. With the remaining very small amount associated with LV network.
- Reinforcement capex has been relatively constant over the previous and current periods, with some temporary increases that appear to be associated with zone substation developments. This pattern however has to be seen in the context of the growth in peak demand during that period, whereby peak demand did not increase substantially in the current period due to the GFC.
- The forecast capex in the next period is set to be below levels expected for the end of the current period, and around average historical levels.

Broadly, the reinforcement category is considered to capture capex that is primarily driven by demand considerations, most notably the growth in peak demand. As such, a major component of this category is expected to capture projects whose primary aim is to increase the capacity of the network (or augment the network) to ensure that the forecast growth in peak demand will not result in obligations being breached or performance degrading. Additionally, Aurora has allocated other types of capex into this category, most notably:

- projects whose primary aim is to improve the management of demand, which may be affected by existing issues such as incompatible voltage phasing between adjacent networks, the inability to transfer load to adjacent feeders, and limited switching arrangements

- fault level mitigation projects.

Given the categories available, we consider it reasonable to allocate these types of project to the reinforcement category. Moreover, we understand that most other DNSPs have allocated such projects to this type of category also.

To review Aurora's reinforcement capex we have undertaken the following:

- comparative analysis of Aurora's reinforcement capex against the equivalent capex of the Victorian DNSPs
- a detailed review of a selection of Aurora's projects and programs.

In appreciating Aurora's capex in the context of our review, it is important to note the difference between Aurora and other NEM DNSPs with regard to the plans that underpin reinforcement capex. Most other DNSPs' proposals have had a number of fairly major projects associated with zone substation and sub-transmission developments that constitute a large portion of reinforcement capex. Often, these DNSPs will use high-level approaches to estimate the required capex at distribution levels.

Aurora's proposal on the other hand, owing to Aurora only owning a small amount of sub-transmission and associated zone substations, consists of a very large number of distribution level feeder augmentations. A large portion of these projects have been developed through a bottom-up process. There are only a few projects that could be considered major. Furthermore, many of the projects should be considered as project complexes (i.e. groups of smaller augmentations that together are aimed at addressing a localised and related set of issues).

The important point here is that distribution projects generally do not have long lead times and often there are limited alternatives to specific needs. As such, extensive financial and/or economic analysis of options that would cover a 5-year capital plan appropriate for a revenue proposal will not be available. Moreover, the solution to specific distribution issues cannot be as readily investigated via the desk-top approaches to our detailed reviews e.g. assessing the appropriate solution to a specific HV feeder constraint may require detailed knowledge of the existing feeder arrangements, including loadings, switching arrangements, and topology.

As such, there is limited ability for a detailed review to determine the most appropriate solution and timing at a specific project level across a large number of selected projects. Therefore, it is important to appreciate our review and findings across the various approaches we have applied with regard to how we develop an appropriate allowance.

5.2 High-level comparative analysis

To assess the relative level of historical and forecast capex in the reinforcement category against the equivalent capex of the Victorian DNSPs, Nuttall Consulting has undertaken analysis that supplements the benchmarking provided in Section 3.

As discussed above, reinforcement capex should have some relationship to the growth in peak demand. Therefore, to provide a suitable metric to compare the level of reinforcement capex between DNSPs, the total average annual capex over a 5-year period for each DNSP has been normalised using the growth in peak demand (MW) that the DNSP faced in that period. This normalisation should also allow for differences in scale between networks.

As is also discussed in the benchmarking section, the level of capex for networks of a similar asset scale can be affected by customer density. As such, we have also assessed this metric against a density parameter, using km of HV feeder per 100 customers as the density parameter[30].

Ideally, for distribution networks, it would also be useful to consider an additional metric that uses the number of new customer connections as a normalising parameter. However, at the time of undertaking this analysis, Aurora was not able to provide this data. Furthermore, we have excluded CitiPower from this analysis, as we consider that its predominantly CBD/urban network would mean it would not be a suitable comparative DNSP.

To see the absolute level of the metric and the movement of this metric, we have evaluated two 5-year periods: one predominately covering historical capex and the other forecast capex. To aid in the readability of what follows, we have called the two 5-year periods: *current* and *next*. The current period for each DNSP relates to the 5-year period up to the commencement of the next regulatory period that has most recently been reviewed by the AER. The next period relates to the 5-year period that follows this current period. For the Victorian DNSPs, the current period covers 2006 to 2010, with the next period being 2011 to 2015[31]. For Aurora, the current period is defined as 2007/08 to 2011/12[32], with the next 2012/13 to 2016/17.

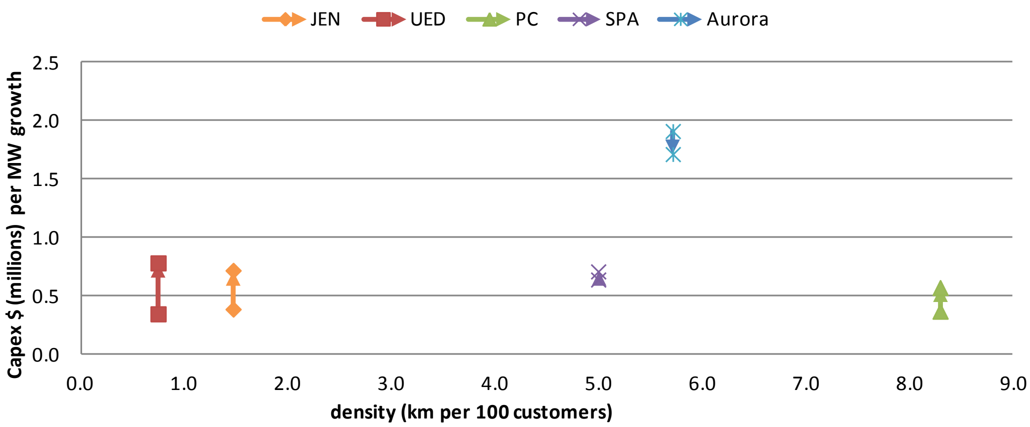
Figure 12 below show the results of this analysis. This shows all 5 DNSPs. The two points for each DNSP reflect the capex metric in the current and next regulatory periods.

[30] The analysis uses actual customer numbers and length of HV line in 2009/10 as the reference year for calculating density.

[31] For the Victorian DNSPs, capex in the current period is that provided in their relevant proposals with further updates made by the AER, based upon regulatory accounts information for 2010. The allowance made by the AER is used for the next period.

[32] It is recognised that the current regulatory period for Aurora is actually 4.5 years; however, for consistency a 5-year period has been used.

Figure 12 Reinforcement high level comparative analysis results



This analysis suggests that Aurora's reinforcement capex is significantly greater than the level required by the Victorian DNSPs. In this regard, Aurora's reinforcement capex in the current period per MW of growth in peak demand has been over four times greater than Victorian DNSPs, with the Victorians at around $0.4 million per MW of growth and Aurora at $1.9 million. Even though the Victorian DNSPs were allowed a significant increase in reinforcement capex by the AER for their next period, increasing their capex to on average $0.7 million per MW of growth, Aurora's forecast is still over twice this, at $1.7 million per MW of growth.

Interestingly, the Victorian DNSPs do not indicate a strong correlation of this capex with customer density, so this should not be a significant differentiator for Aurora. Possibly more importantly, based upon information provided in the various revenue proposals, the Victorian DNSPs appear to be operating with significantly higher utilisation levels for their HV feeders than Aurora[33][34]. It would be reasonable to assume that as the utilisation increases, there would be an increased need for augmentation for the same peak demand growth. As such, if anything, it may be expected that Aurora would need a lower level of capex per MW of growth than the Victorian DNSPs.

We do accept that there are some matters that may be resulting in higher comparative levels of reinforcement capex than the Victorian DNSPs. Most notably, the Victorian DNSPs had a far greater level of peak demand growth in the current period and were forecasting a far greater level in the next period. In this regard, the Victorian's growth was between 3.5% and 5.1% in the current period, whereas Aurora's was only 1.0%, with growth only really occurring over the first half of the current period prior to the GFC. Victoria is expecting growth rates at 2.2% and 5.5% in the next period, whereas Aurora is expecting around 1.0%.

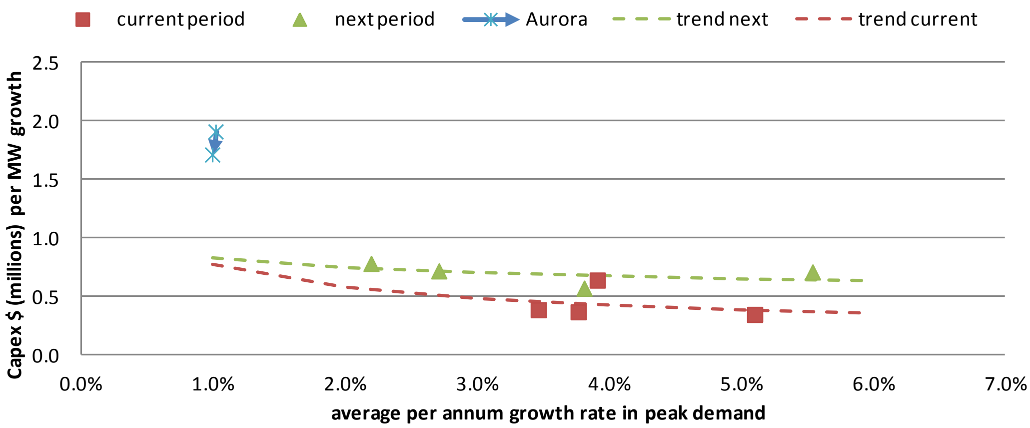
These higher growth rates may well mean that the Victorians can find some scale efficiencies, when optimising larger capital programs to cater for this growth. Also, as the growth in peak demand reduces then the effects of customer "churn" (i.e. customer

[33] Utilisation here is considered to be the ratio of the peak demand to the planning rating of a feeder.
[34] Based upon the data provided in the RIN templates provided by the DNSPs.

moving from one place to another) may be more significant in driving the capex need. The metric we are using here will not capture the effect of churn.

To assess this issue, we have examined the relationship between the Victorian DNSPs' growth rates and their capex levels to attempt to estimate equivalent capex levels for a 1% growth rate. This analysis is shown in the Figure 13 below, where the dashed lines indicate the capex trend from the growth rates for the Victorian DNSPs, based upon the capex metric in the current (red markers) and next period (green markers).

Figure 13 Reinforcement capex relationship with demand growth



This analysis suggests that the Victorian DNSPs would have still incurred and are forecasting to incur considerably less than Aurora if the growth rate is adjusted to 1%. Our analysis suggests Aurora is still over twice the Victorian amount for the current and next periods.

Another matter that may be causing the increased need for capex in the case of Aurora may be the new reliability standards that were introduced for Transend and have impacted Aurora's capex in the current period. Although Aurora's obligations associated with developing the network to cater for peak demand are similar to Victoria (i.e. they are largely risk based rather than strict redundancy standards), Transend's state-based obligations have resulted in the development of a number of new substations. This in turn means that Aurora needs to develop the distribution network to allow these to be connected and offload the existing substations.

It is difficult to quantify this impact in our analysis. However, it seems reasonable to assume that if this is causing some increased need on one hand then this should be reducing needs that may occur in its absence on the other (e.g. the extra substations and associated feeders should reduce feeder overloads that would have eventuated without these developments). As such, we may expect greater gains to be seen in the next period, which is not the case.

On balance, we consider that the analysis supports a view that Aurora may not be managing assets in a prudent and efficient fashion. At the very least, these findings support the need for our detailed review of Aurora's capex in these categories.

5.3 Detailed review

Nuttall Consulting had undertaken a review of the methodology applied by Aurora to develop its reinforcement capex, and a more detailed review of a selection of planned projects and programs that Aurora considers underpin its forecast capex in the next period.

To undertake this review, we first performed a review of relevant documentation provided by Aurora with its proposal, most notably:

- Capacity management plan[35], which summarises the methodology applied and key projects and programs.
- Demand management plan[36], which summarises the non-network solutions that Aurora has assumed can be used to defer the need for some of its planned projects.
- Proposed program of works (POW)[37], which is a spread sheet that details the specific planned works that Aurora has assumed in developing its expenditure forecast - this spreadsheet provided the detailed plans that underpinned the projects summarised in the capacity management and demand management plans.
- Aurecon reports[38], which are a set of reports, one for each area of Aurora's network, prepared by an independent expert. Each area report details the strategic plans associated with the future development of the network in that area. These reports discuss the methodology applied, committed projects, existing and future network limitations, projects and options to address these limitations over a 5-year, 10-year and 20-year horizon.
- Futura report[39], which is a report by an independent expert on the ability and efficiency of non-network solutions to defer network solutions. The findings of this study informed Aurora's Demand Management Plan, noted above.

This review lead to the targeting of four of Aurora's eleven planning areas for more detailed review: Hobart East, Hobart West, North West and North Coast. These four areas were targeted as they covered a large level of planned augmentations, plus they included a range of large and small projects across the next period, and a range of load growths. The projects reviewed in these four areas, as identified in Aurora's Capacity Management Plan, are listed in Table 6 below.

[35] AE033 – Management Plan 2011 – Capacity (partially confidential)
[36] AE034 – Management Plan 2011 – Demand Management
[37] AE083 – Aurora's Proposed Program of Work (confidential)
[38] AE043 to AE054 – Set of Aurecon System Strategic Planning Capacity Reports
[39] AE055 – Futura Report – Proposed Non-network Initiatives

Table 6 Reinforcement projects review in selected areas

Project/program	Capex ($ millions)[a]
9.4.1 Austins Ferry zone substation	0.5
9.4.3 Richmond zone substation	5.5
9.4.4 Rosny zone substation	2.5
9.4.5 Sandford zone substation	0.5
9.4.7 Wesley Vale substation	6.0
9.4.8 Wynyard substation	0.1
10.4.1 Conductor augmentation - Bridgewater	0.3
10.4.1 Conductor augmentation - Chapel St	1.5
10.4.1 Conductor augmentation - Devonport	0.1
10.4.1 Conductor augmentation - Geilston Bay	0.2
10.4.1 Conductor augmentation - Hobart sub-transmission	0.1
10.4.1 Conductor augmentation - North Hobart	0.6
10.4.1 Conductor augmentation - Railton	0.4
10.4.1 Conductor augmentation - Sandford	6.9
10.4.1 Conductor augmentation - Sandy Bay	0.9
10.4.1 Conductor augmentation - Smithton	0.2
10.4.1 Conductor augmentation - Ulverstone	0.1
10.4.9 Conversion - Richmond area	4.1
10.4.11 System fault level - Chapel St	0.6
Total	**31.2**

a – inclusive of overheads

The majority of other projects and programs were reviewed, based upon a consideration of the methodology and rationale adopted by Aurora to determine those components. For some of these, area-specific issues determined through the project reviews noted above, were included within our considerations. Table 7 below lists the relevant projects and programs, as identified in Aurora's Capacity Management Plan.

Table 7 Reinforcement programs reviewed

Project/program	Capex ($ millions)[a]
10.3 Additional processes	8.8
10.4.12 Mobile generation	2.4
10.4.3 DINIS API	5.1
10.4.5 Regulators	5.5
10.4.7 Operation	10.2
10.4.8 Development	4.1
11.4.1 Distribution substations	9.3
11.4.2 Low voltage networks	1.3
Total	**46.8**

a – inclusive of overheads

The high-level review of the available information noted above indicated significant deficiencies in information suitable for our review. As such, a further information request was provided to Aurora, via the AER[40]. This requested further information to support the specific projects in the four targeted areas and the programs.

5.4 Detailed review findings

To discuss our detailed review, we consider it sensible to discuss the following RIN sub-categories separately:

- HV feeders and zone substations
- Distribution substations
- LV network

The HV feeders and zone substation sub-categories have been combined here, as generally for Aurora the zone substation category covers HV feeder activities associated with substation developments.

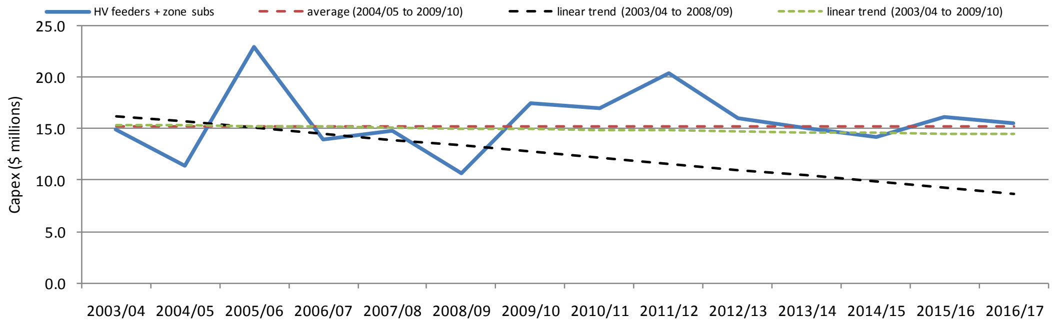
The main findings of the review of these three categories are summarised in turn below.

5.4.1 HV feeders and zone substations

Figure 14 below shows the profile of capex allocated to HV feeders and zone substations (the solid blue line). This includes the actual capex prior to 2010/11, and the estimate and forecast from 2010/11. The chart also includes an indication of average and linear trends of actual capex (the dashed lines) for comparative purposes.

[40] The request was made, via the AER, on 18/7/11. A response was provided by Aurora on 29/7/11

Figure 14 Reinforcement – HV feeder and zone substation capex trends



This chart indicates that capex in the next period is forecast to be at levels consistent with the longer term average and linear trend. The forecast is below levels estimated for the latter half of the current period.

As noted above, we have reviewed a significant number of projects and programs to assess the reasonableness of Aurora's forecast. A broad finding of our review of these projects and programs is that the methodology applied by Aurora to produce the forecast is appropriate to identify possible needs and strategic solutions. To a reasonable degree, this process aligns with the actual planning processes Aurora applies in its normal planning activities.

However, most projects reviewed only appear to have small components for which we can clearly determine a direct relationship with the growth in demand, and as such, the need is clearly related to maintaining the service to customers in the face of the forecast growth in demand (i.e. a capex objective in the NER). A large portion of the capex appears to be driven primarily by a desire to improve the operating efficiency of the network and the associated impact on reliability and risks. Even though in all cases reviewed we see no reason to doubt that specific technical issues may exist that may be affecting the *idealised* operation of the network, we have not been presented with any substantive analysis that supports the view that undertaking these elements of the projects at the time proposed would provide a net benefit or ensure compliance with external obligations. In effect, they may well appear reasonable from the perspective of those technically responsible for managing the network, but may not necessarily be commercially or economically justifiable to be undertaken at the time proposed by Aurora. On the other hand, if the capex is justified then we would expect there to be an appropriate adjustment to the operating expenditure forecast and/or reliability targets to account for these benefits.

We understand that Aurora has allowed for some reduction in future operating expenditure in its proposal. However, we have not been presented with evidence that clearly supports that this adequately accounts for this portion of reinforcement capex, in addition to the other productivity improvements this is set to reflect. It is also our understanding that specific adjustments to Aurora's reliability targets have not been proposed.

Furthermore, in a few cases, we did not consider that Aurora had adequately justified that the options it was proposing were reasonable, and in particular, that lower cost options may not be the most appropriate solution to address identified issues.

The following summarises more specific findings on these matters. More detailed discussions of specific projects within the four areas reviewed are contained in Appendix B.

Area review findings

With regard to specific projects we reviewed, we consider that three could be viewed as major projects relative to typical projects Aurora may undertake. These are:

- Richmond zone substation development ($5.48 million) and the associated voltage conversion project ($4.1 million)
- Sandford augmentation ($6.8 million)
- Wesley Vale zone substation development ($6.1 million).

The partial need for all three of these projects was due to the growth in demand and the resulting overload of substation transformers or HV feeders. However, particularly for Richmond and Wesley Vale, the need for a significant portion of these projects appears to be existing load management issues. If this is the case then we would expect that appropriate reductions in opex and improvements in reliability would occur if this capex is justified.

In the case of the Sandford augmentation, we consider that Aurora is proposing a very costly solution, involving the development of sections of underground and submarine sub-transmission lines operating temporarily as HV feeders. While we agree that this solution is in line with the longer-term strategy to develop a new substation in that region, our view is that a much lower cost, short-term, solution most likely could be found, assuming more rigorous analysis is undertaken. Moreover, Aurora is also proposing a non-network solution to defer the need for the related new Sandford zone substation project. We do not consider that Aurora's capex (and opex) allowance for this non-network solution is consistent with the assumption that this network project will be required also. Our view is that the non-network solution will most-likely mean that a network solution will not be required in the next period. This matter will be discussed further in Section 5.5.2 on Aurora's non-network plans.

We found similar issues with many of the other projects reviewed, covering:

- 9.4.4 Rosny zone substation
- 10.4.1 Conductor augmentation - Bridgewater
- 10.4.1 Conductor augmentation - Chapel St
- 10.4.1 Conductor augmentation - Devonport
- 10.4.1 Conductor augmentation - Smithton
- 10.4.1 Conductor augmentation – Ulverstone

- 10.4.1 Conductor augmentation - Hobart sub-transmission
- 10.4.11 System fault level - Chapel St

For many of these projects, as noted above, we found that there would need to be a significant operating cost and/or reliability benefit in order to justify the capex i.e. it would only be prudent and efficient to undertake the project at the time proposed if these benefits were sufficient to achieve a positive net benefit.

In the case of the Hobart Sub-transmission project and Chapel Street fault level project, we do not consider that Aurora has adequately demonstrated that the scale of the project proposed is justified.

Only in the following cases do we consider that Aurora's proposed projects, in terms of timing and scope, appears to be reasonably justified:

- 9.4.1 Austins Ferry zone substation
- 9.4.5 Sandford zone substation
- 9.4.8 Wynyard substation
- 10.4.1 Conductor augmentation - Geilston Bay
- 10.4.1 Conductor augmentation - North Hobart
- 10.4.1 Conductor augmentation - Sandy Bay

In this regard, we consider that the timing of the need is reasonably justified (i.e. asset overloads have been forecast that will most likely require network investment in order to maintain service levels to customers) and the options proposed by Aurora to address these needs appear reasonable, in the specific circumstances.

In the case of the substation projects, Austins Ferry, Wynard substation, and Sandford zone substation, these three developments are considered by Aurora as good candidates to be deferred by the non-network solutions. Aurora has allowed for some modest capex to cover design, fees and land purchases where needed, which we consider is reasonable in the circumstances. Further discussions of our review of the non-network projects are contained in Section 5.5 below.

We also consider that feeder loading information provided by Aurora largely supports the timing and scope of the three feeder augmentations projects listed above.

Finally, with regard to the Railton conductor augmentation project, we do not consider that Aurora has provided any substantive information that would allow us to perform a review of this project.

Efficiency and reliability improvement

Aurora is also proposing a number of projects and programs that we consider the primary driver is improving efficiency and/or reliability. These projects cover:

- 10.4.12 Mobile generation
- 10.4.7 Operation: HV phasing, security, switching, transfer

- 10.4.8 Developments
- 10.4.9 Conversion

We have reviewed and considered the needs and rationale underlying these programs. In general, we consider that the needs and solutions proposed seem reasonable i.e. the technical matters discussed are common industry issues for an electricity distribution business and the solutions proposed are "good-practice" approaches to ameliorate the issues. However, the projects do not appear to be primarily driven by non-compliance issues resulting from the forecast increase in demand. Instead, these programs address existing issues generally associated with operational inflexibility (e.g. the management of load under planned or unplanned outages).

Consequently, the prudent and efficient (and "best-practice") action would be to only incur the capex associated with these programs if they will realise sufficient operational cost savings and/or reliability improvements and/or further capital efficiencies to ensure that there is a net benefit.

Aurora has not provided any substantial analysis to demonstrate that its proposed level of capex for these programs constitutes an appropriate amount – i.e. a demonstration that the capex will most likely result in net benefits. We do accept that it may be that not all of the benefits could be realised in the next period, and hence, even if net benefits exist, some allowance for additional revenue may be required. On the other hand, it may be that there are still some "low hanging fruit" such that the benefits for some works will far exceed the capital cost. In the absence of such cost-benefit analysis, we consider it is reasonable to assume that any allowance for capex for these programs in the next period should assume that a significant portion will be justified by opex reductions and reliability improvements in the next period.

Other programs

Aurora has included a number of programs that we consider are primarily related to capacity needs driven by the growth in demand (i.e. anticipated network overloads). These cover:

- 10.4.3 DINIS API
- 10.4.5 Regulators

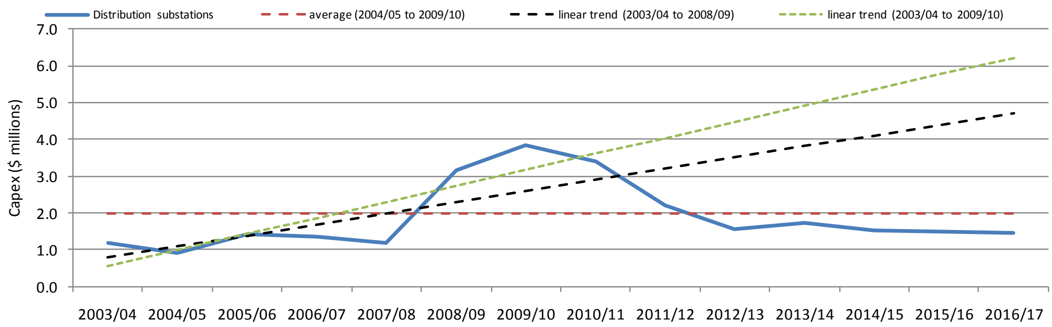
For these programs, Aurora has forecast a number of general feeder and regulator augmentations based upon power systems analysis of its set of feeders, and the identification of specific feeder sections and regulators that may be overloaded. Engineering judgement, based upon knowledge of the network and the identified issues, has then been used to develop a capex forecast from the results of this analysis. This methodology, in principle, appears reasonable in the context of Aurora's overall approach to producing the reinforcement forecast. Due to the large number of minor augmentations resulting from this process and the detailed knowledge required to assess the most appropriate solution, it is not feasible within our review to undertake a detailed review of the specific augmentation items developed through this process.

Aurora has also included a program item that captures the capex associated with various demand management initiatives (10.3 Additional process). These initiatives largely constitute the non-network solutions that Aurora assumes will defer the need for network solutions, such as those discussed above. Our review of Aurora's non-network projects is discussed in more detail in Section 5.5 below.

5.4.2 Distribution substations

Figure 15 below shows the profile of capex allocated to distribution substations (the solid blue line). This includes the actual capex prior to 2010/11, and the estimate and forecast from 2010/11. The chart also includes an indication of average and linear trends of actual capex (the dashed lines) for comparative purposes.

Figure 15 Reinforcement – Distribution substation capex trends



This chart indicates that capex in the current period increased significantly between 2008/09 and 2010/11 from levels over the previous period. We understand that this was due to a targeted program to upgrade heavily loaded transformers. The forecast in the next period is just below the historical average, and well below the recent level. However, it is marginally above the level prior to the targeted program.

Aurora developed this forecast by:

- estimating the loading of the population of distribution transformers, based upon customer numbers supplied by the substation and an assumed customer demand
- ranking of the severity of the estimated overload based upon the nameplate rating of the distribution transformer
- further engineering judgement to account for data issues and potential synergies with other work programs.

The forecast has been developed in three broad categories, covering:

- small pole mounted substations (below 50 kVA)
- large pole mounted substations (above 50 kVA)
- ground mounted substations.

We have reviewed the methodology applied by Aurora to develop its distribution forecast. In principle, we consider it appropriate in the circumstances. In this regard, the estimation of loading using customer numbers and ranking of the level of overload is a reasonable process, given that actual loading is generally not recorded for the vast majority of distribution transformers. This process is similar to processes we understand that other NEM DNSPs used to estimate the loading of distribution transformers, where actual measurements are not taken.

That said, the criteria used to produce the volume of replacements needs to be appropriate. In the case of Aurora, it appears that although they have used a bottom up process to determine the level and ranking of overloads, a top-down approach has been used to set the total volumes. This seems to have set the volume to ensure capex is in line with historical levels.

Given the large increase in upgrades that has recently occurred, it could be argued that a much lower level should be required in the next period – possibly lower than the level prior to the targeted program. In effect, the overloads have largely been cleared. This may be also suggested from the profile of the capex at the end of the current period, shown in the chart above, which is trending down into the next period.

However, counter to this, Aurora is claiming that generally the volume proposed for replacement still captures the high priority transformers, being estimated to be over 150% loaded.

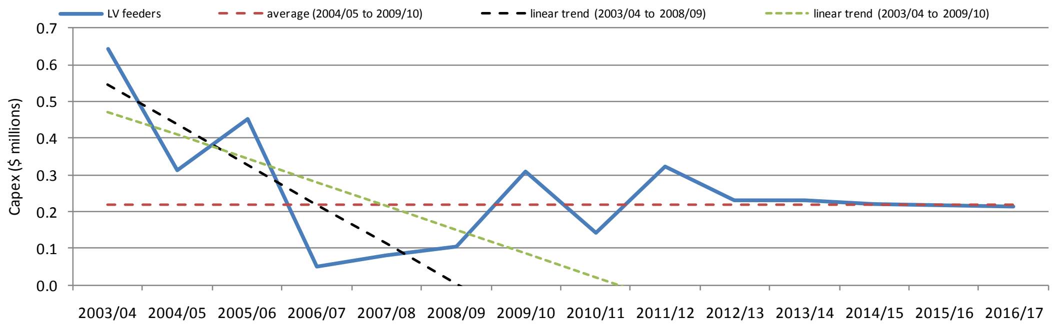
Current design standards for distribution transformers would limit the overload to 150%; as such, this could be considered reasonable. But older transformers could have significant design margins that could mean they could be very heavily loaded without increasing risks significantly or it may be that further analysis (that Aurora stated it would do prior to the upgrade) may find the estimate overstated the loading. As such, it could be that Aurora’s criteria still overstates the number of transformers requiring upgrade in the next period.

On balance, given the forecast is broadly in line with the longer term trend and Aurora is claiming that it is still predicting heavily loaded transformers are on its system (above 150% of nameplate), we consider the forecast is reasonable in the circumstances.

5.4.3 LV network

Figure 16 below shows the profile of capex allocated to LV networks (the solid blue line). This includes the actual capex prior to 2010/11, and the estimate and forecast from 2010/11. The chart also includes an indication of average and linear trends of actual capex (the dashed lines) for comparative purposes.

Figure 16 Reinforcement – LV network capex trends



This chart indicates that capex in the current period has reduced from levels incurred over the previous period, particularly the first half of the previous period. The forecast in the next period is in line with the historical average.

The upgrade of the LV network is a reactive program, and as such, we understand that historical trends have been used to prepare the forecast.

Given the low level of capex in this category and the fact that it is broadly on trend with recent levels, we have not reviewed this category in any detail and consider the forecast to be reasonable in the circumstances.

5.5 Non-network expenditure

Aurora has proposed a number of non-network projects and programs as alternatives to network solutions to issues. As non-network alternatives usually address demand-driven network needs, Aurora's approach to non-network expenditure is discussed here.

The specific plans that underpin Aurora's proposal cover two forms of project:

- **Broad-based programs** covering general programs and trials of various non-network options and technologies. A portion of this expenditure is proposed by Aurora to be funded through the AER's DMIA scheme. The remainder is included in the general opex and capex components.

  As far as we are aware, there is no specific substitution of network capex (or opex) allowed for in the proposal to justify the expenditure on the broad-based programs. Rather, Aurora sees these as administration and management costs associated with the implementation of the non-network strategy and other trials and studies that will provide knowledge and understanding to guide the future strategy.

- **Location-specific projects** covering specific non-network solutions to specific network issues that have been identified through the planning process (e.g. Aurecon review and reporting), which has been the subject of discussion in this section of our report.

  The non-network expenditure allowance associated with these projects are considered by Aurora to be a direct substitution for network expenditure that would be required to address the network issues, if the non-network solution was not to be used.

The focus of our review has been on the substitution possibilities between network capex and non-network expenditure. This includes both capital and operating expenditure on non-network activities. More specifically, our review has focused on network capex in the next period that can be deferred by non-network solutions. As noted above, the capex component is allocated to the "10.3 Additional processes" category in Aurora's capacity plans and associated proposed program of works.

We have not undertaken a review of Aurora's approach to assessing non-network opportunities in the next period, and associated structural arrangements. These matters appear to be most relevant to Aurora's demand-side engagement strategy, which is discussed in its proposal, and for which an allowance appears to be included in its forecast opex.

5.5.1 Overview of Aurora's non-network plans

Aurora's non-network plans are discussed in a specific management plan provided in support of its proposal (the DM plan)[41]. This plan provides some background on Aurora's load and its suitability for non-network solutions, the various regulatory instruments that are driving its approach to considering non-network options, and matters associated with the administration and implementation of its non-network strategy.

The DM plan also summarises the individual broad based and location-specific project and programs. The broad-based plans cover a range of programs aimed at investigating approaches to manage and influence customer load at times of peak demand. These projects include:

- the further development of time of use tariffs and the trial of approaches to incentivise appropriate load response from residential and small business customers
- a study of the water heating load on the network to determine its potential for demand management and develop an appropriate strategy
- the development of educational material and associated schemes to incentivise the construction of new developments in a way that aids demand management
- the development of material and engaging with customers and stakeholders to raise the awareness of the cost of addressing peak demand
- a trial of direct load control and associated technologies, and studies into incentives required to encourage participation
- a trial of LED streetlight technology

[41] AE034, Management Plan 2011, Demand Management

- the development of a framework and associated contracts to allow for the procurement of network support agreements from large commercial and industrial customers
- a study to assess opportunities through the correction of power factor (e.g. where the power factor may be within regulator obligations, but further correction may be beneficial)
- a trial, including the development of marketing/education material, with institutional partners to enhance their participation in demand-side management initiatives
- an investigation into whether there is a case to support the further roll-out of natural gas to areas that have electricity network constraints
- the development of a business case and project plan to undertake system-wide load management, based upon the findings of some of the trails and studies listed above
- the development and implementation of internal staff training packages.

The location-specific projects cover five network needs that Aurora considers would require significant network investment in the next period. The DM plan discusses the specific network issues and Aurora's preferred network solution that it considers is required in the absence of the non-network solution. The DM plan also summarises the various non-network initiatives it considers would be suitable for the specific customer and load circumstances. Depending on the circumstances, these initiatives broadly cover programs identified in the broad-based programs.

The DM plan provides a summary of the opex and capex requirements for the non-network plans, but it does not provide any substantive justification for the plans.

In support of the DM plan, Aurora has also provided a study performed by an independent consultant (the Futura report)[42]. The Futura report provides a more extensive discussion on much of the background material in the DM plan. It also provides some detail on a national and international survey the consultant has conducted of non-network initiatives applied elsewhere.

Importantly for this review, it also provides more detailed discussions of both broad-based and location-specific opportunities. For both, it discusses the nature of the non-network projects and provides some summary details of the scope and costs associated with specific projects.

With regard to the location-specific projects, it provides an overview of the process it followed to determine the best network-project candidates for non-network solutions and a reasonably detailed discussion of the particular load and customer characteristics for these locations. This discussion includes the possible level of load relief achievable through the various opportunities and the likely cost of this relief (in terms of $ per kVA of reduction).

[42] AE055, Identification of non-network initiatives for the 2012-17 EDPR, Futura Consulting, dated July 2010

To demonstrate whether a non-network project is suitable for deferring the network solution, the Futura report presents analysis indicating whether the least-cost non-network solution is less than the avoided cost of the network option. For each of the five location-specific projects discussed, the report shows that the cost of the non-network solution should be lower than the deferral value of the preferred network solution.

5.5.2 Nuttall Consulting review

We have reviewed the DM plan and Futura report. It is clear from this review that the DM plan is based upon the findings of the Futura report, both in terms of the non-network plans and the costs for these plans. In this regard, the specific broad-based and location-specific plans and costs recommended in the Futura report appear to be directly those included in the DM plan.

The process applied by Aurora and methodology applied by Futura appear reasonable. In this regard, the Futura analysis appears to represent a level of detail and thoroughness that we consider is at least equal to that which we have seen through other regulatory reviews of NEM DNSPs.

Due to the limitations of our review, we have not been able to conduct an audit of important inputs into the Futura analysis, particularly those associated with the load and customer characteristics. Furthermore, owing to the limited published data available in this area, we have not been able to conduct a thorough review of the underlying non-network cost assumptions. Nevertheless, based upon our assessment of the analysis and our general experience on related matters, we see no reason to dispute these inputs and assumptions.

Importantly for this review, three of the five location-specific projects relate to the projects we have selected and have discussed the need and network solution above (and in Appendix B). These projects are:

- Sandford zone substation
- Wynyard terminal station
- Austins Ferry.

For these three projects, we have conducted a more detailed review to confirm that the Futura analysis is consistent with analysis Aurora has presented elsewhere on the network need and network preferred option. In all three cases, the assumptions on the network need, the timing of this need, and the cost of the preferred option are in accordance with the analysis presented in the relevant Aurecon reports.

We have also assessed the economic analysis presented to justify the non-network solution. In all cases, the analysis supports the selection of the non-network option. However, we have two main concerns with the analysis, in the context of our findings discussed above on the network plans.

Firstly, as was alluded to above, in the case of Sandford, the Futura analysis assumes the full cost of the project will be deferred by the non-network solution. This is not what

Aurora has allowed for in its proposal, where it has included the sub-transmission line works, which constitute a large portion of the network solution. We do not consider that the non-network solution would be economic if this was to be the case. The Futura analysis seems to recognise that the non-network analysis needs to address the issue raised by Aurora as driving the need for the sub-transmission works i.e. heavily loaded feeders. As such, our view is that it is reasonable to assume that the non-network solution will relieve this network need, and consequently, the sub-transmission works proposed by Aurora should not be necessary – or a far more modest project should be sufficient to manage the risks.

Secondly, in the case of the new Wynyard terminal station, as discussed in Appendix B, we did not consider that the most pressing need for the project related to the matter being considered in the Futura report. The Aurora analysis and the Futura analysis appear to assume that the timing is primarily related to the overload of Transend's transformers, and as such, the timing is effectively a compliance issue for Transend. However, we have not been presented with evidence that this is the case. As such, we consider that the timing is related to the loading of the feeders. Although this inconstancy exists, based upon the non-network solution proposed, which is largely based upon customers in the Wynyard area, we consider the non-network solution to still be appropriate. It is also noted that Aurora has focused the solution discussed in its DM plan on a specific customer in the Wynyard region.

Based upon our review, we consider that location-specific capex and opex allowances for non-network solutions we have reviewed are reasonable. It may well be that some further level of substitution between network and non-network costs is likely to be achievable, and prudent and efficient. However, given the analysis presented, these opportunities are most likely to be more marginal than the projects Futura has determined, and therefore, the revenue available through allowed capex for Aurora's network plans is likely to be a reasonable approximation of the revenue required for alternative non-network solutions, if they are found.

In the case of the broad-based projects, given the study performed by Futura, we see no clear reason to consider the plans and costs (opex and capex) assumed by Aurora are unreasonable. However, we understand that Aurora has not made any specific adjustments to either the load forecast and capex plans to account for these costs. In these circumstances, we consider that whether or not there should be an allowance for this component of non-network expenditure relates more to regulatory matters that the AER is in the best position to consider; for example, the incentives on Aurora to undertake these plans if an allowance is made, the risks faced by Aurora and its customers if an allowance is made and costs are incurred, and the appropriate regulatory mechanism for allowances in these circumstances.

Although we have accepted Aurora's demand management plans above, we do have a number of concerns with Aurora's total capex and opex allowances, where we consider that Aurora may be proposing allowances in excess of its plans.

In the case of capex, as discussed above, we understand that Aurora's non-network capex is included in the "additional processes" program. Aurora has allocated $8.8 million to this program, based upon its proposed program of works. However, the DM plan only allows for $3.2 million[43]. Based upon our review of the line items allocated to the "additional processes" program, we believe that the large majority of this program relates directly to non-network initiatives. We have requested that Aurora provides an explanation of the difference; however, Aurora's response on this matter does not provide any information to substantiate the increase[44].

Without explicit justification for this increased amount, based upon our overall review of reinforcement capex and non-network expenditure, we see no reason to allow for this component of capex in the next period. Table 8 provides our estimate of the unsubstantiated amount of non-network capex allocated to the "additional processes" program.

Table 8 Reconciliation of DM plan capex to "additional processes" capex

	Reinforcement capex ($ millions)					
	2012/ 2013	2013/ 2014	2014/ 2015	2015/ 2016	2016/ 2017	Total
Additional processes - total	1.8	1.8	1.4	1.6	2.1	8.8
Network component[a]	0.0	0.0	0.0	0.0	0.3	0.3
DM plan component	1.0	0.5	0.5	0.5	0.6	3.2
Unjustified non-network component	**0.8**	**1.3**	**0.9**	**1.1**	**1.2**	**5.3**

a – line item described as "Upgrade Regulator Various locations"

With regard to opex, we consider that there may be a double counting of the opex associated with external resources for the broad-based programs for the load control architecture study, power factor correction study, and the residential and small business hot water study. For these three items, there are similar amounts allocated to both the standard opex allowance and the opex allowance to by funded through the DMIA. This amount totals $0.65 million in the next period.

5.6 Developing a substitute allowance

In the sections above, we have shown a number of matters that we consider relevant to deciding whether Aurora's proposed reinforcement capex can be considered to reflect the capex criteria. Most notably:

- Aurora's reinforcement capex in total compares unfavourably to similar Victorian DNSP capex when adjusted for the level of growth in peak demand. This analysis suggests Aurora's reinforcement capex over the current period has been over twice the average level of the Victorian DNSPs, and is forecast to be approximately twice

[43] Table 4, NW-#30172001-v2-Managament Plan_2011_Demand_Management

[44] AER043 - request provided in email dated, 27 September 2011, response provided 30 September 2011 (partially confidential).

the level again in the next period to that allowed by the AER for the Victorian DNSPs.

- A large portion of Aurora's reinforcement capex does not appear to be justified based directly upon the need to maintain the service levels of the network or comply with obligations in light of the forecast growth in demand; rather, it relates to existing network arrangements that result in operational inflexibility when managing demand. In these cases, we would expect that the capex would be justified provided there were sufficient operational and reliability benefits in undertaking these projects.
- In a number of cases, we do not consider that Aurora has adequately demonstrated that its capex, for specific proposed projects, is a reasonable estimate of the likely requirement. In these cases, we consider it far more likely that a much lower level of capex will be required during the next period, assuming a more rigorous analysis is undertaken.
- Finally, in the case of non-network capex, although we found the stated plans to be prudent and efficient, we consider that there is a large component of additional capex that is not supported by the information provided.

Given the approach Aurora has applied to develop its overall capex forecast, we consider that the above should be sufficient to reject this forecast.

In developing a substitute allowance for reinforcement capex, we have had to consider two issues.

The first concerns the appropriate allowance for the capex that is largely justified due to its operational or reliability benefits. On this matter, we note that Aurora has allowed for an annual productivity improvement in its opex forecast. Through the meetings we have held with Aurora during the course of this review, we understand that Aurora considers that these productivity improvements should inherently allow for the opex savings resulting from the capex component noted above. As such the capex should be allowed for.

However, our review has focused on capex, and as such, we have not undertaken a review of the overall opex forecast and the methodology applied by Aurora to develop it. Furthermore, although we have requested information on the benefits anticipated from the reinforcement capex, at the time of drafting this report we have not been provided with any substantive information that confirms this. As such, it is impossible to confirm with any certainty what capex is justifiable based upon these operational benefits, and how much, if any, is already accounted for through the productivity improvements assumed in Aurora's proposal. That said, as will be noted later on the findings of our review of non-system capex, the IT upgrades that we have accepted, were put forward by Aurora as the main projects that would lead to the productivity improvements. Moreover, if significant opex savings are anticipated in the next period due to these project components then we also expect some improvement in reliability. It is our understanding that the reliability targets proposed by Aurora definitively do not allow further anticipated reliability improvements.

The second issue concerns the appropriate allowance for the capex that is largely justified to maintain service levels in light of the forecast growth in demand. In this regard, our project reviews found very little expenditure was clearly supported on these grounds. As such, if we developed a forecast based strictly upon only those components of projects that have been clearly justified on these grounds then this component would be very small. This position however would conflict with the findings of our high-level analysis.

To address these two issues, we have derived a capex allowance based upon two components:

- demand component - the amount necessary to maintain service levels in light of the forecast growth in demand
- efficiency benefit component - the additional amount where we would expect there to be opex and/or reliability improvements in the next period that would economically justify the capex.

These amounts have been developed using a bottom-up process, based upon the projects we have reviewed, but with due regard to our expert judgement where uncertainty exists. For each of these projects, we have assigned the proportions we consider reflect these two components.

In setting the demand component for each project, we have attempted to err on the side of caution to ensure a sufficiently large amount is provided to reasonably ensure growth in demand can be met without impacting the performance of the network. Importantly, this amount also allows for a proportion of the capex that we consider may be justified by benefits that will only eventuate in periods after the next and the further degradation of the existing operational issues that may result during the next period.

The efficiency benefit component covers the remaining capex where we consider that this must be justified based upon opex and reliability benefits. It is important to note that we are not advising that this capex is justifiable; rather, if the AER makes a capex allowance for this component, it needs to satisfy itself that there are appropriate adjustments to the opex and/or reliability targets to ensure that this capex component would result in net benefits.

To develop an overall allowance for reinforcement capex, we have considered the projects identified through the four areas reviewed separately from the other more generic programs reviewed.

For each project reviewed in the four areas selected, we have determined a proportion of capex relevant to the two components noted above. The projects have then been grouped into three categories:

- HV feeder projects[45]

[45] This covers the projects categories under the heading 10.4.1 in Aurora's capacity management plan.

- zone substations projects involving non-network solutions
- the remaining zone substation projects.

The proportions relevant for each project have then been used to calculate the average proportion (as a percentage) over all the projects we have reviewed in each of the three categories noted above.

To assign a proportion to the projects in the areas we have not reviewed, we have used the relevant average proportion to apply to these projects. Given our review covered a large portion of the planned projects, we consider this assumption to be reasonable.

In determining these average adjustments, we have excluded the Sandford HV feeder project (i.e. the network component) as we consider that the inclusion of this project in calculating the average for the HV feeder group would bias the findings too unfavourably for Aurora due to the large cost of this project. Furthermore, we have treated the Railton conductor augmentation project as one of the projects not reviewed, as we were not presented with sufficient information to review this project.

Table 9 below shows the proportions we determined for each project reviewed in the three categories. Table 10 shows the average proportions we have calculated for the projects in each category. It is these averages that we have used to adjust the capex for the equivalent projects in the areas we have not reviewed.

