Nuttall Consulting

Regulation and business strategy

Report – Capital Expenditure

Victorian Electricity Distribution Revenue Review

A report to the AER

Final Report

4 June 2010

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Executive Summary

Background

The Australian Energy Regulator (AER) is assessing proposals from the five Victorian Distribution Network Service Providers (DNSPs) to determine their regulated revenues for the period 1 January 2011 to 31 December 2015.

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

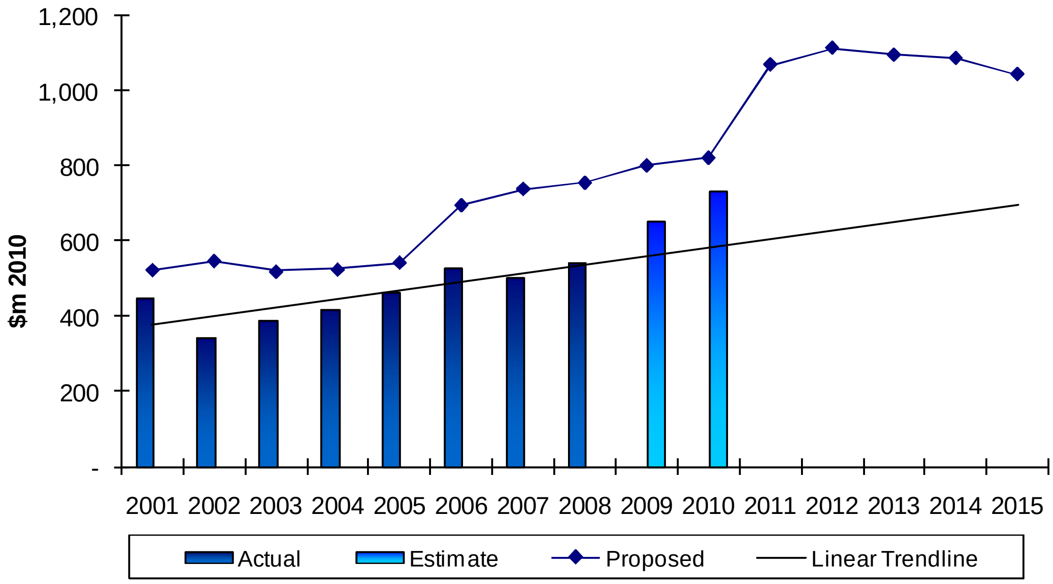
This report and appendices detail our review and recommendations on capex (the capex review) and also our findings on other specific matters where the AER had requested advice.

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 assessment of the DNSP’s capital expenditure forecast for the next period.

Expenditure analysis

Nuttall Consulting has compared recent actual capital expenditure of the DNSPs in the National Electricity Market (NEM). The recent actual capital expenditure of the Victorian DNSPs compares favourably on a state-by-state basis and individually when compared across a range of performance metrics. This analysis suggests that the Victorian DNSPs currently have the lowest capital cost base in the NEM.

With regard to capex trends for the Victorian DNSPs, the figure below shows the aggregate capex proposed by the five Victorian DNSPs for the previous, current and next control periods. The figure also shows the actual expenditure incurred in the previous and current periods as well as the expenditure that the DNSPs are estimating for the remainder of the current period.



This figure highlights a number of important matters:

- For the next regulatory period (2011-2015), the Victorian DNSPs are forecasting a significant increase in capital expenditure. The average net increase ranges from 72% for Powercor to 156% for SP AusNet[1].
- Capital expenditure has been trending up over the current and previous periods; however, the DNSPs' forecasts are well above this trend. The DNSPs are also forecasting a significant step change in expenditure levels in 2011.
- From 2001 to 2008 all DNSPs have forecast higher levels of capital expenditure than they have incurred. For the current period, the over-forecast is estimated to range from 13% for SP AusNet to 30% for United Energy. Interestingly, for most DNSPs, the accuracy of their forecast in the first half of the current period is as poor – if not poorer – than for the 2nd half of the period.

Given the good comparative performance of the Victorian DNSPs and the very significant proposed increases, it was agreed with the AER that our capex review would be approached in the following manner:

- recent actual capital expenditure can be considered to reasonably represent the efficient cost base
- the onus is on the DNSP to appropriately demonstrate that their proposed increases can be reasonably considered prudent and efficient.

Assessment of capex proposals

Nuttall Consulting has undertaken a high-level review of the DNSPs' expenditure and the basis for the increases presented in the DNSPs' proposals.

Based upon the findings of our high-level review, we have also conducted a detailed review of "targeted" matters, including specific project and programs. A particular focus of this

[1] when compared to recent actual expenditures incurred (2006 to 2008).

review has been those matters that are driving the proposed increases in expenditure. The matters for the targeted review were discussed and agreed with the AER.

Based upon the materiality of the proposed increases, the detailed review has focused on[2]:

- Reinforcement expenditure for each DNSP - in terms of the methodology adopted to prepare the forecasts and a selection of targeted projects and programs
- Reliability and Quality Maintained (RQM) expenditure for each DNSP - in terms of the methodology adopted to prepare the forecasts and a selection of targeted projects and programs
- Environmental, Safety and Legal (ESL) expenditure for the majority of DNSPs – in terms of the most significant programs driving the proposed increases in expenditure
- Various other expenditure categories depending on the DNSP - in terms of the most significant programs resulting in proposed increases in expenditure.

To conduct this review, Nuttall Consulting has assessed relevant documents provided by the DNSPs to support their proposals, held meetings with the DNSPs, and made a number of additional information requests.

Review findings and recommendations

Based upon the findings of our review (high-level and detailed), we do not consider that any of the DNSPs have adequately demonstrated that their overall proposed expenditure increases can be considered prudent and efficient. This view is based upon concerns we have with:

- the DNSPs justification for the variations from past forecasts
- the lack of substantiation of the overall changes to risk levels through the proposed plans
- the lack of evidence that many of models used to develop the forecasts can be considered “fit for purpose”, in terms of producing forecast appropriate for regulatory purposes
- numerous areas where we considered overestimation could be occurring
- lack of recognition of synergies or benefits between individual projects and programs.

In general, we consider that the plans proposed by the DNSPs are reasonable at an internal level to identify likely future network needs, work levels, and associated expenditure. However, we consider that as the plans advance through the DNSPs’ capital governance processes significant reductions will occur, resulting in a) the deferral of some projects, b) the selection of more efficient solutions, and c) the decision not to undertake certain projects at all.

Given the following:

[2] It has been agreed with the AER that Nuttall Consulting would not review expenditure on customer connections as this would be reviewed by the AER.

- the good historical comparative performance of the DNSPs relative to other NEM states
- the relatively consistent historical expenditure trend
- the consistent historical overestimation of the DNSPs forecasts
- the findings of repex modelling, which support expenditure being in line with the historical trend
- the findings of targeted detailed reviews, which also support expenditure being in line with the historical trend,

we consider that a reasonable estimate of prudent and efficient capex should be relatively consistent with the recent historical level with some modest allowance for increasing needs due to the aging of the network and further demand growth.

We have developed a capital expenditure forecast that we consider reasonably represents a prudent and efficient level that allows the DNSPs to meet their obligations. This is based upon:

- adjustments to the DNSPs' RQM forecasts to ensure they are consistent with the historical expenditure levels with increases as suggest by our replacement modelling
- adjustments to the DNSPs' reinforcement forecasts to ensure they are consistent with the historical expenditure levels with increases based upon our probabilistic assessment of the project reviewed (i.e. the likelihood that projects and expenditure will occur as proposed by the DNSPs)
- adjustments to the ESL expenditure, based upon the lack of substantiation by the DNSPs that the increases were justified, which brings it more in line with historical levels
- adjustments to other expenditure categories, based upon the lack of substantiation by the DNSPs that the increases were justified, which brings it more in line with historical levels.

Our recommended capex (excluding new customer connections) represents approximately[3] a 40% reduction on the DNSP proposals and a 35% average increase on the actual expenditure incurred over 2006 to 2008. The recommended adjustments for each DNSP are summarised in the tables below.

[3] These figures are approximate only due to 1) the targeting exercise, which means that Nuttall Consulting has not reviewed certain categories of some DNSPs, and 2) the various matters that were not included in our review (e.g. labour and material escalations, related party margins, etc).

	$millions (2010)				
	2011	2012	2013	2014	2015
CitiPower - proposed	132.7	149.1	160.9	159.0	153.5
CitiPower - recommended	**91.8**	**89.8**	**97.4**	**73.9**	**79.7**
Powercor - proposed	204.6	202.8	215.1	230.3	226.9
Powercor - recommended	**123.7**	**129.3**	**133.4**	**138.9**	**144.5**
Jemena - proposed	111.4	114.4	105.2	91.4	91.8
Jemena - recommended	**49.0**	**53.7**	**53.8**	**52.6**	**54.3**
SP AusNet - proposed	197.1	232.1	210.3	212.3	184.5
SP AusNet - recommended	**110.4**	**114.1**	**120.7**	**131.3**	**135.7**
United Energy - proposed	157.3	147.3	142.1	126.2	105.9
United Energy - recommended	**88.4**	**89.9**	**88.8**	**90.3**	**93.8**
Total - proposed	803.2	845.7	833.6	819.2	762.7
Total - recommended	**463.4**	**476.8**	**494.1**	**487.1**	**508.0**

DNSP	% reduction	% increase – 2006-2008 actuals	% increase 2006-2010 estimate
CitiPower	43%	87%[4]	47%
Powercor	38%	20%	17%
Jemena	49%	15%	1%
SP AusNet	41%	32%	-4%
United Energy	34%	46%	16%
Victoria	**40%**	**35%**	**13%**

The recommended capex allowance has been developed at a capex category level, but the overall view has been formed from both “top-down” and “bottom-up” assessments. As such, the recommendation should be viewed in its entirety. As history has shown, external events and further DNSP analysis and planning may result in significant variations at the project and capex category levels. The DNSPs will continue to manage capex expenditure as they best see fit and are in no way constrained to adhere to individual capex category allowances. Should the DNSPs challenge this recommendation, it will be important that they demonstrate why they cannot manage the overall risks within the overall recommendation. Focusing only on the matters raised in the detailed reviews may not adequately address this matter.

It is also worth noting that the Nuttall Consulting capex recommendation could be considered conservative, as it has been produced as an aggregate of individual category

[4] The greater increase accepted for CitiPower is due to two very costly projects that gained approval in the current regulatory period, but a large portion of the costs will be incurred in the next.

estimates without further adjustments. It may be reasonable to expect that greater levels of capital and operational synergies may be realised as overall expenditure needs increase.

Important caveat associated with our recommendation

This recommendation excludes allowances for new bushfire driven programs. For example, the two rural DNSPs are proposing very large programs to replace conductors, which appear to be mainly driven by bushfire risks. These matters and others are currently under the consideration of the Bushfire Royal Commission. The AER may need to re-consider these matters subsequent to the findings of the Royal Commission.

1 Introduction

On 1 January 2009, the Australian Energy Regulator (AER) assumed responsibility for the economic regulation of electricity distribution networks in Victoria, under the National Electricity Rules (NER). Under these rules, the Distribution Network Service Providers (DNSPs) are required to submit a regulatory proposal to the AER.

The regulatory proposal must contain a number of elements, including a year-by-year forecast of capital expenditure (capex) for the next regulatory control period. In the case of Victoria, the next regulatory control period is from 1 January 2011 to 31 December 2015. This is referred to as the "next control period". The current regulatory control period commenced on 1 January 2006 and will expire on 31 December 2010.

There are five DNSPs licensed in Victoria and the subjects of this review. These DNSPs are:

- CitiPower Pty - "CitiPower"
- Jemena Electricity Networks (Vic) Ltd- "Jemena"
- Powercor Australia Limited - "Powercor"
- SPI Electricity Pty Ltd - "SP AusNet"
- United Energy Distribution Pty Ltd - "United Energy"

The AER is required to assess the DNSP regulatory proposals in accordance with the provisions of the NER.

Nuttall Consulting has been engaged by the AER to provide technical advice on the DNSPs proposals and provide a report of our findings and recommendations on these matters. This document represents the draft report commitment of this appointment.

The assignment is focused on the capex proposals of the DNSPs, but also includes support and advice in relation to operating expenditure (opex) and other technical matters on an “as-needs” basis.

1.1 Terms of reference and methodology

The AER has engaged Nuttall Consulting for advice in relation to the Victorian DNSP’s capital expenditure (capex) as set out in the respective DNSP revenue proposals and supporting documents. The services required of the consultancy include:

- to recommend to the AER capex allowance adjustments, if any, for each DNSP for the next period to support the AER making a determination under the NER
- to provide recommendations on technical matters concerning the proposed opex step changes
- other technical advice on an as-needs basis.

Our analysis of capital expenditure in the next regulatory period has involved:

- historical and forecast capex analysis for each DNSP, and capital expenditure in the other NEM states
- age-based replacement modelling
- a review of the capital governance processes
- identification and targeting of matters for a more detailed review
- review of policies, procedure, and forecasting methodologies associated with the targeted matters
- targeted 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 assessment of the DNSP's capital expenditure forecast for the next period.