Table 9 Reinforcement adjustments to selected projects

category	Project/program	Demand	Efficiency benefit
Zone substations involving non-network solutions	9.4.1 Austins Ferry zone substation	100%	
	9.4.8 Wynyard substation	100%	
	9.4.5 Sandford zone substation	100%	
Remaining zone substations	9.4.3 Richmond zone substation	33%	67%
	9.4.4 Rosny zone substation	70%	30%
	9.4.7 Wesley Vale substation	33%	67%
HV feeder	10.4.1 Bridgewater	33%	67%
	10.4.1 Chapel St	33%	67%
	10.4.1 Devonport	33%	67%
	10.4.1 Geilston Bay	90%	10%
	10.4.1 Hobart sub-transmission	33%	
	10.4.1 North Hobart	100%	
	10.4.1 Sandy Bay	100%	
	10.4.1 Smithton	70%	30%
	10.4.1 Ulverstone	90%	10%
Not applicable	10.4.1 Sandford	0%	

Table 10 Reinforcement average component in each category

Category	Demand	Efficiency benefit
Zone substation projects involving non-network solutions	100%	0%
Remaining zone substation projects	40%	60%
HV feeder	64%	34%

It is important to note that in defining these components we have excluded any allowance for the Sandford HV feeder project, as we consider that this would be inconsistent with the analysis provided in the Futura report and our acceptance of the non-network project (allowed for in "10.3 additional processes" program).

For the remaining programs assessed through the methodology review, we have determined similar demand and efficiency components to derive our total reinforcement allowance. Table 11 shows these components for each of the programs reviewed (excluding 10.3 Additional processes).

Table 11 Reinforcement adjustments to selected programs

Project/program	Demand	Efficiency benefit
10.4.12 Mobile generation		100%
10.4.3 DINIS API	100%	
10.4.5 Regulators	100%	
10.4.7 Operation	25%	75%
10.4.8 Development	25%	75%
10.4.9 Conversion	25%	75%
10.4.11 System fault level	50%	
11.4.1 Distribution substations	100%	
11.4.2 Low voltage networks	100%	

Finally, with regard to the "10.3 Additional processes" program, as discussed in Section 5.5.2 on non-network expenditure, we consider that a large component of this program has not been substantiated by Aurora. Therefore, we have removed this component from the capex for this program (see Table 8 for amount removed).

To ensure consistency in the opex component of non-network expenditure with these findings, opex associated with the location-specific non-network projects should be allowed.

Table 12 below show the reconciliation between the reinforcement capex proposed by Aurora and the substitute allowance based upon the methodology described above.

Table 12 Reinforcement adjustments to proposed capex

	Reinforcement capex ($ millions)[a]					
	2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	Total
Proposed	18.4	18.3	17.2	19.0	19.7	92.6
Nuttall Consulting	16.9	16.6	16.2	12.0	17.8	79.6
Demand	9.9	9.8	9.7	8.1	9.1	46.5
Efficiency benefit	7.1	6.8	6.5	3.9	8.8	33.1

a – based on capex in proposed program of works spreadsheet, inclusive of overheads and excluding capitalised SOMPR and capex labour

The demand component we have determined represents a 50% reduction on the forecast proposed by Aurora. The efficiency benefit component represents an additional 36% of Aurora's proposed reinforcement capex. However, for the reasoning discussed above, the AER will need to decide whether an allowance for this efficiency benefit component is appropriate, and if so, whether appropriate adjustments to Aurora's opex forecast and reliability targets have been made.

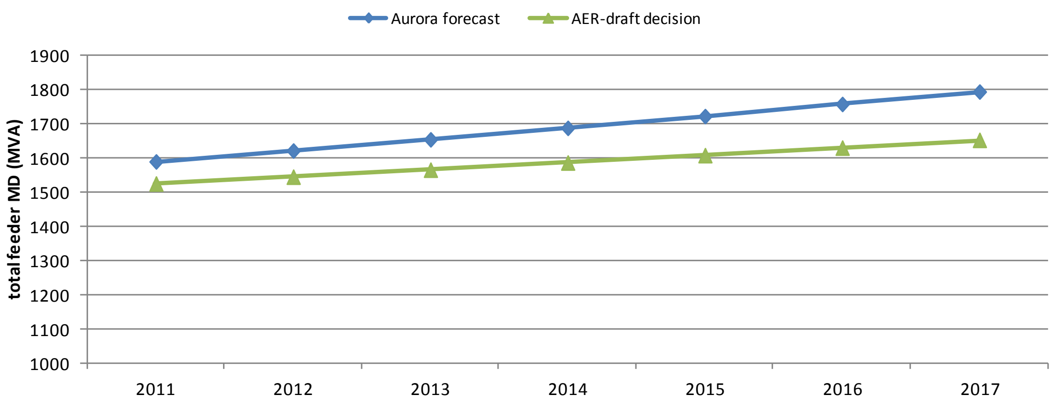
5.7 Implications of the AER draft decision on the load forecast

The discussion above and associated capex allowance assumes that the load forecast underpinning Aurora's reinforcement plans is appropriate. We understand that the AER is considering using an alternative to the maximum demand forecast that Aurora has assumed to develop its capex plans. More specifically, we understand that the AER considers that Aurora's forecast may overstate the maximum demand in the next period.

The AER has provided to us a spreadsheet that details a revised maximum demand forecast. This spreadsheet provides the revised forecasts down to the individual feeder level[46].

Figure 17 below summarises the aggregate feeder demand based upon the feeder-level maximum demand forecast assumed by Aurora[47] and the equivalent forecast provided by the AER.

Figure 17 AER maximum demand forecast – aggregate HV feeders



This figure clearly shows that the AER forecast is lower than Aurora's, both in terms of its starting point and the growth rate. On average, it would appear from this that projects could be deferred by around 3-4 years i.e. the delay between the original demand level and the revised level. Moreover, the growth in the aggregate maximum demand of the HV feeders over the next period, derived from the AER forecast, is approximately 38% less than the equivalent forecast used by Aurora.

As a first approximation, this reduction in maximum demand growth may suggest the appropriate reduction in the demand component of reinforcement capex that we have derived above. However, at the localised level (e.g. substation and feeder level) there are significant differences in the two forecasts both up and down.

Given these localised variations, we have applied a more rigorous approach to assess the likely impact of the AER forecast, involving the reassessment of the timing of each of the

[46] Provided in an email from the AER, dated 14/9/2011

[47] The Aurora forecast is based upon the aggregate of the HV feeder forecast provided in NW #30201055-v1-2010_Feeder_Loading_-_PD_Data.xls

projects in the four areas we have reviewed in light of the AER forecast. To ensure that our analysis aligns with Aurora's original analysis, we have used the spreadsheet provided by Aurora[48], which contains its analysis of the loading levels of each individual feeder with the planning ratings of each feeder to indicate the timing of overloads. We have updated this analysis with the AER forecast in order that we can determine for each feeder the year when its peak loading will be above its planning rating. This analysis allows us to gauge whether projects are likely to be advanced or deferred, and in turn whether justification for the capex is stronger or weaker.

In the case of the zone substation projects, we have undertaken a similar analysis using the aggregate of the feeder maximum demand relevant to the substations driving the need for the substation project.

To ensure consistency with our approach used to derive an allowance, discussed above, we have revised the demand proportions based upon this analysis.

Table 13 below provides summary comments on the findings of our analysis of each project.

Table 13 Project review comments based upon AER maximum demand forecast

Project	Comment
9.4.1 Austins Ferry zone substation	**Justification not changed: demand component remains at 100%** The timing mainly relates to loading of the Claremont and Bridgewater transformers. In total, maximum demand is increasing, possibly suggesting a two-year advancement. However, Claremont has a much lower maximum demand in the AER forecast, suggesting the transformers will not be overloaded in the next period. On the other hand, Bridgewater has a much higher maximum demand, suggested the transformers would be overloaded much earlier. Given the Aurocon reports suggest that transfers are available to manage these overloads until 2016, but it is not clear from the information provided exactly what these transfer are, it seems reasonable to assume that some of the significant differences between the two forecast relate to these transfers. Furthermore, given that the non-network solution being proposed for this project, and accepted by us, is allowing for the early introduction of demand management, it seems reasonable to us to assume that a more modest increase in maximum demand could be managed without altering the timing of the project.
9.4.3 Richmond zone substation	**Justification not changed: demand and efficiency components remain at 33% and 67% respectively** The feeder loading at Richmond is not clear from the AER forecast. Assuming the relevant growth is related to Sorrel then this has slightly higher growth. This suggests the project may be advanced. However, as many other factors influence the timing of this project, most of which do not appear to be directly related to peak demand, we consider it reasonable to assume that the timing will not

[48] NW #30201055-v1-2010_Feeder_Loading_-_PD_Data.xls

Project	Comment
	change significantly.
9.4.4 Rosny zone substation	**Justification stronger: demand component increases from 70% to 90%, efficiency changes to 10%** This project includes a series of HV feeder developments throughout the next period. The timing of the Rosny development is mainly related to loading at Rokeby (and Lindisfarne). Rokeby has a higher maximum demand in the AER forecast. This increase suggests that project elements may be advanced, possibly 2 to 3 years. However, it is noted that most of this advancement is due to 3 MVA step up at the commencement of the AER forecast. Assuming this is mainly due to difference in available transfers that have occurred between the two forecasts, it is more likely that the advancement is more in the order of 1 to 2 years. Furthermore, it is also noted that the project is intended to relieve some heavily loaded feeders at Geilston and Bellerieve. The maximum demand at these substations is less in the AER forecast. This may tend to defer the need for some elements of the project.
9.4.5 Sandford zone substation	**Justification not changed: demand component remains at 100%** The need for the Sandford development is associated with Rokeby load, which is discussed above. Noting the comments above, this project may need to be advance by a year. However, given that the non-network solution being proposed for this project, and accepted by us, is allowing for the early introduction of demand management, it seems reasonable to us to assume that a more modest increase in maximum demand could be managed. Furthermore, as noted for the Sandford feeder augmentation discussed below, we are allowing for additional expenditure that may be able to be used to manage the increased maximum demand on certain heavily loaded feeders.
9.4.7 Wesley Vale substation	**Justification not changed: demand and efficiency components remain at 33% and 67% respectively** The need for this project is based upon a Transend issue. As it is not clear what forecast this timing is based upon, we are not suggesting any change to this project.
9.4.8 Wynyard substation	**Justification is weaker, but not changed: demand component remains at 100%** The timing of this project is based upon three feeders supplied from Burnie. Burnie has a slightly higher growth (which is still relatively low) but a slightly lower maximum demand at the commencement of the forecast. The overall effect is to defer the timing by 1 to 3 years. Although, as noted in our main project review (see Appendix B), the loading of these feeders may be related to developments at a level localised to these feeders, not the Burnie substation.
10.4.1 Bridgewater	**Justification stronger: demand component increases from 33% to 70%, efficiency changes to 30%** This project addresses three feeders. Based upon the Aurora forecast none of these feeders appears to be overloaded. The AER forecast still indicates no clear need for one feeder. However, for the other two, the loading has increased

Project	Comment
	significantly, indicating loading will be above the planning rating between 2010 and 2013. This is broadly in line with timing proposed by Aurora.
10.4.1 Chapel St	**Justification weaker: demand component reduces from 33% to 10%, efficiency changes to 90%** This project addressed four feeders. One feeder no longer indicates an overload in the next period. Another suggests its overload may be deferred by 1 to 3 years. For another, the loading has not changed significantly, but its loading is only marginal as to whether it will be overloaded in the next period anyhow. Only one of the four feeders has an increased loading, suggesting the feeder is currently overloaded.
10.4.1 Devonport	**Justification not changed: demand and efficiency components remain at 33% and 67% respectively** This project addresses two feeders; however, we did not consider that the need was directly related to the growth in peak demand. The AER forecast has a higher growth rate for both these feeders and indicates both will be closer to their planning ratings. Nonetheless, neither feeder is forecast to exceed its planning rating in the next period.
10.4.1 Geilston Bay	**Justification reduced significantly: demand component reduces from 90% to 33%, efficiency changes to 67%** This project addresses a single feeder. The AER forecast still results in the feeder being above its planning rating at the commencement of the next period, in line with the Aurora forecast. However, the AER is forecasting a much lower growth rate (0.25% compared 2.73%). As such, the maximum demand will be much lower than assumed by Aurora at the time of the augmentation proposed by Aurora, which is near the end of the period. As such, it seems reasonable to assume that the project could be deferred out of the next period.
10.4.1 Hobart sub-transmission	**Justification reduced: demand component reduces from 33% to 25%** The project feeder overloads are not directly a driver of this project. However, as the project is driven by the loading at Lindisfarne, which is forecast by the AER to grow at a much lower rate than Aurora has forecast, it could be assumed that the justification for the project will reduce.
10.4.1 North Hobart	**Justification reduced significantly: demand component reduces from 100% to 33%, efficiency changes to 67%** This project is related to the loading of three feeders. The Aurora forecast indicated that all three of these feeders were currently above or very near their planning rating. However, the AER forecast has significantly lower maximum demand for all feeders, resulting in no feeders exceeding their planning rating in the next period, and only two approaching the rating near the end of the period. It is also noted that the loading of the North Hobart transformers may also be a factor in the need for this project. The AER forecast for the North Hobart station suggests load level may be deferred by 2 to 3 year from those assumed in the

Project	Comment
	Aurora forecast.
10.4.1 Sandford	**Justification stronger: demand component increases from 0% to 10%** This project is related to three feeders supplied from the Rokeby substation. As discussed above, the AER forecast for Rokeby has a higher growth rate plus there is a noticeable step increase in the maximum demand of each of these feeders. As such, the AER forecast tends to bring forward the Sandford feeder projects, by up to 3 to 4 years[49]. That said, we still consider our view (Appendix B.2.13) on more appropriate short-term solutions should be still relevant. As such, these solutions in combination with the non-network solution should be sufficient to manage the higher growth rate, without the need for the more costly major development in the next period.
10.4.1 Sandy Bay	**Justification reduced significantly: demand component reduces from 100% to 33%, efficiency changes to 67%** This project addresses four feeders. Based upon the Aurora forecast all feeders showed some level of overloading through the next period. The AER forecast indicates that two feeders will no longer be overloaded in next period. The remaining two are still justified, with one more heavily loaded. This is mainly due to a step increase in maximum demand however; the growth rate is actual forecast to reduce. Therefore, it seems reasonable to assume that the justification for the demand component of this project is significantly reduced.
10.4.1 Smithton	**Justification not changed: demand and efficiency components remain at 70% and 30% respectively** The AER forecast indicates that the maximum demand on the two relevant feeders will be lower than forecast by Aurora, plus a lower growth rate will occur. This may suggest that the justification will be weaker, but it is not clear if this loading is relevant to the need for this project. These feeders are not near their planning ratings in either the Aurora or AER forecast.
10.4.1 Ulverstone	**Justification not changed: demand and efficiency components remain at 90% and 10% respectively** The AER forecast does not indicate any significant change to the timing of the two feeders associated with this project.

This table indicates that the timing of the zone substation projects may not change, or may possibly be advanced. However, a larger portion of the HV feeder projects may be deferred.

The findings have been used to calculate revised average components for the three categories of projects, as shown in Table 10 above. Based upon these findings, we have

[49] It is worth noting that it is not clear to us why the most critical feeder has a higher maximum demand in the AER forecast. This may suggest that load may have been temporarily transferred to this feeder, and as such, the advancement of the need suggested here is greater than will occur.

calculated that the AER forecast will lead to an overall reduction of 9% on the demand component of capex for the projects reviewed.

It is not possible to undertake this type of analysis on the generic programs we have reviewed. Therefore, where we considered these programs to be largely driven by peak demand, we have used the average reduction noted above to make an adjustment to capex for those programs.

Table 14 below provides further comments on whether this reduction has been applied, and the rationale for this decision.

Table 14 Reinforcement adjustments to selected programs

Project/program	Comment
10.3 Additional processes (inc. non-network)	No change as timing of non-network projects was not affected
10.4.12 Mobile generation	No change as timing not related to peak demand forecast
10.4.2 Embedded generation	No change as timing not related to peak demand forecast
10.4.3 DINIS API	Assume reduction based upon average percentage from project reviews
10.4.5 Regulators	Assume reduction based upon average percentage from project reviews
10.4.7 Operation	Assume reduction based upon average percentage from project reviews
10.4.8 Development	Assume reduction based upon average percentage from project reviews
10.4.9 Conversion	Assume reduction based upon average percentage from project reviews
10.4.11 System fault level	No change as timing not related to peak demand forecast
11.4.1 Distribution substations	Assume reduction based upon average percentage from project reviews
11.4.2 Low voltage networks	No change as forecasting approach not related to peak demand forecast, given trending approach used by Aurora to determine forecast

Based upon the above, we have recalculated the capex allowance in the demand and efficiency components as shown in Table 15.

Table 15 Reinforcement adjustments to proposed capex – AER load forecast

	Reinforcement capex ($ millions)[a]					
	2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	Total
Proposed	18.4	18.3	17.2	19.0	19.7	92.6

	Reinforcement capex ($ millions)[a]					
	2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	Total
Nuttall Consulting	16.5	16.2	15.8	12.2	17.6	78.4
Demand	9.3	8.8	8.8	7.4	8.4	42.6
Efficiency benefit	7.3	7.4	7.0	4.8	9.2	35.7

a – based on capex in proposed program of works spreadsheet, inclusive of overheads and excluding capitalised SOMPR and capex labour

The demand component represents a further reduction of 8% over the allowance discussed above, and a reduction of 54% over Aurora's capex forecast. Conversely, the efficiency component has increased by 8%.

It is important to note that in performing this analysis we have not undertaken a review of the AER forecast or the underlying rationale for the adjustments. As such, our findings presented here should not be taken as our agreement or otherwise on the appropriateness of the AER maximum demand forecasts.

6 Non demand capex

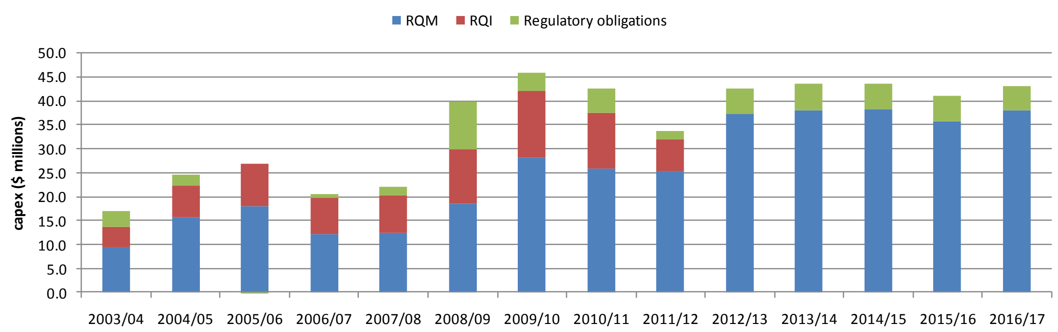
6.1 Introduction

In this report non-demand capex covers the following three RIN capex categories RQM, RQI and regulatory obligations. We consider it sensible to review these three RIN categories together due to the relationship between:

- similar asset replacement activities that may be included in both RQM and the regulatory obligations categories
- network upgrades that may be primarily required to maintain reliability (allocated to RQM) and similar upgrades that will result in reliability improvements (allocated to RQI).

Figure 18 below shows a stacked chart of the capex allocated to the RQM, RQI and regulatory obligations RIN categories.

Figure 18 Non demand capex by RIN category



This chart indicates the following:

- The total capex in these categories increased almost two-fold from the previous to the current period. Aurora has forecast capex in the next period to be around similar levels to that in the current period.
- A significant portion of the capex in the current and previous periods was considered to be required to improve reliability (RQI). However, Aurora is not forecasting any further capex to improve reliability in the next period; although, it is forecasting a significant step up in RQM capex at the commencement of the next period.
- A smaller portion of capex is allocated to the regulatory obligations category. This category also showed a significant increase in capex from the pervious to the current period, but is forecast to be maintained at similar levels to the current period.

We have reviewed the detailed breakdown of the works categories that Aurora has allocated to these three RIN capex categories. This indicates that a large portion of expenditure relates to the replacement (or upgrade) of assets to address condition, safety and environmental issues. We consider that a large portion of capex in these works categories should have some correlation to the age of the assets. Therefore, the repex model should be a suitable tool for assessing these types of activity.

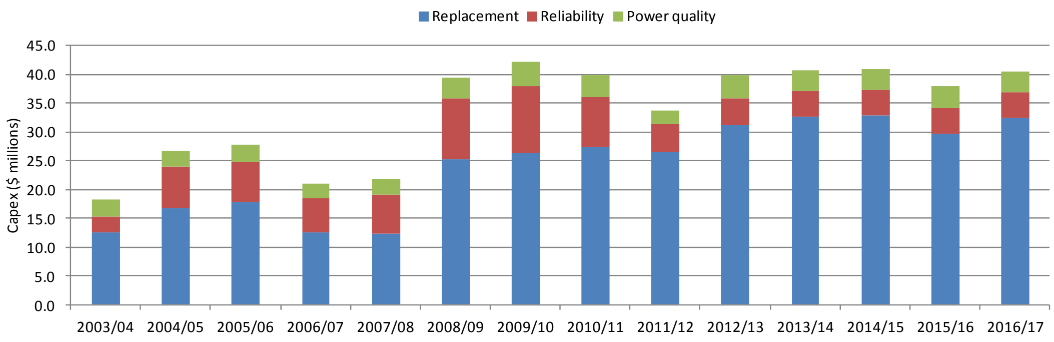
Other works categories however relate to upgrades of existing assets to address power quality obligations (e.g. voltage limits, fluctuations and harmonics) and upgrades primarily driven by considerations concerning the reliability of supply to customers. We consider it unlikely that age will be as strong an indicator of the need here, and as such, the repex model is unlikely to be as useful.

To undertake our review, we have recast Aurora's expenditure into the following three broad categories[50]:

- **Replacement,** which allows for the replacement (or upgrade) of assets to account for non-demand related matters, such as asset condition, safety, or environmental risks and obligations
- **Power Quality**, which allows for the upgrade of assets to comply with power quality obligations
- **Reliability**, which allows for the upgrade of assets to directly address customer reliability concerns (and associated operational issues).

Figure 19 below shows a similar stacked chart to the above, but based upon our allocation to these three categories[51].

Figure 19 Non demand capex by review category



The chart shows that:

- Replacement expenditure is still forecast to have a step increase at the commencement of the next period, but this is not as great as the rise seen in the current period.

[50] This process has involved our mapping of Aurora's work categories these three review categories.

[51] There are minor difference between this chart and the chart above due to the different data set used. This chart is based upon the "capex by work category" spread sheet with our estimate of overheads and capitalised emergency response removed.

- Reliability driven capex on the other hand is forecast to be reducing from the higher levels that have occurred in the current period.
- Power quality capex is the smallest component, and is forecast to be at levels similar to the current period.

Our review of non-demand related capex has included:

- comparative analysis of Aurora's non-demand capex against the equivalent capex of the Victorian DNSPs
- replacement modelling, using the AER's repex model
- analysis of Aurora's capex trends
- the detailed review of Aurora's asset management plans and forecasting methodologies associated with non-demand capex.

This section is structured such that we first set out our comparative analysis. Following this we then provide a more detailed review of the three categories, discussing the repex modelling, capex trend analysis and our detailed reviews.

6.2 Comparative analysis of non-demand capex

To assess the relative level of historical and forecast capex in the non-demand categories against the equivalent capex of the Victorian DNSPs, Nuttall Consulting has undertaken analysis that supplements the benchmarking provided in Section 3.

To provide a suitable metric to compare the level of non-demand capex between DNSPs, the total average annual capex over a 5-year period has been normalised to account for the scale of the DNSPs networks by using the HV feeder length as the normalising parameter. In this regard, the HV feeder length is used as a proxy for the relative volume of assets.

As is also discussed in the benchmarking section, the level of capex for networks of a similar scale can be affected by customer density. As such, we have also assessed this metric against a density parameter, using km of HV feeder per 100 customers as the density parameter[52].

We consider these to be appropriate parameters for this purpose. Other metrics and parameters, including composites, may be also suitable; but, given this analysis is being used as a guide only, we do not consider the additional complexity of analysing a range of metrics is warranted.

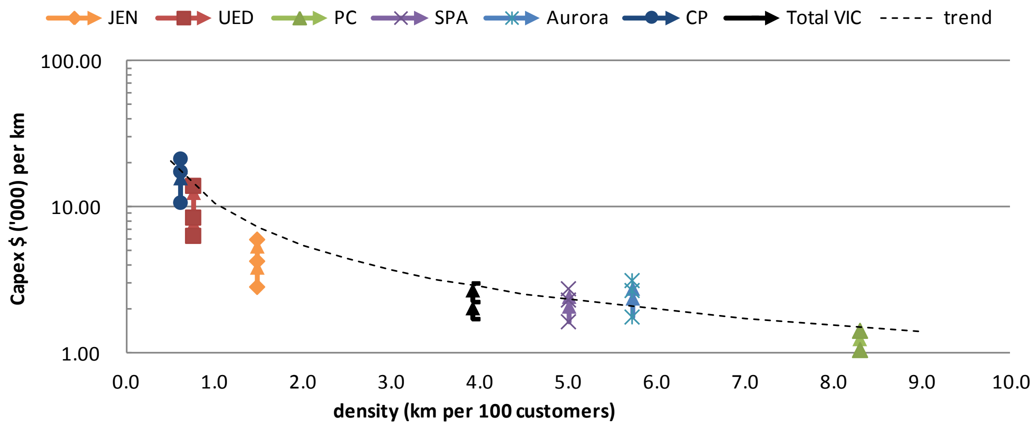
Finally, to generate a measure of the relative position of DNSPs' capex, we have also estimated the average capex per km of all DNSPs as a function of their density. To undertake this analysis we have assumed an $a/x+b$ type relationship (where x is the density) and estimated the coefficients using a least-squares method.

[52] The analysis uses actual customer numbers and length of HV line in 2009/10 as the reference year for calculating density.

Similar to the approach we applied for the equivalent reinforcement capex analysis (Section 5.2), to see the absolute level of the metric and the movement of this metric, we have evaluated three periods: two predominantly covering historical capex and the other forecast capex. To aid in the readability of what follows, we have called the three periods: *previous*, *current* and *next*. The previous and current periods relate to the two 5-year periods up to the commencement of the next regulatory period, most recently reviewed by the AER, for each DNSP. The next period relates to the 5-year period that follows this current period. For the Victorian DNSPs, the previous and current periods cover 2001 to 2005 and 2006 to 2010 respectively, with the next period being 2011 to 2015[53]. For Aurora, the previous and current periods are defined as 2001/02 to 2006/07 and 2007/08 to 2011/12[54], with the next 2012/13 to 2016/17.

Figure 20 and Figure 21 below show the results of this analysis. Figure 20 shows all 6 DNSPs plus the Victorian average. The three points for each DNSP reflect the capex metric in the previous, current, and next regulatory periods. The dashed black line represents the estimated average trend discussed above. Figure 21 shows the same results, but centred on Aurora and its closest peers (by density), SP AusNet and Powercor.

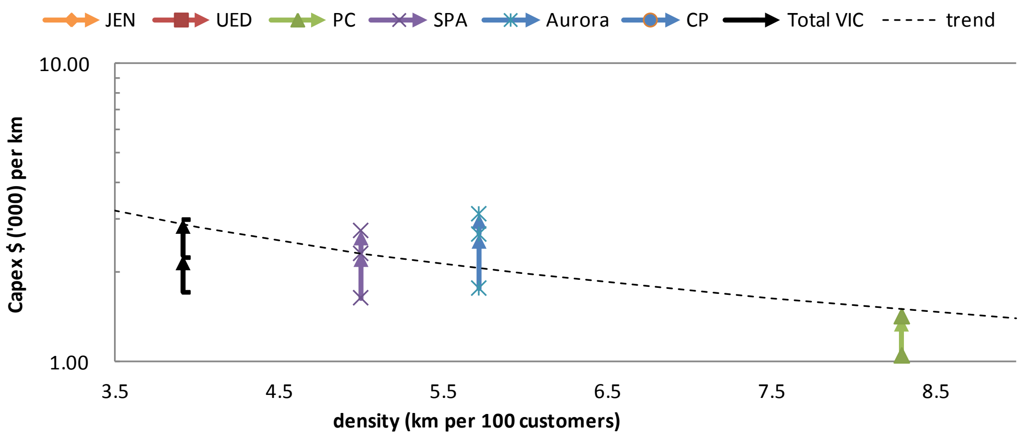
Figure 20 Non demand high level comparative analysis results



[53] For the Victorian DNSPs, capex in the previous and current period is that provided in their most recent proposals with further updates made by the AER, based upon regulatory accounts information for 2010. The allowance made by the AER is used for the next period.

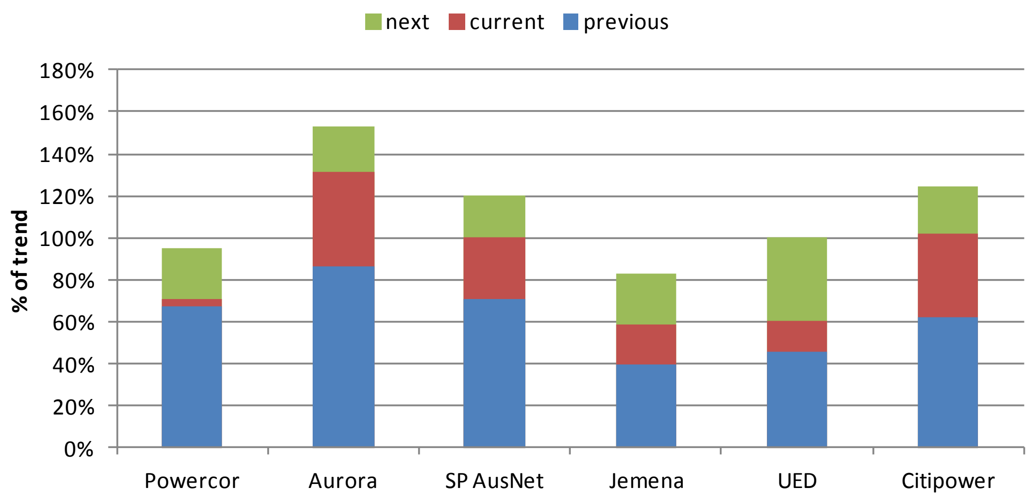
[54] It is recognised that the current regulatory period for Aurora is actually 4.5 years; however, for consistency a 5-year period has been used. Furthermore, due to lack of data for 2001 to 2003, the previous period for Aurora uses only the three-year average from 2004/05 to 2006/07.

Figure 21 Non demand high level comparative analysis results - focus



This analysis suggests that Aurora's non-demand capex is above the level required by the Victorian DNSPs for a similar scale and density. To illustrate the relative scale of this difference, Figure 22 below shows the percentage difference from the trend line for each DNSP and their non-demand capex in the previous, current and next regulatory periods.

Figure 22 Non demand comparative results - summary



Based upon this analysis, Aurora appears to have spent and is forecasting to spend on average 50 - 80% above the Victorian DNSPs in capex per km, when adjusted for scale and density. With regard to its two closest peers, Powercor and SP AusNet, Aurora's capex forecast for the next period, it is approximately 60% greater than Powercor and 30% greater than SP AusNet, adjusting for scale and density.

There are a number of factors that could affect the comparison of Aurora's expenditure with the Victorian DNSPs, many of which should favour Aurora with regard to the level of capex required in these categories.

Firstly, as noted in Section 3, the Victorian DNSPs have a far greater proportion of sub-transmission assets. This imposes greater capex requirements on these networks. With regard to Aurora's closest peers, Powercor and SP AusNet, both of these DNSPs invested small proportions in sub-transmission in their current and previous periods; therefore, this is unlikely to greatly affect the comparisons in these periods. However, the AER allowed greater levels of investment in the next period, and therefore, it may be expected to be more significant in the next period.

Secondly, some of the historical increase may be due to Aurora's historical requirement to improve the reliability of its network, which was historically poorer than the Victorian DNSPs. Furthermore, recently the Victorian DNSPs have seen a degradation in reliability, which could suggest an underinvestment in these periods. This may explain some of the variation in the current and previous periods. However, the Victorian allowances for the next period were considered sufficient to arrest this decline, and as such, if anything, it may be expected that the Victorian DNSP capex would be above the trend. As Aurora is in the reverse position, if anything, it may be expected that it would be at or below the trend. Therefore, comparative levels of reliability and historical capex associated with reliability do not appear to be an explanation for Aurora's relative position to the Victorian DNSPs in the next period.

Thirdly, it is also important to note that many Victorian DNSPs had significant increases in capex allowed for in the next period due to bushfire management. This represented a major step change in the Victorians' risk position. This issue does not appear to be affecting Aurora. Once again, suggesting that, if anything, at least for the next period, it could be expected that Aurora would need a lower level of capex than the Victorian DNSPs.

Finally, the age of the network may be considered a driver of expenditure in this category i.e. older networks may require more capex. However, as will be shown below, our repex modelling indicates that Aurora has one of the youngest networks. Our analysis suggests that Aurora's network is younger than Powercor's and at a similar age to SP AusNet's. Therefore, the age of the network cannot be considered a primary reason for Aurora's higher levels of capex in these categories.

Obviously, the above analysis has not attempted to adjust for environmental conditions and past maintenance and operation of the network. Both of which could affect current levels of capex. Furthermore, the trend line does not necessarily reflect the efficient frontier - just the average trend. Nonetheless, we consider that the analysis supports a view that Aurora may not be managing assets in a prudent and efficient fashion. At the very least, these findings support the need for our detailed review of Aurora's capex in these categories.

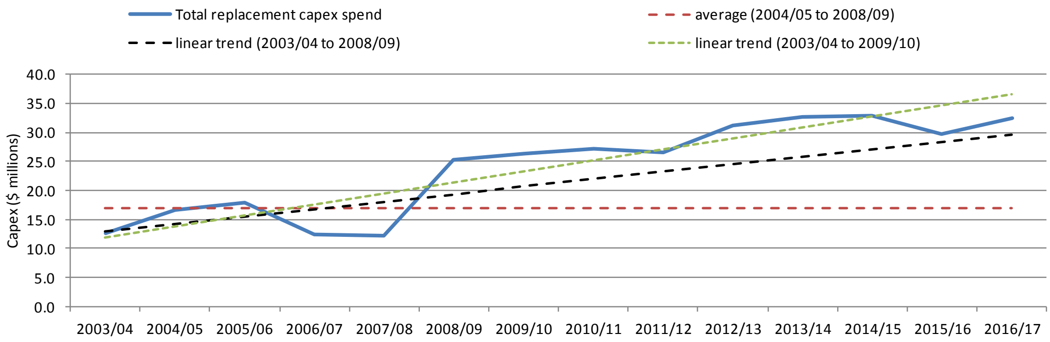
6.3 Replacement expenditure

6.3.1 Overview of capex

This section discusses our review of the replacement capex component. To aid in this analysis and the presentation of our findings, we have allocated the relevant Aurora work categories to the most appropriate RIN asset category.

Figure 23 below shows the profile of Aurora's total replacement capex[55] (the solid blue line). This includes the actual capex prior to 2010/11, and the estimate and forecast from 2010/11. The chart also includes an indication of average and linear trends of actual capex (the dashed lines) for comparative purposes.

Figure 23 Replacement – overall capex trends



The chart indicates that replacement capex was relatively constant between 2003/04 and 2007/08, but then increased significantly over 2008/09. It is forecast to increase again at the beginning of the next period, and then remain relatively constant. These results indicate that replacement capex in the next period is proposed to double from the levels incurred in the previous period.

Moreover, replacement capex in the latter half of the current period and the next period is set to be well in excess of the historical average and the 2003/04 to 2008/09 trend. It is however in line with the 2003/04 to 2009/10 trend, which allows for the large increase that occurred from 2008/09.

This section first sets out the high-level findings of our repex modelling and then provides our review of the individual asset categories.

6.3.2 Repex modelling

6.3.2.1 Introduction

Nuttall Consulting has developed a replacement model for the AER (the "repex model") to support the review of DNSP revenue proposals. The overall philosophy behind the model's functionality, in a regulatory context, is similar to replacement models previously used in Victoria and currently used by Ofgem in the UK. In this regard, the model forecasts replacement needs at an aggregate level using age as a proxy for the many factors that drive individual asset replacements.

The main model inputs are:

- age profiles at an asset level i.e. the quantity of assets installed in each year

[55] All capex discussed in this section is based upon work-category capex provided by the AER. We understand that this capex is real $2009/10 and exclusive of overheads and capitalisation of emergency response.

- asset replacement life (the mean life and standard deviation of that life) for each asset represented in the model
- asset unit replacement cost for each asset represented in the model.

A more detailed discussion of the repex model and our views on various matters associated with its application can be found in our two reports to the AER associated with our capex review of the most recent Victorian DNSP's revenue proposals.

The repex model has been used to assess the replacement component of the non-demand capex. For Aurora, the repex model was developed for the asset categories where appropriate data was available. This represents the majority of the replacement capex. The main asset categories excluded were "services", "distribution other", "zone substation other", and the "other" asset categories. The "distribution switchgear" category has been modelled, but overhead-line switchgear has been excluded from this category. These exclusions were due to either the absence of suitable age profiles or expenditure data.

We have applied a similar process to that used in our analysis of the Victorian DNSPs. This has involved the development of a "calibrated model", where asset lives and unit costs are calibrated to Aurora's historical levels.

In addition, a "benchmark model" has been developed. The benchmark model uses benchmark lives developed from the set of calibrated lives determined from both the Victorian and Aurora repex modelling.

The following summarises the process applied to generate these two models.

Calibrated model

The calibrated model aims to provide a replacement forecast that reflects a DNSP's recent actual replacement levels, allowing for past risks, asset management practices, and replacement costs of the DNSP. This entails estimating the asset lives and units costs that reflect historical replacement volumes and actual expenditure levels.

The model development steps cover the following:

1 **Model population**.

The model has been populated with data provided by Aurora in its RIN response. For Aurora, this data included approximately 100 age profiles, disaggregated across the 12 RIN asset categories. For each age profile, Aurora provided units costs and replacement lives.

2 **Model calibration**.

a. **Determine historical volumes**

Aurora provided estimates of historical volumes of replacement assets. For some assets this was estimated via knowledge of expenditure and an assumed unit cost; for others, Aurora provided known volumes.

These volumes estimates were for the capex allocation in the RQM category. As noted in the introduction, we have recast non-demand data. Therefore, we recalculated the Aurora volume data using the process applied by Aurora and our revised allocation to our replacement category.

b. Determine historical expenditure

Historical expenditure at the asset category level was determined from our mapping of Aurora's individual work categories to the asset categories, based upon an understanding of the asset activities allocated to that work category.

c. Asset replacement life and unit cost calibration

The Aurora replacement lives and unit costs were then adjusted to ensure that the initial year of the model forecast (2009/10) reflected the average replacement volumes and costs of the previous 5 years (2004/05 to 2008/09). This calibration exercise also attempts to allow for the projected growth in expenditure. The box below provides further details of this calibration process.

3 Generate forecast

The "calibrated" lives and unit costs generated in stage 2c above were then used to simulate the replacement needs into the future – the "calibrated model" output.

One important assumption we have applied in the modelling concerns the replacement life. The model uses a normal distribution to determine a replacement forecast. As noted above, this requires a mean life and standard deviation to be provided as inputs. Aurora did not provide standard deviations as part of its RIN response. In the absence of this information, we have assumed that the standard deviation is equal to the square root of the mean life. This assumption has carried through into the benchmark models. This assumption is in line with the assumptions we applied for the Victorian DNSPs modelling, and we understand a similar assumption was used in the UK by Ofgem[56].

[56] Pg 40, Electricity Distribution Price Control Review Methodology and Initial Results Paper, Ref 47a/09, dated 8 May 2009. Available on Ofgem website.

Box 1. Repex model calibration process

For each asset category:

1 **Initial asset life calibration**

a. Calculate the historical average annual number of replacements during 2004/05 to 2008/09 (inclusive).

b. Set the asset life to ensure that the volumes forecast in the initial year (2009/10) equal the historical average calculated in step 1a.

Depending on the available data, this was either performed at the individual age profile level or a more aggregate level.

2 **Asset unit cost calibration**

a. Calculate the historical average annual capex during 2004/05 to 2008/09.

b. Set the unit costs to ensure that the expenditure forecast in the initial year (2009/10) equals the historical average calculated in step 2a.

For all asset categories, this was performed at the aggregate level using a global scaling of all unit costs in that asset category.

3 **Secondary asset life calibration** - to allow for projected growth

a. Adjust the asset lives determined in Step 1b to allow for the growth in replacement predicted by the model, allowing for 3 years of growth[57].

For all asset categories, this was performed at the aggregate level using a global scaling of all asset lives in that asset category.

Benchmark model

The benchmark model aims to provide a replacement forecast that reflects a set of benchmark replacement lives. For this analysis, the benchmark lives are determined at an asset category level.

The benchmark life for each asset category has been calculated from the set of asset lives determined for the Victorian DNSPs and Aurora through the calibration process described above. The benchmark life for each asset category was set as the mean life of all the DNSPs, excluding CitiPower. CitiPower has a fully urban network, with a large level of undergrounding. Its calibrated lives are generally much longer than those of the other DNSPs, and as such, it was considered that the use of these lives may bias the analysis too strongly against Aurora.

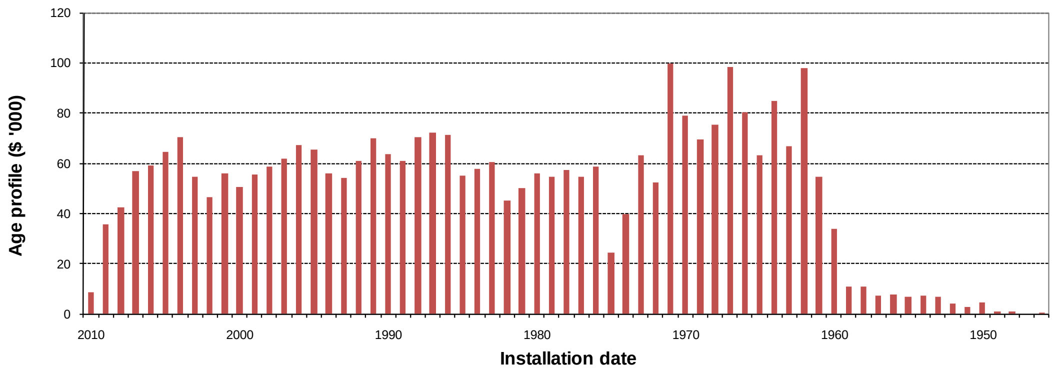
The benchmark lives and the unit costs developed through the calibration exercise were used to simulate the replacement needs into the future – the "benchmark model" output.

[57] 3 years is used to move from the mid-point of the average (2006/07) to the first year of the forecast (2009/10).

6.3.2.2 Results and discussion

Figure 24 shows the age profile of Aurora, based upon the data provided by Aurora.

Figure 24 Aurora age profile



This indicates a very steep rise in the installed assets from pre-1960 to post-1960. Given asset lives may be around 50 to 60 years, this supports the view that Aurora may require increasing levels of capex to address the aging of its network. That said, it is noted that the age profile has a very steep rise from 1960 to 1964. This rise may be anomalous due to the approximations Aurora has made to produce this age profile, and therefore, the rate of increase may be more gradual. As will be discussed further below, the repex model predicts a steep rise in replacement needs. Therefore, it may be that this predicted increase is also overstated by the model.

Table 15 provides a comparison of the average asset age and calibrated life of Aurora compared to the five Victorian DNSPs.

Table 16 Asset age and life comparative results

DNSP	Age	Calibrated Life
Aurora	24.2	57
Powercor	28.0	63
SP AusNet	25.1	53
Jemena	23.6	57
UED	27.7	59
CitiPower	36.5	77

This table indicates that Aurora has a relatively young network compared to the Victorian DNSPs, with only Jemena appearing to have a younger network[58]. It also indicates that

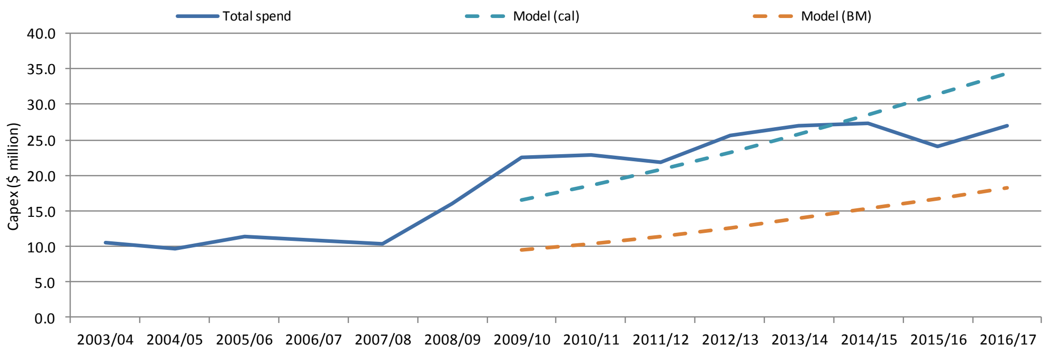
[58] The table also indicates the much longer asset life of Citipower than those of any of the other DNSPs, supporting our view that Citipower should be excluded from the benchmarking.

Aurora's replacement lives, which reflect actual replacement levels, are on average shorter than the Victorian DNSPs, with only SP AusNet having shorter lives.

This tends to support the findings of the non-demand comparative analysis, which indicated that Aurora was spending a higher level of capex on non-demand activities than the Victorian DNSPs.

Figure 25 shows a comparison of Aurora's replacement capex (actual and forecast) against the output of the calibrated and benchmark models.

Figure 25 Repex model output comparison



This shows that the calibrated model forecasts a level of replacement capex that is similar to the Aurora forecast in the early part of the next period and higher in the later half. This suggests that Aurora is allowing for longer lives in the next period than it has achieved recently, which could be considered to support a view that its forecast is allowing for further efficiency gains.

However, in our view, the calibrated model output should be viewed as an upper limit. The steep gradient of age profile for assets installed around 1960 and the narrow variance of the normal distribution for the replacement life (via our assumption that the standard deviation is equivalent to the square root of the mean) tends to result in the model predicting a very high ramp-rate in expenditure, over 10% per annum. We consider that this may well overstate the replacement need. For example, as will be discussed further below, for the poles category, existing condemnation rates determined through actual pole inspections are not showing this level of historical annual increase.

The benchmark model output supports a much lower level of capex from that forecast by Aurora. Assuming the recent level of replacement by the Victorian DNSPs represents prudent investment levels, then this suggests that Aurora's current asset management practices and/or its forecasting methodologies may be overstating the prudent investment needs of the network.

These aggregate level findings vary at the asset-level. Table 17 below shows a comparison of the calibrated lives for Aurora against the benchmark lives[59].

[59] To demonstrate the difference of Cititpower's asset lives to other DNSPs, we have included them here even though we have not used these for benchmarking purposes.

Table 17 Asset life comparison – by asset category

Asset	*CitiPower*	Powercor	SP AusNet	Jemena	United Energy	Aurora	Benchmark
Poles	*78*	66	56	55	65	**56**	**59.9**
Overhead conductors	*86*	79	87	68	85	**61**	**76.0**
Underground cables	*87*	43	42	60	60	**54**	**51.8**
Zone substation switchgear	*65*	60	64	63	63	**63**	**62.5**
Distribution transformers	*56*	47	53	48	54	**49**	**50.2**
Power transformers	*65*	68	83	67	71	**72**	**72.3**
Distribution switchgear	*63*	42	39	42	34	**43**	**40.0**

This indicates that Aurora's calibrated lives for poles, overhead conductors, and distribution transformers are shorter than the benchmarks, suggesting that the prudent level of investment in these categories may be below that of Aurora. However, Aurora's calibrated lives for underground cables and distribution switchgear are longer than the benchmarks, suggesting Aurora may be setting the prudent level of investment or even be under investing in these categories.

For zone substation transformers and switchgear, it was not possible to determine calibrated lives as Aurora did not replace any assets recently for age-related reasons. Therefore, we have assumed the benchmarks represent the calibrated lives for these assets.

It is important to note that this benchmarking exercise has not tried to resolve the many factors that could impact the true benchmark life – this would require a far more detailed data gathering and review exercise. There are certain asset level issues we are aware of that may mean that calibrated lives should differ, which would affect the benchmarks. Most notably in this regard, we consider the following are important matters:

- **Conductors**. Aurora has recently been addressing non-compliance issues associated with line clearance obligations, which may be impacting its calibrated lives. Conversely, the AER, in response to findings of the Victorian safety regulator (Energy Safe Victoria), allowed for large increases in conductor replacement in the next period, which would not have been allowed for in their calibrated lives.
- **Underground cables**. As will be discussed further below, Aurora is yet to address certain risks associated with existing cables, which we understand the Victorian have already addressed to some degree. As such, this will tend to understate Aurora's lives compared to the Victorian DNSPs.

Therefore, the repex model findings need to be considered in the broader context of our non-demand comparative analysis discussed above and our detailed reviews at the asset category level, discussed below.

6.3.3 Asset category review

Table 18 below indicates the proposed capex and variations from historical amounts at the asset category level.

Table 18 Capex levels and variations – by asset category

Asset	Average capex per annum		% of capex	% change to next period
	2003/04 to 2010/11	Next period	next period	
Poles[60]	4.56	8.01	25%	75%
Conductors[61]	5.05	6.54	21%	30%
Underground cables	0.86	2.92	9%	238%
Services	2.03	1.56	5%	-23%
Distribution transformers	1.05	4.06	13%	286%
Distribution switchgear	3.49	5.06	16%	45%
Distribution other assets	0.00	0.17	1%	na
Zone transformers	0.11	1.60	5%	1362%
Zone switchgear	0.05	0.69	2%	1172%
Zone other assets	0.03	0.05	0%	54%
Other	1.60	1.18	4%	-26%
Total replacement capex	18.85	31.82	100%	69%

As may be expected given the rural nature of large portions of Aurora's network, the poles category contains the largest portion of replacement capex at 25%, with conductors, distribution transformers and switchgear representing the other most significant portions. In total these four asset categories represent 74% of the replacement capex in the next period. Aurora is also proposing between a 30% and 286% increase from historical average levels in capex in these categories.

[60] Note, due to the allocations used by Aurora, cost associated with pole top structures are included in the poles category.

[61] The work category, RESGI, was originally omitted from the data provided by the AER. It is included in this table, but not the analysis that follows. This work category related to the conductor category and totalled $0.25 million, the majority of which was incurred in 2003/04. We do not consider that this omission has any material impact on the findings presented in this report.

The next most significant assets are underground cables, services, and zone substation transformers and switchgear. These four categories represent a further 21% of capex in the next period. Capex on services is proposed to reduce by 23% from historical average levels, but capex on underground cables and the zone substation assets is set to increase dramatically, by between 238% and 1362%. That said, capex in these asset categories was very low in the previous and current periods, and as such, this level of increase should be viewed in this context.

The remaining asset categories, “distribution other”, “zone substation other” and “other” have a very low level of capex (approximately 5%).

To assess each of the asset categories in more detail, we have:

- undertaken analysis of the capex profile and trend at the aggregate asset level
- considered the findings of the repex modelling at the aggregate asset level
- undertaken detailed reviews of Aurora’s specific asset management plans and forecasting methodologies that underpin its historical and forecast capex.

The detailed review has covered the material provided by Aurora to support its proposal, most notably:

- relevant asset management plans
- risk assessment documents
- forecast justification and associated spreadsheets (justification documentation).

We have also held sessions with Aurora staff to discuss the programs and clarify matters covered in these documents.

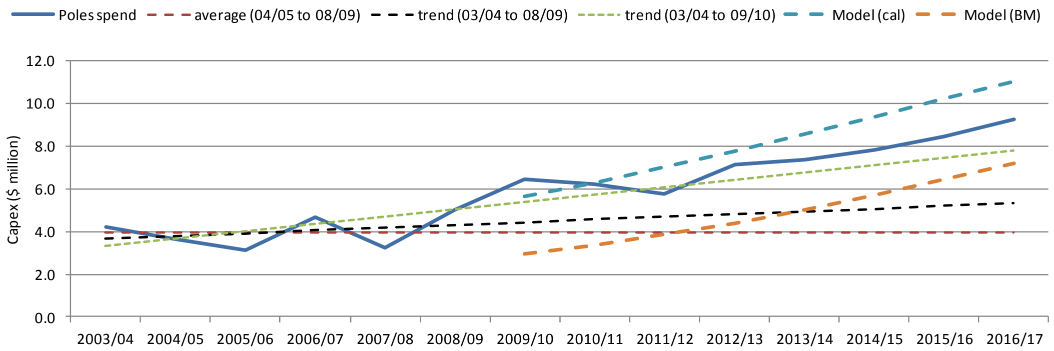
Our review of each asset category is discussed in turn below.

6.3.3.1 Poles

Figure 26 below shows the profile of the total capex allocated to the pole asset category (the solid line). This figure also shows the average historical capex and historical capex trends projected into the next period (the dashed lines).

All work programs covered by the poles asset categories are considered to have a strong correlation to age, and therefore, the total capex in this asset category has been modelled through the repex model. The calibrated and benchmark repex model results are also shown on this figure.

Figure 26 Replacement – poles capex trend



The above figure highlights the following:

- Poles capex was relatively flat between 2003/04 and 2007/08, but then had a significant increase in 2009/10. Aurora has noted in its proposal and meetings that 2009/10 was a particularly bad storm year, and as such, we understand that this was a factor driving the increase in that year.
- Aurora's forecast is just above the linear trend (03/04 to 09/10 actuals). This trend and Aurora's forecast are also below the calibrated repex model findings. However, the forecast is well above the linear trend excluding 2009/10.
- The calibrated model lives are also below the benchmark lives. The benchmark repex model suggests much lower levels of capex may be prudent, which are more in line with historical levels.

Overview of programs

The various programs[62] categorized under the pole category include the replacement of poles that have been condemned as a result of the routine pole inspection cycle, the replacement of poles that have been damaged as a result of severe storms and the staking of poles that have been condemned due to the groundline condition of the pole. The replacement of HV insulators that have been identified as being in poor condition are also included under these programs.

Aurora is proposing to spend a total of $40.0 million on these pole work categories, which represents an increase of approximately 75% over historical levels in the current and previous periods. Aurora has forecast expenditures for pole staking and the volumes of poles to be replaced resulting from severe storm damage to remain constant in the next regulatory period relative to historical expenditures.

The most significant increase in forecast expenditures is in the replacement of poles anticipated to be condemned as a result of routine pole inspection cycles, with expenditure over the next regulatory period forecast to increase by nearly 70% relative to the current period.

[62] The Poles programs include REPOL, RESTK and REHIN work categories

Aurora has advised that generally forecast replacement volumes are based on historical trends. However, in the case of the replacement of poles condemned during the routine inspection cycles, forecast quantities are based on the current trend of condemning poles and the age profile of current poles, which it considers indicates that a significant number of poles will exceed the age of 40 years during the next period.

Nuttall Consulting Review

We have reviewed Aurora's programs associated with the poles category, including the methodology Aurora applied to prepare its forecast.

While carrying out our detailed review we noted several inconsistencies in the data and information provided by Aurora. Firstly, the documentation provided to justify the methodology indicated that over the next regulatory period Aurora has assumed that pole staking volumes will increase from 1550 per annum to 1750 per annum; however, the forecast annual expenditures remain relatively constant over the period. Secondly, in relation to historical pole replacement numbers, there appears to be a significant inconsistency between the numbers quoted in the justification document and the numbers detailed in the volumes spreadsheet.

To assess the implications of these inconsistencies, we have taken the total forecast volumes for both pole replacements and staking, excluding the poles replaced as a result of storm damage, and calculated both condemnation rates and implied asset lives. We have used these total numbers as they represent the total number of poles condemned at groundline resulting from the routine pole inspection cycles. The decision to either replace or stake a pole is based on the condition of the pole and associated hardware above ground, and generally, if the condition indicates a life of 15 years or more is achievable, the pole is staked rather than replaced. But in either scenario the pole is defective at or below the groundline.

These calculations indicate that the total annual condemnation rates are forecast to increase from approximately 4.0% to 5.3% over the determination period, implying average asset lives of between approximately 25 and 19 years respectively. Aurora currently schedules routine groundline inspections on 3.5 yearly cycles and whilst we would expect condemnation rates of this order of magnitude during the initial cycles, over time we would expect to see the condemnation rate return to levels of 2% to 3%, which implies service lives of 30 to 50 years. This seems particularly reasonable in the case of Aurora, as the overwhelming majority of poles are either steel, concrete, or treated wood.

In relation to the proposed program to replace HV insulators found to be in poor condition, Aurora indicated that approximately 100 outages are caused by insulator failures every year that may or may not result in a pole top fire. Aurora also indicated that approximately 50 poles top fires occur every year of which 80 percent have unknown causes. Nuttall Consulting is aware that this is a significant issue particularly when steel cross arms are used, and notes that replacing a defective insulator in a timely manner can often avoid the costs and interruptions associated with replacing poles damaged by pole top fires. Whilst the program has not been consistently deployed in the past, we concur with Aurora's view that this program should be allowed for in the capex works program for the next regulatory period (i.e. it is reasonable to consider that it is required to meet the NER capex obligation to maintain the safety of the distribution system).

Nuttall Consulting Recommendations

Based on our detailed review, we believe that Aurora has taken an overly conservative approach to forecasting pole condemnation volumes for the next period. In addition, we believe that current condemnation rates are above the long-term averages currently being achieved with similar pole populations and inspection procedures on the mainland.

This finding appears to be in line with our repex modelling, which indicates that Aurora's lives are on average shorter than those achieved by the Victorian DNSPs. On this matter, we note that Aurora's asset management plan suggests that wood pole lives should be shorter than those achieved on the mainland due to the type of wood used[63]. However, given the treatment processes applied by Aurora, we do not consider that this should explain the significant difference in lives, or the sharp increase in condemnation rates it has forecast.

Therefore, we consider that total historical volumes should be used to forecast expenditures over the next regulatory period for the pole replacements and pole staking programs. We note that whilst volumes are forecast to increase annually for pole staking over the determination period costs have been forecast to remain stable.

In relation to HV insulator replacement, we accept that the works are prudent, and hence, an allowance should be included in the capital forecasts for these works.

Based on this assessment, we estimate the total capex Aurora has proposed for these programs should be reduced by $14.7 million. This estimate has been calculated by assuming historical expenditures for pole replacements are maintained over the next regulatory period in line with the linear trend (excluding 2009/10). This position places the Aurora forecast far closer to the benchmark repex model, which we consider is reasonable given our findings of the detailed review.

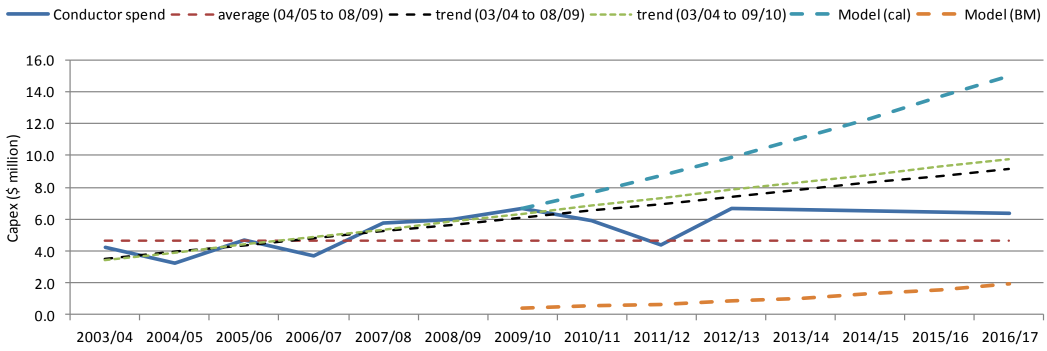
6.3.3.2 Conductor

Figure 27 below provides a similar chart to that discussed above for poles, showing the profile of the total capex allocated to the conductor asset category (the solid line) and historical capex trends projected into the next period (the dashed lines).

All work programs covered by the conductor asset categories are considered to have a strong correlation to age, and therefore, the total capex in this asset category has been modelled through the repex model. The calibrated and benchmark repex model results are also shown on this figure.

[63] Pg 17, Management Plan 2011, Overhead System and Structure (AE030)

Figure 27 Replacement – conductor capex trend



This analysis indicates the following:

- Capex on conductors has been rising gradually over the previous and current periods. Aurora is proposing capex to continue at existing levels, with a minor reduction over the next period.
- The forecast capex is below the linear trend, but is above the historical average.
- This level of forecast capex is also well below the calibrated model, suggesting Aurora is anticipating lives will be extended in the next period. The calibrated lives are shorter than similar historical Victorian DNSP lives, and as such, the benchmark model indicates a much lower level of capex. However, care must be applied in appreciating these benchmark results, as the rural Victorian DNSPs were allowed a significant increase in conductor replacement levels to reduce bushfire risks. We have not modelled this impact, but it could be expected to raise the benchmark results significantly, placing these more in line with Aurora's forecast.

Overview of programs

We consider that the conductor category will include a suite of 11 work categories[64]. Aurora has forecast total expenditures on these work categories of $32.7 million over the next regulatory period, which is approximately a 18% increase over the current period.

Six of these work categories constitute the majority of the forecast expenditures over the next 5 year regulatory period. These six work categories are (by work category title):

- Replace HV Copper Conductor
- Replace/Relocate LV OH (low clearance)
- Fire Mitigation Projects (conductors)
- Replace LV OH (substandard)
- Replace HV 3/12 GI Conductor
- Replace HV feeders (aged/safety)

[64] Conductors include the following work categories, REHCR, REHSA, REHVE, RELCL, RELCR, RELCU, RELSF, RELSQ, REMCU, REMGI and SIFIC

The following provides further details on each of these programs.

Replace HV Copper Conductor

The aim of this new program is to replace substandard and poor condition copper conductor in the network. Aurora currently has approximately 2400 km of copper conductor installed in the network of which the majority was installed prior to 1964. The smallest conductors, 7/.044, 7/.048 and 7/.064, are considered substandard as they do not comply with the relevant Australian standard, AS7000. Aurora has identified that it has approximately 435 km of these substandard conductors, which have a substantially higher risk of breaking than other conductors.

Over time copper conductors anneal due to the heat generated by fault currents. This affects their tensile strength. This condition can be readily identified by the colour of the conductor and its scaly appearance. Annealed conductors are subject to more failures, which can easily be identified by the number of crimp links or joints in each span.

Aurora has advised that it carried out an audit of 20% of the copper conductors in service during 2010, and concluded from this audit that the replacement of 35 km of copper conductor per annum over the next regulatory period would address the substandard copper conductor issues.

Replace/Relocate LV OH (low clearance)

The aim of this ongoing program is to relocate or replace LV overhead conductor to address low clearance risks associated with road crossings and contact with people and vegetation. There are minimum clearance standards for conductors from ground, structures and roadways, which are governed by Australian standards, AS3000 and AS7000 (formerly C(b)1).

Aurora identified approximately 1,100 low voltage and service conductor clearance defects every year. The justification documentation provided by Aurora states that the forecast expenditures are based on annual historical volumes; however, the total expenditure over the next regulatory period is approximately 18% lower than the previous period.

Fire Mitigation Projects (conductors)

The aim of these projects is to reduce the risk of distribution assets starting fires. These fire mitigation projects only relate to HV and LV overhead conductor fire mitigation works in very high and high fire danger areas.

Typically fires are started by either clashing conductors dropping molten metal on the ground with the potential to start a fire or conductors breaking and falling to the ground where arcing can potentially start a fire. On average, Aurora records 50 outages per annum relating to clashing conductors and over 100 outages per annum relating to broken conductors. The main causes of clashing conductors are slack spans, overly long spans and uneven sags. In some instances the actual construction of the distribution line contributes to this problem, such as short cross arms and vertical construction.

The main cause of broken conductors are the substandard conductors still in service, such as 7/.044, 7/.064 copper conductors and No. 8 gauge steel. Other potential causes are live line clamps directly clamped onto the conductor, broken insulators, crossarm failures, and third party impacts due to low clearances. This program also covers the relocation of overhead lines due to vegetation fire risk.

Aurora currently has identified 1,154 long HV spans and 18,141 long LV spans within fire danger areas. The proposed program covers the replacement of up to 85 HV spans per year. A specific allowance for the long LV spans is not included as LV issues can normally be addressed through simpler and less costly methods, such as the installation of fibreglass spacers.

The total forecast expenditures for the proposed works over the next regulatory period is $4.5 million, around a 300% increase over the previous 5-year period.

Replace LV Feeders (substandard-safety)

The aim of this ongoing program is to replace poor condition or substandard construction LV feeders, as identified by inspections and audits. Minimum requirements for the LV feeders are defined by national guidelines. The works generally involve the supply and installation of poles and minor LV augmentations.

Aurora has forecast total expenditures for the next regulatory period of $4.1 million. As these works were historically carried out under a different work category, historical costs are not readily available. Nonetheless, Aurora has advised that approximately 1,100 substandard LV conductors and services are identified each year, and the volumes which underpin the forecast estimates for these works are based on historical levels.

Replace HV galvanised iron conductor

The aim of this ongoing program is to replace substandard and poor condition galvanised iron (GI) conductor. Galvanised iron (GI) conductor came into service in the 1940s and Aurora stopped installation of single strand No. 8 GI in the 1970s. The use of imperial 3/12 GI was replaced with the metric 3/2.75 GI around 1976, which is the present day Aurora standard for rural conductors.

The main issue with the GI conductor is that when subjected to wind borne salt spray and sea fogs, salt crystals are deposited on the steel conductors. A galvanic cell is formed which removes the zinc coating over time. Once the zinc coating has been removed, severe corrosion of the steel results leading to loss of mechanical strength and eventual conductor failure.

There is approximately 5,900 km of GI conductors in the network, of which approximately 784 km (or 13%) of GI conductor are located within 2 km of the coastline. Aurora has advised in its justification documentation that, based upon its analysis of failures, the profile of conductor quantities, ages and locations, it has estimated that 20 km per year will require replacement over the next regulatory period. This represents approximately 12.8% of the GI conductor population located within 2 km of the sea.

Aurora has forecast total expenditures over the next regulatory period to be $2.9 million, which is approximately 7% more than the previous 5-year period. However, the forecast annual expenditures align with the more recent historical levels of actual and budgeted expenditures.

Replace HV Feeders (safety)

The aim of this program is to replace sections of HV feeders where the location or condition poses a safety risk. The rectification work includes relocating, undergrounding or augmenting HV conductors.

Aurora advised in its justification documentation that it expects to identify approximately 100 defective HV spans per annum, but that it will prioritise the defects in order to reduce the amount of work undertaken each year in the next period, in order to contain expenditures.

Aurora has forecast total expenditure over the next regulatory period of $2.1 million, which represents a significant reduction over the previous 5-year period.

Other smaller programs

The remaining five work categories are:

- the relocation or replacement of HV overhead conductor to address low clearance associated with road crossings and potential vegetation contact that cannot be addressed as an asset repair(REHCR)
- the relocation of assets away from heavily vegetated areas to alleviate excessive cutting or total tree removal (REHVE)
- the relocation or replacement of LV overhead conductor with LV ABC to address low clearance associated with buildings (RELCL)
- the relocation or replacement of LV overhead conductor with underground cable to address low clearance associated with buildings (RELCU)
- the replacement of sections of LV feeders that complied with standards of the day but currently present a risk to public safety (RELSF).

In total the forecast expenditures for all five programs is $3.5 million for the next regulatory period representing approximately a 10% reduction over the previous 5-year period.

Nuttall Consulting Review

Nuttall Consulting carried out a detailed “bottom up” review of all 11 programs included in the Conductor category. Based on these reviews, we have concluded that all the programs appear reasonable, in principle. In this regard, much of the work is required to comply with current standards, and a significant driver for undertaking the project are the safety risks. We also note that many of these types of program are also being addressed by other NEM DNSPs. Most notably for the six main programs:

- HV copper conductor replacement is driven by safety and reliability risks associated with broken conductors
- LV OH low clearance is driven by risks associated with public safety
- Fire mitigation is driven by public safety risks associated with bush fires
- LV feeders substandard replacement is considered by us to be standard industry practice, due to the public safety implications
- GI conductor replacement is showing extremely high GI conductor failure history for conductors located in close proximity to the sea.

With regard to the appropriate volume for these programs, given the magnitude of the risks we have noted during our review, we consider the proposed volumes that underpin the forecasts to be reasonable.

It may be considered that this view is counter to our repex model findings where we have noted that the Aurora forecast is much higher than a benchmark forecast. However, we consider that the benchmark figure may understate requirements due to the conductor age profile, which show a very sharp increase in the quantities installed after 1960. This may be overstating the rise in the calibrated model, but it may also be overstating the reduction through the benchmark model.

Furthermore, we have noted through the unit cost review that the conductor replacement unit costs assumed by Aurora to prepare the forecast may be high (see Section 4.2). This may suggest an adjustment to the conductor forecast is appropriate even if we consider the volumes to be reasonable. However, given the scale of the various issues we have noted during our detailed review, we consider that the forecast overall capex in the next period, which is still below the historical trends, is not clearly unreasonable noting the continued aging of the network. This view would still be relevant even if unit costs were lower. Therefore, in light of this view, we do not believe that our findings on the unit costs clearly supports a reduction on Aurora's forecast.

On balance, we consider that Aurora's capex in the conductor category can be considered a reasonable estimate of the prudent and efficient level to maintain performance and address the safety issues.

6.3.3.3 Distribution transformers

Figure 28 and Figure 29 below shows the capex profile and trends for distribution transformers. The majority of work programs covered by the distribution transformer asset categories are considered to have a strong correlation to age, and therefore, the majority of capex in this asset category has been modelled through the repex model. The calibrated and benchmark repex model results are also shown on Figure 29, which excludes the proportion of capex not modelled.

Figure 28 Replacement – distribution transformer capex trend

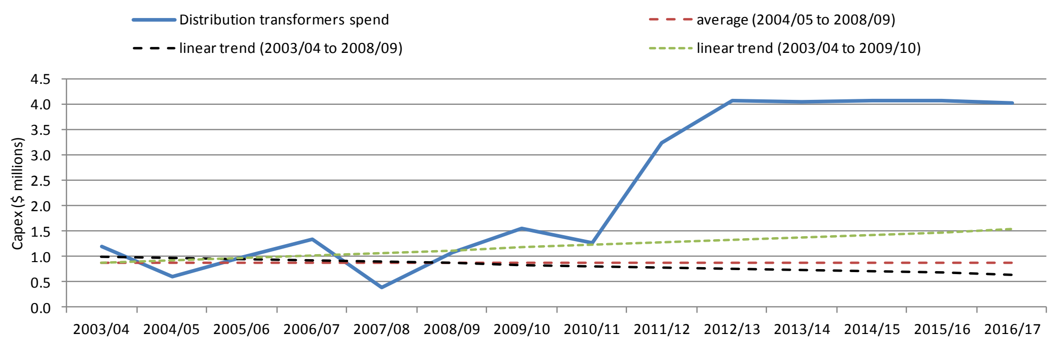
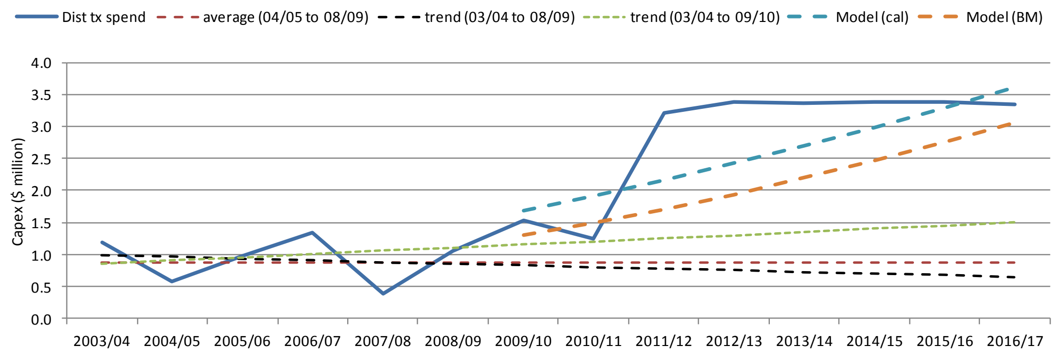


Figure 29 Replacement – distribution transformer capex trend – repex modelled



This analysis highlights the following:

- Capex is relatively variable, but was at a lower level prior to 2009/10. Capex increased in 2009/10 and is forecast to have a further large step increase in 2011/12 before flattening off. We understand the step increase in 2009/10 was partly due to a new outsource contract that enabled a backlog of works on ground mounted substations to be addressed, and storm activity that year, which impacted pole mounted transformers.
- The forecast is well above the linear trend, even allowing for the increase in 2009/10.
- The forecast is also above the calibrated model, suggesting Aurora is anticipating shorter lives in the next period. Furthermore, the calibrated lives are on average shorter than similar VIC DNSP lives. As such, the benchmark model suggests a lower level of capex may be prudent.

With regard to the programs that could not be analysed through the repex model, these account for a very small proportion of capex (approximately $0.2 million per annum in the next period), but all are showing a step increase from existing levels. These programs cover earthing upgrades on ground mounted substations and other safety and environmental minor upgrades.

Overview of programs and detailed review findings

The distribution transformers category includes a suite of nine programs[65]. These programs are:

- Replace Regulator (Three Phase)
- Replace Ground Mounted Transformers
- Replace Transformer H-Pole Structure
- Replace Transformers
- Replace Transformers (leaking)
- Replace Regulator (single phase)
- Upgrade Ground Mounted Substation Earthing
- Addressing Safety Issues associated with Regulators
- Address Safety and Environmental Issues in Ground Mounted Substations.

Aurora has forecast total expenditures for the next regulatory period of $20.3 million, which is approximately 170% more than the total actual and budgeted expenditure of the preceding 5 years.

Replace Regulators (Three Phase)

The aim of this new program is to replace three-phase regulators that are in poor condition and are at risk of failure. Currently, Aurora has eight three-phase regulators, which were installed prior to 1966, and five of an unknown age that are assumed to be of this vintage.

In order to determine forecast expenditures, Aurora has assumed that one of these three-phase regulators will require replacement each year of the next regulatory period.

There will be a minor reduction in maintenance costs as the three-phase units (which are on a four-year maintenance cycle) will be replaced by single phase units (which are on a 10-year maintenance cycle) and the single-phase units will not require the monthly checks to ensure correct operation.

Aurora has no asset failure data to support the assumption that oil tests will indicate that one three-phase regulator will require replacement per annum. Hence, we believe that this assumed failure rate appears excessive and consider it more reasonable to assume that the failure rate will continue to be around the recent historical rate, two per 5-year period. As Aurora has forecast total expenditures of $1.7 million for the next regulatory period to allow for the replacement of 5 regulators, we recommend that this forecast be reduced to $0.7 million to allow for the replacement of 2 regulators over the 5 year period rather than 5. This recommendation represents a reduction of $1.0 million over the 5 year regulatory period.

Replace Ground Mounted Transformers

[65] Distribution Transformers includes the following work categories REGMR, REGTF, RETXH, RETXL, REURG, REGEA, RETXE, SIREG and SIGMS

The aim of this ongoing program is to replace ground mounted transformers that pose a safety risk to field staff and/or the public, or pose an environmental risk. The main issues are the exposed bushings on transformers installed in the 1960s and 1970s and rusting transformer tanks which are located within 20 m of coastal areas or on highly corrosive industrial sites. The exposed bushings pose safety threats if clearances are not adequate in enclosed substations (25 sites) or are located in fence enclosures (4 sites).

Aurora has 65 transformers located within 20 m of the sea and 19 of these transformers are exhibiting severe corrosion.

19 of these sites with transformers that have exposed bushings, corrosion and PCB contamination are planned for rectification by 2016/2017.

Based on our detailed review of the justification documentation provided in support of this program, we believe the proposed works are prudent and the volumes (19 sites) underpinning the forecast estimates are reasonable.

Replace Transformer H-Pole Structure

The program involves the replacement of H-structure substations due to their condition or location, such as overhanging roadways and being vulnerable to being hit by high loads. A separate program is required for these works due to their high removal and redesign costs when compared to a transformer mounted on a single pole. The replacement solution is either a single pole substation or a ground mounted substation if the load is large. There are currently 242 H-structures in the system, with 184 of them in urban areas.

Aurora intends to replace 2 sites per annum compared to historical volumes of 1 or 2 sites per annum. An initial audit has already identified 10 sites as a safely risk due to their position.

Based on our detailed review, we consider that the program is prudent and the volumes underpinning the forecast estimates are reasonable.

Replace Transformers

There are two components to this program, the replacement of transformers damaged during extreme events, such as storms or bushfires, and the replacement of transformer neutrals.

In order to determine forecast expenditures, Aurora has relied on historical data to determine the annual volumes of transformers predicted to be replaced as a result of extreme weather events. Historical transformer replacement levels resulting from extreme events are 100 per annum.

The aim of the transformer neutral replacement program is to improve public safety by ensuring that the neutral connection on transformers is secure. The work involves the inspection and maintenance of all LV connections on all transformers that have been in service for over 40 years. It will include the inspection and testing of transformer earths to ensure integrity and adequacy.

While Aurora has not provided estimated volumes of transformer LV and earths requiring inspection, testing and maintenance, historically 60% to 70% of the total expenditure on this work category has been spent on the replacement of transformers damaged by extreme weather events, and this ratio has been used to forecast ongoing expenditures.

Our detailed review has indicated that the program is prudent due to the public safety implications associated with defective or missing substation earths, and that the proposed volumes appear reasonable.

Replace Transformers (leaking)

The aim of this ongoing program is to reduce the risk to the environment posed by leaking transformers. Transformers manufactured before 1986 were constructed of mild sheet steel with copper windings. The clearances internally were very generous, which meant that any water ingress through gaskets could settle at the bottom of the tank without affecting the electrical performance. The resulting corrosion results in oil being allowed to escape the tank. Because the corrosion occurs at the bottom of the tank, the total contents of the tank may drain away. The majority of transformers purchased since 1986 are galvanised both inside and out alleviating this problem.

Routine replacement of leaking transformers has been forecast to occur at a rate of 50 per year, which aligns with historical data.

Our detailed review has indicated that the proposed works are prudent and the proposed volumes are reasonable.

Replace Regulators (single phase)

The aim of this program is to refurbish single-phase regulators at the time of their routine mechanical maintenance to ensure the units achieve their full asset life. Aurora undertook an audit of HV regulator sites in 2009. The following problems were identified with the single-phase regulators:

1. 10% of the single-phase regulator population had developed serious rust on both the regulator tanks and the cooling fins
2. a number of sites showed signs of corrosion and water ingress in the tap position indicators.

In addition, a failure had occurred in February 2006 as a result of faulty tap-changer motor drive capacitors, which are located in the regulator tank.

The works associated with this program involve the refurbishment of the single-phase regulators when they are removed from service on their 10-year maintenance cycle. They include the repair and treatment of the tank with a protective coating, the relocation of the tap changer motor drive capacitor to the control cubicle and the replacement of the tap position indicators.

Our detailed review has indicated that the proposed works are prudent as they will substantially extend the service lives of single phase regulators at minimal cost. In addition the alignment of the refurbishment with the maintenance cycles appears reasonable.

Upgrade Ground Mounted Substation Earthing

This new work category relates to the any rectification work required to bring a ground mounted substation site up to standard when it is found to be substandard as a result of the earthing audit program. Aurora has advised in its justification documentation that the majority of ground mounted substation earthing systems have not been tested since they were installed and that it proposes to commence a program of inspection and remedial works at sites identified as posing a high risk to the public. These sites include substations located in close proximity to swimming pools, schools and shopping centres.

Any rectification of defective earths identified in the current and preceding periods were repaired under the REGMS work category (discussed in the distribution switchgear category), so there is no historical expenditure data available for this new work classification. Aurora has based the forecast expenditures on an assumption that 20% of the sites inspected will require some rectification work but without any specific historical data it is not possible to verify the validity or reasonableness of this assumption.

However, if all the new work categories that were once carried out in REGMS are summated the total annual forecast expenditures appear to be slightly lower than the actual and budgeted expenditures of the previous three years, which include the switchgear replacement program.

In our experience, the majority of DNSPs have a program in place to regularly monitor the efficacy of all distribution substation earthing systems, usually on a 5-year cycle. Hence, we believe the program proposed by Aurora is prudent. From the information provided it is not possible to form a view as to the reasonableness of the quantum of rectification works underpinning the forecast expenditures, but a review of all the new work categories that once comprised REGMS appears reasonable.

Address Safety and Environmental Issues in Regulators

The aim of this program is to address safety and environmental risks associated with regulator sites, such as the rectification of fences that do not comply with AS2067, Clause 5.2.8, and the installation of second gates so as to ensure two egress paths, as per AS2067, Clause 5.1.5. In addition, AS2067, Clause 6.7.11 (Amended 2009), requires that every high-voltage installation containing equipment with more than 500 litres of a liquid dielectric such as transformer oil, shall have provision for containing the total volume of any possible leakage and meet the overall objectives of AS1940, Appendix H. Aurora notes that currently only approximately 30% of ground mounted regulator sites have adequate oil containment.

Aurora currently has a ten year prioritised program in place to address the substandard fencing and egress issues at ground mounted regulator sites to minimise the risk to the public and increase operator safety. The justification documentation for this program also states that a proritised program is in place to provide adequate oil containment facilities at all ground mounted regulator sites. 18 sites have been identified as requiring rectification works which are within 100 m of waterways and Aurora proposes to upgrade 1 site per annum.

This proposed program is basically a compliance issue as Aurora would be expected to comply with all current legislation, regulations, standards and accepted industry practice.

Hence we consider the program to be prudent and the proposed volumes that underpin the forecast expenditures appear achievable.

Address Safety and Environmental Issues in Ground Mounted Substations

This program has four components related to safety and environmental issues in ground mounted substations, which are aimed at addressing the following issues:

1 asbestos

2 oil containment

3 confined space issues

4 fire standards non-compliance.

Aurora currently has 633 substation sites that contain asbestos, varying from buildings to padmount substations. Within these sites, doors, enclosure material and LV switchgear may have Asbestos Containing Material (ACM). Aurora's periodic ACM inspection has identified a rate of one ACM site per year approaches a friable condition and requires removal. Aurora has used this historical volume to determine forecast expenditures.

Distribution transformers contain a mineral insulating oil for both electrical insulation of the internal components and cooling. The relevant Australian standard, AS 2067, Clause 6.7.11, requires that every high voltage installation containing equipment with more than 500 litres of transformer oil shall have provision for containing the total volume of any possible leakage. At the beginning of the next regulatory period, Aurora will have 21 sites where oil containment is required. It is proposed to address four sites per year over the next regulatory period.

Aurora conducted an audit of confined spaces in 2009, and a total of 602 sites were identified as containing a confined space. Aurora has 12 sites where the whole site is classed as a confined space. A prioritised six-year program of 2 sites per year beginning in 2012/2013 and finishing in 2017/2018 is planned to either relocate or remote control all of the confined space substation sites.

Currently, 21 ground-mounted substations contain a CO^2 injection piping system to assist in extinguishing fire at these sites. This system relies upon TasFire supplying and maintaining a transportable CO^2 unit. TasFire has indicated it will no longer supply the transportable CO^2 containers. In liaising with TasFire, Aurora has a program in place to convert all existing CO^2 systems in vault-type and building-integrated substations to a new "Stat-X" fire suppression system. Aurora plans to convert four sites per year from 2011/2012 to 2016/2017.

All these works are proposed to ensure compliance either with an Australian Standard, the Building Code of Australia or Workplace Health and Safety and Regulations 1998. Hence we accept that the proposed works are prudent. Our detailed review of the justification documentation indicates that the proposed annual volumes and timing of the proposed works are reasonable.

Nuttall Consulting Review

Nuttall Consulting carried out a detailed review of all nine programs included in the distribution transformer category. Based on these reviews, we have concluded that all the programs appear reasonable, in principle. Most notably, the programs will address a number of safety and environmental risks and some related compliance issues.

Based upon our assessment of the forecasting methodologies, we also consider that the volumes seem reasonable in most cases. The one exception relates to the 3-phase regulator replacement programs. In this case, we believe that the assumed future failure rate, which is used to determine the forecast volume, appears excessive. In our view, this is most likely to be similar to the historical rate.

Aurora's total forecast expenditure for all nine programs over the next regulatory period is \$20.3 million. Based upon the adjustment to the failure rate for 3-phase regulator replacements, we consider a reduction of \$1.0 million over the 5 year regulatory period is appropriate. Hence, our recommended total forecast for the next regulatory period for the distribution transformers category is \$19.3 million.

We note that this recommendation is still above the calibrated repex model, and well above the benchmark model. However, based upon our detailed review of the programs, we consider that there are a number of significant safety and environmental issues that need to be addressed. As also noted through our unit costs review, our analysis did not suggest that Aurora's unit costs associated with distribution transformers are inefficient. As such, we have found no evidence to say that the increases we have allowed for cannot be considered prudent and efficient. It is worth noting however with regard to the capex objectives, we consider that this allowance is well in excess of historical levels to allow safety obligations to be complied with in the next period (i.e. NER capex obligation 6.5.7(a)(2)). As it appears from the Aurora documentation that this will result in a level of compliance in excess of that currently achieved, it seems reasonable to say that this allowance will materially *improve* the safety of the distribution system at least for this asset class – rather than *maintain* (i.e. NER capex obligations 6.5.7(a)(4)).

Furthermore, given that this allowance is above the historical trend, and most issues are focused on older and poorer condition assets, we do believe that there may be some offset to opex and reliability due to the increased volumes allowed for in these programs. However, it is likely to be only a small proportion of the capex above the historical trend, as the main reason for the step increase in program volumes is to reduce existing safety risks.

6.3.3.4 Distribution switchgear

Figure 30 below shows the capex profile and trends for distribution switchgear. Approximately half of the work programs covered by the distribution switchgear asset categories are considered to be suitable for modelling through the repex model. The calibrated and benchmark repex model results are also shown on Figure 31, which excludes the proportion of capex not modelled. Figure 32 shows the capex profile and trend charts for this remaining capex. The distinction between the portion we can model and the portion we cannot, largely relates to the fact that we have age profiles for ground mounted switchgear, but do not for line switchgear. As such, we cannot model the line switchgear replacement through the repex model.

Figure 30 Replacement – distribution switchgear capex trend

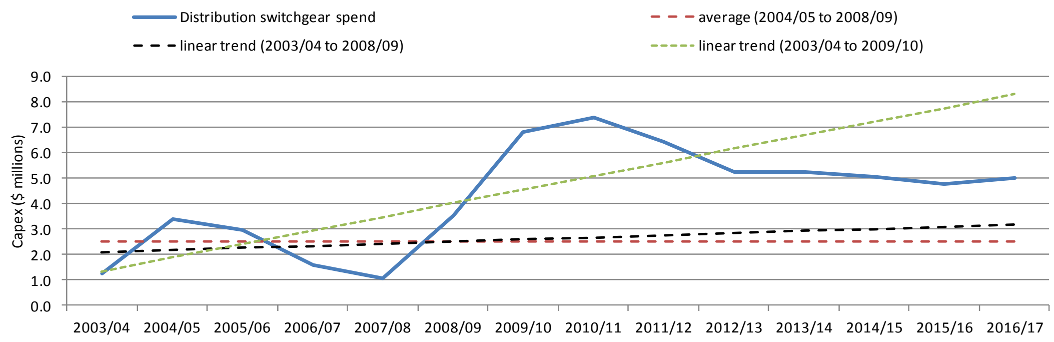


Figure 31 Replacement – distribution switchgear capex trend – repex modelled

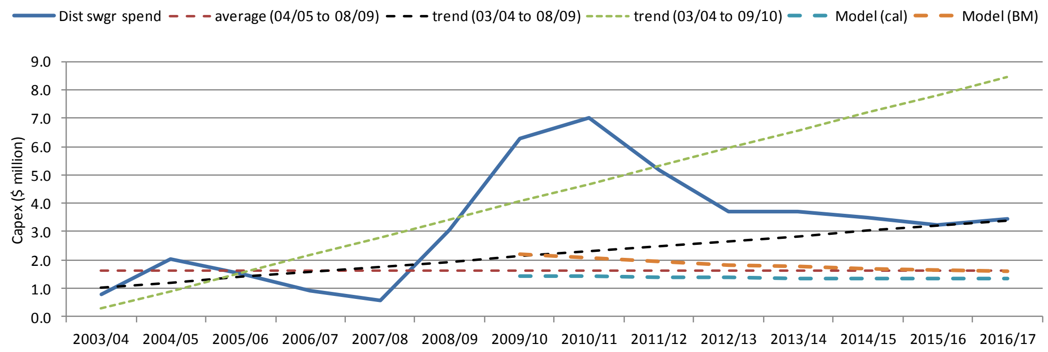
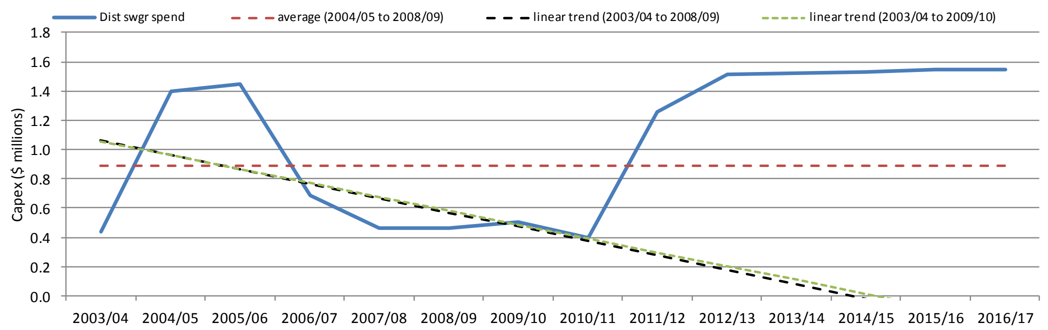


Figure 32 Replacement – distribution switchgear capex trend – not repex modelled



The analysis indicates:

- The capex profile is similar to distribution transformers. Capex is relatively variable, but was at a lower level prior to 2009/10. Capex increased significantly in 2009/10, but is forecast to reduce slightly in the next period. We understand the step increase in 2009/10 was due to the same reasons for the similar increase in distribution transformer capex noted above i.e. a new outsource contract that enabled a backlog of works on ground mounted substations to be addressed, and storm activity that year, which impacted line switchgear activity levels.

- The forecast level of capex is below the linear trend including the 2009/10 increase, but is well in excess of the linear trend if we exclude this year, and well below the average historical level of capex.
- For the portion of capex that could be assessed through the repex model, Aurora's forecast is also well above the calibrated model findings, which suggests Aurora is anticipating reduced lives in the next period from those it has achieved historically. The calibrated lives are on average slightly longer than similar Victorian DNSP lives, but the benchmark model is still well below Aurora's forecast, suggesting that Aurora's forecast may be above prudent levels.
- As noted above, the portion not assessed through the repex model, mainly relates to programs associated with the replacement of line switchgear. The current period has seen a significant reduction in capex from the previous period, but Aurora is proposing a significant step increase at the end of the current period and into the next period, which will result in capex returning to levels similar to those of the previous period.

Overview of programs and detailed review findings

The distribution switchgear category encompasses seven work programs[66]. These programs include:

- replace overhead switchgear (safety)
- replace ground mounted high voltage switchgear
- replace ground mounted low voltage switchgear
- replace reclosers
- replace overhead switchgear
- fire mitigation projects – Switchgear
- replace ground mounted substations.

We have included the work category labeled "Replace Ground Mounted Substations" in the distribution switchgear category because a significant proportion of the forecast expenditure for this work category is associated with either the replacement of distribution switchgear or the replacement of substations as a result of the replacement of distribution switchgear.

Aurora has forecast total expenditures for the distribution switchgear category of $25.3 million for the next regulatory period, which is a very similar level to the preceding 5-year period, $25.2 million.

Replace Overhead Switchgear (Safety)

The aim of this new program is to replace LV links with fuses on distribution substations to address public safety. Aurora has advised in its justification documentation that it

[66] Distribution Switchgear includes work categories REOHQ, REHSW, RELSW, RERER, REGMS, REOHS and SIFIF,

proposes to replace the existing LV links in substations that are located outside very high and high fire danger areas with fuses rated on the size of the transformer. This is different to the LV Fuse Reach Management Program as in this program the fuses are rated to the LV circuit, and hence, it involves a design component to analyse the loading on the LV circuit.

Aurora has identified that in July 2005 there were 5,635 (21.2%) transformers without LV fuses, of which approximately 602 sites were located outside high and very high fire danger areas. It proposes to replace all the LV links at these sites by 2017. Aurora has estimated that 120 sites per year will be replaced.

Whilst there are several industry accepted approaches taken in relation to the protection at distribution substations, most DNSPs adopt the use of both HV and LV fusing based on transformer ratings. Hence we believe that this new program proposed by Aurora is prudent in relation to the installation of LV fuses on distribution substations located outside high and very high fire danger areas. In relation to the proposed annual volumes the program appears reasonable in view of the risks associated with the current situation and Aurora's current risk profile.

Replace Ground Mounted High Voltage Switchgear

This work category comprises the following components:

1 Replace High Voltage Switchgear – RGB24;

2 Replace High Voltage Switchgear – Oil-filled; and

3 Replace High Voltage Switchgear – Fault Replacement.

The aim of these programs is to reduce the environmental and safety risks posed by these assets.

Brown Boveri RGB24 units were installed from the late 1970s to early 1980s. The design of the rear epoxy spouts allows the collection of dirt and moisture over time, which eventually causes insulation failure and flashover that leads to failure of the switchgear. Aurora's asset records indicate, as at August 2010, there are approximately 45 RGB24 HV switches in service.