It is important to note that the form of the review of capex was guided by two important assessments. The first was a review of the prior proposals from the DNSPs for previous regulatory control periods and analysis on how accurate these proposals had eventually been. The second was a review of the relative capital efficiencies of the DNSPs, particularly with respect to other NEM states. Nuttall Consulting undertook elements of this assessment under a previous assignment to the AER.

This findings on these matters directed Nuttall Consulting to consider that the existing level of capex was relatively efficient for the Victorian DNSPs and that the historical accuracy of the DNSPs capex proposals was relatively poor.

As a result, the AER and Nuttall Consulting agreed a set of targeted capex reviews that were focussed on areas of significant capex increases. Areas where capex was not increasing above historical trends were then either not reviewed, or reviewed at a high-level only. The existing level of DNSP capex was considered to represent an efficient base.

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

The structure of the Nuttall Consulting review is aligned with the capex categories that have historically been utilised for economic regulation of the Victorian distribution industry. The DNSP proposals also generally aligned with these categories to a greater or lesser extent. These categories include:

- new customer connections (NCC) - including load movement
- reinforcement
- reliability and quality maintained (RQM)
- environmental, safety and legal (ESL)

- non-network general (including IT and other assets).

Nuttall Consulting has not audited the category allocations of capex as they have been applied by the DNSPs. Anecdotally there would appear to be differing approaches to these allocations - particularly in the ESL and RQM categories.

Following the commencement of the Nuttall Consulting review, it was agreed with the AER that the NCC review would be undertaken by the AER, with Nuttall Consulting reviewing specific and targeted projects.

In parallel with the Nuttall Consulting review of capex, the AER and their consultants have reviewed other elements of the DNSP proposals. The parallel reviews that are relevant to the Nuttall Consulting review of capex include:

- a review of the demand forecasts of the DNSPs
- a review of "business as usual" opex
- a review of labour and material inflation on the capex forecasts
- a review of 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.

1.2 Structure of report

The report is structured as follows:

- In section 2, 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 3 provides a discussion on the replacement modelling we have undertaken as part of this review
- In section 4, we summarise the DNSPs capex programs and provided a summary of our overall findings and recommendations on the DNSPs proposed capex.
- Section 5 provides an overall summary of our review findings and recommendations.
- Our detailed reviews of each of the capex categories for each of the DNSPs are provided in Appendix A to E.
- Appendix F contains results from Nuttall Consulting's comparative analysis of the NEM DNSPs' capital expenditure, which are discussed in Section 2.
- Appendix G contains the Nuttall Consulting review of the DNSPs' capital governance documentation.
- Appendix H contains additional results from our replacement modelling.

- Appendix I provides the Nuttall Consulting targeted review of opex step change areas identified by the AER. It is important to note that the review of these opex matters is included in this report for completeness. The main body of the report only discusses matters associated with the capex review.
- Appendix J provides Nuttall Consulting's analysis of historical load profiles, which is related to our review of reinforcement expenditure.
- Appendix K provides the Nuttall Consulting investigations into the DNSPs proposals associated with Advanced Metering Infrastructure (AMI).

2 DNSP expenditure analysis

This section presents our analysis of the DNSPs historical expenditure, including an assessment of the relative capex efficiency of the Victorian DNSPs, an assessment of the accuracy of the DNSPs' previous capex forecasts, and the variation from trend of the DNSP's capex forecasts for the next period.

2.1 Actual expenditure levels

2.1.1 Major state comparison

The Victorian DNSPs compare well when overall capex is compared with that of Queensland and NSW[5]. The following figure shows the average level of capex for the last 5 years for each state compared with the current regulated asset value.

Figure 1 - Capex as a percentage of asset value

There are a number of factors that are beyond the immediate control of the DNSPs that may impact this comparison. In addition, the review of capex does not consider the trade-offs with opex and service standards. For this reason this comparison is not intended as mechanism for setting capex levels, but of identifying areas for specific review.

This comparison has been undertaken for different benchmark measures including the number of customers served, length of overhead and underground lines, energy delivered and maximum system demand. These benchmarks were chosen to provide a selection of efficiency measures. In isolation, any single comparative measure will have strengths and

[5] These states are considered most comparable based on the number of customers served and that each state has more than one supplier.

weaknesses. In aggregate, these measures provide a strong indication of the relative capital efficiency of each state.

The above chart is representative of the mix of benchmark measures that were assessed by Nuttall Consulting. The Victorian DNSPs placed as the most capital efficient in each of these measures with the exception of the "per km of line" measure where they were second to NSW. A complete listing of the benchmarks used is provided in Appendix F.

This range of measures would seem to suggest that the overall Victorian levels of capex as revealed for the last 5 years are relatively efficient when compared with Queensland and NSW.

Observation: The overall level of capex in Victoria as revealed in the previous 5 years appears relatively efficient.

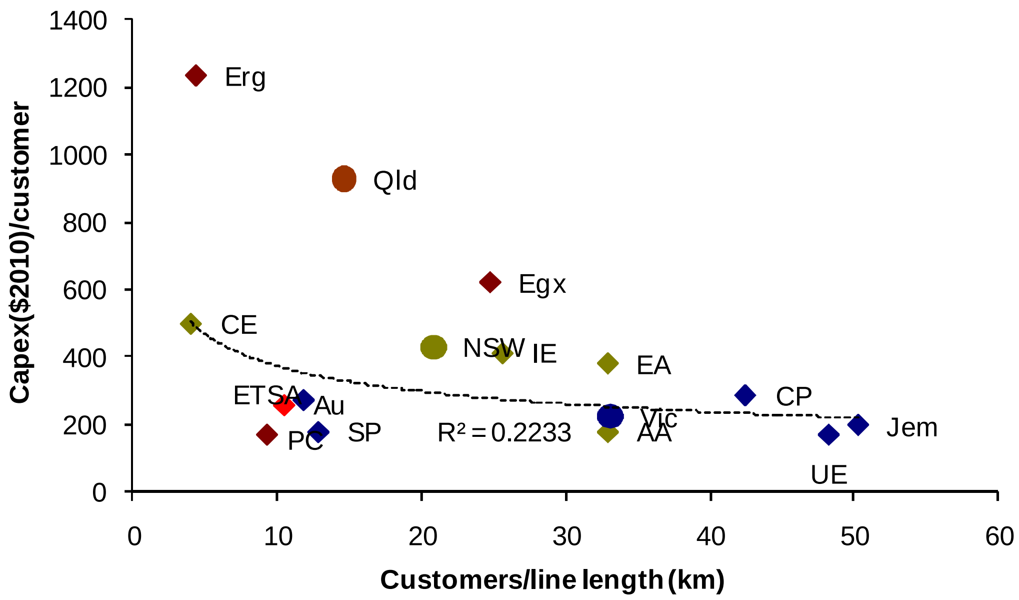
2.1.2 DNSP comparison

When comparing capex at an individual company level there are factors that significantly impact expenditure and influence the value or accuracy of the benchmark. The most significant of these factors is the customer density of the areas serviced by the DNSP. One way of considering the customer density is to take account of the number of customers per km of overhead or underground distribution line.

The following chart shows the capex spent[6] per customer for each of the NEM DNSPs.

[6] Reported capex for last 5 years in $2004.

Figure 2 - capital expenditure per customer[7]



The above chart appears to indicate that the overall level of capex for the Victorian DNSPs is broadly below the level of comparable DNSPs.

The above benchmark has been undertaken for different comparison measures including the value of the regulated asset base, length of overhead and underground lines, energy delivered and maximum system demand.

These benchmarks were chosen to provide a selection of efficiency measures. A complete listing of the benchmarks used is provided in Appendix F. In isolation, any single comparative measure will have strengths and weaknesses. In aggregate, these measures provide a strong indication of the relative capital efficiency of each of the DNSPs.

The above chart is representative of the mix of benchmark measures that were assessed by Nuttall Consulting The Victorian DNSPs placed as relatively capital efficient in most of these measures, with CitiPower and Jemena appearing above the trendline in a couple of instances.

In aggregate, these charts would suggest that the revealed capex of the Victorian DNSPs for the last 5 years is relatively efficient and that individual DNSPs appears to benchmark consistently well in comparison to other NEM businesses.

Observation: The individual Victorian DNSPs appear reasonably efficient when compared to interstate DNSPs.

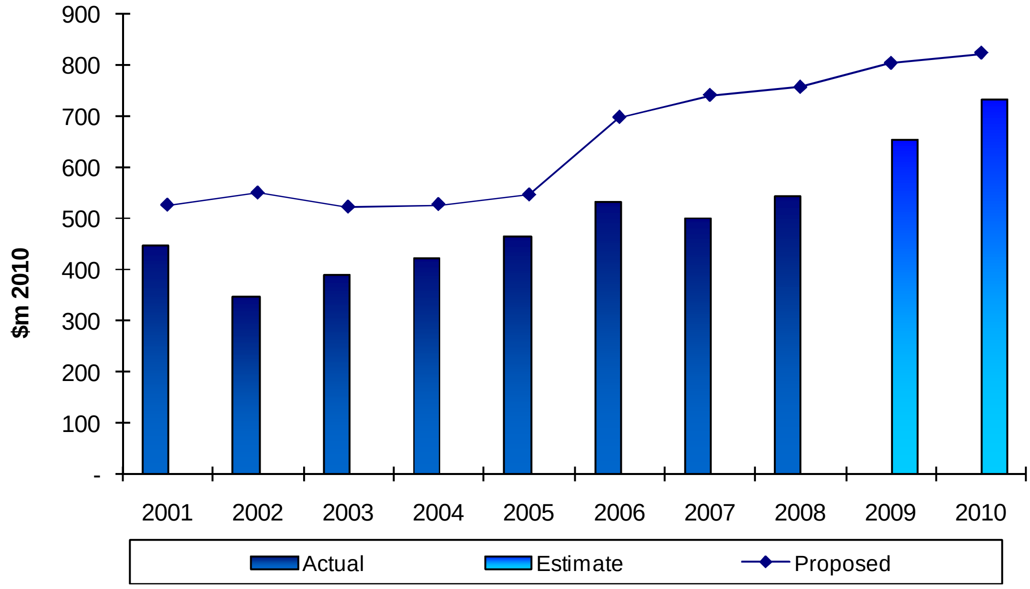
[7] Legend: AA – Actew/AGL, AGLE – Jemena (formerly AGL and Alinta), Au – Aurora Energy, CE – Country Energy, CP – CitiPower, EA – EnergyAustralia, Egx – Energex, Erg – Ergon Energy, ETSA – ETSA Utilities, IE – Integral Energy, PC – Powercor, SP – AP AusNet, UE – United Energy

2.2 Forecasting accuracy

The Victorian DNSPs are commercial operations and therefore have a strong profit motive. One means for increasing profitability is for the businesses to spend less capital than the regulatory forecast. This can be achieved in the longer term by improving efficiency or by having a more favourable capital benchmark established for the next regulatory control period.

The accuracy of the DNSP forecasts for the previous 2 regulatory periods is highlighted in the following chart.

Figure 3 - Proposed and actual capex for Victorian DNSPs



It is clear from the above chart that the actual expenditure levels are more closely related to future expenditures than the forecasts. The overall trend in expenditures is generally upwards and this trend would appear to be a much more accurate predictor of future capex requirements than the forecast figures.

The DNSPs have proposed capital forecasts for the next regulatory control period. It is the purpose of this paper to review that forecast and make a recommendation to the AER on whether those forecasts are reasonable. If the forecasts are not considered reasonable, Nuttall Consulting is required to recommend an alternate forecast.

There are two aspects to the DNSP forecasts contained in their proposals:

- The forecasts for the 5 years of the next Regulatory Control Period
- The estimates of expenditure for the remaining two years of the Current Regulatory Control Period.

This report is primarily focussed on assessing the forecasts for the next Regulatory Control Period, however the estimates for the remaining years of the current period are important in understanding the base or starting point for the next 5 years.

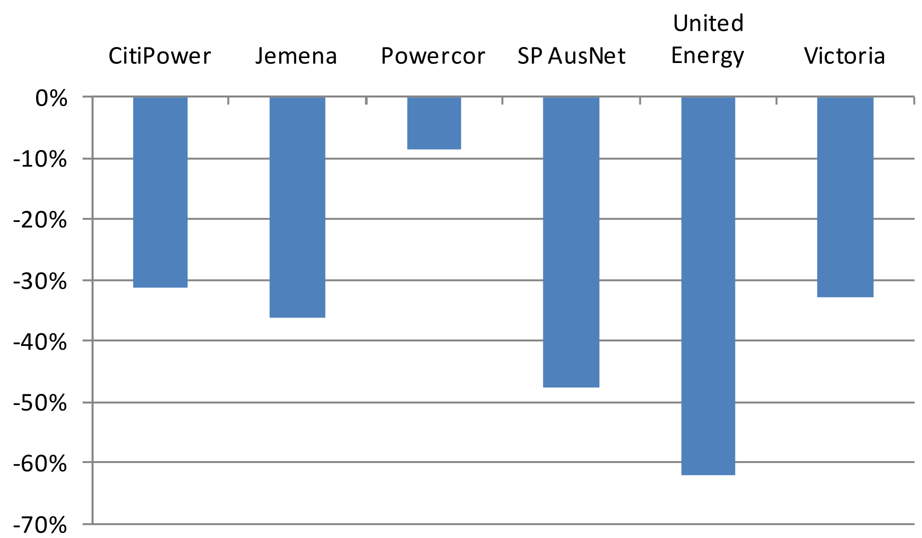
The DNSP forecasting accuracy for both of these aspects are considered below.

2.2.1 Next Regulatory Control Period forecast accuracy

The average level of forecasting inaccuracy for the Victorian DNSPs over the last 8 years is 33%. This means that proposed expenditures are on average 33% more than the actual expenditures incurred by the DNSPs for the last two Regulatory Control Periods[8].

This measure considers actual expenditure in the current regulatory control period as well as the previous period. Capital expenditure trends are reasonably variable from year to year, so it is necessary to consider a longer period of time to assess the accuracy of the DNSP forecasts.

Figure 4 - Forecasting (actual vs forecast capex)



The results of this assessment show that the Victorian DNSP have consistently overforecast the capital requirements in the previous and current Regulatory Control Periods.

Observation: The Victorian DNSPs have consistently forecast higher levels of expenditure than have actually been required, although there is a significant level of variability in the level of forecast inaccuracy.

2.2.2 Current period estimate forecast accuracy

The remaining years of the current regulatory control period are 2009 and 2010. Although the calendar year 2009 is complete the audit and reporting of this years' expenditures will not be complete until April 2010. This date is too late for direct input to this review.

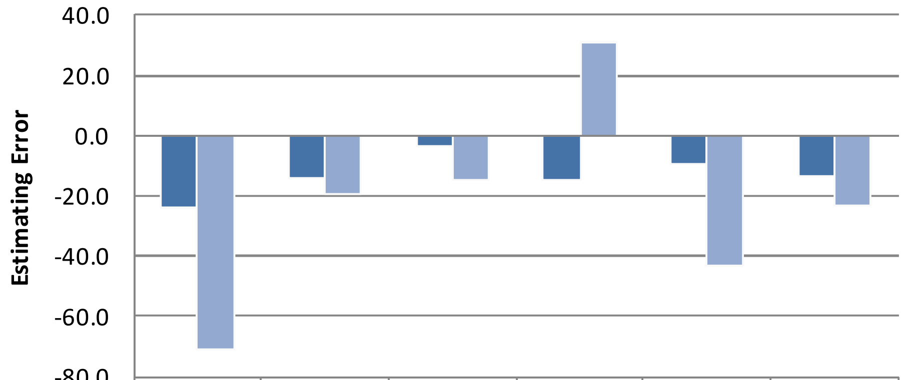
[8] Using actual expenditure as the baseline.

Therefore the DNSPs have each provided estimates for the 2009 and 2010 capital expenditures.

Although these estimates are not the focus of this review they are important as they set the starting point or base years for considering the next Regulatory Control Period.

Nuttall Consulting has reviewed the accuracy of the estimates provided by the DNSPs as part of the 2005 EDPR process. The results of this review are provided in the following chart.

Figure 5 - 2004 and 2005 DNSP Estimating Accuracy



	Jemena	CitiPower	Powercor	SP AusNet	United Energy	Victorian Avg
2004	-24.1	-13.7	-3.4	-14.9	-9.1	-13.1
2005	-70.7	-19.0	-14.9	31.2	-43.3	-23.3

The above chart highlights that there has been a consistent inaccuracy in the estimating of capex in the remaining years of a Regulatory Control Period. SP AusNet are the only DNSP to provide an estimate that was subsequently overspent. All other estimates were over-forecast when compared the the expenditure that did eventuate. The 2004 estimates are clearly more accurate than the 2005 estimates.

If we consider the absolute error in terms of 2005 forecasting, the average for Victoria is 35.8%. This is a very large forecasting error considering the relatively short timeframes involved.

It may be argued that efficiency improvements by the DNSPs have contributed to the overall underspend, however this is not considered likely to account for the majority of the differential.

Observation: The Victorian DNSPs have estimated higher levels of expenditure for the remaining years of a Regulatory Control Period than have actually been required. There was a single exception to this in the previous period.

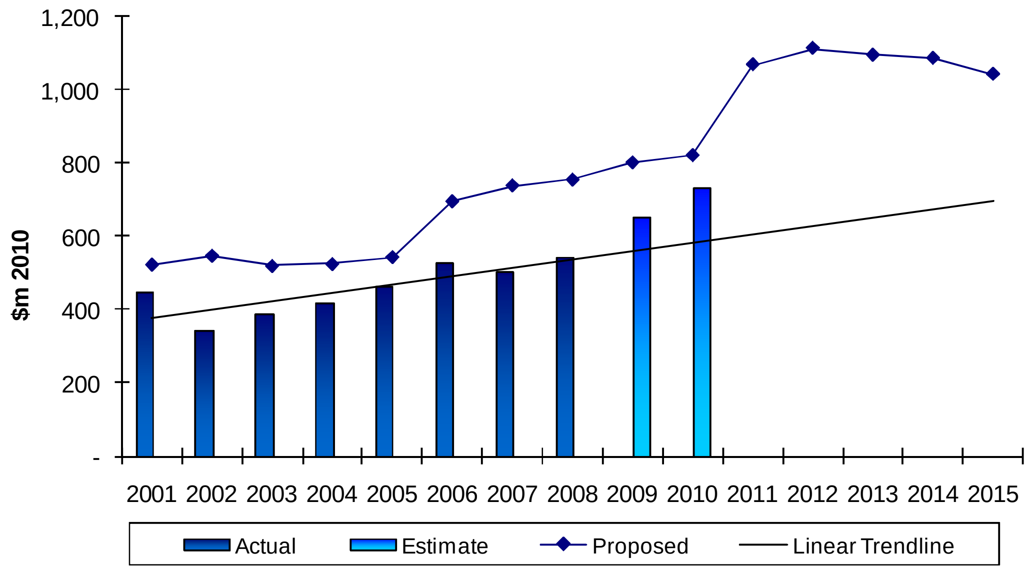
2.3 Expenditure trends

This section reviews the trends revealed by historical levels of capex and compares these with the DNPS forecasts.

2.3.1 Actual to forecast

The Victorian DNSPs are forecasting capex that is considerably higher than current levels of expenditure. The following chart shows the actual capex incurred in the two previous control periods and current Regulatory Control Period. The chart also shows the sum of the capex that was proposed by the Victorian DNSPs for each of the Regulatory Control Periods.

Figure 6 - Victorian Capex



As discussed in the previous chapter, the DNSPs have consistently forecast expenditures that have been well above the resultant capex that was incurred. The above graph also provides a linear trendline based on the actual capex incurred since 2001. This trendline does not include the estimated figures for 2009 and 2010 as previous estimates have proven to be inaccurate.

As discussed in the previous section, the overall accuracy of the DNSP forecasts has been quite low with average forecasting inaccuracy of 33% across the DNSPs over the current and previous Regulatory Control Periods. It is clear from the above chart that previous actual expenditures are more closely aligned to the forecast expenditure than the DNSP forecasts. The simple trendline used in this chart is also much better aligned with actual expenditures than the DNSP forecasts.

It may be argued that efficiency improvements by the DNSPs have contributed to the consistent underspend that has been observed since 2001, but it is unlikely that such improvements would account for the majority of the difference. In this regard, efficiency gains would most likely occur incrementally and result in greater levels of underspend occuring in the later years of the regulatory period. However, the above chart indicates that the greatest levels of underspend have occured in the earlier years of the regulatory period.

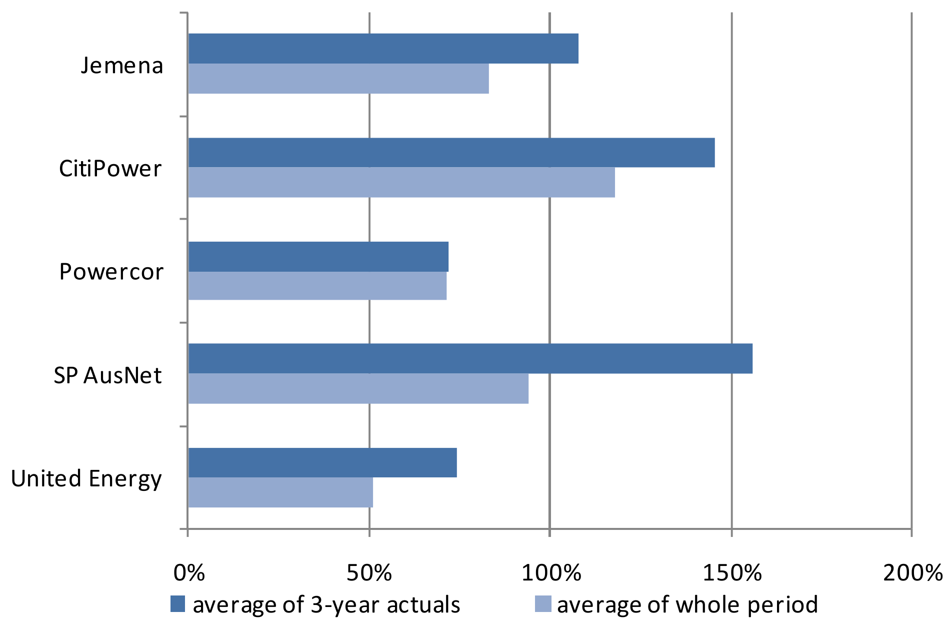
All Victorian DNSPs are forecasting significant increases to capex. These forecast increases to capex are significantly higher than the existing levels of expenditure and higher than the linear trendline of actual expenditures. The relationship between these factors is similar to the same time 5 years ago when the previous EDPR was being assessed.

The following chart provides the individual increases in capex that are forecast by each DNSP. The calculation of the expenditure increase has been done by comparing the average 5 year forecast capex with:

- the average of the actual expenditure in the current Regulatory Control Period and
- the average of the actual and estimated expenditure in the current Regulatory Control Period.

Due to the historical estimating errors identified in the previous section, the 3-year variation comparison is considered most representative of the proposed increase in capex.

Figure 7 - Actual to forecast capex comparison



SP AusNet and CitiPower are forecasting the greatest increases in capex for the next Regulatory Control Period. Powercor and United Energy appear to have the most conservative forecast increases.

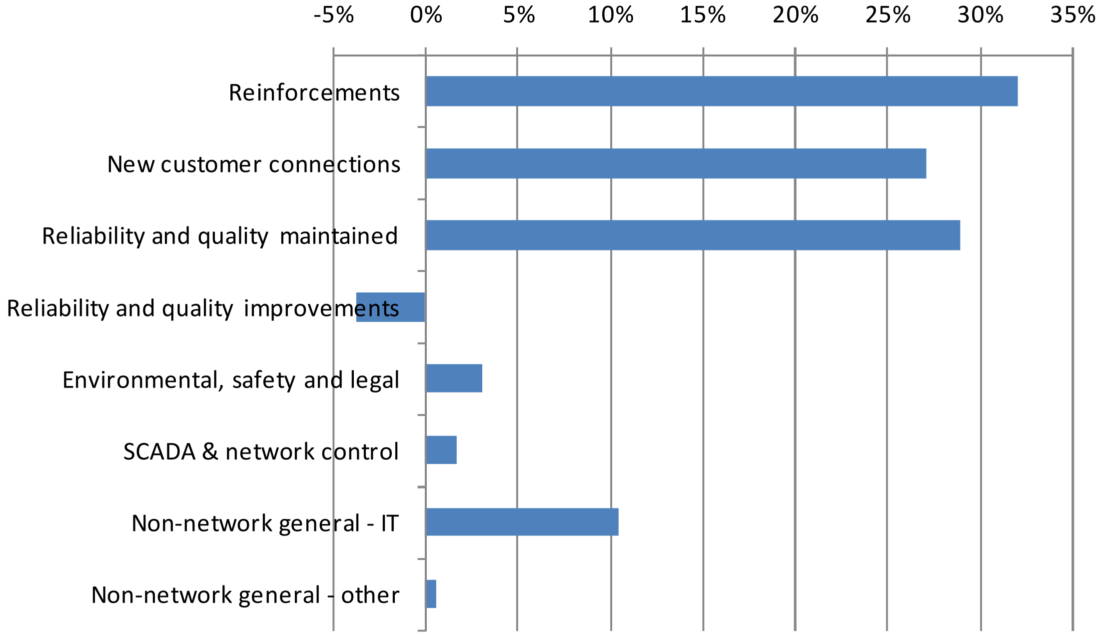
The majority of forecast increases in capex are occurring in three main categories:

- reinforcement
- new customer connection and load movement

- reliability and quality maintained.

These three categories account for over 80% of the forecast capex increases when compared against actual expenditure for the last three years. The Reliability and quality improvements category shows a slight decrease as no DNSPs have forecast expenditures in this category.

Figure 8 - Capex category contributions to increases



Observation: 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, and reliability and quality maintained.

2.4 Summary

This section has considered the historical expenditures of the Victorian DNSPs in aggregate and individually. 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.

In summary, the observations from this section are:

- The overall level of capex in Victoria as revealed in the previous 5 years appears relatively efficient.
- The individual Victorian DNSPs appear reasonably efficient when compared to interstate DNSPs.