Aurora has commenced a program to replace all Brown Boveri RGB24 switchgear over a 10 year period commencing in 2011/2012, scheduled for completion by 2021/2022. The program involves the replacement of the switchgear at four sites per annum.

Replacements will be prioritised by monitoring partial discharge, ozone and noise - all of which are indicators of imminent flashover - during the four-yearly switchgear maintenance program.

We consider this program to be prudent and the annual volumes proposed seem reasonable. We understand that most other NEM DNSPs have or are also undertaking programs to replace this type of switchgear.

Oil-filled switchgear was installed from the 1960s to 1980s. This type of switchgear is contained in building, fence and padmount type substations throughout the state, with a total population of approximately 327 sites. Aurora expects to have 311 sites with oil filled switchgear in service at the beginning of 2012/2013.

The program involves the planned replacement of the HV switchgear at approximately 31 sites containing oil-filled switchgear per year. This constitutes an overall increase in volumes over a 10 year period, ending in 2021/2022.

Aurora has not provided any fault data or other asset condition information to support the decision to substantially increase the oil filled switchgear replacement program. Hence, we see no reason to consider that it is not reasonable to assume that the current replacement rate is sufficient to maintain the performance of Aurora's distribution system. This position appears to be in line with our repex modeling, which did not indicate an increasing need for switchgear replacements.

Turning finally to the fault replacements, Aurora advised in its justification documentation that it experiences approximately four HV switchgear faults per annum, excluding incidents relating to RGB24 and Siemens switchgear. The program involves the reactive replacement of the HV switchgear at four sites per year as a result of switchgear failure. As such, we consider this forecast to be reasonable.

Replace Ground Mounted Low Voltage Switchgear

This work category is comprised of the following components:

1 Replace Low Voltage Switchgear – Live Front Boards; and

2 Replace Low Voltage Switchgear – Asbestos.

The aim of this program is to reduce the environmental and safety risks posed by these assets.

Many of the low voltage boards installed in Aurora's building and vault-type substations are of open-type or live front construction, which pose a risk to personnel safety. In addition, some of these boards are located in cramped operating conditions with little access for escape in the event of contact with live parts. The justification documentation advised that Aurora has a total of 310 sites that contain live front boards. A sample audit of 154 sites has been carried out by Aurora. This audit identified 30 sites, or 19%, as high risk sites. These sites are scheduled for removal by 2012.

Based on the number of high risk sites identified in the audit and the current rate of remedial work, it is estimated by Aurora that a further 30 sites will need to be replaced, which equates to 6 sites per year.

We consider this ongoing program to be prudent and the volumes proposed per annum to be reasonable.

Nilsen LV circuit breakers have asbestos arc chutes. This presents the risk of potential asbestos exposure during maintenance activities. In its justification documentation, Aurora states that this program will continue at a rate of six sites per year, with all high-risk asbestos arc chutes to be removed by the end of 2013/2014.

Based on our review of the supporting information provided by Aurora, we consider the program to be prudent and the proposed annual volumes to be reasonable.

Replace Reclosers

The aim of this program is to replace Nulec reclosers that are in poor condition or faulty. The justification documentation states that Aurora currently has approximately 250 Nulec reclosers installed in the system. Aurora states that, while Nulec reclosers only have a manufacturer assessed asset life of 20 years, replacement will be undertaken based on condition assessments and as driven by other business drivers.

This is an ongoing program and as replacements are triggered by incidents and equipment failures there is no proposed changes to the program or the forecast volumes. As such, we consider the program to be prudent and the volumes to be reasonable.

Replace Overhead Switchgear

There are five components to this program:

1 Replace Air Break Switch (ABS)/HV Links

2 Replace complete EDO unit (obsolete equipment)

3 Replace EDO fuse tubes (correct operation)

4 Replace EDO unit with Boric Acid Fuse Unit (in high fault level areas)

5 Replace sectionaliser (ABB and AK).

Pole shrinkage over time can lead to loose fitting crossarms and hardware and results in movement of Air Break Switches (ABS). This can lead to misalignment of contacts resulting in "frozen" contacts or operating mechanisms, which results in the ABS being inoperable and/or subject to severe arcing during operation.

HV links have a single break action and are not rated for breaking current. The ABS/HV link replacement program is ongoing and historically Aurora has replaced one ABS per annum, and hence, this volume has been assumed to remain constant going forward.

Aurora stated in its justification documentation that the replacement of complete EDO units (condition) is driven by the fact that EDO fuse tubes installed prior to 1990 (Taplin/Stranger/Morlynn RE) do not fit with the modern 'c' type carriers and that EDO units with cracked or brown insulators have been identified as a contributor to an increasing number of pole top fires.

EDO replacement is based on EDO failure rates, which are approximately 150 per year. This ongoing program also complements the EDO replacement proposed under the fire safety program (SIFIR).

We are aware that the replacement of older style EDOs (i.e. those fitted with brown insulators) is common practice throughout the industry for similar reasons to those stated by Aurora. Hence, we consider this type of program to be prudent, and as the replacement volumes are based on historical failure rates they appear reasonable.

The replacement of EDO fuse tubes may be required when the tube of an EDO fuse weathers, and the internal fibres swell. This swelling can cause the fusible link to stick, preventing the tube from dropping out after a fault operation. If the tube does not drop out (i.e. it "hangs up"), electrical tracking can occur inside the tube, which in turn creates heat, causes the fuse tube to catch fire, burn in half, and drop to the ground, potentially starting a fire. Aurora stated in its justification documentation that inspections have revealed indications of fuse tube deteriorating at five years, with an increased risk of "hang ups" after ten years.

Aurora stated that "*the aim of this program is to ensure that by 2020 there are no EDO fuse tubes in the system that are greater than ten years old. Ten years was chosen as the preliminary asset life of the fuse tubes for replacement however, condition monitoring of new tubes will be undertaken to evaluate the legitimacy and effectiveness of a ten year replacement program*."[67] Aurora proposes to replace 3,500 fuse tubes during the next regulatory period. This program is a new program and no historical data for fuse tube failure has been provided. In addition, we note that in the justification document for work category SIFIF, a decision was made to extend the replacement program over a period of 20 years in order to comply with Aurora's current policy of no price rises to the customer[68].

While we are fully aware of the issues described, the service lives attributed to drop out fuse tube/carriers seems very short as many of these fuses have been in service for considerably longer periods. We note that the replacement of these fuses in very high and high fire danger areas is a different issue, given the far greater risks, but these are addressed in another program. In the absence of any specific data addressing service lives of these assets, we recommend that a "business as usual" approach be taken to the program of replacing fuse tubes outside designated very high and high bushfire areas. This program is a significant proportion of the proposed expenditure for Replace Overhead Switchgear and our recommendation would result in total reduction in forecast expenditure over the next regulatory period of approximately $1.8 million.

Aurora proposes to replace EDO fuses in areas where the fault level exceeds the EDO manufacturers rating of 6 kA. Boric acid fuses will be installed in control stations and on transformers in areas of where the fault level exceeds 6 kA. Aurora has 216 control station EDOs and 905 transformer EDOs located in the high fault level areas, and the proposed volumes are based on ensuring that all control station EDO fuses that protect multiple transformers in high fault areas are replaced by boric acid fuses by 2020.

Due to the issues associated with switchgear operating in areas where the fault level exceeds the rating of the equipment, we consider that this program is prudent and the proposed annual volumes appear reasonable.

Fire Mitigation Projects – Switchgear

SIFIF comprises two components:

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[67] Pg 5, NW-#30199593-v4A-Justification_REOHS_-_Replace_OH_Switchgear (confidential)

[68] Pg 6, NW-#30199841-v2-Justification_SIFIC_SIIF_-_Fire_mitigation_projects (confidential)

1 replace EDO Fuse Tube in high and very high fire danger areas

2 replace EDO with Fire Safe Alternatives in high and very high fire danger areas.

The first component of this program is the same as the Replace EDO fuse tube (correct operation) component of Replace Overhead Switchgear discussed above, except it relates to EDOs that are located in very high and high fire danger areas. The reason for the fuse tubes failing are exactly the same as are the potential outcomes; however, the risks due to fire start are significantly higher.

Aurora has advised in its justification documentation that it proposes to replace fuse tubes at up to 150 sites per year in very high fire danger areas, and, up to 267 sites per year in high fire danger areas. Aurora's original intention was to ensure that there were no EDO fuse tubes greater than ten years old in the system by 2020 and to maintain a ten year replacement cycle. However, the program has been extended to 2030 and a twenty year replacement cycle to align with Aurora's strategy of no price increases to the customer.

However, the replacement of older EDO fuse tubes with new tubes only alleviates part of the problem associated with fire starts and the correct operation of a new fuse tube can still result in a fire start. Hence, we recommend that the expenditures proposed for this program be redirected to the second component of this program, which provides a permanent solution to the problem.

The second component of this program is the replacement of EDOs with fire safe alternatives, such as boric acid fuses. Devices such as boric acid fuses only expel gases and not plasma and particles like EDOs, are more resilient to lightning strikes and do not "hang up" like EDOs.

Aurora's justification document advises that the volumes proposed for this program are up to 70 sites in very high fire danger areas, and up to115 sites in high fire danger areas.

The program is to be prioritised so that control stations in very high and high fire danger areas that protect multiple transformers on a spur line are replaced first. This program is a trial as part of Aurora's strategy to ensure that all control station EDO fuses that protect multiple transformers are replaced by a fire safe alternative, such as boric acid fuses, by 2020. The program has been extended to 2030 to align with Aurora's strategy of no price increases to the customer.

We consider this program to be prudent as it provides a permanent solution to the problems associated with the potential fire start properties of EDOs. In addition the volumes based on a 20 year replacement program appear reasonable.

Replace Ground Mounted Substations

Whist this program could be reviewed as part of Distribution Transformers, we have decided to include it under Distribution Switchgear heading as a reasonable proportion of the work is related to the replacement of switchgear for resonance purposes or the replacement of substations as a result of the need to replace distribution switchgear.

The aim of this ongoing program is threefold: to address ferro-resonance issues, replace 11 and 22 kV padmount/kiosk substations, and replace rusting substation enclosures with marine grade enclosures.

Within Aurora's distribution network there are approximately 160 sites susceptible to ferro-resonance including:

1 ground mounted substations containing Hazemeyer MD4 HV switchgear

2 ground mounted substations connected to the overhead system via underground cables and protected by single-phase switching devices, such as single-phase Expulsion Drop Out fuses (EDOs).

The main issues associated with ferro-resonance are the complex switching associated with the operation of a site susceptible to ferro-resonance and the possibility of sustained high voltages and high currents if a single fuse element fails. The forecast volumes that underpin the forecast expenditures are based on the annual historical rate of replacement of one site per annum. We consider that this program is prudent and, based on the magnitude and consequence of the issues, we consider the forecast volume is reasonable.

Aurora has advised in its justification documentation that approximately 33% of padmount and kiosk replacements are carried out as part of the replacement of Brown Boveri RGB24 distribution switchgear, as discussed above. The remaining padmount and kiosk substations are replaced as part of an ongoing program based on poor asset condition, which includes oil leaks, mal-operation of protection or deterioration of the enclosure.

Aurora advised that its asset records indicate, as at August 2010, there were approximately 45 sites containing RGB24 HV Switchgear and approximately 38 11 kV and 22 kV padmount/kiosk substations nearing the end of their useful life.

The program involves the replacement of approximately four sites with RGB 24 switchgear, and the replacement of approximately nine sites per year, due to poor condition. We consider this program to be prudent and the forecast volumes align with the associated Brown Boveri RGB24 switchgear replacement program, which we consider reasonable.

In relation to the forecast volumes associated with the padmount and kiosk replacement program, the historical volumes for 2009/10 and 2010/11 appear very high and Aurora explains that these volumes were associated with catch-up works. The forecast volumes appear to align closely with the 2008/09 volumes, and hence, we consider them to be reasonable.

Maintenance checks have identified that transformers located within 20 miles of coastal areas or near highly corrosive industrial sites rust at a far greater rate than in other locations. The program involves the replacement of one site with accelerated corrosion per year. The work associated with this ongoing program is the replacement of corroded enclosures with marine grade aluminium enclosures and application of protective coatings to the transformer tanks.

Aurora's asset records indicate, as at August 2010, there are approximately 65 ground mounted substation sites within 20 miles of coastal areas or near highly corrosive industrial sites.

Based on our detailed review we consider that this program is prudent that the maintenance of the existing program of addressing one site per annum is reasonable.

Nuttall Consulting Recommendations

Based on our detailed review of each of the work categories included in the distribution switchgear category we consider that the majority of the programs are prudent and align with current industry-wide practices. In addition, the forecast volumes that underpin the forecast expenditures also appear reasonable with the following exception.

The program to replace all EDO fuse tubes outside very high and high fire danger areas to ensure that by 2020 there are no EDO fuse tubes in the system that are greater than ten years old is not supported by any asset condition data. We are aware that there are many fuse tubes still in service in other distribution areas that are much older than 10 years and continue to operate correctly. This is a new program and Aurora proposes to replace 3,500 fuse tubes during the next regulatory period. In addition, Aurora states that "*condition monitoring of new tubes will be undertaken to evaluate the legitimacy and effectiveness of a ten year replacement program*."[69]

Accordingly, we do not agree that these additional works be included in the program of works for the next regulatory period and the assets continue to be run to failure. We therefore recommend the removal of $1.8 million from the forecast expenditures associated with this program.

We concur that the program to remove expulsion type fuses from areas designated very high and high fire danger areas is prudent. Therefore, we believe that the forecast expenditures for the replacement of older EDO fuse tubes in these areas should be redirected to this program, because this would provide a more effective and permanent solution to the fire-start problems associated with expulsion fuses.

6.3.3.5 Underground Cables

Figure 33 below shows the capex profile and trends for underground cables. A large portion of the work programs covered by the underground cable asset categories are considered to be suitable for modelling through the repex model. The calibrated and benchmark repex model results are shown on Figure 34, which excludes the proportion of capex not modelled. Figure 35 shows the capex profile and trend charts for this remaining capex.

[69] Pg 5, NW-#30199593-v4A-Justification_REOHS_-_Replace_OH_Switchgear (confidential)

Figure 33 Replacement – underground cable capex trend

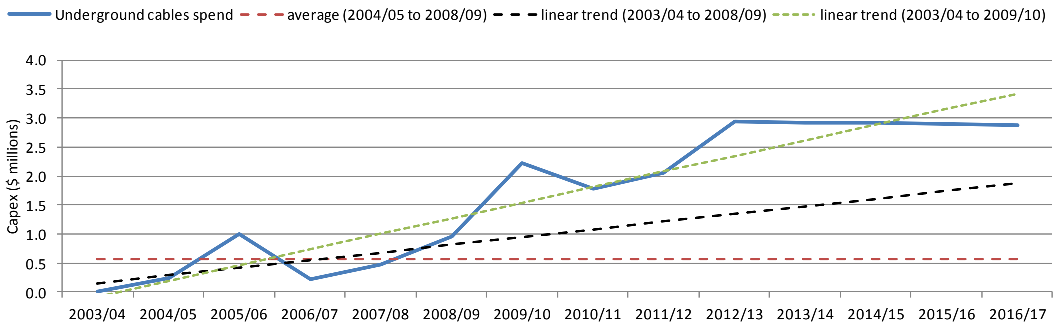


Figure 34 Replacement – underground cable capex trend – repex modelled

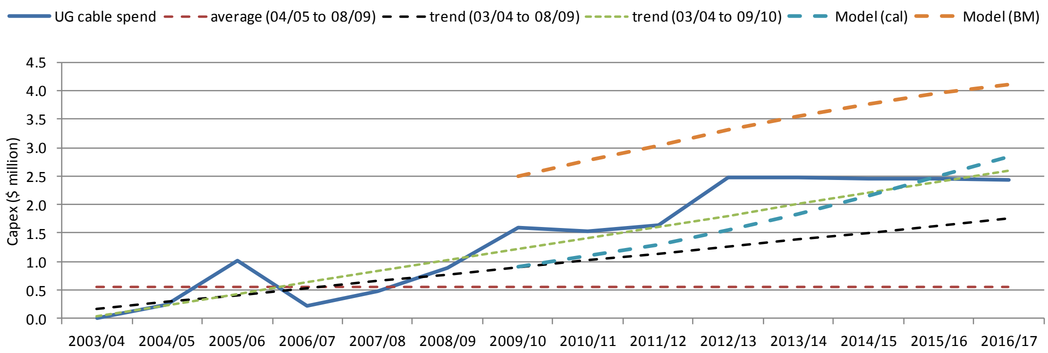
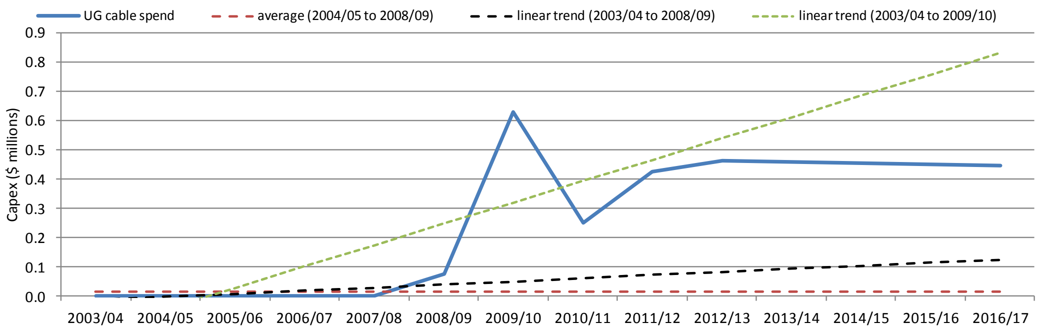


Figure 35 Replacement – underground cable capex trend – not repex modelled



This analysis indicates:

- Capex has been ramping up over the previous and current period, with a step up in 2009/10, and a further step forecast for the commencement of the next period with capex staying relatively constant through the next period.
- The forecast is close to the linear trend allowing for the step up in 2009/10, but is well in excess of the linear trend excluding that year, approximately 4 to 5 times greater than historical average.
- The capex profile is similar for the portion assessed through the repex model. The calibrated model predicts an increase broadly in line with the linear trend allowing for the 2009/10 step increase. However, the calibrated lives are on average longer

than similar Victorian DNSP lives. The benchmark model predicts a capex in excess of that forecast by Aurora. This may suggest Aurora is under-investing in cables, or at least, support the prudency of Aurora's forecast.

- The capex not assessed through the repex model mainly relates to the replacement of potheads. As noted below, this is the continuation of programs that commenced in the current period. Capex is forecast to continue at the average levels incurred since the commencement of these programs.

Overview of programs and review findings

The underground cables category includes a number of programs[70] including the proactive and reactive replacement of CONSAC cables, the replacement of HV and LV underground cables, the replacement of underground furniture and the replacement of 22kV,11kV and LV cast iron potheads[71].

Aurora has forecast total expenditures for the underground cable category of $14.6 million for the next regulatory period, which represents an approximate 90% increase over the previous 5-year period.

CONSAC Cable Replacement

The CONSAC cable replacement program is the most significant program in the underground cable category. This program represents 55% ($8 million) of the capex in the next period allocated to underground cable asset category. Aurora is forecasting capex on this program in the next period to increase by 77% from the amount in the previous 5-year period.

The aim of this ongoing program is to reduce the risk to the public posed by broken neutrals as a result of cable failures of a particular type of LV cable known as CONSAC. Aurora has 189 km of CONSAC currently in service and Aurora contends that approximately 30 km is located in high failure areas.

CONSAC cables have customer's neutrals connected directly onto the aluminium sheath. If these are not adequately sealed to prevent moisture ingress they oxidise. This can eventually cause an open circuit, or broken neutral, which can pose a serious public safety risk due to the potential for electric shock. This is a problem commonly experienced by all DNSPs that have used CONSAC in urban residential developments and other LV underground situations.

Bopole joints are a type of LV underground T-joint used in Aurora's distribution system in conjunction with CONSAC cables from 1971 to 1973. Installation of these joints was discontinued as a result of high failure rates attributed to moisture ingress into the joint over time and is another driver for this program. Again, when CONSAC cable was initially brought onto the market there were many different types of joints available that were

[70] The Underground Cables programs include SIPRU, REUCS, REUGC, REUGF, REULC, REPOA, REPOB and REPOC work categories

[71] We also included the spend in the SIPRU work category in the underground cables category. This program covers design costs associated with some underground cable projects. As there is a very low level of expenditure allocated to this work category, we did not include this in our detailed review.

supposed to make the connection of customer mains simple, cost effective and requiring low levels of operator skill. Many of these joints later proved to be defective in so far as they did not provide an effective barrier to moisture ingress and failed relatively quickly in service. This particular problem is not peculiar to Aurora's network.

Aurora has replaced approximately 30km of CONSAC since the program commenced in 2008 and proposes to replace 6.6km per annum during the next regulatory period.

Our detailed review of the justification documentation provided for the CONSAC replacement program indicates that the program is prudent and that the proposed volumes and timing appears reasonable. Our view is based on the safety implications of not replacing defective CONSAC, the fact that a proactive program allows for work to be scoped and programmed in a cost efficient manner, and the fact that CONSAC faults are difficult to locate and repair quickly and cost effectively.

Furthermore, Aurora also advised that in 2008, it implemented a proactive replacement program of CONSAC cables after analysis revealed that over 70% of LV cable failures were directly related to CONSAC cables, despite being only 17% of the total LV cable population.

Hence, we consider that these works should be included in the program of works for the next regulatory period and the volumes proposed appear reasonable. That said, given the stated historical performance of CONSAC, we would consider that such a targeted program would have a significant portion also justified via the opex and reliability benefits. As such, we may expect that any increase in the scale of this program from historical levels should have fairly significant offset allowance in the opex forecast and reliability targets.

High Voltage Underground Cable Replacement

The aim of this program is to replace HV underground cables found to be in poor condition as the result of a cable failure or associated asset replacement programs. Aurora has 1350 km of HV cables in service including MIND, oil filled and oil draining paper insulated cables and XLPE insulated cables. This program allows for the replacement of 0.4 km of general HV cables and 0.4 km of oil-filled HV cable.

Aurora has forecast a substantial increase in expenditure over the next regulatory period compared to historical trends, $2.3 million compared to $0.3 million actual and budgeted for the preceding 5 years.

Our detailed review of the justification document provided for this program does not support increasing the forecast expenditures above historical trends, as no basis was provided for the volumes included in the forecasts. Hence we believe that a prudent expenditure forecast for high voltage cable replacement for the next regulatory period would be $0.3 million as per historical expenditures, a reduction of $2.0 million for the five year period.

Replace Underground Furniture

Underground cables are joined or terminated in various above and below ground enclosures, collectively known as underground furniture. Underground furniture (HV and

LV) is designed to provide a safe, secure and weatherproof environment for cable terminations, joints and associated equipment.

This work category comprises four components:

1 replace underground link boxes or distribution boxes

2 replace underground furniture (general)

3 install above ground signage on cable route

4 install identification tag and collect field data.

The aim of the first two components is to reduce the safety risk posed to the public and operators of poor condition assets. The aim of the third component is to reduce the risk of accidental damage to underground assets. The aim of the fourth component is to provide better asset data and improve asset management decisions.

Aurora has forecast a small increase of approximately $0.3 million over the next regulatory period compared to the actual and budgeted historical spends in the previous 5-year period to account for the targeted replacement of underground link boxes, based on the risk they pose to both the public and Aurora’s field staff.

Aurora has advised that forecast expenditures for these works are based on historical trends with the exception of targeted replacement of underground LV link boxes and aboveground LV distribution pillars in poor condition. In relation to this program, Aurora has advised that, by the start of the next regulatory period, there should be 8 underground LV link boxes outstanding, which are scheduled to be replaced by 2015. Following this, poor condition aboveground pillars will be targeted.

Our detailed review of these proposed works indicates that the Aurora forecast expenditures appear prudent and the forecast volumes reasonable.

LV Underground Cable Replacement

Aurora has a total of 876 km of LV underground cable currently in service, of which 687 km is XLPE insulated with the remainder CONSAC. This is a new work program that aims to replace LV underground cables found to be in poor condition, as the result of a cable failure or associated asset replacement programs.

Provision has been made to replace 0.6 km of general LV cables when cable in poor condition is identified (generally as a result of cable failure) or when opportunities arise due to upgrade or rectification work associated with other assets. The forecast expenditure for these works is $0.7 million, and, being a new program, there is no historical data.

Our detailed review of the justification documentation provided for these works does not support the inclusion of this program in the capex works programs for the next regulatory period. While the basis for the forecast expenditure was provided, the justification for the program was not addressed. Historically LV XLPE cables are very reliable and in the absence of specific details of historical LV XLPE cable defect information, we do not consider this program to be either prudent or reasonable. The LV CONSAC cable is a separate issue, treated under its own specific program and discussed above.

Based on this analysis, we would not allow any expenditure for the LV underground cable replacement program during the next regulatory period. This amounts to a reduction of $0.7 million across the period.

Replace 22kV, 11kV and LV Cast Iron Potheads

The aim of this ongoing program is to reduce the risk to the public posed by all cast iron potheads currently in service. There have been several incidents of failure of cast iron pothead terminations where the cast iron casing has cracked leading to water ingress and failure of the termination. In several instances, failure of the termination has resulted in the casing being blown apart, posing a risk of injury to the public and Aurora staff. The force behind the explosion is proportional to the voltage level.

The safety issues associated with cast iron potheads are well documented and most DNSPs have either replaced or have replacement programs in hand. Aurora intends to have the majority of the cast iron potheads replaced by the end of the next regulatory period.

Our detailed review of the justification documentation provided in support of this work category indicted that Aurora currently has 165 cast iron potheads still in service. The forecast volumes are based on replacing the majority of these potheads by the end of the next regulatory period.

Aurora has included a total of $2.2 million for cast iron pothead replacement programs over the next regulatory period. The majority of this forecast expenditure ($1.6 million) relates to the replacement of 11 kV potheads. The majority of these cast iron potheads are located in public places, and hence, any explosion would have safety implications for both the public and staff. We concur with these replacement programs being included in the program of works for the next regulatory period as they are prudent and the proposed volumes are reasonable.

Nuttall Consulting Recommendations

Based on our detailed bottom up review we consider that the LV CONSAC cable, underground furniture, pothead replacement programs are reasonable. Although, in the case of the LV CONSAC program, we do believe that there should be significant benefits due to the increased replacement levels that should result in reductions in opex and improvements in reliability.

We do consider that other proposed increases are not justified from information provided by Aurora. In these cases, we consider that:

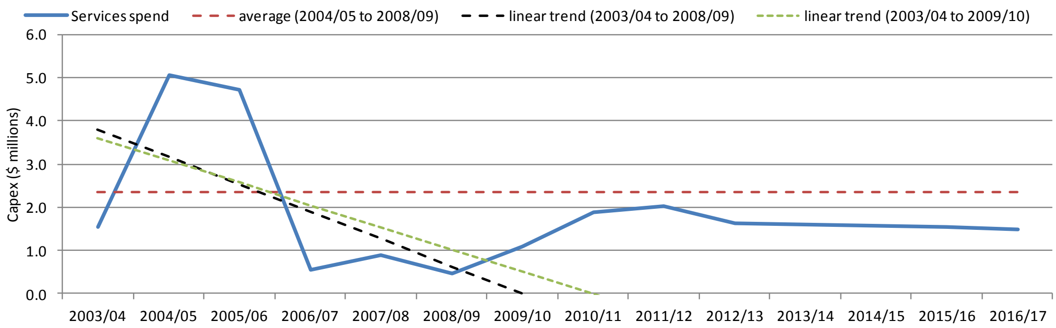
- the LV Underground cable replacement program (excluding the CONSAC program noted above) be removed from the program of works proposed for the next regulatory period
- the forecast expenditures for the high voltage cable underground replacement program be based on historical costs and budgets.

We estimate that these adjustments will result in a $2.7 million reduction to the underground cable category over the five year regulatory period.

6.3.3.6 Services

Figure 36 below shows the capex profile and trends for services. This asset category has not been assessed through the repex model as age profiles were not provided.

Figure 36 Replacement – services capex trend



This analysis indicates:

- Capex had a large increase in 2004/05 and 2005/06, which we understand was to replace a large number of service fuses, due to a safety issue that was discovered. Following this, capex was at lower levels between 2006/07 to 2009/10 as services were replaced under the reactive replacement program.
- Capex increased in 2010/11 in response to the pro-active replacement program, and is forecast to be at around historical average levels (excluding the fuse replacement program) in the next period.

Overview of programs and review findings

The programs in the services category include the replacement of overhead services and fuses and the changeover and upgrading of services on Telstra poles[72].

Replacement of OH Services and Fuses

The major work category in Services is the replacement of overhead services and fuses. The aim of this program is to reduce the risk to the public posed by broken neutrals and reduce supply interruptions resulting from overhead service and service fuse failures. The total expenditure for the next regulatory period is forecast to be $7.7 million compared to $6.2 million for the actual and budgeted expenditures for the preceding 5 years. Aurora has based its forecast volumes on removing defective services identified during a 2008 audit by the end of the next regulatory period.

Our detailed review of the Justification documentation for the replacement of overhead services and fuses revealed that an audit was carried out in 2008 that indicated that there were approximately 26,000 defective services on the network. Aurora stated that it

[72] The Services programs include RESTE and SCSRE work categories

expects approximately 1,500 defective services to be replaced each year under fault conditions and a further 1,300 defective services per year as a result of customer generated work. Aurora also forecasts to proactively replace 2,400 defective services, bringing the total number of defective services replaced per annum to 5,200.

We believe that Aurora has omitted to deduct the defective services replaced as a result of those replaced under fault and those replaced as a result of customer generated works. These replacements would total approximately 8,400[73] from 2008 till 2012 leaving 17,600 outstanding defective services at the commencement of the next regulatory period. At a replacement rate of 5,200 per annum, all outstanding services should be replaced within 3.4 years, not 5 years. This represents a 32% reduction in the forecast volume of planned replacements.

It was noted in our unit cost study, Section 4, that we found that Aurora's unit cost for planned service replacements is much higher than that allowed by the AER for the Victorian DNSP decision. However, the assumed replacement volumes in the proposed program of works spreadsheet that underpins Aurora's forecast does not reconcile with the volumes provided to us to justify the service replacements discussed here. In this regard, as noted above, we have been advised that 2400 services per annum are forecast for planned replacement, whereas the proposed program of works spreadsheet assumed 1600 per annum. This may suggest that Aurora has not applied the correct unit cost for these planned replacements. Assuming the unit cost should reflect the 2400 units then the effective unit cost assumed by Aurora may be much lower. This effective unit costs is more in line with the benchmark figure. Therefore, we do not consider a further reduction is warranted to allow for the unit cost finding, given the rationale we have used to determine the reduction.

Accordingly, we would allow $5.2 million over the 5-year regulatory period. This represents a total reduction of $2.5 million over the period, which reflects the 32% reduction in volumes.

Changeover and Upgrading of Services on Telstra Poles

The other work category included in the services category is the changeover and upgrading of services on Telstra poles. This program covers the upgrade and reconfiguration of any LV that is attached to Telstra owned poles and, if major work is required or a problem exists with the pole, Aurora will negotiate transfer of ownership of the asset. The total expenditure for this work category is forecast to remain constant over the next regulatory period at $0.1 million for the five year period.

Aurora advised in its justification documentation that it currently has 2500 joint use Telstra poles. This is common practice throughout Australia and the standard joint use agreement usually states that the distributor is responsible for removing and replacing its assets if and when Telsta has to replace or maintain the poles.

[73] We have used a conservative estimate here (i.e. 3 x 2800 rather than 5 x 2800) as we consider that other factors may result in the reduction through these programs being less e.g. the estimates used by Aurora to determine the number for these programs and the additional defects that may be found.

The justification document advises that forecast volumes and estimates are based on and align with historical spends. We therefore consider that the program is prudent and the volumes reasonable so the works should be included in the program of works for the next regulatory period.

Nuttall Consulting Recommendations

Based on our detailed review of the replacement of overhead services and fuses we have concluded that the number of defective services outstanding at the commencement of the next regulatory period will be significantly lower than assumed by Aurora. We estimate that this would result in a total reduction of $2.5 million over the five year regulatory period.

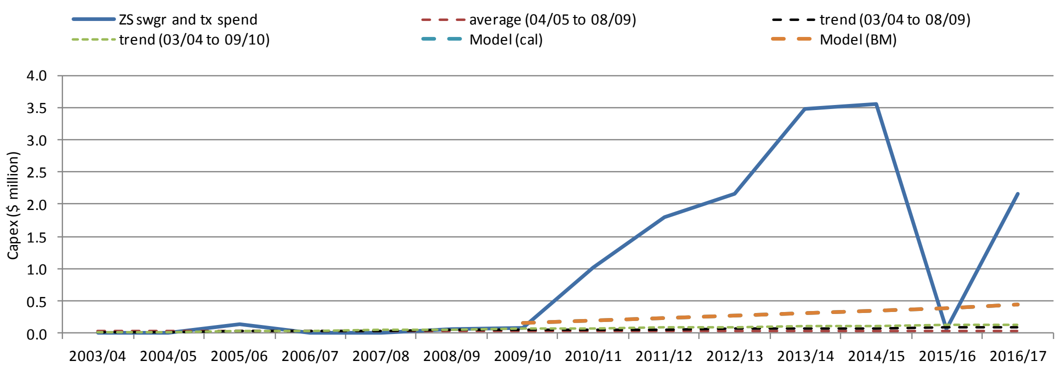
Our detailed review of the changeover and upgrading of services on Telstra poles indicated that forecast expenditures are based on business as usual volumes and hence we consider this work category should be included in the proposed program of capital works.

6.3.3.7 Zone substation switchgear and transformers

Figure 37 below shows a similar chart as those discussed above, showing the profile of the total capex allocated to the zone substation asset category (the solid line) and historical capex trends projected into the next period (the dashed lines).

All work programs covered by the zone substation asset categories are considered to have a strong correlation to age, and therefore, the total capex in this asset category has been modelled through the repex model. The calibrated and benchmark repex model results are also shown on this figure.

Figure 37 Replacement – zone substation capex trend



This analysis indicates that capex is forecast to increase at the end of the current period, and increase further during the first half of the next period. The forecast is well above linear trends and the historical average. The forecast is also well above calibrated and benchmark model predictions.

However, as noted in the introduction, capex in these categories relates to specific large value-low volume replacements, of which there was nothing significant prior to 2010/11. As such, care needs to be applied in inferring too much from the historical trends and the repex modelling, as a few specific future needs would swamp any prediction from historical trends or the repex modelling.

Therefore, our detailed review of these categories has been a significant factor in assessing expenditure for these asset categories.

Overview of programs and findings

The programs include the replacement of the power transformers at Claremont, Derwent Park and Richmond zone substations, the rebuilding of New Norfolk zone substation and the replacement of oil filled switchgear at Sandy Bay, New Town and Derwent Park zones substations[74][75].

The following summarizes the key points associated with the needs for each substation replacement and the more general replacement programs:

Claremont Zone Transformers

The Claremont zone substation has two Wilson 15 MVA power transformers installed, and both were manufactured in 1964. Aurora proposes to replace both these power transformers in 2013/14.

The dissolved gas analysis (DGA) of one transformer shows signs of an inactive thermal condition, physical and electrical oil tests are satisfactory and Furaldehyde levels are still in the healthy transformer range. The oil is considered PCB free. The oil test results supplied for the other transformer indicates that the DGA, physical and electrical oil tests, Furaldehyde and PCB tests are all within acceptable limits.

We cannot identify any compelling reasons, from the oil test results and information provided, to warrant replacing these transformers during the next regulatory period. We agree with the recommendation of the oil testing service, which is continuing 6-monthly oil tests for transformer #1 to monitor the DGA results for any thermal activity, and the maintenance of the current 12-monthly oil tests for transformer #2. However, we consider that it is most likely that these transformers will not be found to need replacing in the next period.

Derwent Park Zone Transformers

Derwent Park zone substation has two 15 MVA 33/12/6.92 kV Wilson power transformers, which were built in 1964. Aurora proposed to replace both these power transformers during 2014/15.

Transformer oil tests for one transformer indicate that the DGA, physical and electrical oil tests, Furaldehyde and PCB tests are all within acceptable limits. The oil tests for the other transformer are all within acceptable limits with the exception of the DGA tests, which indicate the existence of an inactive thermal condition greater than 700 degrees Celsius.

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[74] Zone substation switchgear and transformers includes work categories RERUZ,REUZS, RERZT, and REUZT.
[75] The capex allocated to the zone substation switchgear and transformer category also includes SCNVT. This is program associated with current and voltage transformers. This has a very low level of capex associated with it, $0.1 million per annum, and as such, that category was not part of our detailed review.

The Furaldehyde results for both transformers indicate that the cellusose ageing condition is better than a transformer operating at normal recommended nameplate ratings and temperatures.

Similar to Claremont transformer, we cannot identify any compelling reasons, from the oil test results and information provided, to warrant replacing these transformers during the next regulatory period. We agree with the recommendation of the oil testing service which is continuing 6-monthly oil tests for transformer #2 to monitor the DGA results for any thermal activity, and the maintenance of the current 12-monthly oil tests for transformer #1.

Richmond Zones Transformers

Richmond zone substation has two 2.5 MVA 22/11 kV English Electric power transformers. Aurora proposed to replace both these power transformers during 2016/17[76].

The oil test results for one transformer indicate that the oil is of an aged condition. This is indicated by a neutralisation value at the upper limit of 0.2 mgKOH/gram of oil and an interfacial tension reading of 15 dynes/cm. However, the DGA results are within acceptable limits; the Furaldehyde results indicate the paper aging condition is better than expected for a transformer operating at normal recommended nameplate temperatures and ratings.

The oil test results for the other transformer also indicates that the oil is of an aged condition. The moisture content of the oil is high at 43 mg/kg, the neutralisation value of 0.36 mgKOH/gram of oil exceeds the upper limit of 0.2 mgKOH/gram of oil and the Furan results of 0.77 indicates moderate deterioration of the paper insulation

We could not identify any compelling reasons, from the oil test results and information provided, to warrant replacing these transformers during the next regulatory period.

However, whilst the recommendation of the oil testing service is to continue 6-monthly oil tests for one transformer, and the maintenance of the current 12-monthly oil tests for the other, we consider that both transformers would benefit from oil reconditioning.

Intervening now should prevent excessive sludge build up on the core and provide the best opportunity to extend the service lives of both transformers. We would therefore recommend that an allowance of $100,000 be included in the opex expenditures for 2013 to cover the cost of reconditioning the oil in both Richmond zone power transformers[77].

It is also worth noting that in our review of reinforcement projects (5.4.1 and Appendix B.2.2), we have allowed for the installation of a new 10 MVA transformers at Richmond. This should also allow Aurora to manage risks associated with the aging of these two transformers.

[76] It is worth noting that we understand that the costs for one of the transformers is included in the RQM category, discussed here. However, the cost for the replacement of the other unit is included in the reinforcement section, as the demand level is also considered a driver of the need to upgrade the transformer capacity at Richmond.

[77] Costs based on our estimate, assuming the use of fullers earth technology for oil reconditioning

New Norfolk Zone Substation

New Norfolk Zone Substation was established in 1960. The substation comprises one 22 kV supply feeding four 2.5 MVA 22/11 kV power transformers in parallel and three outgoing 11 kV feeders controlled by Nulec reclosers (which were installed in 2001). The transformers are unbunded and there are no blast walls between the transformers.

The substation is located beneath Transend's 110 kV transmission line.

Aurora proposes to replace this substation during 2016/17 to remove the safety and environmental issues associated with the ageing infrastructure at the current site.

We have reviewed the oil test results for the 4 power transformers located on site. All four have DGA results within acceptable limits; all have very high moisture content exceeding the upper limit of 30 mg/kg and all have high acidity exceeding the unacceptable limit of 0.2 mgKOH/gram of oil. The Furan results for the transformers range from 0.99 to 1.50, indicating a degree of polymerisation of approximately 450 which is on the border of moderate to extensive cellulose deterioration. The transformer oil testing service recommends 6-monthly testing until the oil quality can be improved.

We consider that all four transformers would benefit from oil reconditioning as intervening now should restore the oil quality to within acceptable limits and extend the service lives of the transformers. However, we do not consider that the condition of the power transformers would justify the replacement of the New Norfolk zone substation in the next period.

In addition, while we acknowledge the other risks associated with the New Norfolk zone substation, Aurora has been managing these risks for over 50 years, and therefore, we do not consider that sufficient justification has been provided to warrant recommending replacing this substation during the next regulatory period.

Whilst we do not recommend replacing the entire substation during the next regulatory period, we do recommend that an allowance of $200,000 be included in the opex expenditures for 2013 to cover the cost of reconditioning the oil in the four power transformers[78].

Replace Zone Substation Switchgear

This program involves the replacement of Reyrolle LMT oil-filled switches (OCBs) in Sandy Bay, New Town and Derwent Park Zone Substations. This oil-filled switchgear is approaching the end of its service life; but in addition to removing the threat of explosion and fire, the replacement of the switchgear will also facilitate remote operation as the current switchgear has to be manually recharged. The work involves the replacement of the breaker trucks with vacuum switches and the replacement of the door on the breaker enclosure.

Sandy Bay zone substation OCBs are proposed to be replaced in 2012/13; New Town zone substation OCBs are proposed to be replaced during 2013/14; and Derwent Park zone substation OCBs are proposed to be replaced during 2014/15.

[78] Costs based on our estimate, assuming the use of fullers earth technology for oil reconditioning

Our view, based on a detailed review of the information provided by Aurora, is that this program appears to be prudent and aligns with current industry practice.

We do however consider there to be a significant opex / capex trade off associated with these proposed works, due to the removal of the need to manually recharge the existing breakers. As such, we would consider that a portion of this capex would be offset by the associated opex savings resulting from the replacement of these old breakers with modern units.

Nuttall Consulting Recommendations

Our detailed review did not identify any power transformers that clearly require replacement during the next regulatory period. This view is based upon our assessment of the oil test results and other information provided by Aurora. In addition, none of the substations appear to be operating above their emergency N-1 ratings, bearing in mind that these peak loads occur in winter[79].

Although Aurora has requested the replacement of these power transformers in order to instigate an orderly power transformer replacement program, we consider that such a program should be commenced when the condition of these transformers warrant replacement.

Therefore, we do not consider that any allowance should be made for the proposed transformer replacements. However, six of the transformers will require oil reconditioning in order to maximize the service lives. Accordingly, we recommend that an additional allowance of $300,000 be included in the 2012/13 opex expenditure to cover these additional operating costs.

Aurora currently operates and manages a fleet of 49 power transformers, and while some are approximately 50 years old, our experience is that it is common practice to keep power transformers in service in excess of 60 years subject to ongoing maintenance and condition monitoring.

However, if the allowance for the proposed transformer replacements is removed then we consider that a capital allowance of $1 million in 2013/14 should be included for the purchase of at least one spare transformer, as Aurora currently has no spare power transformers. This should enable Aurora to manage the risks associated with an ageing power transformer fleet.

We do believe that an allowance should be made for the oil-filled switch replacement program, and Aurora's proposed levels seems reasonable. However, we consider that this additional replacement program should result in significant opex savings, as the need to send staff to recharge the closing springs after each operation of the existing switchgear will be avoided.

[79] That is when ambient temperature are lowest. This is the opposite of most states, which are summer peaking, and as such, the combination of high ambient temperatures coinciding with high demand is more onerous on a transformer.

In addition, the ongoing maintenance costs associated with modern vacuum breakers is considerably less than that associated with old oil circuit breakers. Furthermore, any breakers replaced during the next regulatory period will not require any maintenance until the following regulatory period so the savings associated with planned maintenance will not accrue till then.

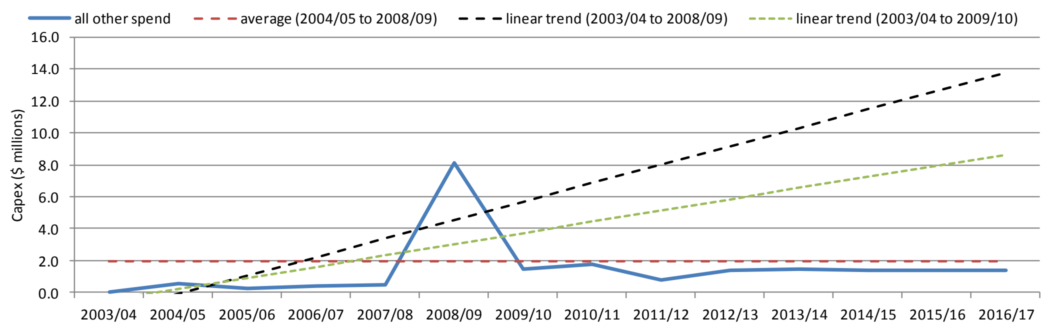
We estimate that the savings associated with the reduced system operating and maintenance requirements will amount to $46,000 per annum across the fleet[80]. These savings should be deducted from the forecast operating expenditures.

Based upon the above, we consider that the Aurora capex forecast on zone substation transformers and switchgear should be reduced by $7.0 million, to $4.4 million.

6.3.3.8 Other (distribution other, zone other, and other)

Figure 38 below shows a similar chart as those discussed above, showing the profile of the total capex allocated to these three other asset category (the solid line) and historical capex trends projected into the next period (the dashed lines). None of these programs were assessed through the repex model.

Figure 38 Replacement – other assets capex trend



This analysis indicates that capex on these programs had a very large spike in 2008/09. This spike was due to the large program rolling out the CablePI device to customers. This device allows for the monitoring of broken neutrals, which represent a shock hazard to customers. We also understand that these devices monitor certain power quality issues, most notably under-voltages.

Excluding the CablePI costs, capex has been at a very low level historically, but is forecast to increase in the next period.

Overview of programs and review findings

Twelve work categories have been allocated by us to these “other” asset categories. These work categories cover only a small portion of capex, and generally programs that cannot be easily classified into the main asset categories.

[80] Assuming $5,000 for reduced operating costs (based upon the cost assumed by Aurora) and $41,000 for reduced maintenance costs (based upon our estimate of typical maintenance costs).

We have reviewed a sample of size work programs under this heading. They are replace rural zone other, replace urban/CBD zone other, replace urban zone substation equipment (safety), replace ground mounted substations safety, replace live line clamps and wild life endangered species protection[81].

The total forecast expenditure for the next regulatory period for all six programs reviewed 44% ($3.1 million) of total expenditure allocated to this asset category. This represents an increase of 210% increase over the previous 5-year period.

Replace Rural Zone Other

This project involves the removal and disposal of all the equipment from the Hamilton Zone Substation, which was decommissioned in 2010/2011, and site reinstatement. This aspect of the decommissioning was omitted from the original project.

This project has been estimated at $0.1 million and we consider it to be prudent as it will avoid the need for future maintenance expenditures.