- The Victorian DNSPs have consistently forecast higher levels of expenditure than have actually been required, although there is a significant level of variability in the level of forecast inaccuracy.
- The overall bias towards over-forecasting may be in some part due to the DNSPs achieving efficiencies in capex. However, these potential efficiencies do not appear to provide sufficient explanation for the variations between forecast and actual capex.
- The Victorian DNSPs have estimated higher levels of expenditure for the remaining years of a regulatory control period than have actually been required. There was a single exception to this in the previous period.
- 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, and reliability and quality maintained.

3 Replacement modelling

3.1 Introduction

Nuttall Consulting has developed a replacement model for the AER (the "repex model") to support the review of the DNSPs capital 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.

From a regulatory point of view, this provides a useful reference to assess regulatory proposals. This approach allows a common framework to be applied without the need to be overly intrusive in data collection and detailed analysis of the asset management plans.

The repex model is most relevant for assessing expenditure in the AER's RQM expenditure category. In some circumstances, it may also forecast expenditure that has been allocated to the ESL category by some businesses.

For this review, we have used the model primarily to assess relative increases in the volume of assets replaced primarily due to age/condition drivers. These volume increases are then used to inform the expected increases in expenditure. This can be considered as a **"top down"** methodology to inform future expenditure patterns.

This approach assumes that the recent historical replacement levels are reflective of the prudent and efficient management of the asset base. Therefore, the recent historical unit costs can be assumed to be reasonably reflective of efficient costs, and such, the scale of the change in the volume of work is the most reflective of increasing (or decreasing) expenditure needs.

It is important to note that a "bottom-up" methodology could be applied with the repex model, but this would require extensive analysis and benchmarking of the model inputs (i.e. the asset lives and unit costs) to build up the replacement expenditure for each DNSP. This process would require detailed and rigorous review and analysis to ensure consistency in the model inputs between businesses. This in turn, generally, requires extensive work with the DNSPs, prior to their submissions, to ensure a reasonably consistent data set is provided at the commencement of the review. This approach has not been adopted for this review.

We consider that the "top down" approach is reasonable, in the Victorian context, given the following factors:

- the findings of our high level benchmarking, which indicated that the actual capex of the Victorian DNSPs compares were very favourable against other states

- our capital governance review, which found the capital governance processes documented by the DNSP's should lead to prudent and efficient expenditure[9], in accordance with the NER and relevant state obligations
- setting aside the impending findings of the Bushfire Royal Commission, the fact that there are no major changes to obligations that should be resulting in step changes to the age/condition based replacement levels
- the findings of our expenditure trend analysis, which indicates that the businesses have historically over-forecast their replacement needs, but the actual expenditure shows a relatively consistent trend.

It is important to note that other factors resulting in increasing unit cost escalation, such as labour and material escalation or changes to cost allocations, are not allowed for in this analysis – and not considered under the overall scope of our capex review. It will be important that the AER reconsiders our findings here in light of its findings on these other matters.

The remainder of this section provides:

- an overview of the repex model, including its inputs and outputs, and replacement algorithm
- the findings from repex models populated with DNSP data supplied during our review
- the findings from repex models that have been calibrated to historical volume and expenditure levels.

Additional model output tables are provided in Appendix H.

3.2 Overview of replacement model

3.2.1 Inputs and output

The replacement model is a high-level model that forecasts replacement needs based upon the age of the DNSP's asset base.

The model requires the asset base to be broken down into a number of discrete asset categories. For each individual asset category, the following inputs are required:

- the age profile (i.e. the quantity of asset and their installation date)
- the mean replacement life and the standard deviation
- the unit replacement costs.

The model takes these inputs and produces the following outputs for each asset category:

- age and asset value statistics based on the input age profile

[9] note: assuming that the documented processes and practices are applied.

- the 20 year replacement forecast (quantities and expenditure)
- the 20 year average age and average remaining life trends.

3.2.2 Replacement algorithm

The model can produce a forecast for each asset category based upon a **probabilistic** replacement algorithm.

This approach assumes a normal distribution for the replacement life across the population, based upon the input mean and standard deviation. Assets are then forecast for replacement, based upon this replacement profile *given* that they have *survived* to their current age indicated by the age profile.

Aggregate replacement costs are calculated simply as the asset quantity multiplied by the unit replacement cost.

3.2.3 Asset grouping

To aid in the presentation and analysis within the model, individual asset categories are aggregated to 11 separate asset groups.

The intention here was to allow DNSP's to develop the individual asset categories as they saw fit for their network. However, all asset categories were given a one-to-one mapping to an asset group that was defined by Nuttall Consulting.

The groupings we have used are shown in Table 1.

Table 1 - Asset groups

Asset group
Poles
Pole top structures
Overhead conductors
Underground cables
Zone substation switchgear
Distribution transformers
Power transformers
SCADA, network control, protection, secondary
Service lines
Zone substation - other
Distribution SWGR

3.3 Repex models based upon DNSP data – the base case

3.3.1 Model population

Five individual replacement models have been developed; one for each of the Victorian DNSPs.

These models have been prepared using data provided by the DNSPs in response to an AER information request. The AER's information request was submitted to the DNSP's prior to lodgement (the "repex model information request"). This information request was based upon advice to the AER from Nuttall Consulting on the data inputs required to perform replacement modelling.

The model data provided by the DNSPs included:

- individual asset category age profiles based upon installation quantities from 2009 and earlier
- asset category replacement lives, including the mean replacement life and standard deviation, if available
- asset category unit costs.

The responses also included other clarifying information on various matters, including:

- the nature of the asset category and boundary issues
- the derivation of the unit cost and asset life data
- the recent historical level of replacement as seen through the recent age profile (i.e. the proportion of the age profile driven by the aging assets
- information on the previous replacement modelling exercise undertaken by the DNSP for the 2006 EDPR.

For the model outputs discussed in this section, we have used the data as provided by the DNSPs. Where some asset categories were related to alternate control services (e.g. public lighting), we removed these for the purposes of modelling.

In some cases, the standard deviation for the replacement life was not provided for specific asset categories. For these categories, we have assumed that the standard deviation is reasonably represented by the square root of the mean life. It is our understanding that this assumption is applied by Ofgem in the UK for similar repex modelling.

These models for each DNSP are termed the "base case" in our discussion.

3.3.2 Base Case model findings

The age profile

Figure 9 shows the aggregate Victorian age profile generated by simply multiplying the asset quantity at each installation date by the unit cost. Figure 10 shows this in a histogram form for each DNSP. This graph indicates the percentage of the total replacement cost of the network in age bands.

These two figures clearly show a significant 4 to 7 fold increase in the quantity of network with installation dates after 1970 from the levels installed prior to 1950.

Given typical replacement lives for network assets of between 40 to 70 years, this supports the view that replacement needs may be increasing across Victoria from present low levels.

Figure 9 - Victorian age profile

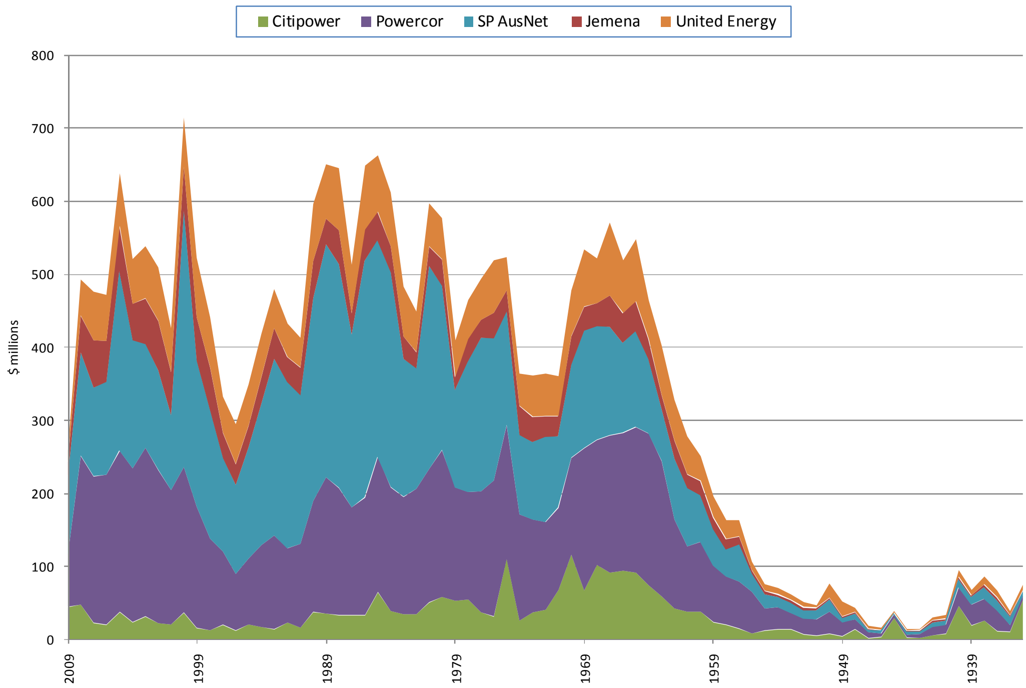
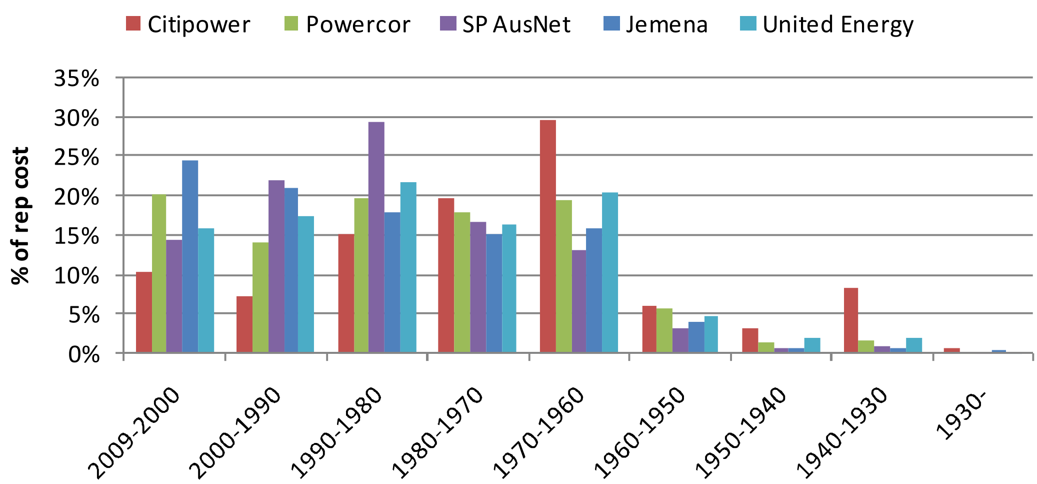


Figure 10 - Victorian age profile - histogram



Average asset age and life

The average age of an asset population provides some indication of replacement needs; however, due to the lack of uniformity of the age profile, the quantity of old assets is generally a much stronger indicator of replacement needs.

Table 2 shows the findings of the analysis of the DNSP age profiles, indicating the average age and replacement life of the networks[10], and the proportion of the network over 90% of the asset life (i.e. the proportion of "old" assets).

Table 2 - DNSP network age and replacement life statistics

	CitiPower	Powercor	SP AusNet	Jemena	United Energy
Age	36.5	28.0	25.1	23.6	27.7
Life	61	58	48	49	51
% of "old" assets	15.0%	7.3%	17.1%	10.4%	14.2%

The main points of note from this table are as follows:

- Citipower has the oldest network, but the longest lives. This is broadly as expected given the historical development of the Victorian network and the significant underground network owned by CitiPower.
- We may expect Powercor and SP AusNet to have a similar age and life due to their development and environment (i.e. the large rural networks). However, SP AusNet appears to be noticeably younger, but expects a much shorter life for its assets. Similarly, for United Energy and Jemena, we would expect these companies to have a similar age and life due to their development and environment (i.e. the large suburban networks). However, Jemena appears to be noticeably younger asset base, and expects a slightly shorter life for its assets.
- SP AusNet has the highest percentage of "old" assets, based upon its view of lives, whereas Powercor has the lowest. But it is important to note the large, 10-year, discrepancy in the average life of these two networks.

Asset group breakdown of the network replacement cost

Table 3 shows the percentage of the total replacement cost of the network in each of the defined asset categories. This indicates the scale of the underground network compared to overhead network reducing from CitiPower's, to Jemena and United Energy, and then to Powercor and SP AusNet. This is largely as expected given the nature of these networks.

Of note is the low percentage in the SP AusNet overhead conductor category, which is not fully in accordance with its largely rural and overhead nature. However, this appears to be

[10] Weighted average is calculated using the total replacement cost of each individual asset category. This is in accordance with the weighted average method used by the ESC and in the AER's RIN templates.

an asset boundary issue, whereby SP AusNet appears to have captured some asset value in its poles and pole top structure categories that others have allocated to conductors.

Table 3 - Asset group breakdown

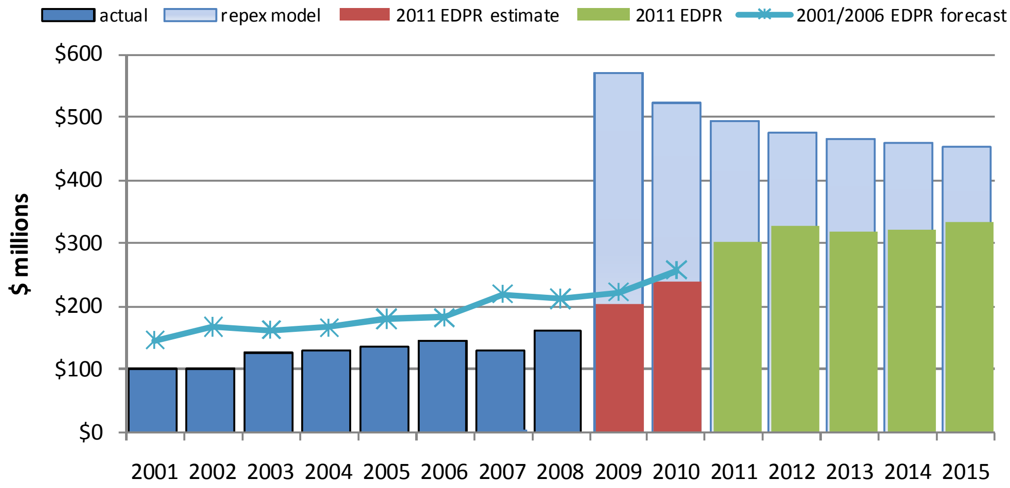
	CitiPower	Powercor	SP AusNet	Jemena	United Energy
Poles	10%	24%	29%	17%	17%
Pole top structures	4%	10%	20%	13%	11%
Overhead conductors	9%	27%	9%	17%	25%
Underground cables	43%	12%	12%	24%	17%
Zone substation switchgear	4%	2%	2%	3%	3%
Distribution transformers	6%	7%	7%	6%	6%
Power transformers	3%	1%	2%	5%	5%
SCADA, network control, protection, secondary	2%	1%	0%	3%	3%
Service lines	6%	8%	9%	3%	4%
Zone substation - other	3%	1%	0%	4%	4%
Distribution SWGR	11%	5%	10%	5%	7%

Expenditure forecast

Replacement expenditure forecasts have been produced for each of the DNSP base case repex models. Figure 11 shows the Victorian aggregate expenditure forecast by the repex models (i.e. the sum of the expenditure from each of the five DNSP base case models). This figure shows the model forecast compared against expenditure in the 5 DNSP's RQM category, covering historical actual expenditure 2001-2008 (the blue bars), the 2008-2009 estimates provided in the 2011 EDPR proposals (the red bars), the 2011-2015 forecasts provided in the 2011 EDPR proposals (the green bars), and the previous DNSP forecasts that they provided in their 2001 and 2006 EDPR submissions.

This figure clearly shows that the replacement expenditure forecasts, based purely upon the DNSPs replacement lives and unit costs, predict a significant increase in replacement expenditure. This increase is well above historical actual levels and the previous forecast levels.

Figure 11 Base case repex model forecast – aggregate

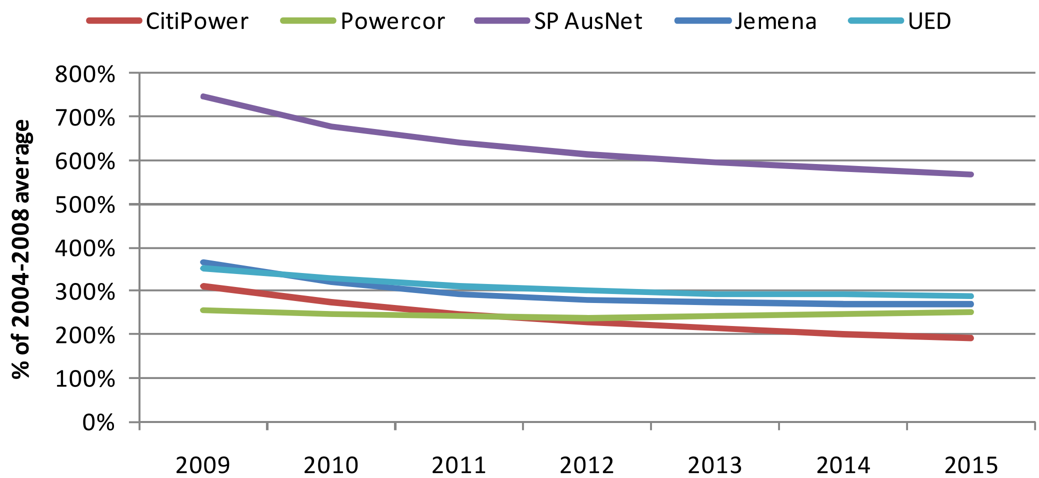


These results clearly show that the raw DNSP data provided for replacement modelling purposes is unlikely to be a reasonable estimator of replacement needs. This suggests that the replacement lives may be too long and/or the unit costs may be too high. It may also be that there is significantly more overlap between the age/condition related expenditure and other drivers than is suggested by the DNSPs.

Importantly, the expenditure profile shows a peak which then reduces over time. This indicates that the replacement lives are set lower than has historically been occurring. In these circumstances, the model sees a "backlog" of replacement needs – essentially predicting the replacement of assets in the first few years of the forecasting period that would have been replaced historically if the input lives were valid.

To demonstrate the relative scale of the increase forecast by the model for each DNSP, Figure 12 shows a comparative plot of each DNSP repex forecast as a percentage of its average RQM expenditure over the previous 5-year period (2004-2008).

Figure 12 Bases case repex model forecast – DNSP percentage increase



This chart indicates that the base-case repex models for all the DNSPs are forecasting expenditure well in excess of the average historical level. All models are also showing a peak in the first year of the forecast, with expenditure reducing after that year, which as noted above, suggest the lives provided by the businesses are too low.

The CitiPower and Powercor base case models forecast increases of approximately 200% to 300%, with Jemena and United Energy slightly higher at 250% to 350%.

The SP AusNet base-case model is showing much more significant increases of between 600% to 750%. Even allowing for the fact that some replacement expenditure for SP AusNet may be allocated to the ESL category, this still suggests an increase of around 500% to 600%.

It is worth noting however that SP AusNet's greater increase appears to be largely due to a very low replacement life given for poles (i.e. SP AusNet has stated 44 years, compared to 56-58 for the other DNSPs). Excluding this issue, the forecast increase is more in line with the other DNSPs.

3.4 Model calibration

The above has shown that the repex model expenditure forecasts, based upon the replacement lives and unit costs supplied by the DNSPs, may not be a reasonable estimate of future replacement expenditure needs.

To calibrate the model outputs to historical replacement levels and costs, we have used historical information supplied by the DNSPs. This mainly includes:

- the replacement volumes indicated by the individual asset age profiles, using the proportion of assets in these profile replacements between 2004 and 2008 as advised by the DNSPs in their responses to the repex modelling information request
- the historical (2006-2008) volumes and expenditure derived from replacement activity code level data provided by the DNSPs – the activity code level data and its relationship to the asset groups is discussed further in the respective DNSP appendices (A to E).

Using this information, the calibration exercise was undertaken as follows:

1. determine the average annual historical replacement volumes (2004-2008) from the data indicated above
2. set the replacement life, such that the 1st year of the forecast (2009) reflects this average volume
3. adjust the unit cost to reflect the relevant average annual activity code expenditure - the average for 2006-2008 was used here as this was the only reliable data available
4. re-adjust the replacement life to allow for the predicted increase in volumes from 2008 to 2009 as indicated by the model.

As noted in the introduction, the purpose of this calibration is to allow percentage increases in expenditure from historical levels to be determined. As such, care must be taken in appreciating the significance of the lives and unit costs derived through this process.

The calibrated lives are the most significant in determining the increases in volumes at the asset group level. The lives should be viewed as an "effective" replacement life in respect of predicting the **proportion** of assets that will be replaced primarily due to age/condition reasons. This may not be fully reflective of the economic or technical life of the individual assets.

The unit cost adjustments are to ensure that the expenditure forecast by the model is reconcilable back to the DNSP's activity code view of their business. Due to limitations in the data available, the process we have adopted has not attempted to reconcile this at an individual asset category level. As such, care should be taken in any comparative analysis of these inputs between DNSPs - we do not consider that there is significant value in such a comparative analysis at this stage.

3.5 Calibrated model findings

Asset lives and old assets

Table 4 shows the findings of the calibration exercise, indicating the average replacement life of the networks, the life extension on the DNSPs' proposed lives (see Table 2), and the proportion of the network over 90% of the asset life (i.e. the proportion of "old" assets).

Table 4 - DNSP network replacement life statistics – calibrated model

	CitiPower	Powercor	SP AusNet	Jemena	United Energy
Calibration life	77	63	53	57	59
Life extension from DNSP life	15	5	4	8	8
% of "old" assets	2.8%	3.3%	2.3%	3.3%	3.5%

The main points to note from this table are:

- The life extensions are broadly in line with the nature of the DNSP's, with the two rural DNSPs (Powercor and SP AusNet) requiring the lowest life extension and the metropolitan DNSP (Citipower) requiring the longest. It is noted however that this does not change the difference in lives seen between the DNSPs, particularly Powercor and SP AusNet.
- The level of "old" assets is considerably lower than under the DNSP's model inputs. This indicates that all the DNSPs have similar levels of old assets, between 2.3% and 3.5%, with Powercor and United Energy showing the greatest levels and SP AusNet the lowest.

Expenditure forecast

Replacement expenditure forecasts have been produced for each of the DNSP calibrated repex models. Figure 13 shows the Victorian aggregate expenditure forecast by the repex models (i.e. the sum of the expenditure from each of the five DNSP base case models). This chart is comparable to base case repex model forecasts shown in Figure 11 above.

Figure 13 shows the model forecast compared against expenditure in the 5 DNSP's RQM category, covering historical actual expenditure 2001-2008 (the blue bars), the 2008-2009 estimates provided in the 2011 EDPR proposals (the red bars), the 2011-2015 forecasts provided in the 2011 EDPR proposals (the green bars), and the previous DNSP forecasts that they provided in their 2001 and 2006 EDPR submissions.

Figure 13 shows that the calibrated repex models have forecast an increase in expenditure. This is above the historical rate of RQM increase, but is well below the increase forecast by the DNSPs.

Figure 13 - Calibrated repex model forecast – aggregate

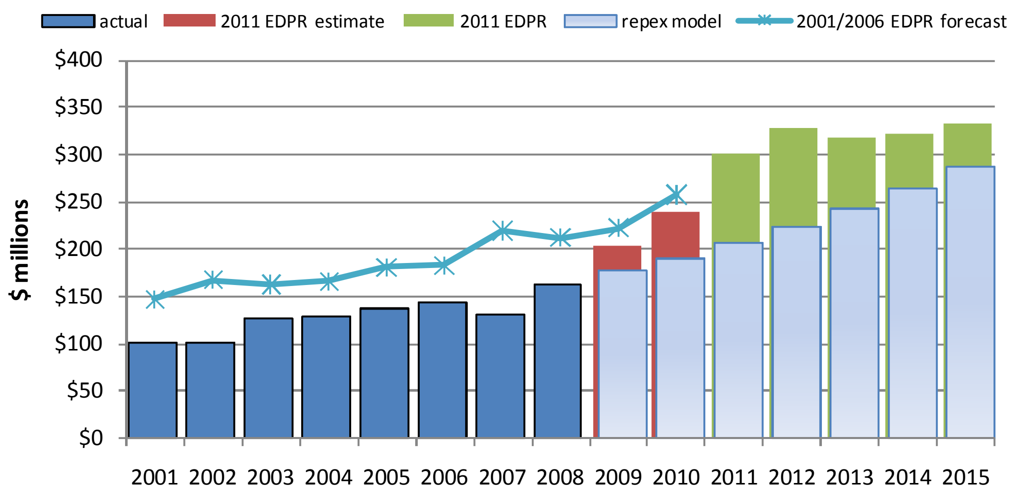


Figure 14 Calibrated repex model forecast – DNSP percentage increase

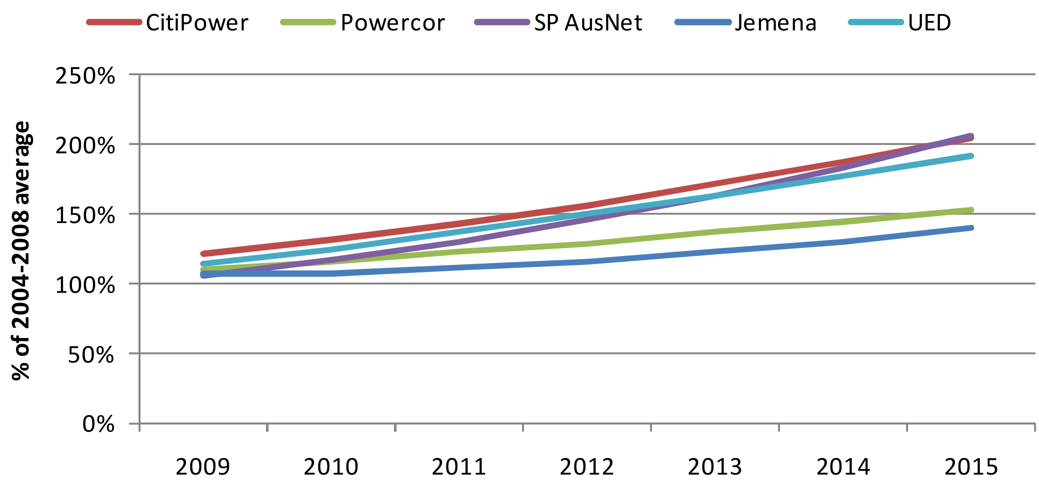


Figure 14 shows the relative scale of the increase forecast by the model for each DNSP. This figure shows a comparative plot of each DNSP repex forecast as a percentage of its average RQM expenditure over the previous 5-year period (2004-2008).