Replace Urban/CBD zone other

The aim of this program is to replace battery banks at zone substations, which have an estimated service life of 10 years. Aurora manages battery replacement through an ongoing program. There has been no historical expenditure in this category in the last period, because the batteries were replaced as part of the major substation upgrades during the early to mid-2000s.

Aurora proposes to replace two battery banks per year commencing 2014/2015.

We consider this approach to managing battery bank replacements to be prudent as they are an essential secondary system having a major impact on safety and network reliability. The timing is based on expected service lives, which for this asset class is considered reasonable.

Replace Urban Zone Substation Equipment (Safety)

The aim of this program is to address issues with fire doors and emergency lighting at Aurora's zone substations.

The installation of fire doors and doorways in fire walls is governed by the requirements of the Building Code of Australia(BCA). The requirements for the maintenance of fire doors are set out in *AS1851 Maintenance of fire protection systems and equipment*.

The installation of emergency lighting, exit lights and warning systems are also governed by the requirements of the BCA. The maintenance requirements for emergency lighting in zone substation buildings are specified in *AS/NZS 2293.2 Emergency evacuation lighting for buildings – Inspection and maintenance*.

Five of the nine urban zone substations are located in buildings constructed in the 1960s and 1970s, and do not comply with current requirements.

[81] The work categories reviewed cover RERZO, REUZO, REUZQ, REGMQ, REHLL, and SIWES. The work categories not reviewed cover RECBA, REGUA, SCMWA, SIPRE, SIPRS, SIUSA

We consider that this program is prudent as it can potentially have a significant impact on the safety of Aurora's staff. All the works are programmed for completion during 2012/13.

Replace Ground Mounted Substations Safety

The aim of this program is to reinforce the doors and locking mechanisms on Aurora's fibreglass padmount substations. The doors of this type of enclosure are easier to lever off than normal steel enclosures. This exposes the public to equipment containing live parts. This issue associated with the fiberglass padmount substation doors is well known and has been addressed by other DNSPs that had this type of substation enclosure in service.

In its justification document Aurora advises that it has approximately 250 sites with fibreglass enclosures and that it proposes to introduce a program to reinforce all sites within a 5-year period, commencing in 2012/2013. The proposed rate of reinforcement is 50 sites per year, as this will ensure all doors are reinforced during the next regulatory period.

We consider this program to be prudent as it removes a known safety risk for the public, particularly as Aurora has 67 sites in close proximity to schools, bus stops and highly populated areas. In addition the forecast volumes are manageable and will remove the threat and risk to the public by the end of the next regulatory period.

Replace Live Line Clamps

The aim of this program is to reduce the risk to the public posed by HV live line clamps causing conductor failure. Line clamps were used to connect new transformers directly to HV feeders without requiring an outage. This connection was intended to be a temporary connection to be changed to a D-clamp at the next planned outage or by a live line crew.

The connection of a live line clamp directly onto a live tensioned conductor can result in arcing, which can erode individual strands of the conductor reducing its tensile strength. The risk is greater for Galvanised Iron (GI) conductor as this arcing can remove the galvanising, which exposes the iron to moisture that may build up under the clamp. This leads to corrosion of the conductor, which can lead to conductor failure or fusing of the conductor to the clamp. The justification document states that an external consultant identified this issue as a significant fire risk during a fire mitigation audit in 2010.

Aurora has advised in its justification documentation that it currently has approximately 10,000 live line clamps in the system and a geospatial and risk based analysis found 1,840 high priority defects in the system. The program aims to address these high priority sites by the end of 2017.

Aurora proposes to replace live line clamps at 300 sites/year, starting with the highest priority sites, mainly live line clamps connected to galvanized iron conductors in close proximity to the sea.

This problem is also well known within the industry and most distributors have, or have programs in place to install, D loops on conductors for the connection of live line clamps.

We consider the program proposed by Aurora to be prudent and the proposed volumes reasonable considering the number of live line clamps directly connected to Aurora's mains.

Wild Life Endangered Species Protection

The aim of this program is to reduce the risk of interactions of distribution assets with endangered species. The separation distances between the conductors and components of the pole top are generally sufficient; however, birds and animals that inadvertently bridge this gap are electrocuted. Furthermore, birds, such as swans, geese, water fowls, raptors and crows, collide with power lines and are electrocuted.

At times these occurrences can result in unplanned outages. Bird collisions are more likely to occur where power lines are erected across flight paths, from roosting or nesting areas to feeding areas and close to bushland. Approximately seven endangered species per year are killed through interaction with Aurora's electricity infrastructure.

Aurora has advised that it has an agreement in place with the Department of Parks and Wildlife since 2008 to install bird perches and insulate the tops of steel lattice towers in endangered species nesting areas to reduce the risk of electrocution. Areas and poles for treatment are identified in conjunction with the Department before work is undertaken. Historically, on average, $0.1 million per year has been allocated to this program, which is in line with the forecast.

We consider this program to be prudent as all rural DNSPs have similar types of programs in place to assist in the protection of wildlife and endangered species. Generally the types and associated costs are negotiated with the authority as is the case in Tasmania.

Nuttall Consulting Recommendations

We have reviewed six of the twelve programs in the "Other" categories in detail and have found all to be prudent. In this regard, they either align with current industry wide practice or are designed to ensure compliance with the relevant standard, code or regulation. In addition, the proposed volumes appear reasonable considering the extent and likely impact of the problems or issues being addressed.

Given this finding (and our findings of the unit cost review), we consider it reasonable to consider the overall capex in the "other" categories to be prudent and efficient.

6.3.4 Replacement summary

Based upon the adjustments, identified above, we estimate that Aurora's total capex for the replacement programs should be as summarised in the Table 19 below. For comparative purposes, this table also indicates Aurora's proposed capex. This estimated adjusted allowance represents an 20% reduction to Aurora's proposed capex for these categories.

Table 19 Replacement adjustments to proposed capex

	Replacement capex ($ millions)					
	2012/ 2013	2013/ 2014	2014/ 2015	2015/ 2016	2016/ 2017	Total
Proposed	31.3	32.7	32.9	29.7	32.5	159.1
Nuttall Consulting	27.4	26.7	25.6	24.8	24.9	129.5
Poles	4.8	4.9	5.1	5.2	5.3	25.3
Conductor	6.7	6.6	6.5	6.5	6.4	32.7
Underground cables	2.4	2.4	2.4	2.4	2.4	11.9
Services	1.1	1.1	1.1	1.0	1.0	5.3
Distribution transformers	3.9	3.9	3.9	3.9	3.8	19.3
Distribution switchgear	4.9	4.9	4.7	4.4	4.6	23.5
Zones substation transformers and switchgear	2.2	1.5	0.6	0.1	0.1	4.4
Other	1.4	1.4	1.4	1.4	1.4	7.0

We consider that this amount should be sufficient to allow for the aging of the network, in order to maintain the network performance and operating costs. We have allowed a number of increases in safety related programs. We consider that these should reduce Aurora's overall risk position from what it has been operating to during the current period.

Two areas where we consider that adjustments may be required elsewhere to allow for the increased program activities relate to the replacement of LV consac cable and the oil filled switchgear at zone substations. We consider that both these programs should provide a significant reduction in overall opex and possibly improvements in reliability. These benefits should justify a large portion of the capex.

As discussed in the reinforcement section, we do not know what is allowed for in Aurora's opex forecast. As such, the AER will need to consider these matters further when deciding on the appropriate capex and opex allowances, and reliability targets.

6.4 Power quality

6.4.1 Overview of programs

The Power Quality component of non-demand capex is based upon the aggregation of capex in eight work categories. This component of capex is required to comply with various state and NEM-wide obligations associated with power quality; the majority relating to voltage obligations. Broadly, the capex can be considered to be broken down into the following four elements, discussed further below:

- reactive programs
- pro-active programs

- introduction of new technology
- surveys and studies.

The large portion (approximately 90%) of the capex relates to a series of "reactive" programs, which are intended to upgrade the network in response to voltage complaints from customers. The majority of this reactive capex is associated with upgrading distribution transformers[82], with the next largest being LV conductor upgrades[83]. A much smaller amount is associated with HV conductor upgrades and upgrades or installations of voltage regulators[84].

Aurora has developed the forecast for the main reactive programs based on the 5-year historical average (2005/06 to 2009/10) level of volumes. The capex forecast is then calculated from the historical costs per job over 2008/09 and 2009/10.

The majority of the remaining capex is associated with a program to install power quality (PQ) metering equipment on the network[85]. We understand that this is recent program that has been ongoing during the current period. The main aim of this program is to reduce costs associated with the reactive program, mainly in terms of the opex associated with responding to the customer complaints and improving capital efficiency (i.e. providing time to allow for solutions to be optimised with other needs rather than the short-term and piecemeal solutions that generally occur as result of the reactive programs)[86]. Aurora also state that this program has been developed with consideration of a future smart meter roll-out, and is aimed at measuring complementary information not available through smart meters[87].

The forecast for this program appears to be based upon assumed numbers and locations for the PQ meters, using Aurora's judgement as to where and how many. An assumed unit cost has been used to produce the capex forecast, based upon the volume assumptions; however, it is not clear how this cost has been derived. The total capex in the next period is $1.1 million. This is slightly below the level in the previous 5-year period, $1.3 million.

The main aim of the programs introducing new technology is to improve the capital efficiency via the deferral of more costly augmentations. The two main programs noted by Aurora are the use of low voltage regulators and the use of upgraded automatic voltage regulators (AVRs) in ground mounted substations[88]. The exact methodology used to determine the forecast is not clear from the information provided; however, it appears to be based upon assumed volumes and unit costs based upon the judgement of Aurora.

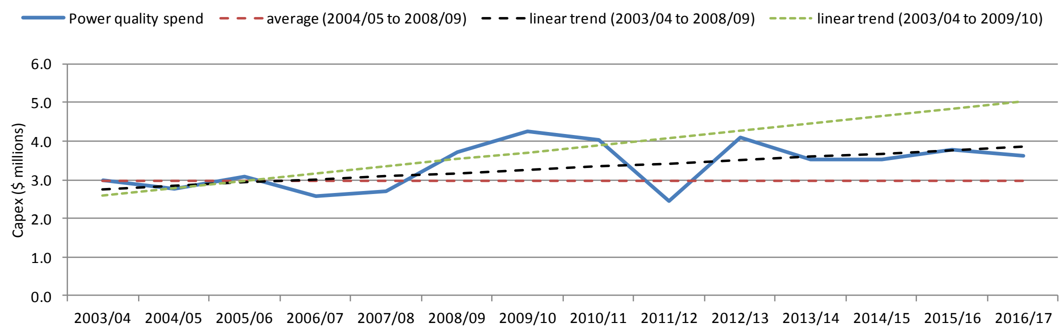
[82] PQTXV
[83] PQLVV
[84] PQHVV, component of PQRIV,
[85] PQMET
[86] See discussion in Section 7 and 8 of the Power Quality Management Plan 2011 (AE026)
[87] See discussion in Section 2 of Aurora's justification document, NW-#30199912-v1-Justification_PD2012_-_PQMET_-Install_Power_Quality_metering (confidential)
[88] Component of PQRIV

The remaining portion of capex is associated with conducting studies and surveys associated with power quality[89]. This appears to be a continuation of existing work associated with national power quality surveys and reporting and the use of consultants to aid in specific jobs. The exact methodology used to determine the forecast is not clear from the information provided; however, it appears to be based upon an assumed capex allowance per annum.

6.4.2 Nuttall Consulting review

Figure 39 below shows a similar chart to those discussed above for replacement capex, showing the profile of the total capex allocated to power quality programs (the solid line) and historical capex trends projected into the next period (the dashed lines).

Figure 39 Power quality capex trend



This chart indicates that capex was relatively constant prior to 2008/09. In 2008/09 and 2010/11 capex increased significantly. Capex is forecast to be above historical average levels, and broadly in line with the linear trend, excluding 2009/10.

To assess this category we have reviewed the asset management plans and justification documents provided by Aurora. The main documents reviewed have included:

- Power Quality Management Plan 2011 (AE026), which outlines the various PQ programs and associated capex and opex, and the needs and intentions of these programs.
- PQ process category analysis (NW 30132733), which provides a discussion on the methodology used to forecast the main reactive programs.
- PQMET forecast analysis (NW 30168190), which provides a discussion on the methodology used to forecast the program involving the installation of the PQ metering.

Overall, we accept that these programs, in principle, are required to maintain compliance with obligations associated with power quality.

[89] PQHVS and component of PQHVV

With regard to the capex associated with the reactive programs, we also agree that the rationale for using the historical averages is reasonable. We consider that such a historical average is also appropriate for the other reactive programs and the studies and surveys.

In applying this methodology, we do note that the category covering the largest portion of capex in the reactive programs (PQTXV) shows a significant increase during 2008/09 to 2010/11 ($2.4 to 2.7 million) from the level prior to this period ($1.4 to $1.7 million). We understand that this is partly related to the introduction of the Cable PI program[90], which found many voltage issues presumably in advance of complaints, and partly related to a change in operating practice that was imposed on Aurora resulting in unit costs increases[91].

The Aurora documentation suggests that external influences have been accounted for and excluded from the trending[92]; however, it is not clear how this has affected the forecast.

We have also considered whether Aurora's methodology, which uses a historical average of volumes and an assumed unit cost, could bias the forecast. This can be the case for work categories, such as these, where there could be a broad range of solutions of differing costs to address any specific voltage issue. To assess this issue, we have analysed the historical trend in capex. Based upon this analysis, we consider that the Aurora forecast is significantly higher (15%) than the historical average, prior to the increase due to cable PI program in 2008/09. We have not been presented with information that clearly justifies that the stated increase due to changes in operating practices could explain this increase.

As such, we consider that the forecast should be based upon the historical average capex, using capex in the 5-year period from 2004/05 to 2008/09. This results in a modest reduction in Aurora's forecast of approximately $1.6 million over the next period.

Turning to the other programs, namely the installation of PQ metering and the use of new technology, we certainly do not disagree that, in principle, such programs may be appropriate and may well represent (at least in part) the prudent and efficient approach to managing power quality issues in the future. However, we do not consider that Aurora's current reactive approach is clearly inappropriate, and it is our understanding that such reactive approaches are applied by other DNSPs. Aurora has indicated in its documentation that the primary aim of these programs is to improve customer service and the efficiency of the business, in terms of reducing both operating and capital costs associated with its reactive programs (and other network needs). Given Aurora has not presented any material that indicates customers have a significant concern with the current standard of service with regard to power quality, we consider that Aurora should only undertake these programs (or portions of them) where it is sufficiently sure net benefits will exist.

[90] See brief discussion in Section 6.3.3.8. This is the device provided by Aurora to customers that is primarily aimed at testing for broken neutrals. However, it also tests for undervoltages, which are a power quality issue.

[91] This second point was stated in meeting, but is not documented anywhere as far as we are aware.

[92] NW 30132733, Section 5, pg 6

As far as we can tell, Aurora is not anticipating any benefits to occur until after the next period, and as such has not factored any capex or opex adjustments into its proposal to reflect these programs. For example, with regard to the PQ metering, Aurora states in its documentation that it is only expecting benefits to occur following the roll out of a "critical mass" of meters, which it considers will occur after the end of the next period.

We do not agree with this view. We consider that the prudent approach would be to analyse, target and prioritise the roll-out in those locations where benefits are most likely to be the greatest. Therefore, we consider it reasonable to assume that benefits will accrue relatively rapidly. We also understand that Aurora has undertaking elements of the PQ metering program throughout the current period. As such, we consider that if the program has been implemented effectively, the net benefits should begin to be realised in the next period.

Given the points above, we recommend that the capex allowance should provide for these programs in total, but an adjustment should be made to the opex allowance to ensure that the impact of the program is revenue neutral over the next period.

We also consider it worth noting that, in total, we still consider that this should provide a conservative estimate of capex required to comply with power quality obligations, as the allowance will still provide for the reactive programs at historical levels. Furthermore, it may well be that some of the non-network solutions proposed for the next period will also dampen the need for some power quality upgrades. This point appears to have been recognised by Aurora in its management plan, but not specifically allowed for[93].

Based upon the above, we estimate that the allowance for the PQ programs should as shown in the Table 20 below. This table also indicates the portion we estimate should be offset by efficiency benefits.

Table 20 Power quality – adjustments to proposed capex

	Power Quality capex ($ millions)				
	2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	Total
Proposed	4.1	3.5	3.5	3.8	3.6	18.6
Nuttall Consulting	3.6	3.1	3.1	3.4	3.3	16.5
Maintain	2.9	2.9	2.9	2.9	2.9	14.3
Efficiency benefit	0.7	0.2	0.2	0.6	0.4	2.1

6.5 Reliability

6.5.1 Overview of programs

The reliability component of non-demand capex is based upon the aggregation of capex in a number of work categories. This component of capex is driven by various reliability

[93] PQ Management Plan, Section 4.3, pg 7

obligations, particularly in the TEC[94]. This obligates Aurora to use "reasonable endeavours" to meet various minimum reliability standards. Related to this, we understand that Aurora, like the Victorian DNSPs, must operate a guaranteed service level (GSL) scheme, which provides payments to customers when reliability falls below defined parameters.

Historically, Aurora's focus has been on improving reliability, but the Aurora proposal states that the aim of programs in next period is to maintain reliability and target worst performing parts of the network.

The main reliability programs can be classified under the following main themes:

- targeted reliability improvement programs (TRIP)
- local reliability programs
- remote control and protection programs.

The proposed TRIP program in the next period is opex and is not discussed further here.

The local reliability program accounts for approximately 30% of the reliability capex in the next period, $6.5 million. It is aimed at specific areas, where customers are considered to be subject to the worst performance. It covers a range of opex and capex programs. The capex programs[95] include:

- general network enhancements identified through monitoring systems
- network enhancements to address problematic assets identified through multiple visits by field staff
- installation of portable fault indicators to detect emerging reliability issues before they occur
- development of short feeder sections to provide alternate restoration paths for selected radial feeders
- network upgrades to mitigate against bird strikes, and the resultant reliability consequences.

Protection and control components accounts for approximately 40% of the reliability capex in the next period, $9.0 million. This component is aimed at enhancing reliability in urban areas, and ensuring good industry practice with regard to protection and control. The capex programs[96] cover:

- replacing existing overhead switchgear with reclosers on heavily loaded spurs
- rectification of protection zones to allow for load growth and network developments

[94] S8.6.11 of Tasmania Electricity Code
[95] Aurora work categories: PRREL, PRTXI, PRHOS, PRREH, PRSPT
[96] Aurora work categories: PRHVR, PRLVR, PRIGF, PRSEC, PRFLT, PRHUG, PRHOF

- replacing existing overhead EDO sectionalisers with enhanced sectionalisers (RL27s) in locations where increased performance is required
- installation of remote control switches (and fault indicators) to reduce operating costs associated with manual switching
- improving the accuracy of ground mounted substation protection drawings, reviews and studies.

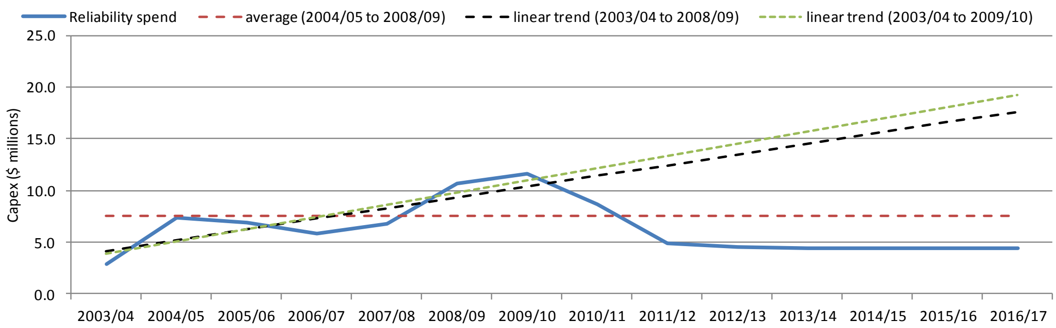
The remaining capex, $6.7 million, relates to four programs that we have considered are primarily related to addressing reliability (and operational inflexibility) issues. These are as follows[97]:

- a fuse reach program
- installation of possum guards
- install lightning arrestors
- development of access tracks.

6.5.2 Nuttall Consulting review

Figure 40 below shows a similar chart as those discuss above for replacement capex, showing the profile of the total capex allocated to reliability programs (the solid line) and historical capex trends projected into the next period (the dashed lines).

Figure 40 Reliability capex trend



This chart indicates that capex was increasing up to 2009/10, but then reduces substantially toward the end of the current period. We understand that the increase reflects a number of new programs initiated to achieve the significant reliability improvements that have occurred over the previous and current periods. Capex is forecast to be at a level similar to those around 2003/04.

To assess this category we have reviewed the asset management plans and justification documents provided by Aurora. The main documents reviewed have included:

- reliability strategy and reliability management plan (AE020 and AE025)
- protection and control management plan (AE024)

[97] Aurora work categories: RELSA, REINC, REILA, REOTC

- various documents referenced in above documents.

Based upon this review, our general view is that all these programs appear reasonable in principle, and constitute an appropriate solution to address possible reliability and operational issues.

However, given the increased allowance over the longer-term historical levels that we have allowed for in the replacement category, we consider that these programs should be considered to enhance the reliability and performance of the network. Therefore, the appropriate capex to cover these reliability programs would be justified by the benefits that would occur through opex reductions and reliability improvements.

For example, the programs to address local reliability issues are aimed at the worst served customers. Therefore, even if these program provide marginal benefits in overall reliability, we would expect that the reduction in historical GSL payments and general reduction in opex costs would need to justify the capex. We do not consider that Aurora has a clear obligation to address poor performance if the solution is clearly uneconomical (i.e. in these cases it would appear continuing with GSL payments would be the prudent and efficient action).

We consider a similar situation is appropriate for the protection and control projects and other reliability programs we have identified. With regard to the protection of control projects, we note that Aurora has undertaken analysis to identify the most likely locations on its network where these programs will be needed. However, we consider that the capex would need to be justified based upon the opex and reliability benefits that will eventuate from these specific upgrades. Given the nature of the proposed works, we consider that it is reasonable to assume that these benefits would occur immediately following the works, and so, should result in opex reductions and reliability improvements in the next period.

Based upon the above, we consider that the reliability capex should be excluded, as we do not consider that Aurora has adequately demonstrated that it is required to maintain service levels. We consider that this position is in line with our findings on similar projects proposed by the Victorian DNSPs.

Alternatively, if a capex allowance is accepted for these programs then the AER will need to confirm that appropriate adjustments are allowed for in the opex allowance and reliability targets to ensure that the capex would result in net benefits.

7 Non system capex

7.1 SCADA and Network Control

Aurora is proposing an increase of over 514% in Supervisory Control and Data Acquisition (SCADA) and Network Control capex for the next Regulatory Control Period when compared against actual expenditure in the current Regulatory Control Period. Aurora estimates that its SCADA and Network Control capex for the current regulatory control period will be $2.3 million. It is forecasting that this will increase to $14.1 million in the next regulatory control period.

SCADA and Network Control activities include the remote communications with field devices and plant to aid in the management and control of the network. Typically this includes communications and control of switches and circuit breakers, and telemetry information about the condition and performance of major items of plant.

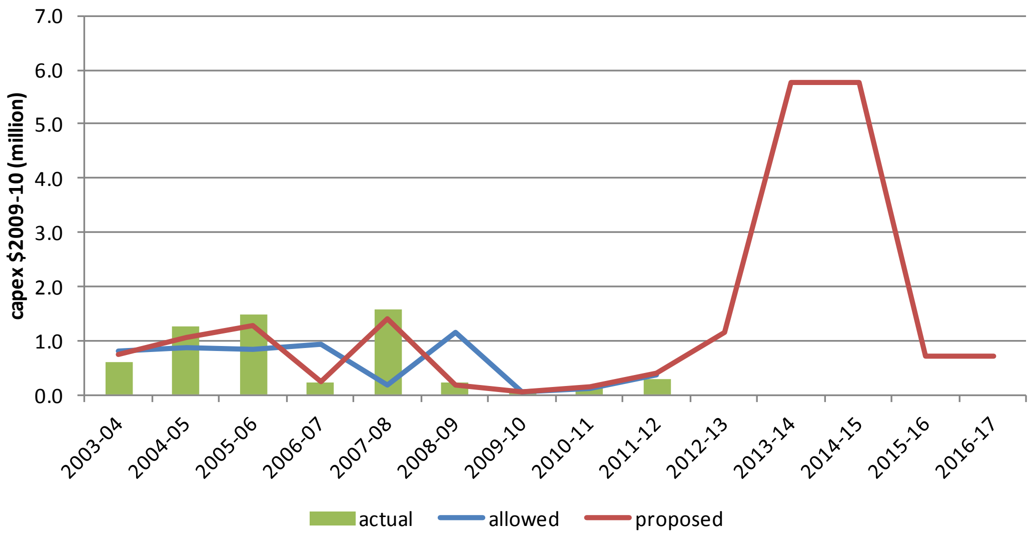
Table 21 - Proposed Aurora SCADA and Network Control capex

Aurora	Costs (2009-10 $000)				
SCADA and Network Control	2012-13	2013-14	2014-15	2015-16	2016-17
Proposed Expenditure	1,157	5,762	5,766	715	707

For the 2006 EDPR, Aurora proposed SCADA and Network Control expenditure of $2.1 million. The resultant actual expenditure for this period is forecast to be $2.2 million[98].

Figure 41 provides a summary of SCADA and Network Control capex for Aurora.

Figure 41 - Aurora SCADA and Network Control capex

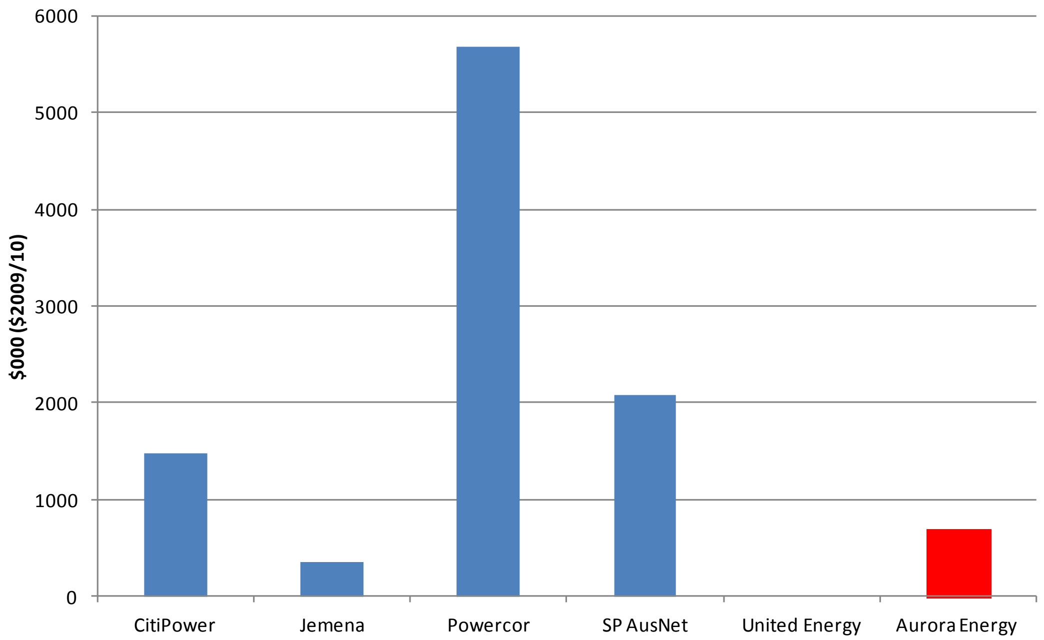


[98] Including 2009 And 2010 Estimates.

Expenditure on SCADA and Network Control in the current period has been relatively low compared to the previous period. Average expenditure for the previous 8 years has been \$0.7 million per annum. This is an average spend of less than one quarter of that proposed for the next period.

The Aurora historical SCADA and Network Control capex appears lower than that of the Victorian DNSPs for the current control period with the exception of Jemena. Figure 42 provides the average annual actual capex for SCADA and Network Control for the historical actual period.

Figure 42 - Historical SCADA and Network Control capex (average per annum)



The above chart shows that the historical SCADA and Network Control capex for Aurora is lower than that of the Victorian DNSPs with the exception of Jemena[99]. The Victorian DNSPs are on average larger in network scale and customer numbers than Aurora and this may account for some of the discrepancy in expenditure. The Victorian DNSPs also service a far greater number of zone substations than Aurora[100]. Zone substations are key assets and are typically hubs for SCADA and Network Control assets.

However, Aurora did not categorise SCADA and Network Control as a category of work during the current period, rather this expenditure was under the Asset Management Capability Category[101]. As the current period SCADA and Network Control capex figures are retrospective allocations, they may not be consistent with the SCADA and Network Control of other DNSPs.

[99] United Energy did not report any expenditure in SCADA And Network Control. This is considered an allocation issue, and does not mean that no capex was spent in SCADA And Network control assets.

[100] The Tasmanian transmission company (Transend) is responsible for the majority of zone substations in Tasmania.

[101] RIN Response Part B Capital Expenditure, P133 Aurora Energy.

Aurora is forecasting SCADA and Network Control capex of $14.1 million for the next control period. This is an average expenditure of $2.8 million per annum and would be significantly greater than the average Victorian DNSP expenditure. The factors driving the proposed increase in Aurora's SCADA and Network Control capex are considered below.

The Aurora proposal[102] identifies the key programs for the next control period as:

- DMS capabilities providing support for network diagram management, control room work flow management, switching and safety logic management, system configuration management and replication capability to provide 24x7 system availability.
- SCADA capabilities providing support for initiating remote control and receiving asynchronous changes of state, analogue management, alarm management, advanced intelligent automated schemes, and online configuration testing and commissioning of incremental additions to the SCADA system.
- Distribution power analysis capabilities providing support for load flow and short circuit calculations, multiple modes for analysis e.g. live and study modes, load profiling and load allocation, and graphical and text reporting.

The Aurora program of works lists three work categories relating to SCADA and Network Control. The activities are divided into two threads and this identifies the responsibilities for delivery of these projects.

The work categories that are listed under the Protection and Control thread relate to the installation of high voltage feeder controls, data acquisition and communications. These are standard SCADA and Network Control category works and represent a similar level of expenditure to historical levels.

The work categories listed under the Network IT thread are titled "IT Software – SCADA" and have a unit type of "SMARTGRID". The naming of this category and the allocation of responsibility to the Network IT group suggests that these works are more typically considered as IT related. The remainder of the "SMARTGRID" unit types are listed as "IT Software – General". Nuttall Consulting asked Aurora about the overall IT spend[103] and the response to this included the SCADA IT software costs.

Nuttall Consulting has also reviewed supporting IT documents and consultants reports provided by Aurora and it is clear that these activities are considered as part of the overall IT strategy for Aurora. Aurora has also confirmed[104] that the proposed "IT Software – SCADA" works are centrally located, and do not relate to specific zone substation or feeder works.

On this basis Nuttall Consulting recommends that the "SMARTGRID" work category items be considered as network IT. Nuttall Consulting has relocated these expenditures to the IT category (Section 7.2).

[102] Ibid P134.
[103] Onsite meeting at Aurora Energy offices, Kirksway Place, Hobart – 8 August 2011.
[104] Ibid.

Table 22 – SMARTGRID costs reallocated to IT

Aurora SMARTGRID	Costs (2009-10 $) 2012-13	2013-14	2014-15	2015-16	2016-17
Reallocated Expenditure	535,427	5,252,458	5,255,615	210,341	209,884

The proposed expenditures remaining in the SCADA and Network Control category have been reviewed by Nuttall Consulting and are considered to represent the prudent and efficient level required to carry out the regulated activities in this area.

Nuttall Consulting notes that the resultant SCADA and Network Control expenditures in this category are lower than the averages of the Victorian network businesses. Nuttall Consulting considers that these expenditures do not represent an under-investment in this area for the following reasons:

- Aurora is a smaller utility than the average Victorian DNSP in terms of assets, customer numbers and energy delivered.
- Aurora is not responsible for the majority of zone substations in Tasmania; and zone substations contain the greater proportion of SCADA

Table 23 - Recommended Aurora SCADA and Network Control capex

Aurora SCADA and Network Control	Costs (2009-10 $000) 2012-13	2013-14	2014-15	2015-16	2016-17
Recommended Expenditure	622	510	510	505	497

The recommended SCADA and Network Control expenditures (Table 23) are based on Aurora's program of works.

7.2 Non-system general – IT

The following section discusses our review the capex allocated to non-system general IT.

7.2.1 Expenditure overview

Aurora submitted IT capex of $46.3 million over the forthcoming regulatory control period, which represents a decrease of 32% from current control period expenditure ($68.3 million).

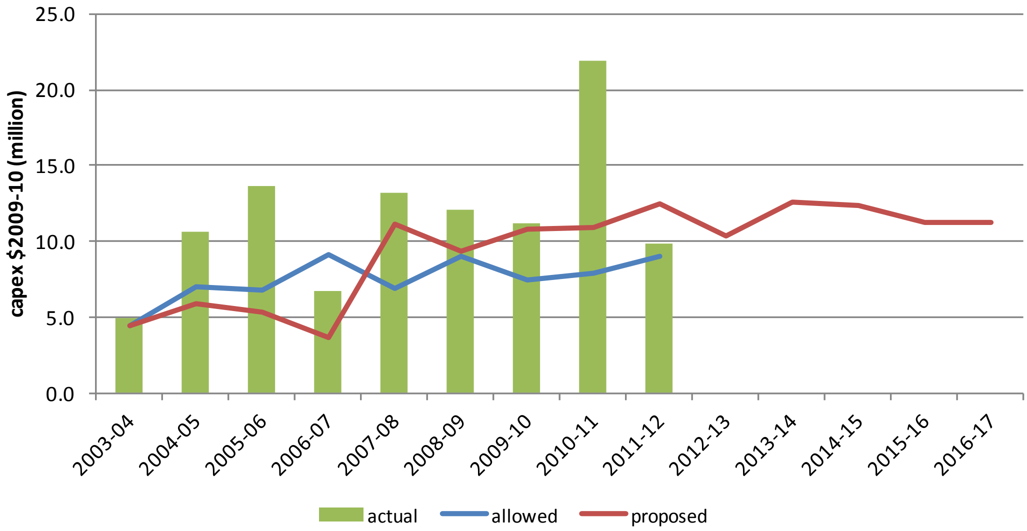
As noted above, Nuttall Consulting has determined that a proportion of the SCADA and Network Control capex should more accurately be allocated to the IT category (Section 7.1). The re-allocated total amount for the next period is $57.2 million as detailed in Table 24 below.

Table 24 – Revised Aurora IT capex

Aurora IT Capex	Costs (2009-10 $000) 2012-13	2013-14	2014-15	2015-16	2016-17
Proposed Expenditure	9,818	7,348	7,148	10,994	10,995
SCADA and Network Control	535	5,252	5,256	210	210
Revised Expenditure	10,354	12,601	12,404	11,205	11,205

Figure 43 highlights the revised IT capex proposed by Aurora for the previous, current and forecast control periods. Actual and allowed IT capex is also shown for the current and previous control periods.

Figure 43 - Aurora proposed vs actual IT capex



Aurora has identified a significant increase in expenditures in 2010/11, which relates to $7.6 million of IT costs that were a result of the mandated implementation of Tranche 5A of retail contestability.

Major proposed IT capital projects include:

- market interfaces
- road lighting
- asset management
- workforce management
- customer case management
- profiling & tariff modelling
- SCADA and Network Control.

During the current control period, Aurora overspent their proposed IT capex from a proposed amount of $54.6 million to an actual spending of $68.3 million. This is an overspend of 25% from the amounts that Aurora considered they would require for the period. Aurora overspent its allowance, primarily due to joining the National Electricity Market and its retail contestability obligations. Aurora states that “These variances relates (sic) to the establishment of IT systems required to support further tranches of retail contestability and NEM activity”.[105] Taking into account the IT expenditures for retail contestability, we consider that Aurora’s proposed IT capex is broadly in line with past expenditure, irrespective of the 16% efficiency benefits.

Figure 44 - Historical IT and Communications capex (average per annum)

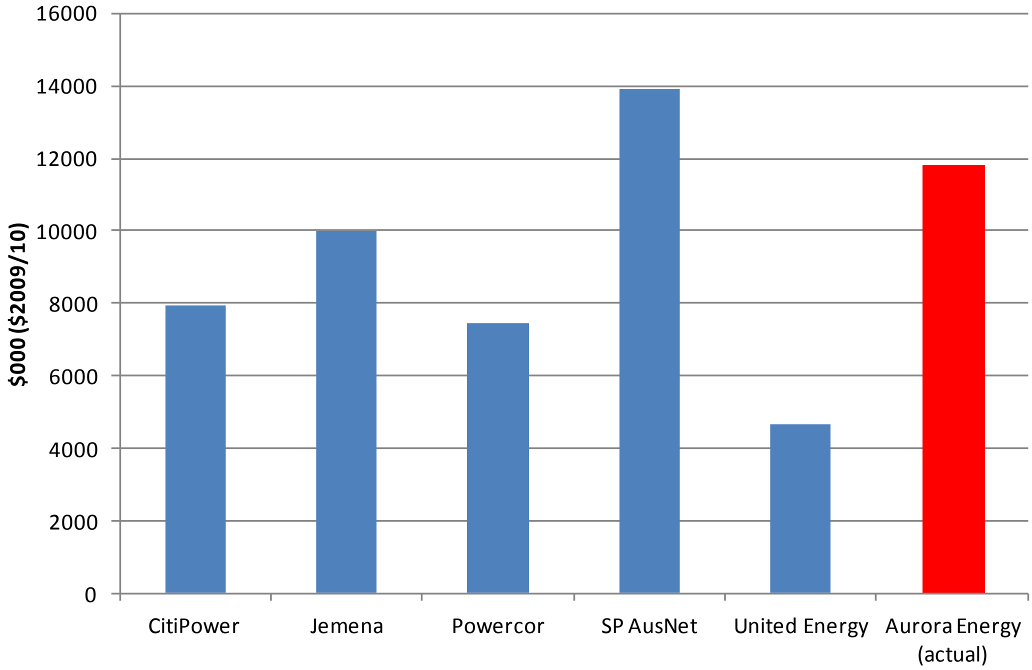
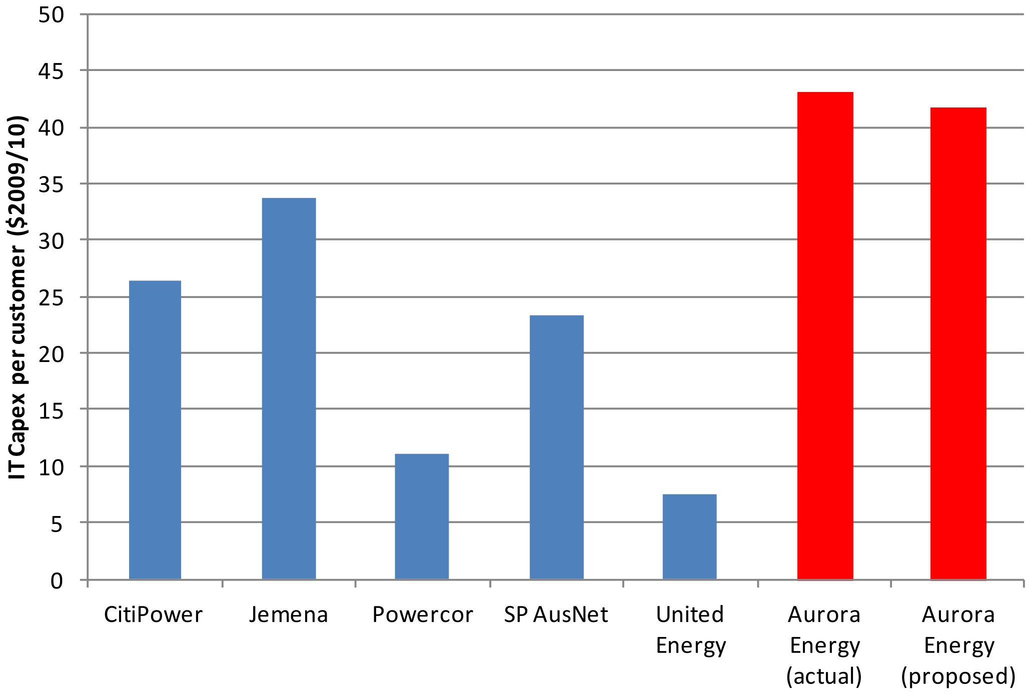


Figure 44 shows that the historical IT capex for Aurora is higher than that of the Victorian DNSPs with the exception of SP AusNet. The Victorian DNSPs are on average larger in network scale and customer numbers than Aurora. It is not immediately obvious why the IT expenditures incurred by Aurora would be greater than the average Victorian level of expenditure.

If we consider the IT expenditure on a per customer basis (Figure 45), we see that Aurora’s historical and proposed IT expenditure is greater than all of the Victorian DNSPs.

[105] RIN Response Part B Capital expenditure,. p161.

Figure 45 - IT and Communications capex (average per annum per customer)



Aurora is proposing forecast IT capex of $57.8 million for the next control period. This is an average expenditure of $11.4 million per annum and is closer to the average Victorian DNSP expenditure, but still considerably higher on a per customer basis. The factors driving the proposed Aurora IT and Communications capex are considered below.

7.2.2 Strategic investment

Aurora is proposing a significant increase in IT capex to achieve a step change in business operations and significant ongoing cost efficiencies.

The information provided by Aurora on the current state of its IT systems identifies a complex IT operating environment with a significant number of small and relatively independent IT systems. The significant step change proposed for the future technological state of Aurora is to adopt a consolidation strategy centred on a tier-one platform.

[redacted]

7.2.3 Strategy and network integration

Aurora had provided detailed information regarding the need for a significant improvement in IT infrastructure and services. This information is well documented and supported.

Aurora's Distribution Network ISG Strategy 2012-2017[106] provides a detailed summary of the drivers, analysis of options and proposed roadmap to achieve the desired future state. Aurora has provided a significant volume of information to support the proposed approach. Much of this supporting information is in the form of reviews and reports from IT consultants.

The goal of the Aurora IT strategy is to enable the goal "to not contribute to any price increases to the customer as a result of our efforts and specifically enable the strategic metrics of 16% operational cost reduction through increasing operational efficiency and $20 million capex reduction over the 2012-2017 RCP"[107].

The above capital and operating efficiencies are quite significant.

Aurora has undertaken a high level review of the business as usual IT activities. From the information provided by Aurora it would appear that the proposed strategic capital IT works[108] are at least equal to the proposed $20 million capital reduction[109]. This still leaves the operating efficiencies which are significant in their own right.

Due to the current state of the proposed IT program, the level of accuracy of the proposed expenditures are not well detailed. This is not a criticism of Aurora and recognises that, in general, the accuracy of project forecast increases as the project progresses along the project management pathway. Aurora has provided a review of the proposed IT programs where the consultant also notes this issue; "Aurora has estimated the costs of strategic IT initiatives at a high level, however, a breakdown of these cost estimates do not exist. There is insufficient information for MHC to provide comment on the adequacy of these costs".[110]

The challenge for this review is to consider whether the information provided reasonably supports the proposed expenditures in light of the National Electricity Rules, and in particular the capital expenditure objectives.

7.2.4 Capital expenditure objectives

In assessing the proposed Aurora IT capex, Nuttall Consulting has considered the following factors.

Table 25 – Capital expenditure factors[111]

Capital Expenditure Factors	Comments
1. the information included in or accompanying the building block proposal;	• Nuttall Consulting has reviewed the information contained in the proposal, information provided at the onsite

[106] NW-#30175103-v1-Aurora_Distribution_Network_ISG_Strategy_2012_-_2017_FINAL.pdf (confidential)
[107] Ibid p3 (confidential).
[108] i.e. those in excess of business as usual.
[109] NW-#30095109-v2E-Asset_Management_Capability_-_2012_-_2017_PS.XLS (confidential)
[110] Marchment Hill Consulting, Network IT Strategy Review, Aurora Energy, Version Number 1.0, 7 May 2010 (confidential)
[111] National Electricity Rules cl 6.5.7(e).

Capital Expenditure Factors	Comments
	meetings, and information submitted in response to specific questions.
2. submissions received in the course of consulting on the building block proposal;	• At the time of drafting this report, no submissions had been received by Nuttall Consulting in relation to the building block proposal.
3. analysis undertaken by or for the AER and published before the distribution determination is made in its final form;	• Nuttall Consulting has relied on analysis and information prepared by the AER as well as its own analysis and review.
4. benchmark capital expenditure that would be incurred by an efficient Distribution Network Service Provider over the regulatory control period;	• The level of IT expenditure in the current period is marginally higher than the proposed IT capex. • Benchmark IT capex for Aurora is greater than the Victorian average both on a per customer and a per business comparison.
5. the actual and expected capital expenditure of the Distribution Network Service Provider during any preceding regulatory control periods;	• Actual IT expenditure for Aurora is significantly greater than originally proposed in the current and previous control periods.
6. the relative prices of operating and capital inputs;	• Aurora is forecasting a significant reduction in labour cost inputs over the next control period based on the implementation of the proposed IT program.
7. the substitution possibilities between operating and capital expenditure;	• Aurora has identified significant operating reductions resulting from the proposed IT programs. • Nuttall Consulting has identified capital efficiencies in network capex for the next control period that will be facilitated by the proposed IT improvements.
8. whether the total labour costs included in the capital and operating expenditure forecasts for the regulatory control period are consistent with the incentives provided by the applicable service	• The proposed IT programs incorporate a number of changes that are likely to result in improvements to reliability outcomes (e.g. works scheduling and fault response). • Aurora has not quantified the proposed

Capital Expenditure Factors	Comments
target performance incentive scheme in respect of the regulatory control period;	reliability improvements that may accrue from the proposed IT capex.
9. the extent the forecast of required capital expenditure of the Distribution Network Service Provider is referable to arrangements with a person other than the provider that, in the opinion of the AER, do not reflect arm's length terms;	• [redacted] • The exact nature of the vendor selection process is not stated.
10. the extent the Distribution Network Service Provider has considered, and made provision for, efficient non-network alternatives.	• IT systems are the enablers of more efficient performance outcomes. However, Aurora has not identified any specific initiatives to target efficient non-network alternatives within the target state architecture.

7.2.5 Recommendations

Based on the above analysis, Nuttall Consulting considers that the IT capex proposed by Aurora for the next control period meets the criteria for acceptance; specifically in relation to the factors identified for consideration in the NER.

The proposed capex is slightly lower than the current period expenditure levels, but higher than the benchmarks of IT expenditure in the recent Victorian review. However, this is balanced by significant operating and capex reductions proposed by Aurora. We also note that Aurora's proposal is broadly in line with past expenditure, irrespective of the 16% efficiency benefits.

Table 26 – Recommended Aurora IT capex

Aurora	Costs (2009-10 $000)				
IT Capex	2012-13	2013-14	2014-15	2015-16	2016-17
Proposed Expenditure	9,818	7,348	7,148	10,994	10,995
SCADA and Network Control	510	5,000	5,000	200	200

Aurora IT Capex	Costs (2009-10 $000) 2012-13	2013-14	2014-15	2015-16	2016-17
Recommended Expenditure	10,328	12,348	12,148	11,194	11,195

It is important to note that in accepting this allowance for IT, we are also accepting that it is reasonably likely that the efficiency benefits will be achieved and are allowed for in Aurora's forecast for opex and capex. Moreover, we consider it reasonable to assume that this IT-related capex is a primary factor associated with achieving the stated efficiency improvements – that is a primary aim of investment in IT.

As has been discussed in both the reinforcement and non-demand sections, through our review of the plans underpinning these components of Aurora's forecast capex in the next period, we have also found a significant level of capex that would also appear to be justified by similar efficiency improvements. As far as we can tell, these improvements must be in addition to the the IT-related improvements. Furthermore, in the case of this network-related capex, we consider it less clear that Aurora's proposed efficiency improvements inherently allow for this capex.

The AER will need to satisfy itself that appropriate adjustments to opex (and possibly reliability targets) have been applied to cover both these cases.

Note: Nuttall Consulting has not assessed the ring-fencing of the proposed IT programs. Although an integrated platform is required, the allocation of Alternate Control Services and non-regulated services may need to be considered.

7.3 Non-system motor vehicle capex

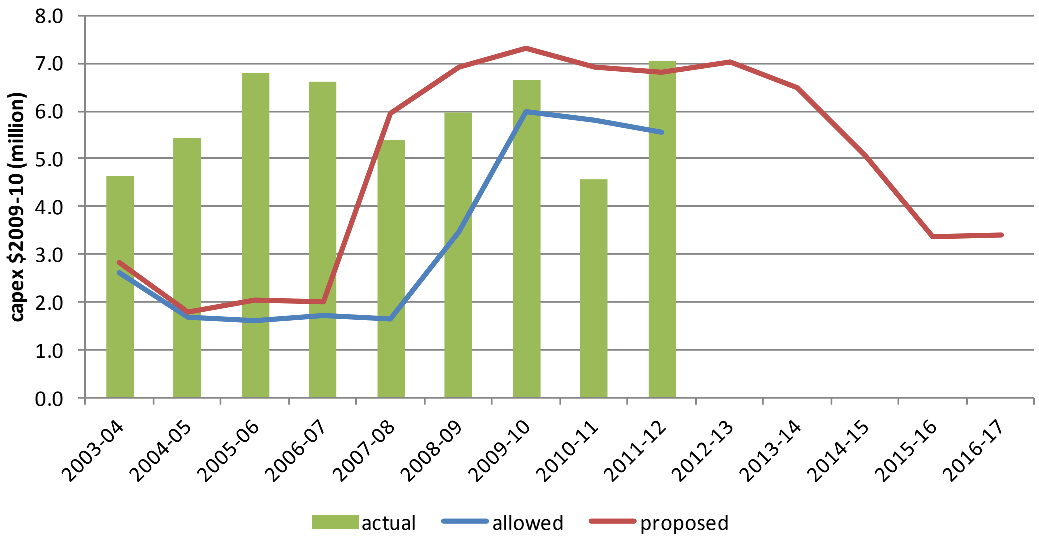
Aurora submitted motor vehicle capex of $25.3 million over the forthcoming regulatory control period, which represents a decrease of 14.5% from current control period expenditure ($29.6 million).

Table 27 - Proposed Aurora Motor Vehicle capex

Aurora Motor Vehicle Capex	Costs (2009-10 $000) 2012-13	2013-14	2014-15	2015-16	2016-17
Proposed Expenditure	7,021	6,487	5,052	3,371	3,382

Figure 46 highlights the motor vehicle capex proposed by Aurora for the previous, current and forecast control periods. Actual and allowed capex is also shown for the current and previous control periods.

Figure 46 - Aurora proposed vs actual motor vehicle capex



During the current control period, Aurora underspent its proposed motor vehicle capex from a proposed amount of $33.9 million to an actual spending of $29.6 million. This is an underspend of 13% from the amounts that Aurora considered they would require for the period. This highlights that the processes for forecasting motor vehicle expenditure for the current period were not able to anticipate the expenditure requirements. Aurora states that "The significant underspend variation between Aurora-proposed expenditure and actual and (sic) expenditure is due to OTTER disallowing $1.5m annually from this capital expenditure category (2007 Final Report, section 4.4.6) and Aurora re-budgeting to accommodate the change".[112]

This explanation of the variation is counter-intuitive as Aurora operates under an incentive regime and has the freedom to make expenditures where it considers they are required. The phrasing of the Aurora response suggests that it would have spent the additional capex if it was allowed. It is not clear whether Aurora reduced expenditure below the efficient or prudent level or whether the OTTER allowance more reflected the prudent and efficient level.

Nuttall Consulting has not been able to undertake any benchmarking of motor vehicle capex against other DNSPs as there is a wide variety of funding methods employed by the DNSPs for vehicles and plant. Many DNSPs lease their vehicles and plant from specialist providers and the expenditures appear as annual operating expenditures. These amounts would therefore not be comparable to the Aurora capex. Aurora purchases motor vehicles and therefore has a significantly greater capex in this category than most other DNSPs in the national electricity market.

[112] Ibid P162.

Nuttall Consulting has not reviewed the rationale for purchasing vehicles in preference to leasing. Aurora has provided a report titled the "Boland Report"[113] that recommends the outsourcing of fleet management services, and also recommends that Aurora "continue to own all fleet assets unless there is a business case to lease".[114]

The Boland Report identified efficiency savings of $773,000 per annum. Of these savings, approximately $290,000 related directly to capex.

The Boland Report and the Aurora participation in the Fleet Management utilities benchmarking group[115] suggests an active program to review and manage the Aurora motor vehicle fleet.

Nuttall Consulting also noted that Aurora uses the State Government contract for vehicle purchasing and individual contracts for trucks and special equipment. This is considered to provide Aurora with access to highly competitive prices for large volume vehicles.

The Aurora Strategic Fleet Asset Management Plan 2011-2016 identifies a sound methodology and approach to the management of fleet assets and incorporates principles of best practice asset management.

On the basis of the detailed management practices, industry benchmarking, and competitive tendering Nuttall Consulting considers that current levels of motor vehicle capex represent an efficient base[116].

The Aurora approach to developing the capex forecast for motor vehicle capex has been difficult to determine.

In the information provided to explain the RIN, Aurora stated that "capex forecasts in the motor vehicles category consists of a 5 year forecast prepared using an excel spreadsheet".[117] Unfortunately, the spreadsheet referred to was not referenced. On the following page Aurora state that "no quantitative models are used in developing the capital expenditure forecast for the motor vehicles category".[118] These two statements appear contradictory.

The AER requested that Aurora clarify this position[119]. Aurora was requested to explain the models and provide detailed descriptions of how the projected (current regulatory control period) and forecast (next regulatory control period) vehicle, plant and equipment capex were developed including:

1 descriptions of input assumptions

2 detailed discussion of the individual models or processes used to develop the expenditure forecasts.

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113 Final Report, Aurora Energy Fleet Management Review, 23rdMay 2008, Logistics Bureau (partially confidential).

114 Ibid p9.

115 Strategic Fleet Asset Management Plan 2011-2016, Version 0.1/0.2, 28 February 2011, Aurora Energy, p22.

116 Noting the potential saving identified by the Boland Report.

117 RIN Response Part B Capital expenditure, Aurora Energy, p67

118 Ibid, p68.

119 Request AER/005 – Regulatory Obligations and Non-System Capex, 7 July 2011

The Aurora response was as follows: "Aurora has not forecast any Plant and Equipment capex in the forthcoming Regulatory Control Period"[120]. Aurora did not provide any additional information on the development of the motor vehicle capex forecast in this response.

Aurora has provided an un-referenced[121] spreadsheet that details fleet and vehicle expenditures[122]. This spreadsheet provides a detailed identification of Aurora vehicles and plant, including:

- passenger and executive vehicles
- 2WD + 4WD Light Commercial vehicles
- trucks
- elevating Work Platform
- vehicle Loading Crane Plant
- borer Erector Plant
- compressor Plant
- winch and Winding Frame Plant
- trailers and forklifts.

The spreadsheet details the replacement of each asset on the basis of age or kilometres. The model is quite complex and appears to be operational in nature as it contains a number of different output sheets for different Aurora business units.

The capex forecasts contained in this spreadsheet are not consistent with those of the Aurora RIN. The spreadsheet capex forecasts are over 50% higher than the RIN forecasts.

Table 28 – Aurora Fleet Reforecast spreadsheet

Aurora	Costs ($2009-10)				
Motor Vehicle Capex	2012-13	2013-14	2014-15	2015-16	2016-17
Expenditure	9,467,058	9,227,948	7,770,597	4,788,109	8,633,534

The differences between the two forecasts may relate to the allocation between regulated and non-regulated activities. If this is the case, it is not evident from the detailed spreadsheet.

The income from the sale of replaced vehicles may also account for some of the difference between the two items. However, the calculation of sales in the spreadsheet does not reconcile the difference between the proposed amounts.

[120] Ibid, p17.

[121] Nuttall Consulting was unable to locate any references to the spreadsheet in the Aurora Energy submissions or responses.

[122] CO-#10199592-v3-2010_2011_Fleet_Reforecast_-_Mel_Scott_Copy_05_11_2010.XLS (confidential).

On this basis, it is not possible to reconcile the spreadsheet to the capex proposed by Aurora for motor vehicles.

As discussed previously in this chapter, Nuttall Consulting considers that the existing Aurora fleet management plan incorporates principles of best practice. Aurora has also sought external review and recommendations for improvements to the fleet management process and has access to government purchasing arrangements. On this basis, the Aurora forecast appears reasonable as it provides for significant reductions (14.5%) on current expenditure levels. Table 29 provides the motor vehicle capex that is recommended by Nuttall Consulting.

Table 29 - Recommended Aurora Motor Vehicle capex

Aurora	Costs (2009-10 $000)				
Motor Vehicle Capex	2012-13	2013-14	2014-15	2015-16	2016-17
Recommended Expenditure	7,021	6,487	5,052	3,371	3,382

7.4 Non-system property capex

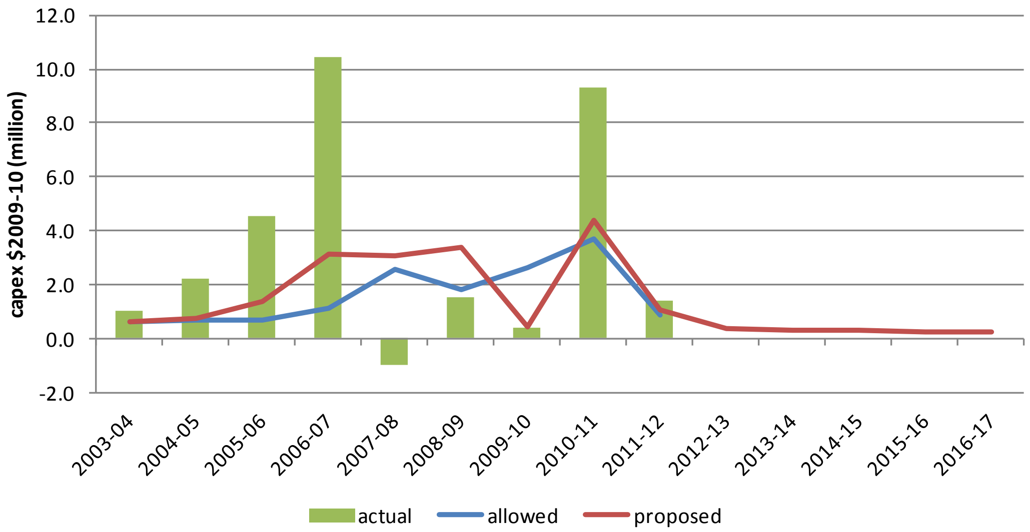
Non-system – property capex standard control capex (property capex) is defined as the replacement, installation and maintenance of non-operational buildings, fittings and fixtures; excluding attributed capitalised overheads. Aurora submitted property capex of $1.4 million over the forthcoming regulatory control period, which represents a decrease of 87.5% from current control period expenditure ($11.7 million).

Table 30 - Proposed Aurora Property capex

Aurora	Costs (2009-10 $000)				
Property Capex	2012-13	2013-14	2014-15	2015-16	2016-17
Proposed Expenditure	352	330	287	253	231

Figure 47 highlights the property capex proposed by Aurora for the previous, current and forecast control periods. Actual and allowed property capex is also shown for the current and previous control periods.

Figure 47 - Aurora proposed vs actual property capex



During the current control period, Aurora underspent its proposed property capex forecast of $12.3 million by 5%. Although the quantum of expenditure for the period is fairly well aligned with the forecast, the alignment of the yearly expenditures is highly inconsistent.

Key activities undertaken by Aurora in the current period include the refurbishment of the head office in Kirksway place in Hobart, the construction of a data centre in Moonah and redevelopment of the Aurora training centre in Mornington. Nuttall Consulting considers that the activities to relocate major office space are difficult to accurately forecast; especially in terms of timing. On this basis, the yearly variations between actual and proposed capex in the current period are not a consideration when reviewing the forecast for the next control period.

Nuttall Consulting understands that Aurora has purchased the land for the data centre in Moonah and is in the process of designing the data centre facilities[123].

In terms of leasing or purchasing, Aurora's current approach is such that office accommodation will be leased, while properties that are used for specific operational requirements should be owned. The purchase of the data centre land and the leasing of Kirksway Place appear consistent with this approach.

The Aurora forecast for property capex for the next control period is significantly less than expenditure in the current period. The reason provided by Aurora for the significant reduction in expenditure in this category is the completion of the Southern Accommodation strategy. This strategy involves the consolidation of accommodation into 21 Kirksway Place, and the divestiture of the Moonah site.

The methodology for determining the property capex forecast is described by Aurora as being part of the development of the five-year strategic plan[124]. The property capex

[123] Aurora Energy Facilities Management Plan May 2010 Version: 1.0

[124] RIN Response Part B Capital expenditure, Aurora Energy, p74

forecast is reported to be developed in accordance with the Facilities Management Plan and the requirements of the Property Register with the age of the facilities as the key driver of the budget.

In the RIN response, Aurora state that "(t)here are no quantitative models used in developing the Property capital expenditure forecast". This would appear inconsistent with the provision of the facilities registers property list spreadsheet that identifies all major properties, values and forecast capex requirements. During the Nuttall Consulting review, Aurora was requested to "(d)escribe and provide the models (spreadsheets, etc) that were used to develop the forward expenditure forecast"[125]. Aurora did not provide any additional information to support the proposed expenditure.

The facilities registers property list spreadsheet identifies $6.5 million of capex for the next control period across 23 depots, offices and response centres. This expenditure is significantly greater than that actually being proposed by Aurora. The level of detail contained in the property list is greater than that provided by Aurora to support the property capex contained in the proposal. It is possible that the allocation of these expenditures to non-regulated activities may account for some of the difference between the two amounts, although this is not identified in the documentation.

The number and value of the properties listed in the facilities register property list spreadsheet would suggest a reasonable level of capex is required to maintain the facilities in a safe operating condition. However, the information in this spreadsheet is not sufficient to determine the appropriate long-term level.

The forecast property capex as submitted by Aurora for the next control period is trending down, but the trend is not consistent or based on any obvious formula. Aurora has not provided any information supporting the starting position for the forecast or the expenditure trend.

Nuttall Consulting is unable to assess the methodology for the property capex forecast due to the lack of supporting evidence or methodology provided by Aurora. It would be unreasonable to assume that no capex is required to maintain the existing property assets of Aurora.

The amounts proposed by Aurora would appear to be the minimum level of expenditure required to maintain the existing Aurora property list. In addition, Aurora states in its facilities management plan that its current accommodation setup is likely to remain largely unchanged. On this basis, Nuttall Consulting recommends that the amounts proposed by Aurora be accepted (see Table 31).

Table 31 - Recommended Aurora Property capex

Aurora	Costs (2009-10 $000)				
Property Capex	2012-13	2013-14	2014-15	2015-16	2016-17
Recommended Expenditure	352	330	287	253	231

[125] Request AER/005 – Regulatory Obligations and Non-System Capex, 7 July 2011

8 Summary capex findings and recommendations

In the preceding sections we have shown the following:

- Our benchmark analysis of Aurora's historical total capex against other NEM DNSPs has found that Aurora's historical capex, when adjusted for scale and density, is similar to NSW levels and below Queensland levels. However, importantly, it is significantly above the Victorian levels, which we consider are a reasonable base to suggest an efficient level.
- Our benchmark analysis of Aurora's historical and forecast *reinforcement* capex against the other Victorian DNSPs has found that Aurora's capex is significantly above the Victorian DNSPs. This analysis has attempted to allow for the key driver of reinforcement capex: the growth in peak demand. Scale and density differences between DNSPs have also been allowed for. This analysis found Aurora's reinforcement capex to be approximately twice as high as the Victorian DNSP's historical and forecast levels.
- Similar benchmark analysis of Aurora's historical and forecast *non-demand driven* capex, adjusting for scale and density, has also found that Aurora's capex is significantly above the Victorian DNSPs. This analysis found Aurora's non-demand capex to be approximately 30% to 60% above the equivalent Victorian capex.
- Our replacement modelling has found that Aurora's forecast capex associated with *asset replacement* activities is in line with its historical asset lives. However, these lives are on average shorter than the asset lives we derived through the similar modelling we undertook for our review of the Victorian DNSP's regulatory proposals. When we adjusted the Aurora modelling for the average asset lives, the forecast was approximately half that proposed by Aurora.
- Our detailed reviews of a large number of projects and programs that underpin Aurora's proposal in the *reinforcement* and *non-demand driven* categories have found a number of cases where we consider the justification of the need for the project has not been adequately demonstrated, or the solution proposed is considered by us to be significantly greater in scope than is likely to be required. Furthermore, the AER has advised us of a revised load forecast that it may use to form its draft decisions. Our reassessment of the prudent timing of the projects under review, in light of this revised forecast, has found that, on average, projects will be deferred from the timings indicated by Aurora.

Taken together, we consider that the above is sufficient to justify that Aurora's capex proposal should be rejected.

One issue we have found with regard to determining a substitute allowance concerns capex that is not clearly required to maintain the performance of the network (i.e. reliability, safety, etc), but which we consider may result in net benefits in terms of reduced opex and improved reliability. In a number of circumstances, we found Aurora's planned projects to be primarily driven by these requirements.

Although requested[126], Aurora has not provided sufficient information to allow us to determine with any accuracy what the opex and/or reliability benefits would be in these cases. It may be that the productivity improvement factored into its opex allowance should cater for these benefits, and as such, the capex should be allowed. However, we are not in a position to test this, as it relates more to the opex forecast, which is outside our scope. Furthermore, we are not sure how the AER intends to treat such capex projects, with regard to the appropriate capex, opex and reliability adjustments.

On this matter, it worth noting we have accepted Aurora's non-system capex. This acceptance is largely based upon our view that the increased capex proposed in IT would result in the productivity gains proposed by Aurora. If this is not the case (i.e. the productivity gain also requires the majority of the other capex programs noted in this report) then this view may need to be reconsidered by the AER.

To develop a substitute allowance, we have estimated the component of capex that we consider is directly required to maintain performance levels (maintain component), and the additional component that we consider relates to efficiency and reliability benefits (efficiency benefit component). In the case of the IT component noted above, we have allowed for this in the maintain component, as we are more certain that it should result in the forecast productivity improvements[127].

We have used the findings of our detailed review to determine the appropriate adjustments to the total capex amount proposed by Aurora in terms of the maintain and efficiency benefit components. To show the sensitivity of these findings to the AER's revised load forecast, we have calculated this allowance based upon both the Aurora and AER forecasts.

Table 32 below provides our estimate of these two substitute amounts, indicating the two components for both[128]. In total, this represents a 12% reduction to the Aurora proposal. However, the efficiency benefit component represents a further 15% reduction should the AER decide to remove this capex component rather than make adjustments to opex and reliability. The AER's load forecast results in a reduction of 8% to the maintain component of reinforcement capex, but this represents only a 1% reduction to the overall maintain component.

Finally, it is worth noting that during the course of this review we have assessed the non-network solutions that Aurora has proposed. Our findings on this were that Aurora has conducted a reasonably thorough assessment of non-network opportunities and has

126 See AER/018, provided to Aurora on 29 July 2011 and AER/009, provided to Aurora on 18 July 2011

127 Although, it is worth noting we have not been presented with evidence that this is the case.

128 This is an estimate for summary purposes only of total capex, exclusive of customer initiated capex, overheads, and capitalised emergency response.

allowed for these where substitution possibilities, between network and non-network expenditure, exist (in both capex and opex). Our substitute capex allowance includes Aurora's proposed costs for these non-network projects. As such, related opex costs should also be allowed to ensure consistency.

There is also a component of non-network expenditure (capex and opex) to undertake broad-based investigations and trials into non-network solutions, but where Aurora did not make any explicit substitutions with network expenditure. We consider that the programs and costs associated with these broad-based programs are not unreasonable, in principle. However, we believe the AER is in the best position to decide how such expenditure should be treated, given the risks faced by various parties and available mechanisms to account for these types of costs. For the avoidance of doubt, our substitute capex allowance includes Aurora's proposed costs for these broad-based non-network projects. As such, related opex costs should also be allowed to ensure consistency. However, our inclusion here should not be interpreted as our acceptance that these costs should be allowed for under these capex and opex mechanisms.

We did find that there was a significant component of capex associated with non-network initiatives where there was no supporting documentation to justify that this could be considered prudent and efficient. We have removed this component from our substitute capex allowance.

Table 32 Overall capex allowance – compared to proposal

	Total capex ($ millions)					
	2012 - 2013	2013 - 2014	2014 - 2015	2015 - 2016	2016 - 2017	Total
Aurora capex	**76.6**	**78.1**	**75.6**	**71.6**	**73.6**	**375.6**
Nuttall Consulting (Aurora forecast)	**70.7**	**70.1**	**67.0**	**59.8**	**64.1**	**331.7**
Maintain	58.7	59.1	56.3	51.2	51.6	276.9
Efficiency benefit	12.0	11.0	10.7	8.6	12.5	54.8
Nuttall Consulting (AER forecast)	**70.3**	**69.7**	**66.6**	**60.1**	**63.9**	**330.6**
Maintain	58.1	58.2	55.4	50.5	51.1	273.3
Efficiency benefit	12.2	11.6	11.2	9.5	12.8	57.3

A Capex benchmarking results

The following appendix contains the benchmarking results that support the discussion in section 3 of this report.

A.1. Overall capex bar charts

The following charts compare the overall capex for Aurora against the overall capex of the other NEM DNSPs. All capex is based on the most recent 5 years of audited capex data as reported to the AER. All dollar figures have been converted to a common base.

Figure 48 – Capex per RAB

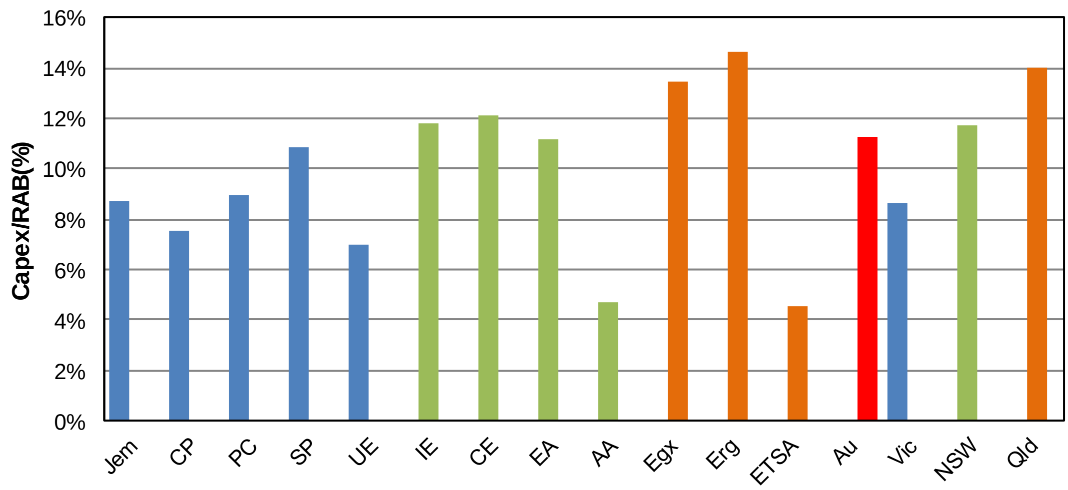


Figure 49 – Capex per line length (km)

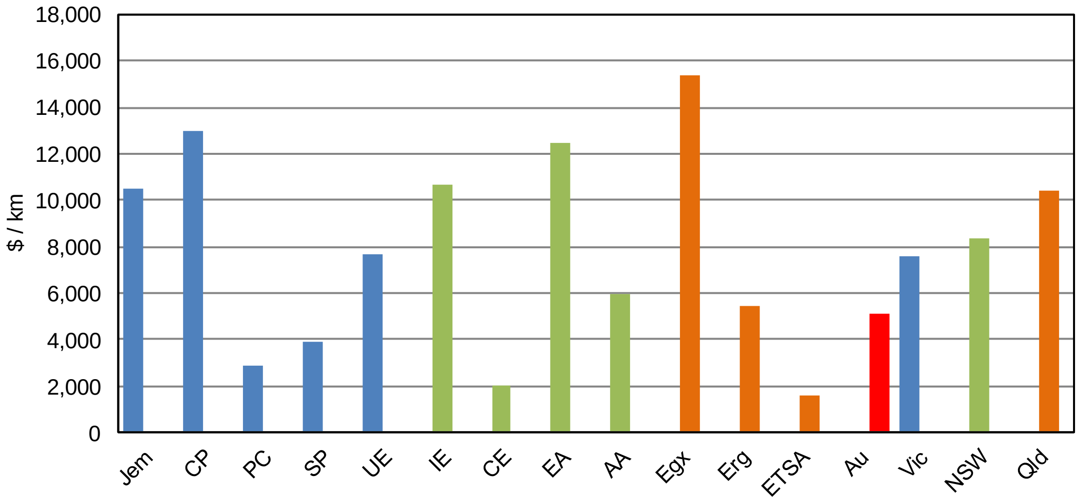


Figure 50 – Capex per customer

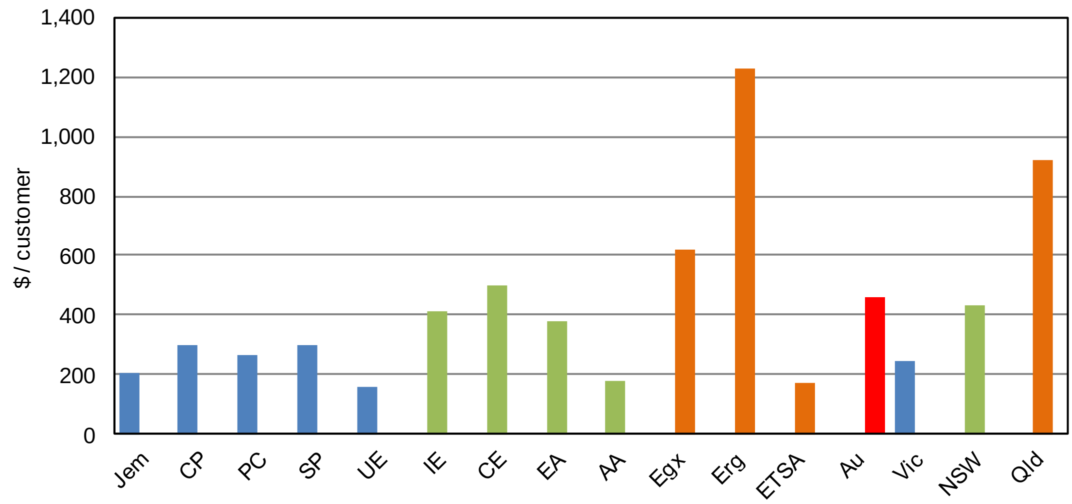
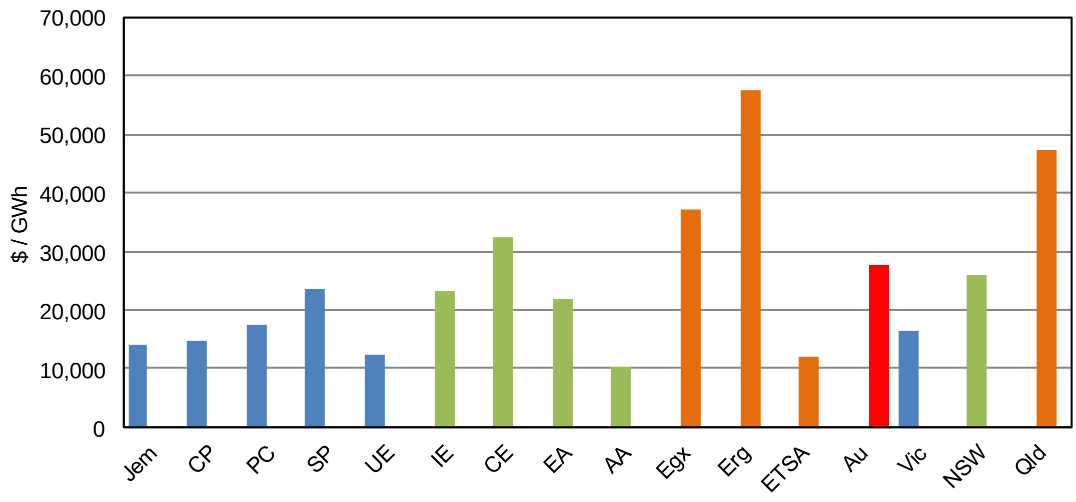
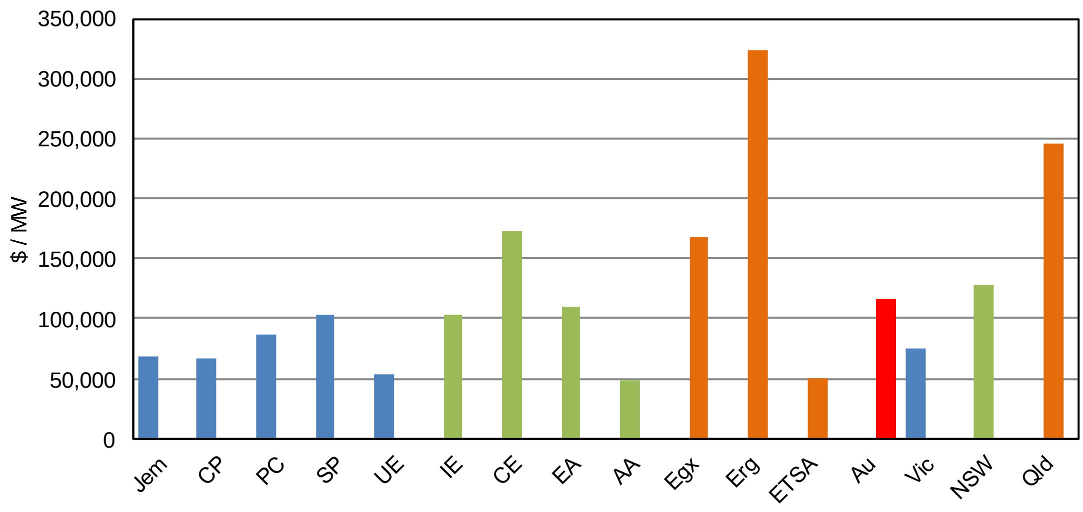


Figure 51 – Capex per electricity distributed (GWh)



As Figure 52 – Capex per peak demand (MW)



A.2. Overall capex scatter charts

The following charts compare the overall capex for Aurora against the overall capex of the other NEM DNSPs against a customer density scale. Customer density is considered to be one of the key exogenous factors impacting capex. The trend lines contained in these charts are simple linear trends based on the average of the Victorian DNSPs. The Victorian trendline was selected based on analysis from the Victorian electricity distribution pricing review in 2010 that showed these businesses as operating at an efficient level.

All capex is based on the most recent 5 years of audited capex data as reported to the AER. All dollar figures have been converted to a common base.

Figure 53 – Capex per RAB

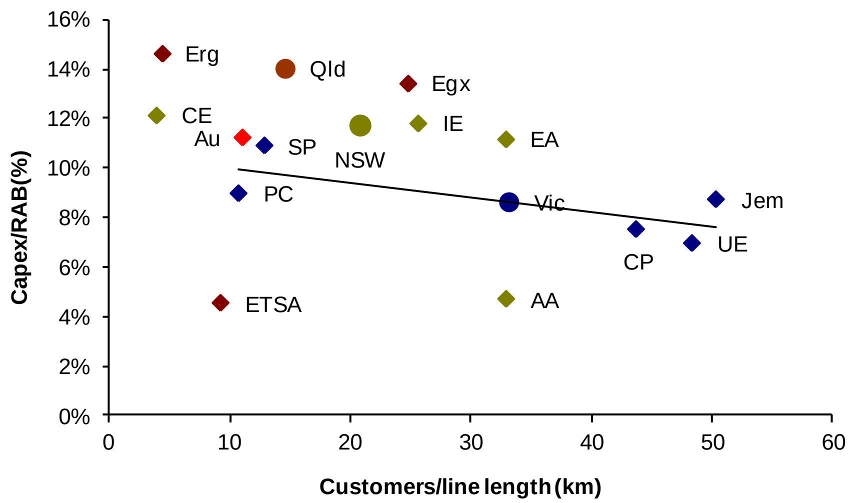


Figure 54 – Capex per line length (km)

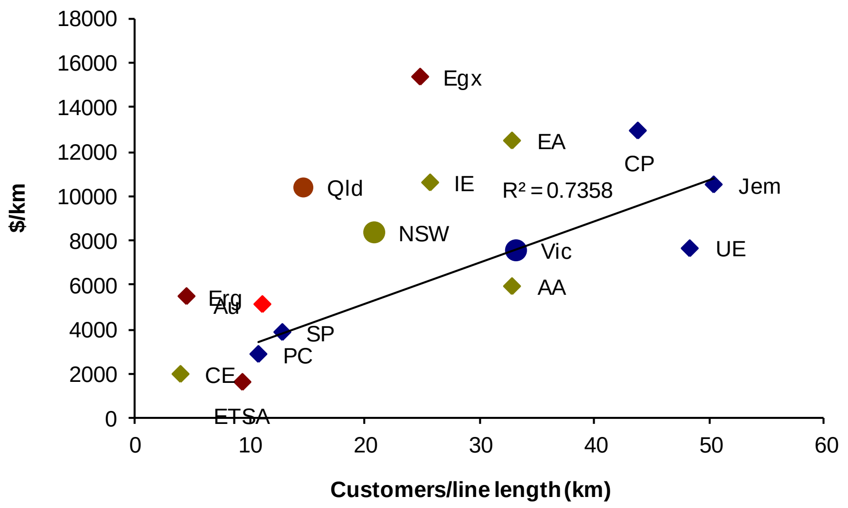


Figure 55 – Capex per customer

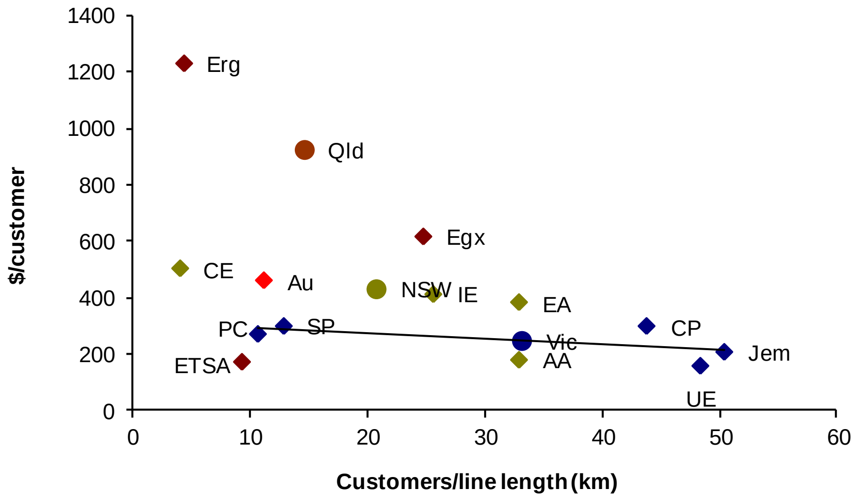


Figure 56 – Capex per electricity delivered (GWh)

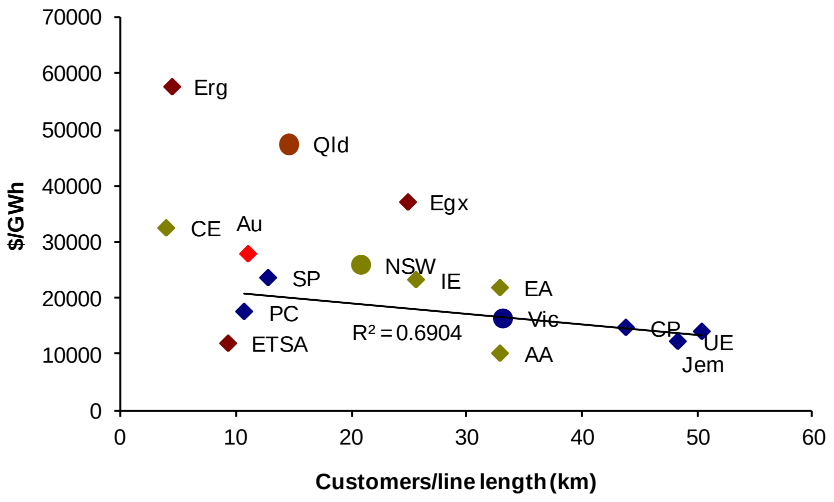
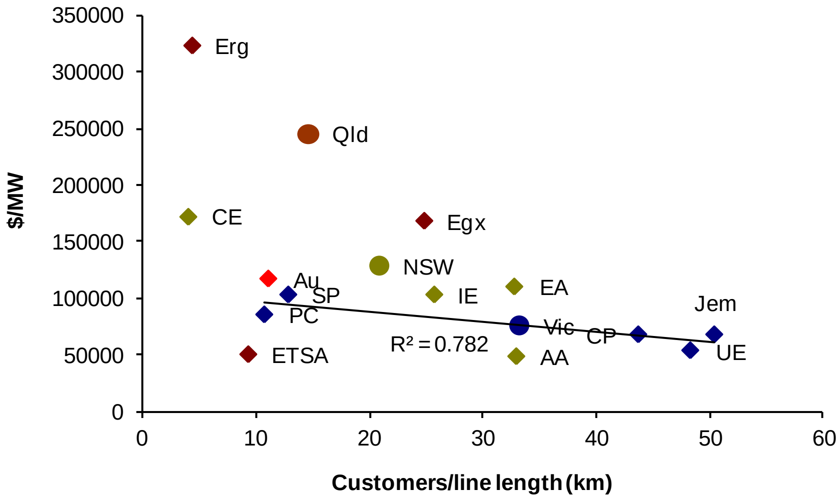


Figure 57 – Capex per peak demand (MW)

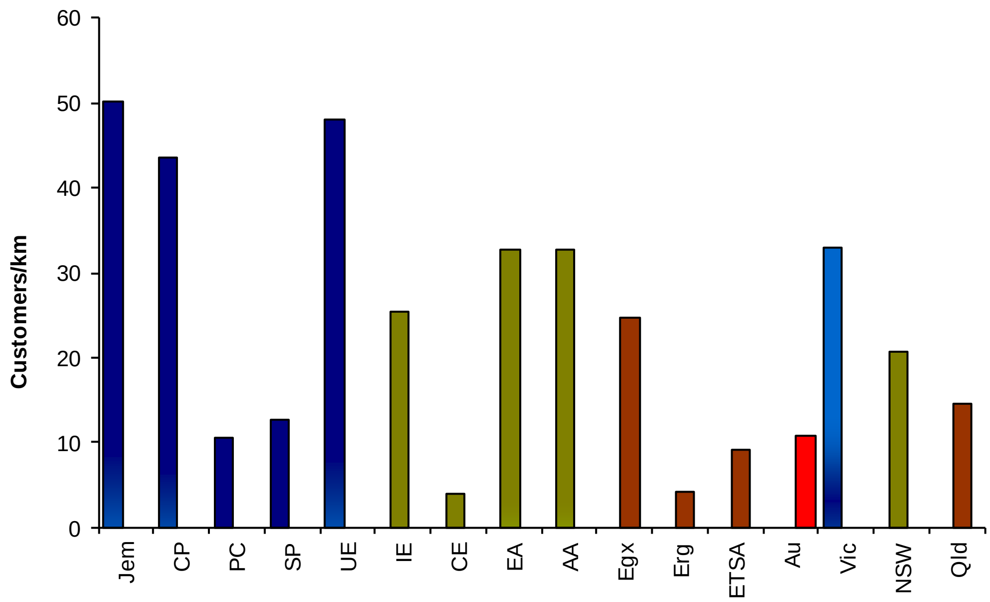


A.3. Customer ratios

The following charts provide an overall indication of some of the key characteristics of the DNSPs as well as state averages for Victoria, NSW and Queensland.

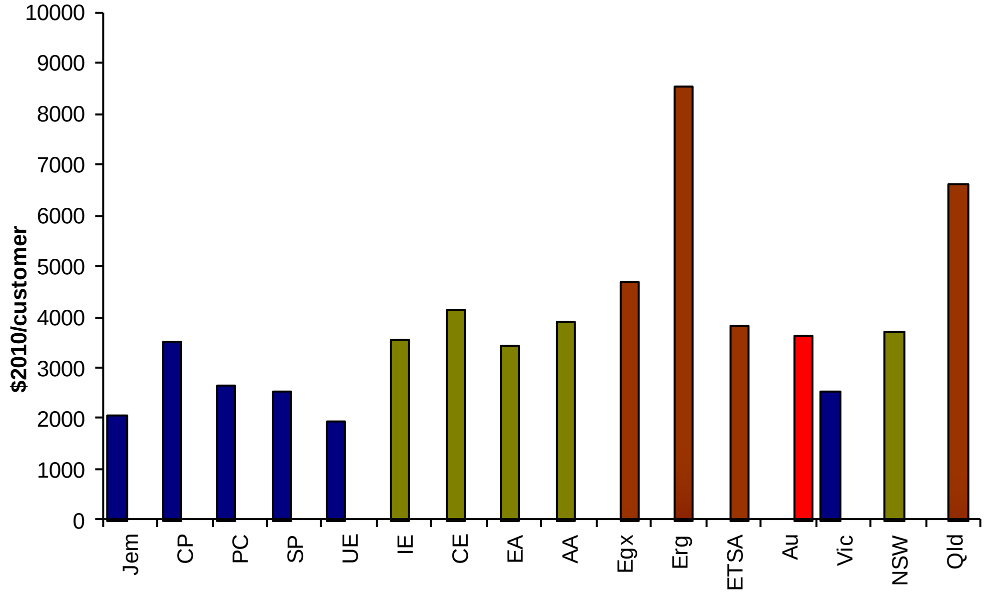
All capex is based on the most recent 5 years of audited capex data as reported to the AER. All dollar figures have been converted to a common base.

Figure 58 – Customers per km of line



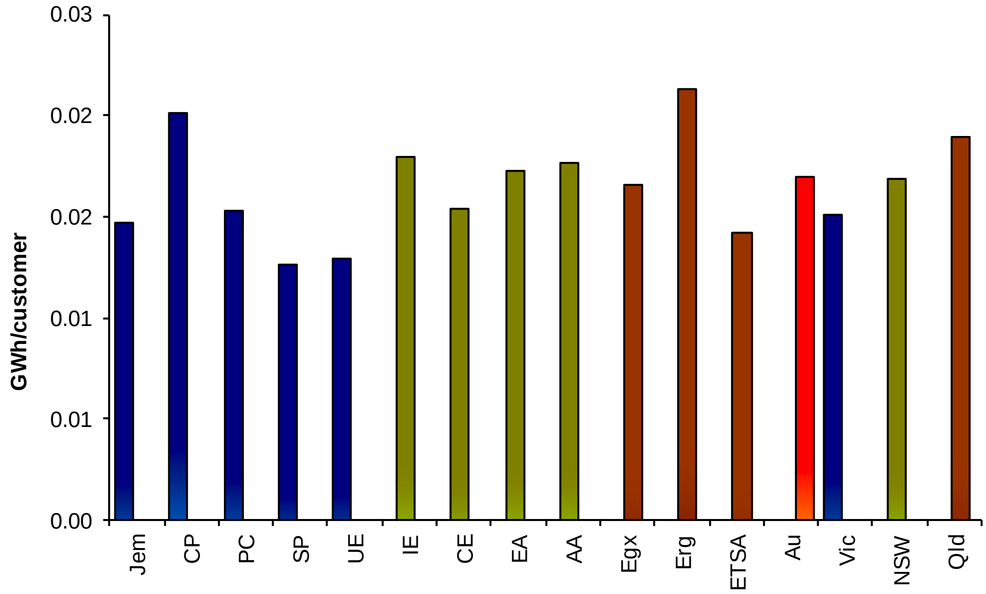
The above chart highlights that the area served by Aurora is relatively rural and has a similar customer density to other rural providers such as Powercor, SP AusNet, Country Energy and Ergon Energy.

Figure 59 – RAB per customer



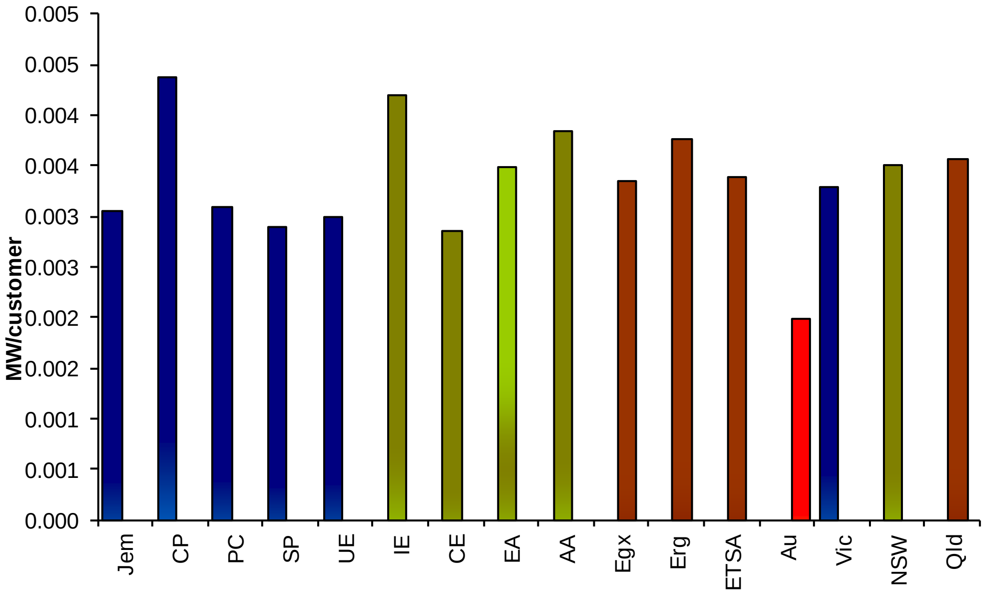
The above chart relates the value of the asset base of each business to the number of customers. The value of Ergon energy stands out as inconsistent with the other DNSPs, even when compared to other rural DNSPs.