This chart indicates that the calibrated repex model for all the DNSPs is forecasting an increase in expenditure from the average historical level of RQM expenditure. All models are also showing the increase to continue throughout the next period.

The Powercor and Jemena calibrated models forecast the lowest increases of approximately 150% by the end of the next period. The CitiPower, SP AusNet and United Energy calibrated models forecast the highest increases of approximately 200% by the end of the next period.

It is worth noting that we consider these predicted increases to be conservative (i.e. on the high side) as it could be expected that as the levels of age/condition driven replacement needs increase, then opportunities to optimise the investment with other drivers (i.e. augmentation) will increase also.

4 Comparative overview of review findings

This section provides a summary of the main matters we have identified that are resulting in the proposed increases and our review findings on these matters. The section is structured to draw out the similarities and differences between the DNSPs. It commences with our review of the capital governance process applied by the DNSPs and then discusses capex, in turn, for each of the AER's capex categories.

4.1 Capital governance review

Nuttall Consulting has undertaken a desktop review of the capital governance practices of the Victorian DNSPs, as defined in their documented policies and practices provided in support of their regulatory proposals. This review has being carried out in conjunction with the broader review of the capital expenditure proposals submitted by the DNSPs for the next regulatory control period.

PAS 55:2008[11] (PAS 55) is a Publicly Available Specification that was developed in response to demand from industry for a standard relating to asset management in infrastructure intensive industries. The approach we have taken to assess DNSP governance documentation against the capex governance requirements is to frame an appropriate subset of criteria derived from PAS 55 and then to assess the documentation against this set of criteria.

Nuttall Consulting considers that the documentation provided by each of the five Victorian DNSPs incorporate well-evolved, fit-for-purpose capital governance processes and practices. They are based on asset management frameworks that have been developed with varying degrees of reference to the PAS 55:2008 standard.

The following table shows the assessed ratings for each DNSP for each assessment element.

[11] The Publicly Available Specification PAS 55:2008 is published by BSI in two parts: (1) PAS 55-1 is *Part 1: Specification of the optimized management of physical assets* and (2) PAS 55-2 is *Part 2: Guidelines for the application of PAS 55-1.*

Table 5 - Governance review summary

DNSP	Policy and strategy	Asset management information	Risk manage-ment	Capex planning	Implement-ation and operation	Management review and continual improvement
CitiPower	3 - high	3 - high	2 - partial	3 - high	3 - high	3 - high
Powercor	3 - high	3 - high	2 - partial	3 - high	3 - high	3 - high
SP AusNet	3 - high	3 - high	3 - high	3 - high	2 - partial	2 - partial
United Energy	3 - high	2 - partial	3 - high	3 - high	3 - high	3 - high
Jemena	3 - high	3 - high	3 - high	3 - high	3 - high	2 - partial

Assessments against each framework element are uniformly acceptable for each DNSP. Thus, it would be expected that a DNSP that applies its documented capital governance processes and practices would be expected to deliver efficient outcomes for its stakeholders[12].

Where "2 – partial" ratings have been assessed, we feel that any shortfall may simply be a matter of documentation rigour within the submitted material, as opposed to any material gap in the DNSP's processes or practices. Although, it is worth noting that we have not conducted an investigation to confirm this view.

In some cases, the relevant material has been found to be distributed across a wide range of documents – this was found to be the case for SP AusNet in particular. While we have no significant concerns over their processes and practices, SP AusNet may benefit from adopting the generally well-structured, PAS 55-based capital asset management frameworks similar to those in use by the other DNSPs.

It is important to note that while this review has not attempt to audit the application of these processes, the findings of this review support our position that the DNSPs historical expenditure can be considered reasonably reflective of prudent and efficient levels.

It is also important to stress however that it is clear from our review of the DNSPs plans, discussed further in the section below, that the full extent of these process have not been applied to these plans. This particularly concerns the level of evaluation and justification that may be expected prior to the approval of specific proposed projects and programs.

[12] Note: Nuttall Consulting has not undertaken an audit or assessment of whether these practices and processes are currently applied or have been applied in the past.

4.2 Reinforcement

4.2.1 Expenditure overview

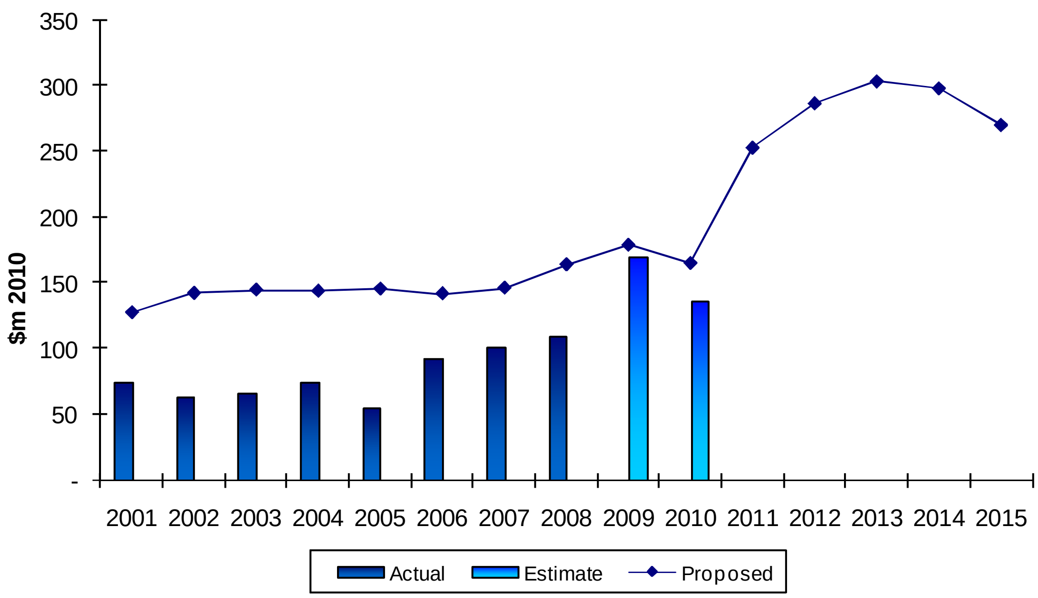
The Victorian DNSPs are proposing an increase of 179% in reinforcement capex for the next Regulatory Control Period when compared against actual annual expenditure in the current Regulatory Control Period.

The DNSPs estimate that reinforcement capex for the 2006-10 regulatory control period will be $609 million. They are forecasting that this will increase to $1,409 million in the 2011-15 regulatory control period.

The DNSPs estimate that reinforcement capex for the 2006-10 regulatory control period is approximately 23% lower than their forecasts prepared for the 2006 EDPR, $793 million.

The following chart provides a summary of reinforcement capex for the Victorian DNSPs.

Figure 15 - Total Victorian reinforcement expenditure



Important points to note from the above chart are:

- actual expenditure has been increasing fairly consistently (at around 6-8% per annum) over current and previous periods (2001-2008)
- DNSPs estimate that the expenditure will increase significantly above the trend in 2009 - although it will back to around the trend by 2010
- DNSPs have forecast that expenditure will have a significant step increase in 2011, with expenditure at a more constant level through the next period
- the 2011-2015 forecast is also significantly higher than the past trend in the 2001 and 2006 EDPR forecasts

- the previous DNSP forecasts provided within the 2001 and 2006 EDPR submissions have been significantly higher than the actual expenditure incurred, with the 2001-2005 actuals at approximately 50% of the 2001 EDPR forecast, and the 2006-2008 actuals at approximately 67% of the 2006 EDPR forecast
- the DNSP forecasting accuracy does not appear to be greater in the early years of the period, which is counter-intuitive to what would be expected.

The chart below indicates the average annual expenditure for each DNSP, showing the averages of the 2006-2008 actuals, 2009-2010 estimates and the 2011-2015 forecasts. This chart also indicates the relative increases in these three averages for each DNSP. The percentage increase for each DNSP from the average annual actual expenditure in the current period (2006-2008) to the average annual expenditure proposed in the next period is also shown in the table below.

Figure 16 – DNSP expenditure increases

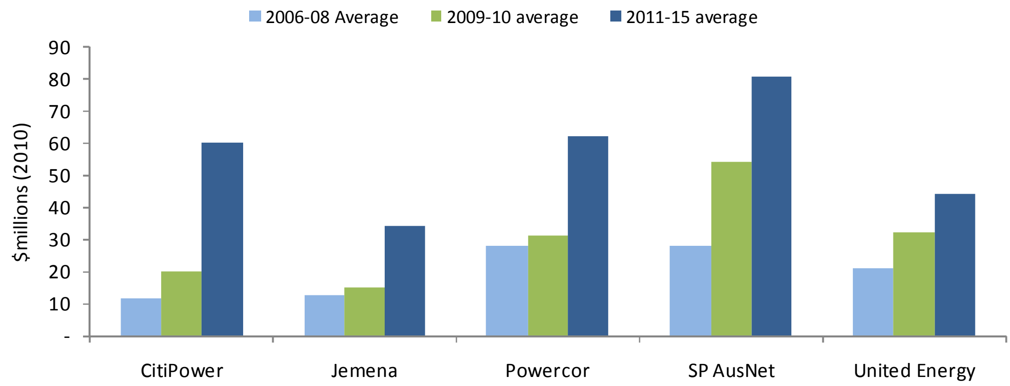


Table 6 - Proposed reinforcement capex increases

DNSP	% increase[13]
CitiPower	420%
Jemena	175%
Powercor	124%
SP AusNet	186%
United Energy	111%
Victoria	**179%**

The main points to note from the above chart and table are as follows:

- The two large rural distributors (Powercor and SP AusNet) are proposing high levels of reinforcement expenditure. SP AusNet is proposing expenditure well in excess of

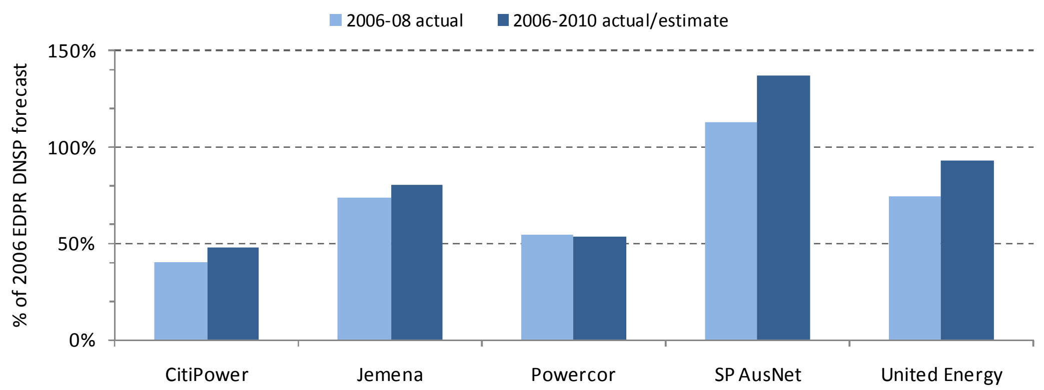
[13] Increase based on comparison with most recent 3 years of actual “reinforcement” capital expenditure

all Victorian DNSPs in the next period. SP AusNet is also estimating the greatest increase (93%) from its actual capex in 2006-2008 to that planned for 2009-2010.

- CitiPower is proposing a significant level of expenditure. This represents a significant increase from the historical pattern, where CitiPower had the lowest level of expenditure. However, it is important to note that 40% of the proposed CitiPower increase is driven by two very large projects, which are discussed further below. Allowing for these two projects, the underlying expenditure is more in line with the historical expenditure distribution between DNSPs.
- All DNSPs are proposing a significant increase in expenditure in the next period from the actual levels in 2006-2008. CitiPower is proposing the greatest at 420%, with others ranging between 110% for United Energy to 186% for SP AusNet. For CitiPower, if the two major projects are excluded, the underlying increase reduces, but is still the highest of all the DNSPs.

The chart below shows the comparisons of the past accuracy of the DNSPs' forecasts within their 2006 EDPR submissions, indicating the accuracy to actual capex in the current period (2006-2008) and the DNSPs' estimates for the whole period.

Figure 17 – DNSP forecast accuracy



This chart indicates the following.

- SP AusNet are the only DNSP that has incurred expenditure above the level it forecast for the 2006 EDPR. For all others, they have significantly underspent on their forecasts, ranging from 90% for United Energy to 47% for CitiPower.
- In the case of SP AusNet, it was stated that it had much higher demand growth and much higher input costs than anticipated at the time of its 2006 EDPR proposal[14]. As such, we consider it reasonable to assume that SP AusNet would have also significantly over-forecast expenditure if it had allowed for these matters in its forecasting process.