Figure 60 – Energy delivered (GWh) per customer



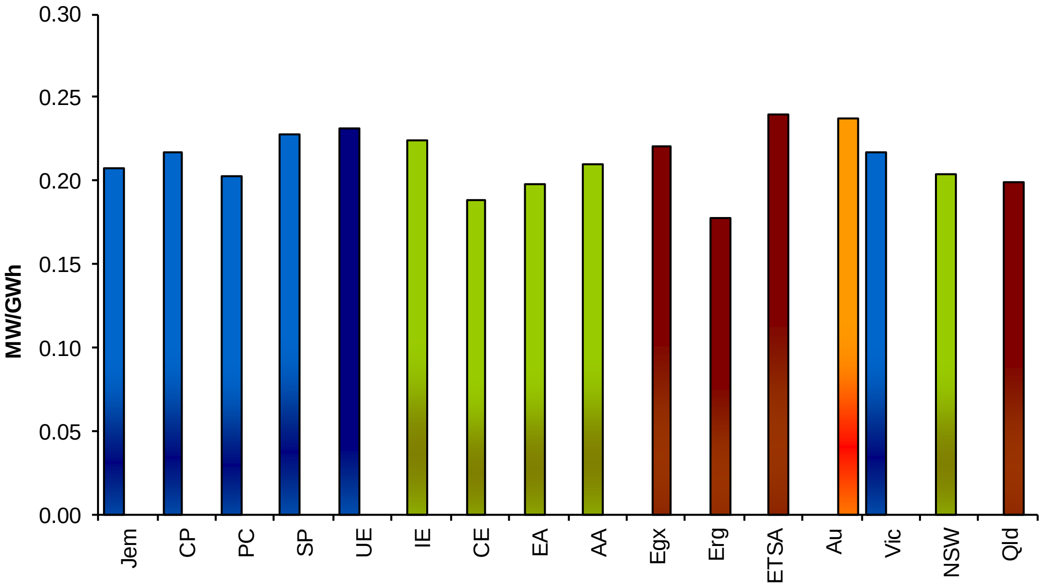
The volume of energy delivered to each customer highlights that the variations between businesses are more based on their location than their geography or demography. The increasing use of air conditioning is considered to be a factor in higher usage in Queensland and NSW.

Figure 61 – Peak demand (MW) per customer



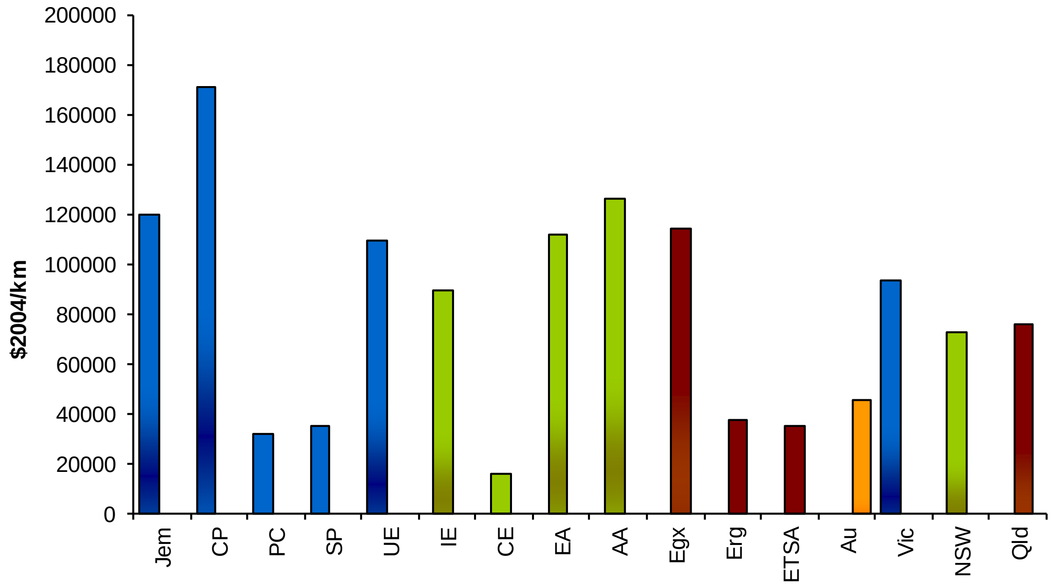
It is not clear why the average demand per customer is quite so low in Tasmania. This may be due to the relatively low penetration of peak usage equipment such as air conditioners.

Figure 62 – Load profile



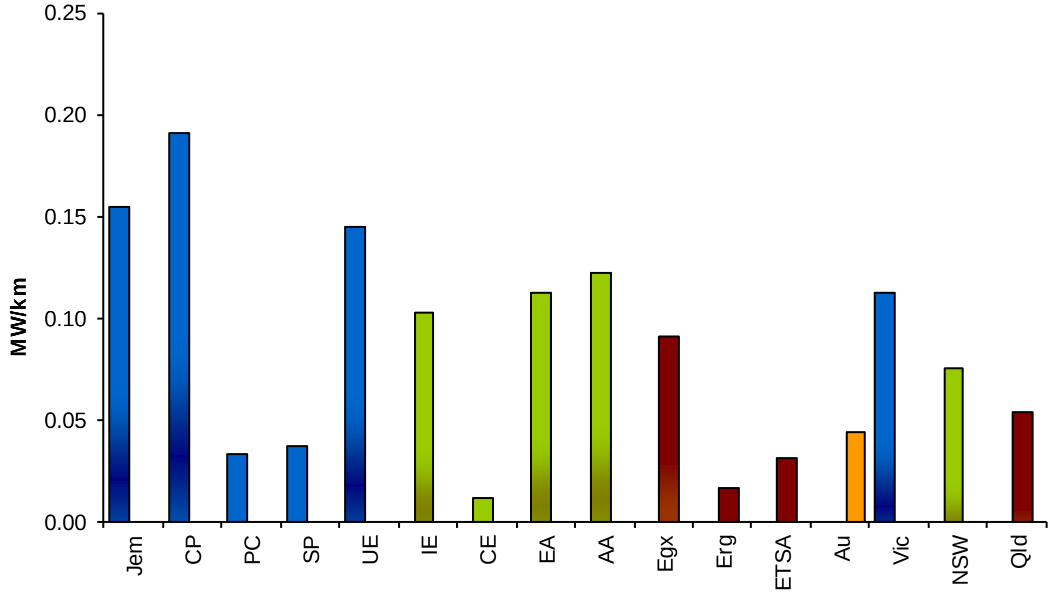
The load profile of a DNSP is the ratio of peak system demand to the average power usage.

Figure 63 – RAB per km of line



The value of assets per length of line is an indication of the demographics of a DNSP. Rural businesses will tend to have long lengths of relatively cheap line, while the urban and CBD suppliers will have more complex and costly assets per line length.

Figure 64 – Load density



The load density of a DNSP is the measure of peak demand per kilometre of line.

A.4. Overall capex scatter charts

The following charts compare the overall capex for Aurora against the overall capex of the other NEM DNSPs against a range of differing scales. While customer density is a key factor in influencing overall capex, there are other factors that may be considered outside the control of the DNSP. These charts are presented for informational purposes and are not intended to suggest that the scaling factors used on the X-axis are true exogenous factors.

The trend line used on these charts is an average best fit trend line. This trendline does not indicate best or efficient performance, but rather the potential relationship between the X-axis and Y-axis factors.

All capex is based on the most recent 5 years of audited capex data as reported to the AER. All dollar figures have been converted to a common base.

Figure 65 – Capex per RAB

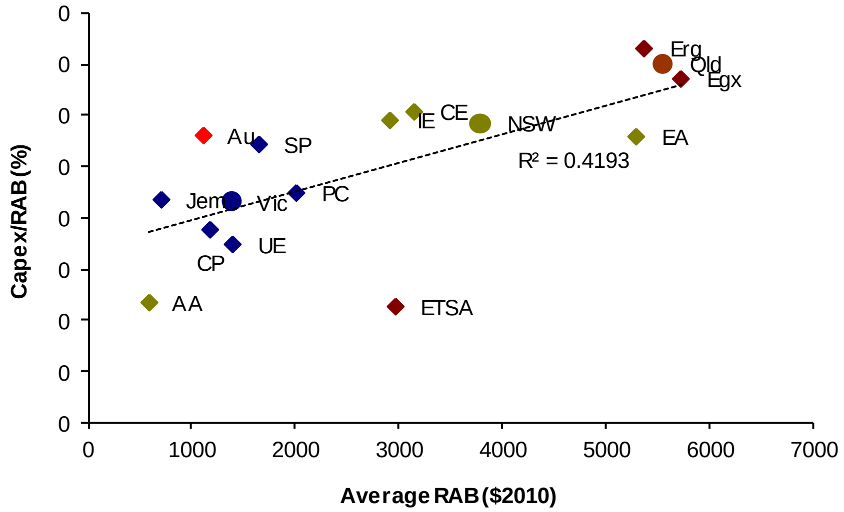


Figure 66 – Capex per line length (km)

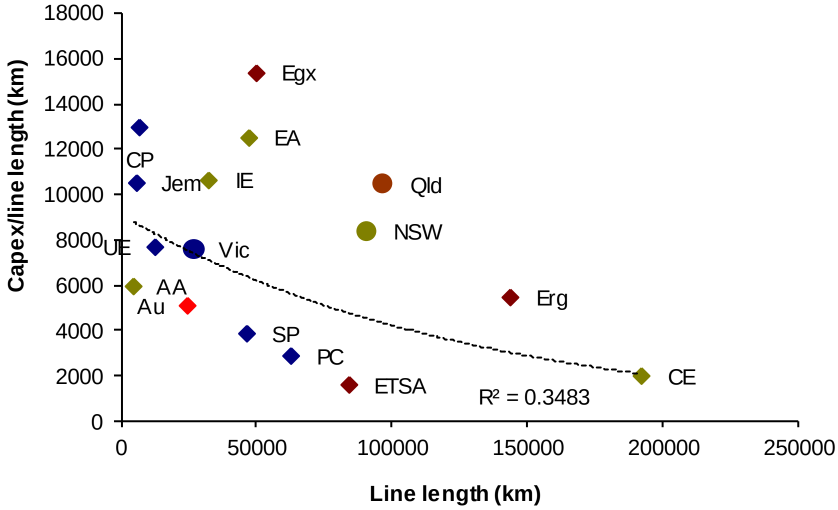


Figure 67 – Capex per customer

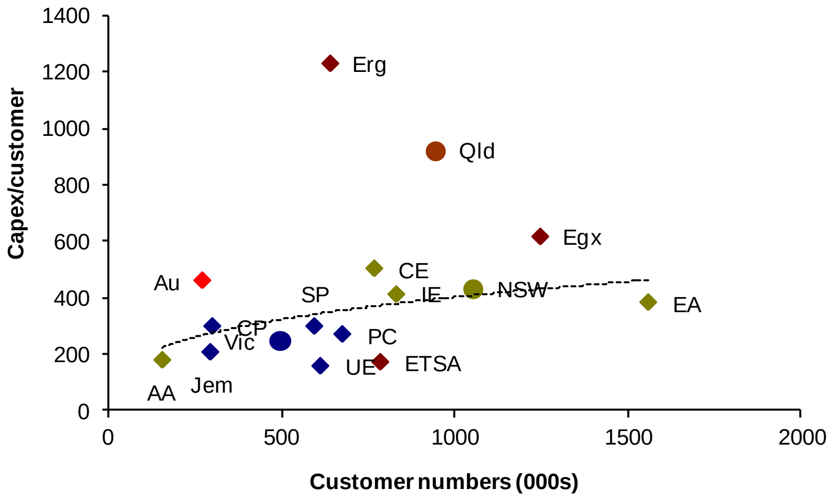


Figure 68 – Capex per electricity delivered (GWh)

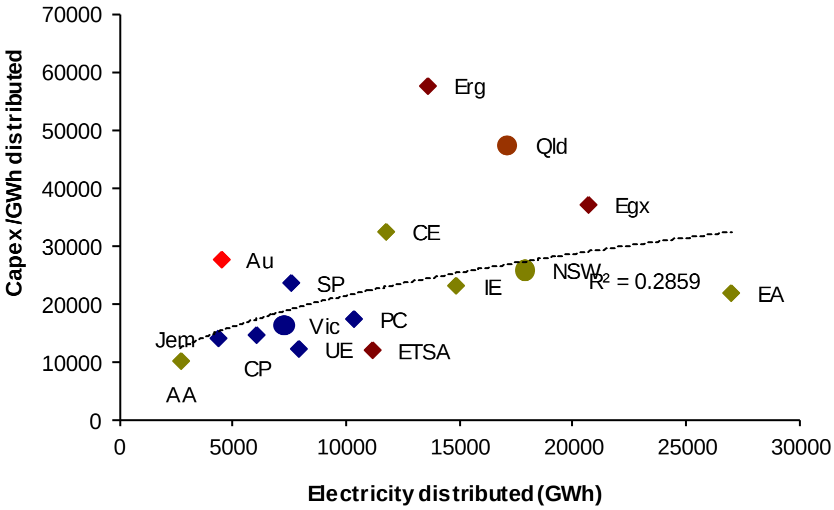
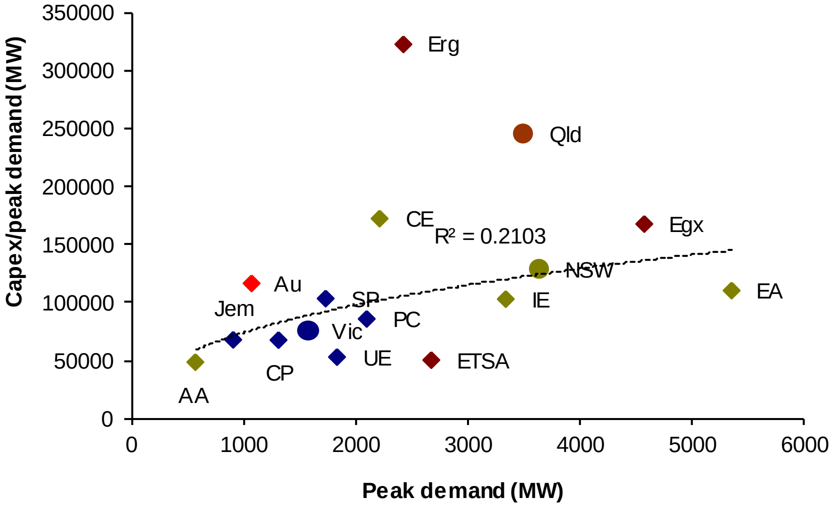


Figure 69 – Capex per peak demand



B Reinforcement capex project review summaries

B.1. Information request

The information provided by Aurora in its revenue proposal was not considered sufficient to conduct a detailed review. Therefore, the following additional information was requested from Aurora[129].

For the following projects identified in the four areas under review:

- 9.4.1 Austins Ferry zone substation
- 9.4.3 Richmond zone substation
- 9.4.4 Rosny zone substation
- 9.4.5 Sandford zone substation
- 9.4.7 Wesley Vale substation
- 9.4.8 Wynyard substation
- 10.4.1 Conductor augmentation - Bridgewater
- 10.4.1 Conductor augmentation - Chapel St
- 10.4.1 Conductor augmentation - Devonport
- 10.4.1 Conductor augmentation - Geilston Bay
- 10.4.1 Conductor augmentation - Hobart sub-transmission
- 10.4.1 Conductor augmentation - North Hobart
- 10.4.1 Conductor augmentation - Palmerston
- 10.4.1 Conductor augmentation - Railton
- 10.4.1 Conductor augmentation - Sandford
- 10.4.1 Conductor augmentation - Sandy Bay
- 10.4.1 Conductor augmentation - Smithton
- 10.4.1 Conductor augmentation - Ulverstone
- 10.4.5 Regulators - Railton
- 10.4.7 Operation - HV phasing - Ulverstone

[129] The request was made, via the AER, on 18/7/11. A response was provided by Aurora on 29/7/11.

- 10.4.7 Operation – Security – Emu Bay
- 10.4.7 Operation – Switching – Chapel Street
- 10.4.7 Operation – Transfer – Hobart East and West
- 10.4.8 Development - Hobart
- 10.4.9 Conversion - Richmond area
- 10.4.11 System fault level - Chapel St

Aurora was requested to provide an explanation and supporting data on the following:

- The specific network issues that the project is intending to address (e.g. exceeding a planning rating, poor reliability, operational inflexibility, etc), including the specific assets associated with the issues, and the associated technical considerations and obligations.
- The historical and forecast changes in compliance, risks and/or operating costs associated with each of the identified issues – e.g. if exceeding planning ratings, when did this occur, or is forecast to occur; if related to other risks, what is the level of risk excepted by Aurora in the previous and current periods, and how is this forecast to change over the next period; if related to operating costs, what are the average annual costs incurred by Aurora in the previous and current periods, and how is this forecast to change over the next period. Where possible, the quantification of levels of non-compliance, risks or costs should be provided for each of the identified issues.
- An overview of the analysis Aurora has undertaken to assess these issues, including the quantification of non-compliance, risks and/or costs.
- The network and non-network options Aurora has considered to address these issues, including a clear description of the relationship between different elements of each project option and the relief of the identified issues.
- The evaluation of these options, including:
  - the advantages and disadvantages of each option
  - the change in compliance, risks and/or costs that should result from each option for each of the identified issues
  - the rationale and/or analysis for the selection of the preferred option
  - the rationale and/or analysis associated with determining the proposed timing of that option – note that this may include the determination of the appropriate staging of more complex projects with various elements.
- Preferred option scope of costs:
  - a breakdown of the scope of the preferred project (only required if more complex than that provided in the POW)

   - the analysis and/or assumptions associated with developing each item in this scope
   - a breakdown of the unit costs used to develop the project cost from the project scope (only required if more complex than that provided in the POW).
- The identification and explanation of any adjustments that have been made to the proposed operating expenditure allowance or reliability targets to account for benefits that may result from this project/program in the next period.

For the following programs:

- 10.3 Additional processes
- 10.4.2 Embedded gen
- 10.4.3 and 10.4.4 DINIS API
- 10.4.5 Regulators
- 10.4.7. operation - HV phasing
- 10.4.7. operation - switching
- 10.4.7. operation - transfer
- 10.4.7. operation - security
- 10.4.8 development - LGA
- 10.4.8 development - thermocouples
- 10.4.8 conversions
- 10.4.10 - SWER
- 10.4.11 - fault level
- 10.4.12 - Mobile generation
- 11.4.2 - LV
- 11.4.1 - distribution transformers

Aurora was requested to provide an explanation and supporting data on the methodology employed to develop the proposed capex, including:

- discussion on the issues being addressed by that program
- the methodology used to derive the proposed capex, including relevant spreadsheets detailing the analysis, its inputs and assumptions
- the rationale that Aurora considers justifies that the methodology is appropriate, in both forecasting capex associated with that specific program and producing an aggregate capex allowance based upon the simple summation of that capex
- the quantification (on a year-by-year basis) of the incremental benefits in the next period that should result from that program, including:

   - improvements in reliability, locally and in total across the system
   - reductions in operating and maintenance costs
   - deferment or improved optimisation of future capital costs
- an explanation, including the source of input data and/or assumptions applied, of the rationale used to calculate the incremental benefits provided in response to the sub-clause above
- the identification and explanation of any adjustments that have been made to the proposed operating expenditure allowance or reliability targets to account for benefits that may result from this program in the next period.

B.2. Project review summaries

In the discussion that follows the following terms are used:

- "response", which refers to Aurora response to the above request[130]
- "feeder loading spreadsheet", which refers to a spreadsheet that provided the forecast loading for each of Aurora's feeders up to 2017 – provided in the response indicated above
- POW, which refers to the spreadsheet provided by Aurora in its proposal that details its proposed program of works for the next period[131]
- Aurecon reports, which refer to the set of Strategic Development Plans prepared by Aurecon and provided with the Aurora proposal (AE043 to AE054).

B.2.1. 9.4.1 Austin Ferry substation

The response indicates that the need associated with the Austin Ferry substation project is primarily due to forecast overloads of existing injection points into the Hobart West area, particularly the Bridgewater terminal station and the Claremont zone substation that is supplied from Creek Road terminal station. The long term project to address the loading in this area is the development of the new Austin Ferry substation. But, for Aurora's proposal, it is assuming that this project can be deferred by the use of non-network solutions. The remaining proposed works allow for the application fees, design works, and land purchase for the substation.

The information provided by Aurora supports the stated needs for this project. As noted in the main body of this report, given the analysis and review undertaken by Futura on non-network opportunities and cost, we also consider that the non-network solution and the associated costs to be reasonable.

[130] Provided in AER emails dated, 18/7/11. Response received in Aurora email, dated 29/7/11

[131] Updated version provided in Aurora email, dated 7/7/11

B.2.2. 9.4.3 Richmond Zone substation (and conversion)

The response indicates that the need for the Richmond zone substation project is related to a number of issues associated with the existing supply from the Richmond substation, primarily covering:

- the forecast overload of the existing transformers (2 x 2.5 MVA), where the existing loading of the substation is well above the N-1 rating
- the poor condition of the existing transformers
- the existing performance of the existing supply, which is via a 22 kV feeder from Sorrel
- various operating issues with the existing arrangements, which limit transfer opportunities and make current load transfers more complex.

During discussions with Aurora they also stated that the voltage drop on the Sorrel feeder was also set to exceed limits.

The proposed substation project, which involves the upgrade of the transformers to a 10 MVA unit and the development of a dedicated supply at 33 kV from the Lindisfarne terminal station and associated feeder augmentations, is also designed to enable the strategic development of the associated distribution network. This strategic development includes the conversion of the Richmond network to 22 kV, part of which is included in Aurora's proposal as the Richmond conversion project (10.4.9).

Based upon the range of issues indicated by Aurora we see no reason to consider that the general strategic plan is unreasonable. However, Aurora has not presented any analysis that supports its view that the project it has proposed is fully justified in the next period.

For example, the Aurecon report discusses the Richmond development. However, the option it discusses involves the replacement of the transformers with single 33/22/11 kV transformers – presumably to address the loading issue and risks associated with the poor condition of the existing transformers. The other components, covering the new 33 kV supply and associated feeder augmentations appear to be proposed for a later date (2017). The Aurecon report does appear to suggest that this proposed timing is more related to budgeting and scheduling considerations rather than technical or economic considerations. Nonetheless, in our view, the appropriate timing for the more extensive supply project, would need to be justified based upon the benefits this larger project will provide. In this regard, it would appear that the 33 kV supply and other feeder costs would need to be justified based upon the opex cost savings and reliability benefits these elements provided. As such, we consider that an appropriate allowance should allow for the 10 MVA transformer installation, which should address loading issues and risks associated with the condition of the existing transformers and possibly the voltage drop issues. However, if a capex amount for the other elements is allowed then this portion should be largely offset by opex reductions and reliability improvements.

B.2.3. 9.4.4 Rosny zone substation

The need for the Rosny zone substation development is related to a number of substation loading issues in the Hobart East area. These matters have been considered by Aurora and Transend, via a joint planning process, during the current period resulting in the application of a regulatory test and associated consultation during the current period. This process resulted in plans to develop a new terminal station at Mornington, and the two new zone substations, Howrah and Rosny.

Proposed feeders for the Rosny zone substation also appear to provide a solution to a number of feeder overloads at Geilston Bay and Bellerive zone substations.

Given the analysis and consultation that has already occurred it seems reasonable to assume that the general plan and timing for the development of Rosny 2012/13 is reasonable – the proposal appears to be in line with the published reports. Furthermore, the POW indicates that 6 feeders are proposed to be developed during the next period. The number and timing of these feeder developments appear to be reasonable with regard to the level of offloading of existing substations that is required to achieve the primary purpose of the new zone substation.

Based upon this, the scope and timing of the proposed project appears to be reasonable. That said, the feeder developments presumably will cut into existing feeders. As such, it should be expected that such a development will improve reliability to customers in the region (i.e. a smaller number of customer will be affected by a feeder fault). We have not been provided any analysis to indicate what this benefit may be, but it seems reasonable to assume that it would be material at least at a localised level.

B.2.4. 9.4.7 Wesley Vale

The response indicates that the need for the Wesley Vale substation development is primarily due to overload issues associated with Transend's terminal station transformers at Devonport. Wesley Vale currently supplies a single customer. Another customer recently closed, reducing the loading at this substation. As such, this existing substation provides an opportunity to develop an additional zone substation at low cost. This substation can also address other issues, including a heavily loaded feeder from the Devonport substation that passes close by and supplies the Port Sorell area, and improve the management of load with the adjacent feeders from Railton.

The project proposed by Aurora includes a large number of feeder augmentations and associated developments to achieve these aims.

Based upon the information provided we consider it reasonable to assume the Wesley Vale development is most likely to be found to be the preferred option to address Transend's loading issues – rather than a Transend solution. Furthermore, cutting into the existing feeder that passes close by to the Wesley Vale substation, such that that load is then supplied by Wesley Vale, seems a reasonable approach to offload the Devonport transformers and improve the supply to that feeder.

However, Aurora has not provided any analysis that supports its view that such an extensive set of feeder augmentations is appropriate. It appears that these are primarily aimed at achieving the improved load management in that area. Therefore, we consider that the justifiable capex for these additional elements would be offset by equivalent opex reductions and improvements in reliability.

B.2.5. 9.4.1 Wynyard substation

The response indicates that the need associated with the Wynyard substation project is primarily due to forecast overloads at the existing Burnie terminal station and the heavy loading of existing feeders supplying the Wynyard region. The long-term project to address the loading in this area is the development of the new Wynyard substation. But, for Aurora's proposal, it is assuming that this project can be deferred by the use of non-network solutions. The remaining proposed works allow for the application fees and design works for the substation.

As this project appear to be partly driven by loading issues associated with Transend's transformers at Burnie, we have reviewed Transend's publically available annual planning (APR) reports to determine whether Transend considers that it will breach its state reliability standards for these transformers.

Transend's 2010 APR states that Aurora has submitted a connection enquiry for the new substation 2013, but notes that the loading on these transformers will not be above their short term rating until 2021[132]. Transend's 2011 APR however does not discuss the Wynyard development. The 2011 APR does indicate that the loading at Burnie was above a state obligation in 2010, but indicates that the planned developments at Emu Bay should relieve this issue[133]. The Aurecon report states that the Emu Bay developments is scheduled to be in service for the end of the current period, 2012[134]. Aurora's forecast demand growth for Burnie is quite low, less than 1%. Therefore, there does not appear to be good reason to consider that the loading on the Burnie transformers will exceed the relevant state obligations in the next period[135].

The Aurecon report indicates that the four feeders supplying the Wynyard region are heavily loaded, and this appear to be an important factor in the need for the project. The feeder loading spreadsheet indicates the three most relevant feeders are loaded to between 67% and 87% of their planning rating, and 78% on average. This overall utilisation is high, but may suggest that this load level may still be manageable throughout the next period if growth is low. Although the overall growth for the Burnie substation is low, based upon discussion in both the Aurecon and Futura reports, it does appear that developments may be planned in the Wynyard area that may mean growth in this area is high.

[132] Pg 85, Transend 2010 Annual Planning Report, available on the Transend website
[133] Pg 72, Transend 2011 Annual Planning Report, available on the Transend website
[134] This is discussed in Section 7.1.1 of the Aurecon report for the North West area
[135] For example, the 2011 APR indicates that the loading at Burnie was 60.11 MVA in 2010, the continuous firm rating is 60 MVA, and the Futura report stated that the Emu Bay project will result in 10 to 15 MVA of load relief.

Based upon the above, it appears that the timing may still be reasonable, but the high feeder loading is the more pressing need. We note that network options discussed in the Aurecon focuses on those relevant to relieve the Burnie transformers. A new feeder may be a lower cost option for such a situation. This option does not appear to have been considered in any detail by Aurora. However, given the issues that are raised in the Aurecon report associated with installing new feeder, we consider it reasonable to assume that a new substation may be the least-cost long term network solution.

It is noted that the analysis in the Futura report assume that the relief of the Burnie transformers is the primary driver when determining levels of relief required. This is inconsistent with our findings above. Nonetheless, the solutions proposed appear to mainly relate to the Wynyard area, and therefore, it seems reasonable to assume that the non-network solution will relieve the loading of these feeders.

Albeit that we consider that the need for this project has not been well presented, on balance, we consider that the proposed timing and non-network solution are reasonable.

B.2.6. 10.4.1 Bridgewater

The response states that the primary issues driving the need for this project are feeder loadings that are forecast to exceed rating. The solution, a feeder augmentation in 2013/14, also has additional benefits in terms of allowing better load management between three existing feeders(48185, 48188 and 48191), plus the ability to separate light commercial and residential load from industrial load. The response also refers to the Aurecon report to support the need and solution.

We have reviewed the Aurecon report and this does indicate that two of the indicated feeders would be overloaded in 2012 (48188 and 48191). However, this also states that these overloads should have been addressed by works committed in the current period. It is also noted that neither the spreadsheet of feeder over loads nor the feeder loadings in the RIN suggest that any of the 3 feeders should be near their planning ratings.

As such, the need for the project to address feeder loading does not appear to be supported by the information provided. If the load management issue is the more pressing need then we would expect that such a project would predominantly be justified based upon the opex and reliability benefits. Information to support this position however has not been supplied either.

B.2.7. 10.4.1 Chapel Street

The response states that the need relates to feeders exceeding their planning rating and the voltage drop exceeding limits. It also states that load management issues associated with the transfers between Chapel Street and neighbouring substations are driving the need for the project.

The project includes a number of feeder augmentations and a distribution substation upgrade.

The response references the feeder overload spreadsheet with regard to the quantification of the issues above, but does not clearly indicate the feeder overloads being addressed. However, the POW does indicate that the proposed works will relieve 20549, 20552, 20535, 20548, and construct 2 new feeders, 556 and 557.

We have reviewed the spreadsheet data on these overloads. This supports Aurora's position that the project will address feeder overloads. These overloads are also suggested in the Aurecon report. However, the response does not provide any significant detail on the rationale for this set of works, as opposed to other options.

In this regard, it is important to note that the works set out in the POW appear to be far more extensive than the works suggested in the Aurecon report that discusses these feeder overloads. In the Aurecon report, it states that a project to relieve 20548 had already been scheduled by Aurora. It is not clear what this project is, but if it had already been scheduled, then in the absence of information to the contrary, it seems reasonable to assume that it would be completed by the end of the current period. Furthermore, the Aurecon report states that the overload at 20535 can be relieved by a "simple" project involving a change to the existing switching arrangements (i.e. at no or very little cost). The Aurecon report also states that 20552 could be relieved by a new 500m tie to feeder 20551, which has a relatively low level of loading. The equivalent project defined in the POW assumes 1 km of underground cable.

This only leaves 20549 possibly requiring relief in addition to the more modest set of works in the Aurecon report. However, the loading spreadsheet indicates that this feeder will only be above the planning rating at the very end of the next period. As such, it may well be that Aurora can accept this risk, given the inherent conservatism in the planning rating analysis.

Based upon the above, it would have to be assumed that the main driver for the increased scope is the voltage and load management limitations. However, there is no real detail that quantifies these needs or the benefits that will be generated by addressing these. With regard to the voltage issue, it is noted that the Aurecon report states that capacitor banks could be used to improve the voltage control at Chapel street. Therefore, it seems reasonable to assume that the load management issues, may be the most significant factor driving the need for the scale of the project. However, if this is the case then a large portion of the project would be justified based upon its operational savings and reliability improvements. Information to support a position that such benefits would justify the capex has not been supplied by Aurora.

B.2.8. 10.4.1 - Devonport

The response indicates that the need for the project is to address load management limitations and increasing the transfer capacity to the Devonport CBD. The project appears to be a small feeder augmentation that reinforces the interconnection between two existing feeders (80005 and 80010).

The loading spreadsheet does not indicate that either of these feeders will be above their planning rating by 2017; although, it does indicate that one is heavily loaded.

This suggests a reasonable possibility that this could be deferred following more detailed analysis of the need and options, and associated cost-benefit analysis. Furthermore, noting that the need for this project appears to be predominantly associated with improving load management, it seems reasonable to assume that if the capex was found to be prudent and efficient then this level of capex would be offset by opex and reliability benefits.

B.2.9. 10.4.1 Geilston Bay

The response indicates that the need for this project is to address the overloading of a feeder supplied from Geilston Bay (26167), which primarily supplied critical loads. It also states that the proposed project, a new feeder, will improve the transfer capability in that area, which is presently limited due to the neighbouring network operating at a different voltage level.

The loading spreadsheet indicates that the feeder is presently over its planning rating, even allowing for the conservatism in Aurora's analysis, noted above. Given the timing is set for 2016/17, it is not clear how Aurora is intending to manage this issue to this time. Nonetheless, there seems a high likelihood that some project will be justified at the proposed time. That said, given the existing load management issues, it seems reasonable to assume that the project would result in some modest improvement in opex and reliability.

B.2.10. 10.4.1 Hobart Sub-transmission

The response indicates that the need for this project relates to existing feeders that limit the use of the full transformer rating at certain zone substations within the Greater Hobart area. The proposed project appears to assume the augmentation of two feeders (308 and 309) to address this issue.

The response refers to the loading spreadsheet with regard to the quantification of this need. However, this spreadsheet does not indicate whether these feeders would be overloaded, and as such, whether this will result in the relevant zone substations being limited.

The Aurecon report however does provide some discussion and information on this matter. This provides the rating of the feeders and indicates that these would limit the supply through the transformers. However, it does not appear to indicate that there is any need to augment these feeders in the next period, as the N-1 loading of these feeders is shown to be below the transformer rating. As such, there does not appear to be a clear need for this project in the next period.

B.2.11. 10.4.1 North Hobart

The response indicates that the need for this project relates to feeders and substation transformers exceeding their planning rating, and the voltage drop exceeding limits. The overall project includes a number of augmentations of existing feeders to relieve these issues. The response does not specify what feeders or substation components will be overloaded. However, the POW indicates that the project components will relieve three feeders (18131B, 18143B, and 18146B).

The feeder loading spreadsheet indicates that all three feeders will be overloaded by 2017; although, it is noted that two (18131B and 18143B) are presently overloaded, while the other one (18146B) will only be overloaded in the last year of the next period. The Aurecon report also stated that the North Hobart substation will be above its transformer rating in 2014.

Based upon the available information it seems reasonable that the majority of the project will be required at the time suggested. Although it appears that the work to relieve 18146B could be deferred, this is only a very small portion of the overall project.

B.2.12. 10.4.1 Railton

The response states that the primary need for this project is due to the voltage drop exceeding limits, driven largely by the installation of irrigation motors. Based upon the POW, the project appears to be a feeder augmentation.

Aurora has not provided any useful information in its response that allows this project to be reviewed. As such, we have excluded this project from our review.

B.2.13. 10.4.1 Sandford

The response indicates that the need for this project relates to feeders, supplied from the existing Rokeby substation, exceeding their planning rating and voltage drops exceeding limits. The long term project to address the loading in this area is the development of a new Sandford substation. But, for Aurora's proposal, it is assuming that this project can be deferred by the use of non-network solutions. The remaining proposed works however still constitute a relatively major project, which allows for the development of two sub-transmission circuits, one of which is assumed to be submarine for a large part of its route. These circuits will operate as HV feeders, relieving the load in the area, until the new substation is constructed, when they will be used to supply this substation.

The information provided by Aurora supports the stated needs for this project. However, we do not consider that Aurora has adequately demonstrated that its proposed solution is the most appropriate. Specifically, we consider that a much lower cost short-term network solution could involve some further voltage support and/or the use of mobile generation during peak period to offload the network. Although we accept that this is not an ideal solution (for example, the noise from the mobile generation would need to be managed), considering the very high cost of the proposed project by Aurora, we consider that this may be an acceptable short-term solution when more detailed analysis is undertaken.

Furthermore, it appears from our review of the Futura report on the non-network solution to the overall Sandford substation development that the Futura analysis assumes that the load relief from the non-network solution will address the feeder issues[136]. Moreover, it

[136] See discussion at end of Section 8.4.1 of the Futura report (AE055)

appears that if this network portion is undertaken then the non-network solution is not economically justifiable. As such, it appears that either a non-network solution is appropriate or a network solution, but not both.

We do note that Aurora considers that there are some risks on its part that a suitable non-network solution will not be found, and hence, the substation development will be required. However, given the focus Aurora is giving in the next period to non-network solution, and the work Futura has undertaken for Aurora in assessing the best opportunities, we consider this to be a small possibility.

B.2.14. 10.4.1 Sandy Bay

The response indicates that the need for this project is due to feeders exceeding their planning rating (4 feeders are discussed: 12019, 12030, 12035 and 12036) and voltage drops within that area exceeding limits. The project involves a number of feeder augmentations to relieve these issues.

The loading spreadsheet indicates that two of these feeders are presently above their planning rating and the other two will be above by the end of the period. The Aurecon reports also discuss these needs and possible solutions. It is noted that it is difficult to reconcile the discussion in the Aurecon reports to the discussion provided in the response to our request. Nonetheless, the timing and costing assumed in the POW to relieve the overloads do not appear unreasonable.

B.2.15. 10.4.1 Smithton

The response indicates that the need for this project is due to inadequately rated conductors associated with heavily loaded feeder spurs – presumably where load has grown above its original design load. It also noted that the project will result in additional benefits associated with increased security and transfer capacity. The proposed project includes a number of minor feeder augmentations.

There is little information provided that allows any real review of these needs or solution to be undertaken. Given the small amount of capex associated with this project, the proposed project may not be unreasonable. That said, noting the additional benefits raised by Aurora, it may also be expected that such a project would result in opex and reliability benefits that would be significant in justifying the capex.

[appears to be existing issues, so timing unlikely to be sensitive to growth rate]

B.2.16. 10.4.1 Ulverstone

The response indicates that the need for this project is due to the overload of two existing rural feeders (82002 and 82006). The response also indicates that the needs and associated benefits are also similar to those discussed above for Smithton (i.e. heavily loaded spurs and improved load management). The proposed project includes a number of feeder augmentations and some additional switches.

The feeder loading spreadsheet indicates that these feeders are heavily loaded, with one already above its planning rating and both forecast to be above their planning rating by 2017. As such, the proposed project does not seem unreasonable. However, as with the Smithton project above, we would expect that the opex and reliability benefits would be material, even if this project could be justified purely on the need to remove these overloads.

B.2.17. 10.4.11 Fault Level projects – Chapel Street

Aurora has proposed a number of projects associated with managing fault level issues. We have reviewed the project associated with Chapel Street in more detail.

The response indicates that fault levels at Chapel Street have recently risen above the fault rating of Aurora's assets. To manage this situation, Chapel Street is normally operated with the bus coupler open. This reduces the fault levels, but imposes operational limitations and risks if certain equipment is operated at certain times. The response indicates that Aurora is presently undertaking joint planning with Transend, but is proposing a project including series reactors to reduce the fault levels.

The response provides little information to review this issue and the solution[137]; however, we see no reason to consider that the high fault levels do not exist and Aurora's solution is not a reasonable option to consider. Nonetheless, we consider that Aurora's proposed project may be erring too heavily on the side of caution, and therefore, there is a reasonable possibility that an alternative may be found that would either defer the need by a number of years or result in a significantly reduced scope. This possibility seems far greater than the counter in which the project would be advanced or be far more costly.

For example, as Aurora notes, joint planning is still occurring and it may be that a transmission solution will be found to be the preferred option. Furthermore, it may be that the existing temporary solution of opening the bus coupler may be found to be the appropriate solution for a longer period. In this regard, we understand that such open points have been adopted in a number of locations for extended periods as the prudent approach to managing high fault levels in Victoria.

[137] The response does include a supporting Transend document, "Fault level at Aurora points of supply", dated November 2010

C Alternative Control Services

Nuttall Consulting has been requested by the AER to investigate a number of specific technical aspects relating to the Aurora submission on Alternative Control Services. The specific items for review include:

(1) Metering – assessment of the reasonableness of Aurora's proposals for the following items, with appropriate benchmarking:

  (a) cost per meter including purchase & installation

  (b) rate of replacement of mechanical by electronic

  (c) meter lives

(2) Fee based services - benchmarking analysis of the prices for the following services against other DNSPs, focusing primarily on DNSPs with comparable customer density:

  (a) Site visit – no appointment

  (b) Site visit – credit action or site issues

  (c) Tariff alteration – single phase

  (d) Tariff alteration – three phase

  (e) Renewable energy connection

  (f) Truck tee-up

(3) Public lighting - assessment of the reasonableness of the following light types, focusing on installation and replacement costs and asset lives:

  (a) 80W Mercury Vapour

  (b) 250W High Pressure Sodium Vapour.

The following sections details the Nuttall Consulting review of these items.

C.1. Metering

Nuttall Consulting has reviewed the Aurora Alternative Control Services proposal relating to meter services. The scope of the review has been to consider the technical issues relating to meter costs, the proposed meter replacement rates and the effective meter lives proposed by Aurora.

In the following analysis, Nuttall Consulting has reviewed the proposed costs, replacement rates and asset lives provided by Aurora. Where Nuttall Consulting does not concur with the position proposed by Aurora, we have detailed the reasons for our position and provided a reasonable alternative.

C.1.1. Cost per meter

The Nuttall Consulting review has considered the purchase cost for the standard electronic meter as provided by Aurora. Nuttall Consulting first sought to determine if the current meter purchase cost was sourced via an open and competitive tender.

Aurora's current electronic meter supplier was selected from a tender process that was performed in 2004. Following a request for more information, Aurora was unable to locate any documentation of this process[138]. Aurora has advised that the steps undertaken in letting the current supply contracts were as follows:

- "expression of interest was sent out with only two suppliers responding with meters that complied with our technical requirements;
- negotiations were completed with both suppliers and contracts let for supply of meters under the approval of Aurora's Board; and
- supply contracts were extended with board approval."[139]

The limited number of tendering companies and lack of supporting information from Aurora means that it is not possible to determine whether the 2004 meter tender could be considered open and competitive. Consequently, we do not believe that the information provided about this tender process is sufficient to allow us to conclude that the current price can be assumed to be efficient.

To test this matter further, Nuttall Consulting has reviewed the current Aurora electronic meter price against the most recent submissions from the Victorian smart meter project. The meters compared in the table below are all single phase, electronic meters that would typically be used for a domestic customer.

[138] Aurora response to questions raised by Cadency Consulting, Aurora/005 – Alternative Control Services, 12 August 2011.
[139] Ibid

Table 33 - Meter purchase cost

Meter description	Meter Cost	Notes
Aurora existing	$55[140]	$2007 – single phase, mechanical meter.[141]
Aurora proposed	$240.10[142]	$2009/10 – single phase, electronic meter, 2 register, 100A and 60A contactors[143]
CitiPower[144]	$140	$2011 – single phase, electronic meter, excludes contactor
Jemena[145]	-	Not provided due to confidentiality restrictions
Powercor[146]	$140	$2011 - single phase, electronic meter, excludes contactor
SP AusNet[147]	-	Not provided due to confidentiality restrictions
United Energy[148]	-	Not provided due to confidentiality restrictions

Existing and proposed base meter costs

There is a very large discrepancy between the previous base meter cost and the new cost proposed by Aurora. It is understood that the existing meter cost for Aurora listed above is based on a mechanical meter and 2007 prices. To the best of Nuttall Consulting's knowledge, no mechanical meters are currently produced by Australian manufacturers. Although it may be possible to purchase mechanical meters from overseas providers, mechanical meters are now considered as an obsolete technology for the purposes of electricity metering. The current industry standard for customer metering is electronic meters. Aurora has advised that the proposed meter cost of $240.10 represents the current contract price for single phase domestic electronic meters[149]. Nuttall Consulting

140 Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania. Final Report and Proposed Maximum Prices - September 2007, OTTER. p265. Note: existing prices (set by OTTER) are based on same price for both electronic and mechanical.

141 Note: Multiple mechanical meters are required where the customer has controlled loads like under-floor heating or off-peak hot water. Aurora has advised that an average of 2 mechanical meters are installed per domestic dwelling.

142 Aurora Energy Meter Annuity Model – based on 2 registers per meter.

143 A contactor is an electronic switch or relay for turning a supply or load on or off.

144 Impaq Consulting, Review of DNSPs AMI Budget Submissions for 2012 to 2015, Version 2.2, 20 July 2011, p14.

145 Ibid, p 50.

146 Ibid, p81.

147 Ibid, p 118.

148 Ibid, p 150.

149 Aurora Energy Meter Annuity Model – based on 2 registers per meter.

has requested Aurora provide evidence supporting this proposed cost. As discussed later in this section, Aurora did not provide sufficient justification supporting this figure.

Aurora and Victorian meter costs

The Aurora meter costs appear high when compared to the current Victorian values. However, the current specifications for the Aurora single phase domestic meter are reasonably extensive with the standard meters providing a large number of features that are not available in a basic mechanical meter (e.g. 2 contactors).

The smart meters used in Victoria are of a much higher specification than that currently required in Tasmania, although economies of scale from the Victorian rollout should reduce the overall prices. The standard electronic meter used by Aurora also contains two contactors that allow for remote or timed switching of the overall supply and a secondary load. These contactors are not standard in the Victorian meter configurations.

The addition of these features and the economies of scale in the Victorian purchases may account for the difference between meter costs. However, the benefits of these features are not quantified.

Aurora has advised that the current meter types have been approved by the Tasmanian economic regulator as the standard meter type[150]. There are no current requirements for an increase to the specifications of the standard electronic meter.

Aurora has advised that a tender process for the next term contract for meters will commence in 2011 and be completed in late 2011. The outcome of this process may provide a more suitable benchmark for the standard meter costs, provided it can be shown to have followed an open and competitive process.

Aurora has provided Nuttall Consulting with a quotation from the current electronic meter provider for additional quantities of the standard meter. The costs of [redacted] per meter[151] contained in this quote are well below the meter purchase costs provided by Aurora in the meter annuity model. The [redacted] quotations are for order sizes of between 27,000 and 10,800 respectively. These volumes represent between 2 and 4 years of meter replacement volumes based on current rates, and 1 to 3 years if new meter installations are considered.

The meter replacement volumes for the next control period are discussed in the following section C.1.4. Nuttall Consulting also notes the high level of technology change and government consideration of smart meter roll-outs. On this basis, it would be prudent for Aurora to purchase smaller numbers of electronic meters to limit the risk of stranded assets.

Aurora has not provided any information to support the cost difference between the current cost price and that proposed in the annuity model. Based on the above, Nuttall

[150] NW-#252665-v1-Reg_Response_-_Metering_070227.pdf (confidential)
[151] QUO-01492-DPJB79-1.pdf (confidential). Based on meter volumes of 10,800 or a single year of the proposed replacement amounts. Note: on-costs are not included in this estimate.