[14] See page 101 of the SP AusNet proposal. This indicates that input costs were around 37.5% higher than anticipated and demand growth to 2008/09 was nearly double that assumed.

- In the case of CitiPower, its 2006 EDPR proposal included expenditure on the two large projects noted above. These projects appear to have been delayed due to the ESC's review that it conducted on one of the projects, and delays in a terminal station development associated with the projects. This however does not account for all the differences as it appears that some of the other projects identified in the 2006 EDPR proposal have also not occurred.

Summary

In summary, reinforcement capex represents a major portion of the DNSPs' proposed capex. All DNSPs are proposing a significant step increase in reinforcement expenditure. The proposed increase is significantly in excess of the past trend in actual reinforcement expenditure. It is also in excess of the trend in the DNSPs' reinforcement forecasts that they prepared for two previous EDPRs.

All DNSPs other than SP AusNet have materially underspent on their previous forecasts. Even in the case of SP AusNet, the demand growth and unit costs assumptions it applied in preparing its past forecast were significantly more optimistic than has occurred. As such, it would appear that SP AusNet would have also significantly over-forecast its actual expenditure if these assumptions had been more accurate.

We do not consider these matters alone justify that the DNSPs' reinforcement forecasts are inappropriate. However, we do consider that they are relevant in the broader context of the findings of our more detailed review discussed further below. We also consider that these findings support the underlying principles of this review, in that the onus is on the DNSPs to appropriately demonstrate that the proposed increases from the historical trend are reasonable.

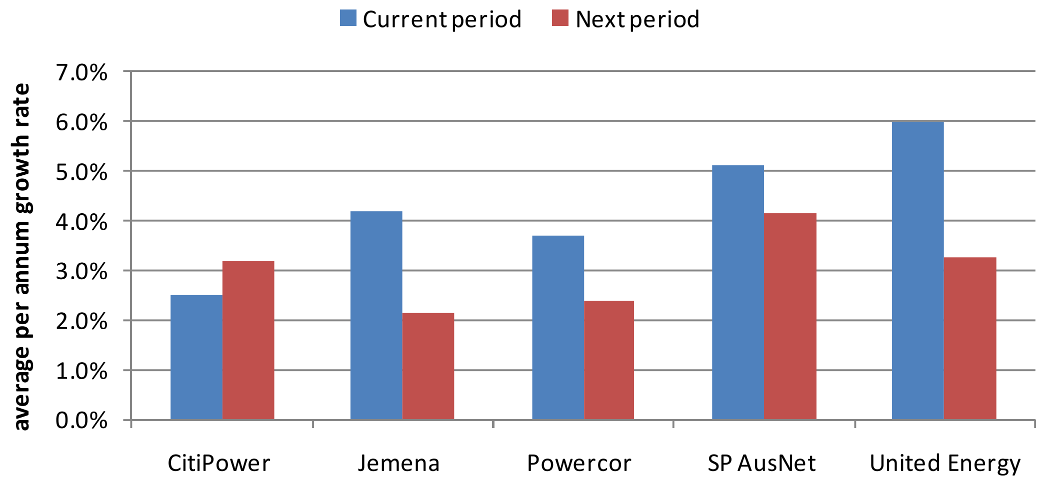
4.2.2 Expenditure drivers and DNSPs' basis for increase

A major driver of reinforcement expenditure is the growth in maximum demand. All DNSPs are forecasting significant levels of demand growth over the next period.

For indicative purposes, the per annum growth rate for each DNSP is shown in the chart below[15]. This shows the DNSPs' forecast growth rate for the next period and the estimated growth rate for the current period.

[15] These figures have been derived from the spreadsheet "ACIL MD reconciliation adjustments", provided to Nuttall Consulting by the AER. Care must be taken with these figures in regard to comparisons between DNSPs as their basis is not fully consistent.

Figure 18 – DNSP maximum demand growth rates



This chart indicates that all DNSPs, other than CitiPower, are expecting demand growth to reduce in the next period. This is most notable for the two suburban DNSPs, Jemena and United Energy, who are expecting demand growth to halve. SP AusNet and Powercor are also forecasting demand growth to reduce significantly.

SP AusNet is still anticipating relatively high levels of growth, above 4% per annum. CitiPower and United Energy are forecasting slightly lower levels, at just over 3% per annum. Both Powercor and Jemena are expecting the lowest growth, with rates just above 2%.

With regard to SP AusNet, it is also worth noting that it is forecasting regions of demand growth well in excess of the average network levels quoted here. These regions have a significant influence on its proposed reinforcement plans.

The other major factor driving reinforcement expenditure is the utilisation of the asset (i.e. the demand carried by the asset compared to its rating). All DNSPs are claiming that the utilisation of their assets is high, and has increased during the current period. The DNSPs consider that this has resulted in the reduced ability to absorb the forecast demand growth without significant increases in investment in new capacity.

The DNSPs' claims of increasing levels of asset utilisation and the future impacts on increasing capex were also consistent themes in their 2001 and 2006 EDPR submissions.

The table below indicates the network types of each DNSP where the greatest increases in expenditure have been proposed.

Table 7 – expenditure increases

Network	CitiPower	Powercor	SP AusNet	Jemena	United Energy
Zone substations	**Very high**	**Very high**	**Very high**	**High**	**High**
ST - lines	**Very high**	**Very high**	**Very high**	Very high	Very high
HV feeders	**Very high**	**Very high**	**High**	Very high	High
Distribution substations and LV	Very high	None	**High**	**Very high**	**Very high**

Key:

Very high - >200% increase

High > 100%

Bold – significant portion of expenditure

The table indicates that all DNSPs are proposing major increases across all parts of their networks.

- **Zone substations** - A significant portion of all DNSPs' reinforcement expenditure involves major programs and projects to upgrade their zone substations, involving numerous new zone substations, and new or upgraded transformers at existing zone substations.
- **Lines** - CitiPower, Powercor and SP AusNet also have major components related to new and upgraded lines, including both sub-transmission lines and HV feeders.
- **Distribution substations** - SP AusNet, Jemena, and United Energy are all proposing major pro-active replacement programs for distribution transformers. CitiPower is also proposing an increase in this area, but this is far less material in the context of its overall reinforcement expenditure.

As noted above, CitiPower has two major projects within its reinforcement category, which accounts for approximately 40% of its expenditure in this category. Both of these projects involve upgrading existing zone substations and adding new sub-transmission lines.

- The **Metro 2012 project** is associated with the need to increase the capacity of the CBD network. The overall project involves the development of a terminal station (i.e. transmission connection point) in the next period. Only expenditure associated with the distribution elements of this project are covered in CitiPower's proposal. The distribution elements of this project were included in CitiPower's regulatory test for the terminal station, which it undertook in the current period to justify the overall development. CitiPower now considers that anticipated costs for the distribution elements have increased by around 20% from that applied in the regulatory test.
- The **CBD security project** is required to improve the security of supply in the CBD – essentially, increasing this from *N-1* to *N-1 secure*. This project was evaluated by the ESC during the current period, although most of the expenditure is needed in the next. ESC considered that this project passed the AER's regulatory test and revised the Victorian Distribution Code to place obligations on CitiPower to

undertake the project. CitiPower now considers that anticipated costs for the project have increased by around 10% from that considered by the ESC to be efficient. It is important to note that this project requires the Metro 2012 project to be in place to realise the increased security.

It is also worth noting that Jemena's proposal includes a major ongoing program, involving the upgrade of the distribution voltage in the Preston area from 6.6 kV to 22 kV. The main need for this upgrade is to provide increases in network capacity; however, the timing appears to be driven by the age and condition of the existing 6.6 kV assets.

4.2.3 Forecasting methodology

The methodologies applied by the DNSPs to prepare their reinforcement forecasts generally reflect their internal planning processes. In this regard, it is important to appreciate that Victoria does not have statutory security of supply standards, as have been adopted in other NEM states, such as Queensland, NSW and Tasmania. Therefore, Victorian DNSPs have adopted risk assessment and management approaches to determine reinforcement needs. These approaches generally consider the risks associated with supplying customers under various normal and outage conditions.

The forecasting methodologies applied are similar for each DNSP at the network category level.

- **Sub-transmission lines and zone substation**. All DNSPs have undertaken a "bottom-up" build from planned projects. The projects are determined via an assessment of the supply risks, such as the level of demand and energy at risk of not being supplied. This approach is based upon probabilistic planning principles, similar to that applied in Victoria for transmission planning (DNSP connections and shared transmission network). The full probabilistic approach forecasts the economic value of the *expected energy not supplied* (EENS) to customers and this is balanced against the costs to reduce the EENS. The DNSPs have applied various input assumptions and criteria to simplify the analysis. As such, the projects are not always based upon a detailed probabilistic assessment. In addition, other known issues are often allowed for to define the overall scope of the project. These other issues may include matters such as the age, condition, or physical circumstances of the existing assets and arrangements.
- **HV feeders**. All DNSPs have developed their forecast at the HV feeder level from a "bottom up" build of indentified projects. At the HV feeder level, the projects are normally identified from analysis of the capacity of the feeders, and determination of the time when there will be insufficient capacity to supply the load and allow for load transfers between feeders.
- **HV distribution transformers and LV networks**. This is developed from a pseudo "bottom-up" approach, whereby the quantity of distribution transformers requiring upgrading are calculated at an aggregate level. This process involves estimating the future maximum demands of the transformer population, based upon customer types and metering information. The number of transformers requiring upgrading

is then determined based upon the quantity with a predicted maximum demand above a function of the transformer rating. The expenditure is calculated based upon the quantity at various standard sizes and a unit cost for that size.

4.2.4 Nuttall Consulting review

Process

The Nuttall Consulting assessment of reinforcement expenditure involved two primary reviews:

- **Methodology review** – a review of the forecasting methodology and associated criteria used by the DNSPs at the various network levels
- **Project review** – various project and programs for each DNSP were reviewed.

It is important to note that the intention of the project reviews has not been to determine whether or not the specific proposed project scope, its timing and cost can be considered prudent and efficient; and if not, what can be. We do not think this is reasonable, given the information asymmetry, the timing of many projects, and the time frame available for our review.

Instead, we have assessed each project to determine the likelihood of the project expenditure being required as proposed. We consider that this is a far more realistic view of how the various projects will advance through the governance processes, resulting in the overall variation to the proposed reinforcement expenditure. This appears particularly relevant to the “bottom up” methodology applied by the DNSPs, where it appears that such a “top down” assessment across the plans has not been considered. This governance issue is discussed further in Section 4.2.4.1.

This project level view has then informed our view of the overall level of reinforcement expenditure. Further details of our methodology, applied to develop our recommendations on the overall level of reinforcement expenditure from the project level findings, are provided in Section 4.2.5.

To undertake this assessment, we have reviewed the material presented by the DNSPs in support of their proposed reinforcement plans, in response to the AER’s RIN. To varying degrees, we considered that this information was insufficient to undertake a detailed review of the DNSPs’ methodology and the selected projects. Therefore, Nuttall Consulting has also:

- made an initial information request to each DNSP to obtain relevant documentation including:
  - project risk assessments (e.g. energy at risk, expected unserved energy, etc)
  - project evaluations analysis
  - project options reports
  - project scoping and costing documents
  - business cases and approval documents

- held meetings with relevant DNSP staff (separately for each DNSP) to clarify matters and determine what further information is required
- made follow-up information requests, based upon these meetings.

More detailed findings of this review are included in the relevant DNSP appendices to this report.

Relationship to the AER review of the DNSP's load forecasts

As noted in our introduction, the AER has separately commissioned a review of the DNSP's load forecast. The findings of this review have been provided to Nuttall Consulting, due to their significance to the DNSPs' reinforcement proposals.

The load forecast findings indicate that the DNSPs have overstated their maximum demand forecasts to various degrees. This appears to be the most significant for CitiPower, Powercor and Jemena, where it appears that the reductions amount to a 1 to 2 years deferral of demand growth.

The reductions are the least significant for SP AusNet and United Energy, amounting to approximately half a year of deferral of growth. However, even in these cases we consider that the reductions are material enough that we would expect them to affect the optimal timing of some projects, and hence, the overall expenditure requirement.

Unfortunately, due to the format of the recommended reductions provided by the AER and the analysis provided by the DNSPs to support their projects, we have not been able to undertake a detailed re-evaluation of projects based upon these recommendations. Nonetheless, given the probabilistic approach we have adopted (discussed further below), we have allowed for the general findings in determining the likelihood of projects occurring as planned.

4.2.4.1 Summary findings from the methodology reviews

Overall, we consider that the DNSPs' methodologies are reasonable for developing capital plans for internal purposes. In this regard, the process should result in the identification of network needs, a list of projects to address these needs, and expenditure projections for the medium-term management of the network. In turn, this process results in a relatively comprehensive list of individual network needs and projects that can be monitored and developed further through the next period.

However, we do not consider that the largely "bottom-up" based process that all the DNSPs have applied has been shown to be "fit for purpose" in terms of being a reasonable unbiased estimator for the future prudent and efficient expenditure at the aggregate level. In particular, we do not consider that such a process adequately allows for the further optimisation of projects and synergies between projects that will occur as the individual projects and the overall capital plans advance through the capital governance process.