Consulting recommends that the meter purchase cost for a single phase meter is set at the current value of [redacted] per meter with an allowance for escalation and on-costs[152]. This value may need to be revised if the results of the meter tender process become available later in the review process.

Nuttall Consulting also notes that the previous OTTER determination accepted a mechanical meter rate of $55[153] per meter. Given that this type of meter is no longer an industry standard for new meters, there are no actual production costs to validate this. Aurora has sought a current quote from a meter manufacturer for mechanical meters, but has advised that this provider no longer manufactures mechanical meters.

On this basis, Nuttall Consulting recommends that the previous OTTER accepted value of $55 is used for mechanical meters with allowances for overheads and inflation incurred since 2007.

C.1.2. Meter on-costs

Aurora is proposing meter on-costs associated with the meter installation. The following table provides the proposed on-costs for single phase, multi-phase and CT meters.

Table 34 - Meter on-costs ($2010)[154]

Meter description	Meter On-cost
Single Phase	51.10
Poly Phase WC	76.50
CT meters	207.40

Aurora has advised that on costs include all aspects associated with warehousing, distribution & delivery, testing and programming. Aurora currently contracts out meter warehousing, testing and issuing of meters to an external party. This contract includes the maintenance of a database containing meter installation data which has been previously extracted via Aurora's IT systems. Aurora stated that it "is not provided with a breakdown of cost to a disaggregate level".[155]

If we assume a meter purchase cost of [redacted] for the smaller order size from the current Aurora meter purchase contract, we arrive at meter on-costs of 27% for the standard single phase meter.

In comparison, CitiPower has reported that the "*cost of all central warehousing and distribution are outsourced and hence market tested with costs based on the value of items passing through the distribution centre. The costs associated with metering are 5 per cent*

[152] e.g. overheads.

[153] Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania. Final Report and Proposed Maximum Prices - September 2007, OTTER. p265

[154] NW-#30205070-v3-AER_021_metering_questions_data.XLS. Question 1B (confidential).

[155] AER-021 Aurora response 2.2.1(b) (confidential).

of the value of purchase price."[156] The CitiPower on-costs do not cover the testing of the meter, and this would be additional to the 5% figure.

More recently, CitiPower and Powercor have identified meter on-costs for the "management of contracts and logistics for meter supply" and for the "testing of meters in conjunction with vendors to validate compliance to specification"[157]. The on-costs proposed by CitiPower and Powercor are 13% and 12% respectively. In their report, the reviewing consultant has recommended significant reductions to these on-costs, although the review process is ongoing and the volume of meters being installed is significantly greater.

The information above suggests that meter on-costs for warehousing, testing and issuing should be in the range of 5% to 13%. Nuttall Consulting is not aware of any additional meter testing requirements or logistical requirements that would require Aurora to incur greater levels of on-costs than those of the Victorian DNSPs.

On the basis of the above information, Nuttall Consulting recommends that an allowance of 10% of the meter purchase cost is reasonable in Aurora's circumstances.

C.1.3. Meter installation costs

Aurora is proposing meter installation costs of $103.70[158]. This is based on an assumed installation of a single meter with two registers. The Aurora meter annuity model on which these costs are sourced is based on meter registers and an assumption that the average customer requires two registers. The basis for the proposed Aurora installation costs is not detailed in the Aurora meter annuity model.

Nuttall Consulting has requested Aurora provide confirmation on the cost build-up and the meter register assumption.[159] However, no supporting information had been provided at the time this report was written. Nuttall Consulting has reviewed the supporting information provided by Aurora. In particularly, Aurora's Threads model provides some limited data, mainly on unit costs of network services direct & shared costs for labour, contractor, materials, etc. However, we were unable to reconcile this model with the costs provided in the Aurora submission on Alternative Control Services. Nuttall Consulting also considered the information provided in the Aurora Program of Works (POW) model and the unit rates model.

The previous meter installation costs as accepted by the Tasmanian economic regulator were as follows.

[156] Submission to Essential Services Commission, 4 August 2005, CitiPower Pty, P17.

[157] Australian Energy Regulator Review of DNSPs AMI Budget Submissions for 2012 to 2015, Version 2.2, Impaq Consulting, P17.
20 July 2011

[158] Meter Annuity Model – single phase domestic $2009/10.

[159] Onsite meeting at Aurora Energy offices, Kirksway Place, Hobart – 8 August 2011.

Table 35 - Meter Installation Costs for 2007-08 (June 2006$)[160]

Meter description	Meter Installation Cost
LV – Single Phase	73
LV – Multi phase	55
Electronic	73
HV	55

This table clearly shows that the proposed cost of Aurora is significantly higher than the previously accepted costs. Most notably, the single phase low voltage installation cost of $73 is well below the costs proposed by Aurora, even allowing for 5 years of escalation.

Nuttall Consulting is not aware of any changes to metering installation requirements, codes or regulations that would require an increase to the cost of meter installations. In the absence of information supporting an increase in meter installation costs, Nuttall Consulting recommends that the current meter installation costs of $73 are maintained[161].

C.1.4. Electronic meter roll-out rate

Based on its meter management plan, Aurora is proposing to replace 108,000 meters over the next five-year regulatory control period.

This will be three times the amount replaced over the same duration in the current control period as highlighted in the following table, which indicates that replacement volumes since 2007/08 have been between 5000 and 9000 per annum.

Table 36 - Meter replacement volumes current period[162]

Financial Year	Replacement volumes
2007/08	6,134
2008/09	7,896
2009/10	8,306
2010/11	8,833
2011/12	5,150
Total	36,319

[160] Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania. Final Report and Proposed Maximum Prices - September 2007, OTTER. p265.
[161] With allowances for price escalation.
[162] NW-#30205070-v3-AER_021_metering_questions_data.XLS. Meters installed (confidential).

The volumes identified in the above table relate to new meters, and not the numbers of meters that are removed from service. The number of meter removals will likely be greater than the number installed as one electronic meter is capable of replacing two mechanical meters in some circumstances.

The information provided by Aurora relating to historical meter installations appears contradictory. The above table was provided in direct response to a request from Nuttall Consulting. However, the Meter Age Data spreadsheet provided by Aurora lists over 100,000 meters as being installed in the last 5 years[163]. Even considering new customer growth it is not possible to reconcile these two numbers. As the Meter Age Data appears to include a large number of "NULL" entries and PAYG[164] meters, Nuttall Consulting has relied on the numbers provided by Aurora in the above table.

Aurora is proposing meter replacements across a number of different business drivers. The replacement programs and volumes are described in the Aurora meter management plan[165] and listed in the following table.

Table 37 - Meter replacement volumes forecast for next control period

Financial Year	Replacement volumes
Compliance	25,750
ERT replacement	7,300
Access and key management	36,000
Reading issues	39,200
Total	108,250

Each of the above programs is considered in the following sections.

Compliance and ERT replacement

Nuttall Consulting has considered the meter replacement categories of compliance and ERT replacement together as both categories basically consider the condition based replacement of targeted meter populations. The Aurora Meter Management Plan (s.8.1) indicates Aurora has moved from age-based replacement of meters to a condition-based (compliance & business needs) approach.

Historically Aurora has replaced meters as they have failed to operate. Aurora is now required to comply with the minimum meter testing requirements established in the Tasmanian Electricity Code. The requirements include sample testing of installed meters. As meter populations age, it is anticipated that certain population samples will fail these meter tests and be programmed for replacement.

163 Meter Age Data.xls

164 Pay As You Go meters are not currently owned by Aurora Energy Networks.

165 Management Plan 2011, Metering Assets, Document Number: NW30161525-V5, Date: 15 July 2011, p11

Nuttall Consulting has reviewed the current meter populations that have recently failed the meter testing procedures and are programmed for replacement[166]. The replacement volumes in the current control period are consistent with the identified meter populations and also consistent with other DNSP meter replacement levels.

Aurora has specifically identified the ERT (Easy Read Technology) meters for replacement in the next period. Aurora has identified that the trigger for the proposed replacement is the remote reading devices. The remote reading devices are no longer supported by the manufacturer and have only a limited operational life.

Aurora has identified the ERT installations specifically for replacement. However, the driver for the replacement program remains as compliance with current codes and licences. For this reason, Nuttall Consulting considers that the ERT replacement program should be considered as a standard compliance replacement program.

It is not clear whether Aurora has replaced any of these ERT installations in the current period. The Meter Age Data and Meter Management plans do not reference any ERT meter replacements in the current period.

However, it appears likely on the information provided, that Aurora is approaching a time when it will no longer be able to access readings from the ERT installations. This would place Aurora in breach of its code obligations. For this reason, Nuttall Consulting considers that the Aurora proposal to replace these assets is reasonable.

Based on our review of the proposed meter replacement volumes for compliance and ERT replacement, Nuttall Consulting considers that the proposed replacement volumes of 25,750 and 7,300 respectively are reasonable.

Access and key management

Aurora has identified approximately 36,000 sites that can only be accessed using customer specific keys or have access difficulties. Difficult access sites include dogs, additions or modifications to buildings affecting reading access, irrigation pumps and communications towers. Aurora is proposing a meter replacement program to provide an electronic meter with remote communications functionality to these installations.

Aurora considers that by addressing these reading and access issues, that it will be able to gain efficiencies in processing and exceptions management and reduce the level of re-reads requiring additional field visits and improve customer service by reducing estimated reads and removing the need to schedule appointments to read meters.

The program proposed by Aurora would appear reasonable if the identified benefits are realised and result in significant operational cost reductions. Aurora has not provided any business case or quantification of the cost savings that would result from the program. The Aurora meter management plan does not identify any current programs for access and key management. This means that Aurora is currently managing the costs and issues associated with key management and limited access.

[166] Ibid, Table 2, p9.

On this basis, Nuttall Consulting recommends that the proposed replacement volumes associated with access and key management are not allowed.

Reading issues

This replacement category directly relates to the proposed replacement of 39,000 PAYG meters and 200 other meters with reading and processing issues.

PAYG

Aurora has identified 39,000 PAYG meters that are currently the property and responsibility of Aurora's Retail Division. Aurora is forecasting that Aurora network will assume responsibility for these meters in the next control period (commencing July 2012).

Aurora has identified clause 9.12.1 of the Tasmanian Electricity Code as requiring the transfer of meters to the network division. The legal reading of this clause is beyond the scope of Nuttall Consulting, although Nuttall Consulting notes that the current Code is dated January 2008. The following section considers the technical aspects of the replacement of the PAYG meters in the next control period.

It has been proposed that Aurora Network should take over ownership of PAYG meters and begin meter reading at these sites on a periodic basis (quarterly or annually). This would require access which is currently not required, raising customer issues. A meter replacement program is proposed to provide an electronic meter with remote communications functionality to these installations to remove the access issues. The ability to remotely read PAYG meters will assist Aurora Network in the preparation and accuracy of DUoS accounts, energy forecasting and the calculation of distribution system loss factors.

Without confirming the legal ownership requirements of the PAYG meters, it doesn't appear reasonable to purchase a meter population only to then replace the whole population. Aurora has identified some advantages to the replacement of these PAYG meters, although the benefits are not quantified and do not appear sizeable enough to economically justify the replacement of the whole meter population.

It may be that the current PAYG meter population would fail the installation testing requirements of the Tasmanian Electricity Code. However, Aurora has indicated that it is not able to provide any information, other than qualitative, to confirm this position.

If the meters do meet the current Code requirements, then it would not appear justified to replace the entire population of 39,000 meters to achieve the benefits identified by Aurora.

Nuttall Consulting is concerned by the scale of the proposed replacement program when combined with the lack of supporting information. Aurora has not been able to provide any factual information supporting the failure modes of the PAYG meter fleet. The PAYG meter fleet is made up of many different meter types and Aurora has not identified which of these meter types are considered to not meet the code requirements.

In addition, the Meter Management plan does not identify any existing electronic meters that have failed compliance testing[167].

As the complete replacement of the PAYG population has not been justified and the costs of the replacement would appear to outweigh the benefits, Nuttall Consulting does not recommend that the proposed meter replacement volumes are allowed.

Other Reading and processing Issues

Aurora has identified meter configuration concerns or other issues at approximately 200 sites, resulting in higher than normal meter reading errors. Aurora reports that these errors result in more time consuming back office processing. Upgrading the metering at these sites and providing remote communications functionality would reduce processing time and reduce the volume of check reads and special reads at these sites.

Aurora has not provided any quantification of the proposed benefits and it is therefore not clear if the value of the benefits outweigh the costs of the proposed works. The Meter management plan does not identify a current program to address reading issues. This indicates that Aurora is currently willing to accept the costs associated with these reading issues.

On this basis, Nuttall Consulting recommends that the proposed additional replacement volumes associated with reading issues are not allowed.

If Aurora is able to develop a business case for the replacement of these meters that has a positive net present value, it will be able to implement this program and benefit from the overall cost reductions in the next control period.

C.1.5. Roll out rate summary

The following table summarises the Nuttall Consulting recommendations in relation to the replacement of meters in the next control period. The recommended replacement amount is consistent with the level of replacement in the current control period.

Table 38 - Meter replacement recommendation for next control period

Financial Year	Replacement volumes
Compliance	25,750
ERT replacement	7,300
Access and key management	-
Reading issues	-
Total	33,050

[167] in accordance with the code and Australian standards (AS 1284.13-2002).

C.1.6. Meter lives

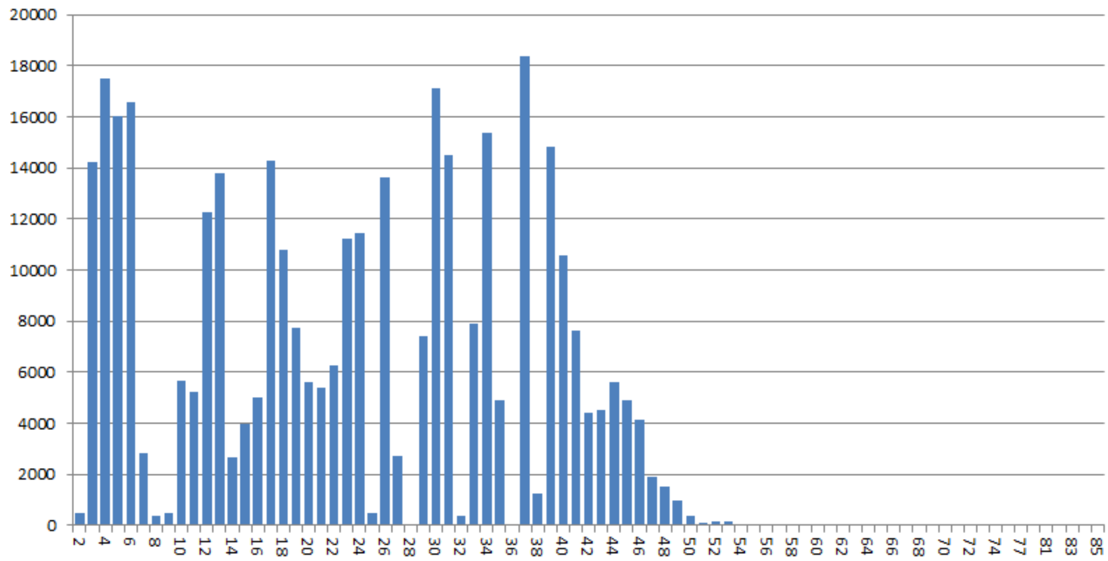
The AER has requested Nuttall Consulting consider the effective lives of the Aurora meter population.

Aurora is proposing a 20 year life for mechanical meters and a 15 year life for electronic meters[168].

Mechanical meters

Mechanical meters make up 78% of the meters Aurora owns. This amounts to 356,197 mechanical meters, out of a total meter population of 455,594[169]. The following chart shows that mechanical meters have been installed for over 50 years. There is a very small proportion of meters that are almost 90 years old, although the volumes are not significant enough to register on the following chart.

Table 39 – Mechanical meter age profile (years)



The average age of the current meter population is 23 years and there appears to be a significant reduction in meter numbers once the age exceeds 40 years. The profile of the volume of older meters, which drops significantly from 40 years to 50 years, tends to suggest that typical mechanical meter lives achieved by Aurora may be in the order of 40 years. Clearly this is significantly longer than Aurora is proposing.

The range of meter lives for mechanical meters in Australia ranges from 20 years to 45 years. The following references identify some meter lives in excess of 20 years:

- In 2008, Country Energy (now Essential Energy) nominated a useful life for mechanical meters of 40 years.[170]

[168] RIN table 4.5.
[169] Meter Age Data.xls
[170] Detailed Summary of Submissions in Response to the Phase 2 Reports on the Cost Benefit Analysis of Smart Metering and Direct Load Control. EMCa. 2008.

- In 2004, the South Australian price review identified average replacement life for mechanical meters to be between 45 to 50 year[171]
- In 2004, the Essential Service Commission of Victoria used a 40 year period for assessing the value of the existing (mechanical) meter population[172]
- In 2003, Aurora argued for a meter life (mechanical) not exceeding 25 years.[173]

It is clear that the Aurora has a very large proportion of meters that are operating reliably with ages well in excess of the 20 year life. The current age profile of a meter population is not necessarily indicative of the effective life of the asset. Meters are often replaced for reasons other than being unfit or unserviceable. For instance, meters may be replaced as old premises are rebuilt, or as customer electrical wiring is replaced. For this reason the average useful life of the current meter population will typically be in excess of the current average age of the asset group.

Nuttall Consulting has reviewed the meter populations that have recently failed the sample testing procedures required by the Tasmanian Electricity Code. The current levels of annual replacement is between 2% and 3% of the current meter population[174]. The existing meter population is clearly not exhibiting signs of requiring imminent replacement and the average meter age will exceed 25 years (under current replacement volumes) by the end on the next control period.

On the basis of the available information Nuttall Consulting considers that a useful operating life for existing mechanical meters is between 30 and 40 years.

Electronic meters

The remaining 22% of Aurora meters are electronic[175], amounting to a population of 99,397 electronic meters out of the total meter population of 455,594. The following chart shows that the majority of electronic meters have been installed in the last 13-14 years.

[171] South Australian Electricity Distribution Price Review, Prepared For Essential Services Commission Of South Australia, PB Australia, 29 September 2004, p86

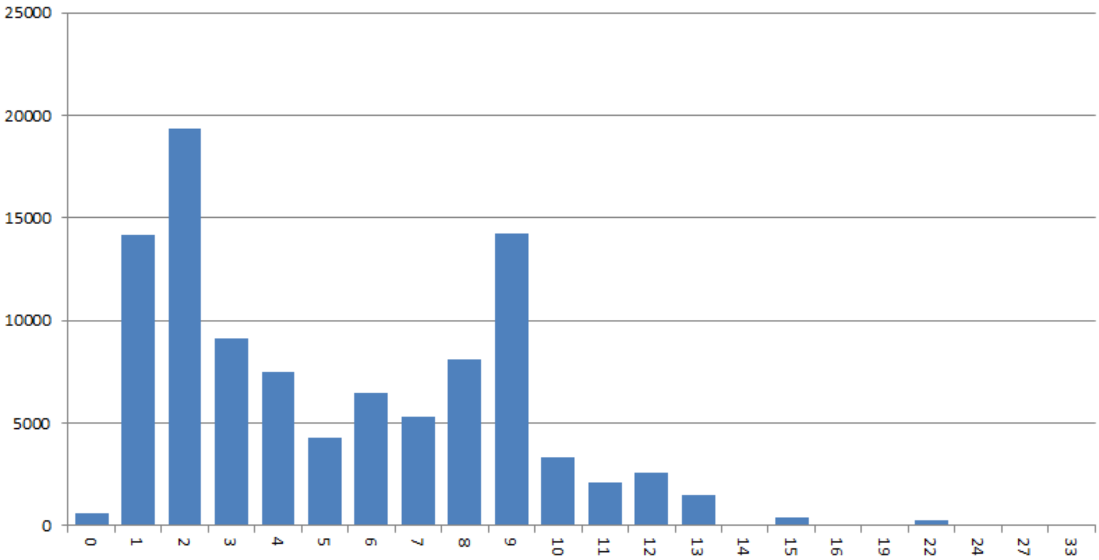
[172] Mandatory rollout of interval meters for electricity customers, Final decision, Essential Service Commission of Victoria, July 2004, p14.

[173] Submission to the Electricity Pricing Investigation Response to Draft Report, Aurora Energy, July 2003, p15.

[174] Based on Meter Age Data.xls and the replacement volumes identified by Aurora Energy in NW-#30205070-v3-AER_021_metering_questions_data.XLS (confidential)

[175] Note: As previously discussed, the meter age profile information provided by Aurora Energy does not align with the replacement volumes provided. Nuttall Consulting is also concerned with the “NULL” and “PAYG” meter numbers that are included in the age profile.

Table 40 – Electronic meter age profile (years)



This age profile tends to support Aurora's proposed asset life of 15 years for meters, although the lack of current electronic meter failures[176] may suggest a longer life. Furthermore, the typical effective life used by Australian DNSPs and meter manufacturers ranges between 10 and 15 years, and the consultant to the Federal Government review of smart meters recommended a useful life of 15 years for electronic meters.[177]

Nuttall Consulting considers that there is strong precedence for adopting a 15-year life for electronic meters, and that there is insufficient empirical evidence for shifting from this position.

C.2. Fee based services

The AER had requested Nuttall Consulting assess specific fee based services proposed by Aurora with particular focus on a benchmarking analysis of the prices against other DNSPs.

The following table provides a description of the actions or tasks typically involved in the provision of the services we have been requested to review.

[176] As identified in the Meter Management plan

[177] Detailed Summary of Submissions in Response to the Phase 2 Reports on the Cost Benefit Analysis of Smart Metering and Direct Load Control. EMCa. 2008.

Table 41 – Fee based service descriptions

Service type	Example actions
Site visit – no appointment	• Visit to a customer's premises during normal business hours where no appointment is required on the regular scheduled day for service delivery and the request is received from the retailer before 3:00pm the previous business day. The visit will be required to energise or de-energise an installation; or to perform special readings. • De-energisation (remove fuse) • New meter reading required • Re-energisation after disconnection for non-payment • Final reading/Transfer of supply
Site visit – credit action[178] or site issues	• De-energisation site visit – performed due to credit action or site issues • Remove fuse and/or confirm de-energisation •
Tariff alteration – single phase	• Visit to a customer's premises during normal business hours to add or modify a single phase metering circuit. • Add metering equipment • Exchange meter
Tariff alteration – three phase	• Visit to a customer's premises during normal business hours to add or modify a three phase metering circuit. • Add 3-phase metering equipment • Exchange 3-phase metering equipment
Renewable energy connection	• Connection of renewable energy meter • Add metering equipment • Exchange meter
Truck tee-up	• Contractor requests tee-up (agreed meeting time) with service connections crew whilst undertaking work at customer's installation during normal business hours. Single and three phase underground tee-up (connection) • Single and three phase overhead tee-up (connection)

Nuttall Consulting has reviewed the current and proposed fee based service charges for Aurora and compared them with similar services from other DNSPs across Australia. The following tables provide the fee based service charges for these DNSPs as well as identifying any specific tasks or actions that relate to the service.

In considering these results, it is important to appreciate certain matters that can result in difference between DNSP's costs. Firstly, the majority of fee based services require travel

[178] Credit action is a disconnection at the request of a retail provider, based on non-payment of account.

to the customer's premises. In these cases, the travel time is a factor in considering the overall cost of the service. DNSPs that service rural and remote areas will naturally require greater travel time than those in urban areas. Aurora has a relatively sparse customer density when compared to the Australian average. The customer density for Aurora is most similar to Powercor, SP AusNet, Essential Energy and Ergon Energy. Nuttall Consulting has considered the specific fees for these DNSPs when reviewing the Aurora proposed charges.

Secondly, Aurora has advised[179] that fee based services for the current Regulatory Control Period were established with OTTER as part of the 2007 Pricing Investigation and were reflective of the internal unit costs charged by Network Services division to Network division for the provision of those fee-based services only. Aurora states that these original costs did not include any charges for the overheads that were incurred by the Network division in the provision of these services, as these costs were already included within the allowance that would be provided to Aurora as part of its Maximum Allowable Revenue (MAR).

Nuttall Consulting has not reviewed the overhead allocation for the proposed services, but notes that the allocation of overheads should be consistent across all DNSPs in the National Electricity Market and consistent with the National Electricity Rules for cost allocation.

The following tables provide the comparative fee based service rates for other DNSPs in the National Electricity market.

C.2.1. Site visit – no appointment

Nuttall Consulting has compared the current and proposed Aurora costs for a site visit to a customer's premises against those of other DNSPs. The following table provides a comparison of these costs.

[179] Information clarification Aurora reponse (sic) to questions raised by Cadency Consulting, Aurora/005 – Alternative Control Services, 12 August 2011

Table 42 – Site visit – no appointment

DNSP	Charge (incl GST)	Notes
Aurora existing	$38.72	• For 2011/12 year[180]
Aurora proposed[181]	$59.62	• For 2012-13 year ($2011/12)
AusGrid[182]	$48.40	• Special meter read • Disconnection visit
CitiPower	$26.20	• Special read • Fuse removal/insertion
Endeavour Energy[183]	$48.40	• Special meter read • Disconnection
Energex	$8.69 $41.00 $66.79	• Special read • Reconnection • Site visit
Ergon Energy	$0.00 $35.09	• Re-energisation and de-energisation • Special meter read
Essential Energy[184]	$48.40	• Special meter read • Disconnection
Jemena	$9.80 $13.28	• Special read • Re-energisation
Powercor	$26.20	• Special read • Fuse removal/insertion
SP AusNet	$17.16	• Field office visit (business hours)
United Energy	$11.28 $40.60	• Special read • Re-energise/de-energise

The fee proposed by Aurora for a site visit with no appointment is considerably higher than almost all other DNSPs. The proposed fee is also significantly greater than the current charge. Nuttall Consulting requested Aurora to provide evidence supporting the increased fee. Aurora has provided very limited information to substantiate the case for such a significant increase and has not identified why the proposed fee is significantly greater than other DNSPs.

On this basis, Nuttall Consulting recommends that the existing fee of $38.72 (including GST) is maintained with an allowance for escalation and allocation of overheads in accordance with the cost allocation methodology.

180 Aurora Energy – Special Services Tariffs. Special Services Tariffs for Period 5 – 1 July 2011 to 30 June 2012
181 Based on Aurora Energy revised Fee Based Services.xls provided on 5 September 2011 (AER/027)
182 Was previously EnergyAustralia networks
183 Was previously Integral Energy networks
184 Was previously Country Energy networks

C.2.2. Site visit – credit action or site issue

Nuttall Consulting has compared the current and proposed Aurora costs for a site visit (for credit reasons or issues on site) to a customer's premises against those of other DNSPs. The following table provides a comparison of these costs. This is a new category for Aurora, although the rationale for splitting this category was not identified.

Table 43 – Site visit – credit action or site issue

DNSP	Charge (incl GST)	Notes
Aurora existing	$38.72	• For 2011/12 year • Previously charged as a non-scheduled site visit.
Aurora proposed[185]	$374.56 $328.99	• Site visit – credit action or site issues (truck) • Site visit – credit action or site issues (ute) • For 2012-13 year ($2011/12)
Ausgrid[186]	$96.80 $162.80	• Disconnection at meter box • Disconnection at pole top/pillar
CitiPower	$26.20	• Applies where a customer is disconnected for non-payment
Endeavour Energy[187]	$48.40	• Disconnection including for breach of customer supply contract
Energex	$0.00	• Services are subject to Schedule 8 of the Queensland Electricity Regulation 2006, which either caps the price or sets the price to nil.
Ergon Energy	$0.00	• Services are subject to Schedule 8 of the Queensland Electricity Regulation 2006, which either caps the price or sets the price to nil.
Essential Energy[188]	$96.80	• Disconnection at meter box no payment (business hours)
Jemena	$32.53	• Temporary disconnect for non-payment
Powercor	$26.20	• Applies where a customer is disconnected for non-payment
SP AusNet	$17.16	• Field officer visit (business hours)
United Energy	$40.60	• Re-energise/de-energise (fuse removal)

The Aurora fees are differentiated by the type of vehicle that is used to respond to the request. The reason for the two fees is not explained, and it is not clear whether the

185 Based on Aurora Energy revised Fee Based Services.xls provided on 5 September 2011 (AER/027)
186 Was previously EnergyAustralia networks
187 Was previously Integral Energy networks
188 Was previously Country Energy networks

different fees simply reflect the vehicles that Aurora has available in the location, or that the vehicles are required for different tasks.

The fee proposed by Aurora for a site visit with no appointment is considerably higher than almost all other DNSPs. The fee is also significantly increased from the current charge.

Nuttall Consulting requested Aurora to provide evidence supporting the increased fee and particularly why this fee should be significantly different from the standard site visit fee. Nuttall Consulting considers that the information provided by Aurora does not establish the case for such a significant increase or why the proposed fee is significantly greater than other DNSPs.

Nuttall Consulting also considers that the new fee category proposed by Aurora is not sufficiently justified in terms of why a separate fee type is required, and why this new fee differs substantially from the existing site visit fee.

On this basis, Nuttall Consulting recommends that the existing fee of $38.72 (including GST) is maintained with an allowance for escalation and allocation of overheads in accordance with the cost allocation methodology.

C.2.3. Tariff alterations (single and three phase)

Nuttall Consulting has compared the current and proposed Aurora costs for a single and three phase tariff alteration against those of other DNSPs. The following table provides a comparison of these costs.

Table 44 – Tariff alteration (1 and 3 phase)

DNSP	Single phase (incl GST)	Three phase (incl GST)	Notes
Aurora existing	$151.80	$176.00	• For 2011/12 year. • Visit to a customer's premises during normal business hours to add or modify a single/three phase metering circuit
Aurora proposed[189]	$176.13	$240.19	• For 2012-13 year ($2011/12)
Ausgrid[190]	NA	NA	• No corresponding fee
CitiPower	$120.85 $45.05	$302.10 $175.75	• Changeover of meter(s) for testing. Refunded if meter proven inaccurate. • Second charge is for additional meters.
Endeavour Energy[191]	$80.30	NA	• Meter testing including the (a) changeover of the meter(s) or the installation of test metering (2 visits).[192]

[189] Based on Aurora Energy revised Fee Based Services.xls provided on 5 September 2011 (AER/027)
[190] Was previously EnergyAustralia networks
[191] Was previously Integral Energy networks

Energex	$104.07	$104.07	• Alterations and additions to current metering equipment
Ergon Energy	$359.48	$359.48	• Moving the meter to a new location. Maintaining existing meters.
Essential Energy[193]	NA	NA	• No corresponding fee
Jemena	$263.70	$263.70	• Retest of types 5 and 6 metering installations for first tier customers <160MWh
Powercor	$120.85 $45.05	$302.10 $175.75	• Changeover of meter(s) for testing. Refunded if meter proven inaccurate. • Second charge is for additional meters.
United Energy	NA	NA	• No corresponding fee

The tariff alteration fees proposed by Aurora are well within the range of fees charged by other NEM DNSPs. Nuttall Consulting notes that these fees are increasing from current levels although the revised allocation of overheads would account for some of this increase.

Nuttall Consulting considers that the time and materials required for a tariff alteration are consistent with the proposed tariff alteration fees. The range of tariff alteration activities is quite large and varies considerably based on the conditions and assets located at the worksite. The number of meters involved, the condition of the meter surrounds and housings, and the tariff options selected by the consumer will all impact the time and materials involved.

Nuttall Consulting considers that the fees proposed by Aurora for tariff alterations are reasonable.

C.2.4. Renewable energy connection

Nuttall Consulting has compared the current and proposed Aurora costs for a renewable energy connection to a customer's premises against those of other DNSPs. The following table provides a comparison of these costs.

[192] In accordance with clause 6.4 of the Market Operations Rule (NSW Rules for Electricity Metering) No.3 of 2001

[193] Was previously Country Energy networks

Table 45 – Renewable energy connection (business hours)

DNSP	Charge (incl GST)	Notes
Aurora existing	$160.77	• For 2011/2012
Aurora proposed[194]	$176.13	• For 2012-13 year ($2011/12)
AusGrid[195]	NA	• No corresponding fee
CitiPower	$402.60	• Installation of solar system <10kW[196]
Endeavour Energy[197]	NA	• No corresponding fee
Energex	NA	• No corresponding fee
Ergon Energy	$775.46	• Provision of meters above the minimum regulatory requirements on request • May not be directly applicable.
Essential Energy[198]	NA	• No corresponding fee
Jemena	NA	• No corresponding fee
Powercor	$402.60	• Installation of solar system <10kW[199]
United Energy	$109.75	• After the first 30 mins, $27.40 for each additional 15 minutes.[200] Cost of meter = $0.00.

The renewable energy connection fee proposed by Aurora is well within the range of fees charged by other NEM DNSPs. Nuttall Consulting notes that these fees are increasing from current levels although the revised allocation of overheads may account for this increase.

Nuttall Consulting considers that the time and materials required for a renewable energy connection are consistent with the proposed fees. The range of renewable energy connection activities is quite large and varies considerably based on the conditions and assets located at the worksite.

Nuttall Consulting considers that the renewable energy connection fee proposed by Aurora is reasonable.

194 Based on Aurora Energy revised Fee Based Services.xls provided on 5 September 2011 (AER/027)
195 Was previously EnergyAustralia networks
196 Installer Guidelines For Grid Connection Of Inverter Power Sources Up To 10 Kw, CitiPower/Powercor
197 Was previously Integral Energy networks
198 Was previously Country Energy networks
199 Installer Guidelines For Grid Connection Of Inverter Power Sources Up To 10 Kw, CitiPower/Powercor
200 Process to connect AS4777 compliant inverter based generation to the United Energy Distribution Network. Solar photovoltaic (PV) and Wind. Date: February 2009

C.2.5. Truck tee-up

Nuttall Consulting has compared the current and proposed Aurora costs for a truck tee-up against those of other DNSPs. The following table provides a comparison of these costs.

Table 46 – Truck tee-up (business hours)

DNSP	Charge (incl GST)	Notes
Aurora existing	$758.34	• For 2011/2012
Aurora proposed[201]	$839.62	• For 2012-13 year ($2011/12)
AusGrid[202]	NA	• No corresponding fee
CitiPower	$682.15	• Elective underground service connection (up to 100Amps)
Endeavour Energy[203]	NA	• No corresponding fee
Energex	$374.89	• Multi-phase overhead service replacement (includes new service)
Ergon Energy	$311.25	• Provision of service during business hours requiring one person crew / additional crew (e.g. safety observer, installation inspection, query tariff, revenue protection activity)
Essential Energy[204]	NA	• No corresponding fee
Jemena	$551.01	• Routine new connection where Jemena is responsible for customer metering (single phase <100 Amps)
Powercor	$682.15	• Elective underground service connection (up to 100Amps)
SP AusNet	$263.30	• Service truck visit (business hours)
United Energy	$115.51	• Service vehicle visits for first 30 mins. • $47.47 for each additional 15 minutes.

The truck tee up fee proposed by Aurora is increased from current levels and significantly greater than most other DNSPs.

Aurora advised[205] Nuttall Consulting that this fee is designed to provide an incentive for Registered Electrical Contractors to reduce the reliance on Aurora crews for onsite works

[201] Based on Aurora Energy revised Fee Based Services.xls provided on 5 September 2011 (AER/027)
[202] Was previously EnergyAustralia networks
[203] Was previously Integral Energy networks
[204] Was previously Country Energy networks

and to minimise the time that Aurora crews need to spend at each site. Aurora has assumed that the truck will require a minimum of 2 hours onsite.

Nuttall Consulting notes that the issue of co-ordinating and handover between Aurora and Registered Electrical Contractors is common across the industry. However, the structure of the Aurora truck tee-up fee is not ideal to provide the intended incentive. Nuttall Consulting considers that a fee with a low initial charge and then additional time-based increments would provide a much greater incentive for contractors to have the site adequately prepared for the Aurora crews. This sort of charging system is common for electrical and plumbing trades and is also utilised by United Energy in Victoria.

A 2-hour fee based on the United Energy charges would result in a cost of $400.33. This is significantly lower than the current and proposed Aurora fees for this service. However, it is significantly greater than the fees charged by SP AusNet and Ergon Energy who have a similar customer density to Aurora. Based on the fees from other DNSPs, Nuttall Consulting considers that a fee based on an assumed time on-site of 2 hours should be in the order of $400. In addition, Nuttall Consulting considers that an incentive mechanism should be established to reward those contractors who require less onsite time from Aurora. This incentive scheme should be consistent with the method of charging that is common in the electrical and plumbing industries.

Nuttall Consulting considers that the United Energy truck tee-up fees are representative of the target fee and an appropriate incentive mechanism. On this basis, Nuttall Consulting recommends the following truck tee-up fee structure and rates (incl GST):

- $115.51 service vehicle visits for first 30 mins.
- $47.47 for each additional 15 minutes.

C.3. Public lighting

The AER has requested Nuttall Consulting to assess the reasonableness of the Aurora costs associated with 2 major lighting types: 80W mercury vapour (MV) and 250W high pressure sodium (HPS) lights. The focus of the Nuttall Consulting review was the technical aspects associated with installation and replacement costs, and asset lives.

The Aurora proposed public lighting charges are built up using an annuity type model. This model identifies 48,190 private and contract lights, of which over 31,000 are 80W MV lights and over 4,200 are 250W HPS lights.

C.3.1. Material costs

The primary material inputs to public lights include the lamp (light globe), luminaire (globe housing, diffuser, and electrical supply), and the bracket that attaches the luminaire to the pole.

[205] Onsite meeting at Aurora Energy offices, Kirksway Place, Hobart – 9 August 2011.

The following table provides the lighting material costs proposed by Aurora. Aurora has indicated that these costs are sourced from current contract costs.

Table 47 – Lighting material costs ($2009/10)[206]

Light Type	Lamp Material Cost ($)	Luminaire Material Cost ($)	Bracket Material Cost ($)
80W MV	1.93	68.49	201.41
250W HPS	27.15	166.45	201.41

Nuttall Consulting has reviewed the proposed lamp costs against those of other DNSPs[207] and the proposed lamp material costs appear reasonable. The luminaire material costs proposed by Aurora appear reasonable as these costs also include the photo-electric cell that activates the lamp based on the level of ambient light, and the ballast that converts the power supply to the appropriate voltage and current type.

The Aurora bracket cost proposed was the same for 80W MW and 250W HPS lamps. This is unusual as 250W HPS lamps are usually utilised on major roads and require a longer bracket for correct placement[208]. Nuttall Consulting requested Aurora to provide a breakdown of the bracket costs.

Aurora provided a spreadsheet of the bracket cost build[209]. The following table provides the bracket costs for each standard bracket type. These costs are reportedly inclusive of store on-costs.

Table 48 – Bracket type costs (as at 11 August 2011)

Bracket Type	Cost ($)
1.5m Bracket	$96.39
2m Bracket	$138.99
3m Bracket	$169.02
Type 1	$322.40
Type 2	$444.34

[206] Aurora Energy Public Lighting Annuity Model V2.xls !Base Volume Data.
[207] - Submission to the Essential Services Commission, Re Review of Public Lighting Excluded Service Charges - Draft Decision, United Energy June 2004,
- Review of Energy Efficient Public Lighting Charges, Submission Prepared for: Essential Services Commission, Alinta Energy, 29 July 2008
[208] Luminaires are classified by AS/NZS1158 Lighting for roads and public spaces
[209] NW-#30206954-v1-Road_Lighting_Bracket_Allocation.XLS (confidential).

Nuttall Consulting has reviewed the Aurora methodology for calculating the average bracket costs. The methodology appears correct and is appropriately weighted for the volumes of each type of bracket.

However, Nuttall Consulting is not satisfied with two input values that have been used in the methodology for determining the bracket costs:

- the volume of longer/more expensive brackets in use for 80W MV lights appears quite high
- the cost for brackets appears high.

Bracket types

The bracket types listed by Aurora[210] have a 1.5m bracket as the shortest length. Nuttall Consulting understands that the default length for bracket arms on residential roads is a bracket arm with a minimum outreach of 1.5m (where this is possible). As is common practice, Aurora has also identified that it does not use 80W MV lights for major road lighting.[211] This suggests that there should therefore be a lesser requirement for longer bracket types.

As the majority of lighting services provided by Aurora are for residential roads, it appears contradictory that Aurora has over 70% of bracket types as greater than 1.5m.

Nuttall Consulting also notes that the bracket allocation numbers for each bracket type are rounded off to even 1000's, with the exception of the most expensive bracket type (Type 2)[212]. This suggests that the means for determining the bracket type volumes were different and that the validity of the volumes may be questionable.

Aurora has not identified the source of the bracket allocation information and had advised Nuttall Consulting that information on the bracket type was not captured in the Aurora information systems.[213] On this basis, Nuttall Consulting has requested that Aurora provide detailed information of the sources of information on bracket types and numbers to support the bracket allocation spreadsheet.[214] At the date of this report, the requested information had not been received. Aurora has acknowledged that these numbers were calculated using managerial estimates and that they have no actual numbers to support the estimates.

Aurora has provided detailed drawings and diagrams of the various bracket types used for public lighting. These brackets range from a "reach" or length of 250mm to 2,000mm for minor roads lighting. This range of brackets is consistent with the range typically seen in other NEM DNSPs. Shorter reach brackets are typically used in residential and low traffic areas where the lighting standards require a lower level of lighting than for major roads.

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[210] NW-#30206954-v1-Road_Lighting_Bracket_Allocation.XLS (confidential).
[211] Management Plan 2011 Public Lighting. Document: NW#-30148124-V5, Date: 9 May 2011, Appendix 2.
[212] For 80W MV lights.
[213] Onsite meeting at Aurora Energy offices, Kirksway Place, Hobart – 9 August 2011.
[214] AER information request: AER/027.

The bracket allocation and costs information provided by Aurora does not list the shorter types of public lighting brackets, although these brackets are very commonly used for minor road lighting in many Australian states. These shorter brackets are commonly attached to the end of crossarm, or connected directly to the pole.

The Aurora lighting manual[215] refers to the Australian Standards for the design and installation of public lighting. On this basis it is reasonable to assume that the Aurora public lighting system should be similar to that of other Australian DNSPs who also work to the Australian Standards.

Nuttall Consulting has been unable to identify any reason that the standard public lighting design for minor roads in Tasmania would not include a sizeable proportion of short reach brackets. Of particular note is that fact that Aurora has standard designs for these brackets, but does not report any of these as having been installed[216].

Nuttall Consulting considers that the prudency of the selection of bracket types is not justified.

It is not possible within the scope of this review to determine the number of locations where a shorter reach bracket would be possible. Nuttall Consulting does not have bracket ratio information from other DNSPs that would allow a substitute percentage to be allocated.

Bracket costs

Aurora has identified a cost of $93.39 for a 1.5m public lighting bracket. This bracket is designed to be placed on a pole in most instances.

The standard bracket cost for Victorian public lighting was assessed by the state regulator as $40[217] per unit. In 2008, this figure was resubmitted by at least one of the Victorian DNSPs as the current cost of a standard public lighting bracket.[218] Nuttall Consulting has not been able to source any additional comparison rates for minor roads public lighting brackets in Australia.

Nuttall Consulting requested that Aurora provide information on the bracket material costs and the unit rates for public lighting assets. The unit rate information that was received is detailed in Table 48 while the source of this information is not identified. Aurora provided a spreadsheet on bracket unit costs[219] that were reported to be sourced directly from bracket invoices. This information did not reconcile with that of Table 16 and it was not clear if the unit costs were inclusive of GST (or not). The unit cost information in the spreadsheet also appeared to relate to a very small number of units, where unit rates should be based on bulk purchase volumes for this sort of material.

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[215] NW-#241856-v1-Lighting_Manual.pdf

[216] NW-#30206954-v1-Road_Lighting_Bracket_Allocation.XLS (confidential).

[217] Final Decision on Energy Efficient Public Lighting Charges, Essential Services Commission, August 2004.

[218] Submission to Essential Service Commission: Draft Decision on Energy Efficient Public Lighting Charges, Jemena, December 2008.

[219] CO-#10325843-v1-Purchase_History_-_Outreach_Arms_180811.XLS (confidential).

Nuttall Consulting considers that the limited amount of public information available with respect to public lighting brackets is not sufficient to conclude that the Aurora costs are inefficient. However, the limited information that is available does suggest that these costs should be investigated in more detail. On this basis, Nuttall Consulting recommends that Aurora provide detailed information of the sources of information on bracket types and numbers to support the bracket allocation spreadsheet.

C.3.2. Installation costs

Aurora is proposing a public lighting installation cost (excluding materials) of $91 and $146 for 80W MV and 250W HPS light respectively.[220]

Nuttall Consulting has reviewed these costs against the labour rates identified by Aurora in the Unit Rates Model and considered the time typically required to undertake a luminaire or bracket replacement. The installation costs proposed by Aurora appear reasonable for the replacement of a single item.

The time taken to replace a luminaire will vary depending upon the manner in which the replacement is undertaken. A replacement as part of a bulk replacement program will attract considerably less travel and worksite preparation time. For the purposes of this review, the assumption is that replacement is occurring on an "as needs" basis and that a reasonable allowance for travel time and site preparation would be required.

Nuttall Consulting notes that the replacement of a luminaire and bracket at the same time would provide for a more efficient unit installation cost, although this would not be the norm given the differing asset lives of the two asset types.

Nuttall Consulting considers that the installation costs proposed by Aurora of $91 and $146 for 80W MV and 250W HPS light respectively are reasonable.

C.3.3. Asset lives

Aurora is proposing the following asset lives for public lighting assets.

Table 49 - Public lighting asset lives[221]

Asset	Proposed asset life
Luminaire	20 years
Bracket	40 years
Pole	50 years

Aurora advised Nuttall Consulting that the above asset lives were those "inherited" from Hydro Tasmania and that they have not changed since the handover. Aurora has not provided any current asset life information for the existing population of public lighting assets.

[220] Public Lighting Annuity Model.xls, !Annuity Calc K30 and K37.
[221] Public Lighting Annuity Model.xls

Nuttall Consulting has reviewed the public lighting asset ages against those of similar jurisdictions. In NSW, the AER has previously accepted an asset life of 20 years for brackets[222], 20 years for luminaires and 35 years for poles[223]. In Victoria, public lighting brackets and poles have historically been depreciated over a 35 year period[224].

The four-year bulk replacement program currently utilised by Aurora is also consistent with Australian industry practice.

Nuttall Consulting considers that the proposed asset lives and bulk replacement programs are reasonable and consistent with industry practice.

[222] Submission for the AER's re-determination of public lighting prices 2010 to 2014, EnergyAustralia, January 2010

[223] New South Wales draft distribution determination 2009–10 to 2013–14, Alternative control (public lighting) services – AER, 6 March 2009

[224] Final Decision on Energy Efficient Public Lighting Charges, Essential Services Commission, August 2004.

D AER Terms of reference

[attached]