It is accepted that in some circumstances these processes will result in some projects being advanced or their scopes increased. However, in our view, the more detailed evaluation and justification associated with obtaining project approval within the governance process will most likely result in overall expenditure being less than the simple summation of the project plans, as applied by the DNSPs to determine their reinforcement expenditure.

With regard to the planning assumptions and criteria used by each DNSP at the sub-transmission level, the key similarities and differences between the DNSPs' are as follows:

- **Maximum demand forecasts** – All DNSPs have assumed one maximum demand condition to determine energy at risk and EENS. Four DNSPs, SP AusNet, CitiPower, Powercor, and Jemena, use 50% PoE maximum demand conditions (i.e. expected annual conditions). United Energy on the other hand has used the far more onerous 10% PoE condition (i.e. a 1 in 10 year maximum demand).
- **Annual load profile** – The DNSPs use different load profiles to predict energy at risk, based upon historical load profiles. SP AusNet and United Energy use the 2007/08 year as a proxy for the future load profile. Jemena use the 1999/2000 profile. CitiPower uses the average of the 2001 to 2005 profiles, and Powercor uses the 2008/09 profile.
- **Outage assumptions** – For transformers, the DNSPs tend to use the outage rates used at the connection point level. This is a 1 in 100 year catastrophic failure with a 2 to 3 month outage time. These are based upon standard industry figures. CitiPower and United Energy have reduced this by assuming a 1 in 200 year event. For lines, the DNSPs tend to use assumed outage rates – although the basis of these is less clear.
- **Other criteria**. Only SP AusNet has rigorously applied detailed probabilistic planning approaches to the development of its reinforcement plans. Jemena and United Energy on the other hand indicate within the their planning methodology documentation that full probabilistic analysis is undertaken. However, at this stage, detailed probabilistic assessments have not been undertaken for many projects, and it appears that engineering judgment has been used to determine project timings in these cases. It worth noting however that this is often based upon the assessment of the level of energy at risk. CitiPower and Powercor are the only DNSPs that have adopted internal planning criteria to simplify the planning analysis. These criteria define the allowable amount of energy at risk and the hours exposed for parts of their network. In this way, CitiPower and Powercor can determine the need for investment when these criteria are exceeded, rather than from a full probabilistic assessment of the economic value of the EENS.

Based upon our review, we are concerned with Jemena and CitiPower's use of older load profiles and United Energy's use of the 10% PoE condition with a 50% PoE load profile. In our opinion, these assumptions may be significantly overstating the EENS, and as such, the level of existing risks.

With regard to the use of the older profiles, based upon our analysis of Victorian load profiles (see appendix J), we would expect that the older profile may be overstating the level of EENS. Load duration curves associated with these older profiles are flatter around the peak demand region. This is due to the relative growth in maximum demand and energy since that time, whereby the growth in maximum demand has been considerably higher.

Furthermore, given that this relative growth difference is predicted to continue through the next period, we would expect that this over-forecasting will increase. We consider that this may result in projects being advanced from their optimal timing by up to 3 years depending on the load growth. For all DNSPs, we consider that the further “peaking” of the demand profile predicted for the next period may result in projects, particularly near the end of the period, being optimally deferred.

For United Energy, we consider that the use of the 10% PoE MD in addition to a load profile more representative of 50% PoE conditions may be significantly overstating the forecasts of EENS. We consider that this may result in projects being advanced by up to 3 years depending on the load growth.

For Powercor, we consider that the 2008/09 year was non-typical as it had a number of extended periods of hot weather. This has resulted in the load duration curve being quite flat near the peak demand region, as such we consider that this may overstate the forecast EENS. We consider that this may result in some projects being advanced from their optimal timing depending on the load growth.

With regard to the outage rates, although it is accepted that these are typical rates applied by the industry, we consider that there is still some discretion that the DNSP can apply. For example, with regard to the transformer outage times, we consider there is scope for this to be reduced via optimisation with spares and contracting arrangements with transformer manufacturers. This becomes particularly relevant when large levels of transformer upgrades are forecast over a short period of time, as is being proposed by many of the DNSPs.

Finally, with regard to the criteria applied by CitiPower and Powercor to simplify the planning analysis, based upon our project reviews, we consider that the criteria are generally conservative – essentially advancing some projects from their optimum economic time.

It is worth noting that the significance on expenditure needs of the methodological issues discussed above, and those associated with the distribution level forecasts (e.g. distribution susbstations), were considered in the context of the project reviews, discussed further below.

4.2.4.2 Summary findings from the project reviews

As noted in Section 4.2.4, the overall aim of the project reviews has been to determine the likelihood that the project expenditure will be required as proposed by the DNSPs. We consider that this is a reasonable approach to account for the likely consequences of the governance processes and the other specific methodological concerns discussed above.

Nuttall Consulting, with the AER, has selected a range of projects from each DNSP for a more detailed review. The projects are indicated in the table below.

Table 8 - Projects reviewed by DNSP

CitiPower	Powercor	SP AusNet	Jemena	United Energy
CDB security project	1 new zone substation	2 new zone substations	Preston area voltage upgrade program	2 new zone substations
Metro 2012 project	2 zone substation transformer upgrades	Sub-transmission line development	2 new zone substations	2 sub-transmission line projects
Various HV feeder projects	3 sub-transmission line upgrades	Various zone substation transformer upgrades	2 sub-transmission line projects	1 zone substation transformer upgrade
3 zone substation upgrade projects		Distribution transformer upgrade program	1 zone substation transformer upgrade	Distribution transformer upgrade program
			Distribution transformer upgrade program	

Our review found a number of issues, where we considered that it was reasonable to assume that the DNSPs were overstating their overall reinforcement needs.

For many projects, our analysis of the benefits through the reduction in EENS did not justify the project at the proposed timing, or the timing was considered marginal. Given some of the points made above on the input assumptions used and how these may be conservative, we consider that there is a reasonable possibility that the optimum time for many projects will be deferred by 1 to 3 years from the times proposed by the DNSPs.

In many cases, alternative lower cost options appear to be reasonable alternatives. We consider that there is a reasonable possibility that a lower cost option may be found to be the preferred option in a number of these cases. We would expect that this further optimisation will occur as the plans flow through the more rigorous evaluation and justifications associated with the approval stages within the capital governance process.

For a few DNSPs, the timing of the project was driven by age and condition considerations. However, in these circumstances, based upon condition information presented for review, we did not consider that there was a clear case that the projects were required at the proposed time. In our view, the condition information suggests that there is a reasonable possibility that the optimal timing will be found to be later. This possibility appears much greater than the projects will be advanced.

For the two major projects proposed by CitiPower, as these have already had approval of some form, we only considered the cost increases proposed by CitiPower. In both case we did not consider that CitiPower had adequately demonstrated that the cost increases were appropriate.

Finally, with regard to the pre-emptive distribution transformer upgrade program that a number of DNSP have proposed, we do not consider that they have adequately demonstrated that this program will realise the benefits that are predicted. In particular, we do not consider that the DNSPs have provided sufficient evidence to show that the program can adequately target the transformers, such that it will reduce the transformer failure rate sufficiently. We also consider that a delay until the AMI roll-out may allow information from these meters to be used to assist in refining the algorithms to allow better targeting. We also note that the STPIS provides some incentive and reward for undertaking these programs as a significant benefit should be in terms of improved reliability.

4.2.5 Overall review findings

The main findings of the review are that the DNSPs have not demonstrated that their proposed reinforcement expenditure can be considered to reasonably represent a prudent and efficient allowance. Based upon the findings of our review, we consider that significant reductions to the proposed plans will occur as the plans pass through the governance processes and more detailed evaluations and justifications are undertaken. This will result in some proposed projects being deferred, and others being reduced in scope or substituted with lower cost solutions.

Given the findings of our high-level expenditure analysis, the methodology review and the detailed project reviews, we consider that it is reasonable to consider that the actual expenditure will be far more in line with the historical trend.

To develop an expenditure profile based upon these findings, we have applied the following process:

1. Each project reviewed has been assigned a probability that the project expenditure will be required at the level and time proposed by the DNSP. Individual project probabilities were classified as low (33%), moderate (50%), moderate/high (70%) or high (90%)[16]. The classification was largely developed from the findings of the specific projects reviewed, but also allowed for the broader findings from the methodology review and expenditure analysis.
2. The average weighted probability at the project level, using the project cost as the weighting, was then determined.
3. The average weighted probability was then applied to the DNSP's proposed total reinforcement expenditure level to determine our estimate of the total reinforcement expenditure.
4. To develop the annual expenditure profile over the next period, we have used the average actual expenditure in the 2006 to 2008 period as a notional 2008 base-line for the expenditure trend. We consider that this is a reasonable starting point given the historical expenditure profile.

[16] The one exception to this concerned the proposed pre-emptive distribution substation upgrade program, where the percentage was set to reflect historical levels.

5 We have then estimated a constant annual expenditure growth rate from that notional point that results in our total expenditure estimate for the next period (as determined in step 3).

The only exception to this process concerns CitiPower and its two major projects, which we do accept will result in a significant step change in reinforcement expenditure during the next period. Expenditure associated with these two major projects has been excluded from the process applied above. Our recommended allowance for these two projects has been added at the end of the expenditure profiling process described above.

The following table summarises our probability weighting and the annual growth rate determined for each DNSP via this process.

Table 9 – adjustment to DNSP proposals

Network	CitiPower[17]	Powercor	SP AusNet	Jemena	United Energy
Proportion of DNSP proposed expenditure	39% (53%)	62%	53%	38%	63%
Annual growth rate (from 2008)	5.7%	8.3%	10.7%	7.4%	7.0%

This indicates that our reductions range from between 37% for United Energy to 62% for Jemena. The capex growth rates determined through this process are between 5.7% for CitiPower and 10.7% for SP AusNet. Given the previous capex growth rates and the reduction in the demand growth rates anticipated for the next period, we do not consider that these rates are unreasonable.

The chart below shows the profile of the overall Victorian reinforcement expenditure, indicating the aggregate expenditure estimated in the current period by each DNSP, their aggregate forecasts for the next period, and the our recommended adjustments.

The individual expenditure adjustments for each DNSP are provided in Table 10 below.

It is important to note that the AER will need to adjust these figures to incorporate its findings on other matters, such as overheads, and labour and material escalations.

[17] The main (un-bracketed) figure quoted here are exclusive of the CBD security and Metro 2012 projects. The bracketed figures include these two projects, inclusive of our recommended adjustments for these two projects.

Figure 19 – Victorian recommended reinforcement expenditure

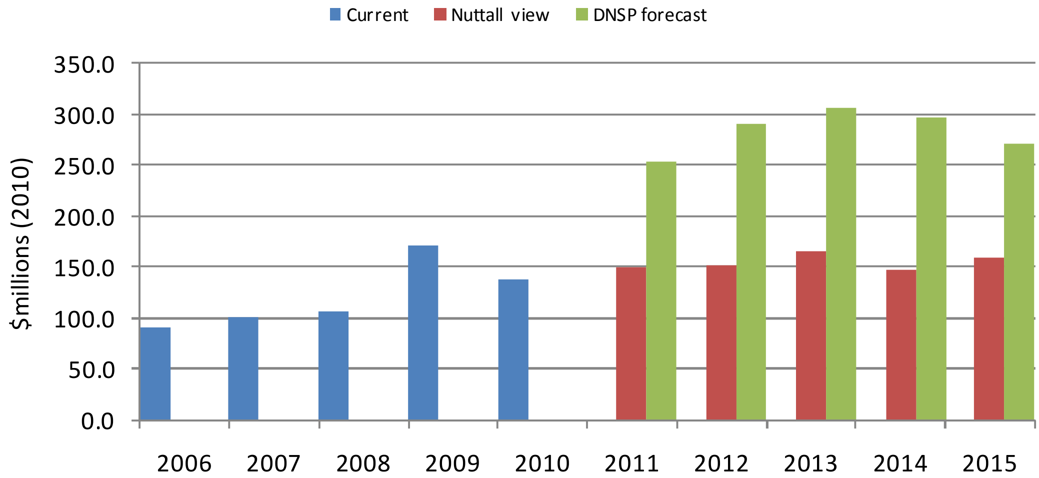


Table 10 – Summary of reinforcement capex recommendations

	$millions (2010)				
	2011	2012	2013	2014	2015
CitiPower - proposed	54.8	59.1	75.7	63.5	47.4
CitiPower - recommended	**45.7**	**38.3**	**43.7**	**14.6**	**15.3**
Powercor - proposed	53.4	55.9	62.6	68.8	70.6
Powercor - recommended	**32.7**	**35.4**	**38.4**	**41.6**	**45.0**
Jemena - proposed	29.4	46.1	41.6	35.1	32.8
Jemena - recommended	**12.2**	**13.1**	**14.1**	**15.1**	**16.2**
SP AusNet - proposed	68.2	87.6	78.9	84.2	85.3
SP AusNet - recommended	**34.6**	**38.3**	**42.4**	**46.9**	**51.9**
United Energy - proposed	47.2	44.1	48.1	46.7	35.5
United Energy - recommended	**24.1**	**25.8**	**27.6**	**29.6**	**31.6**

4.3 Reliability and quality maintained

4.3.1 Overview of expenditure

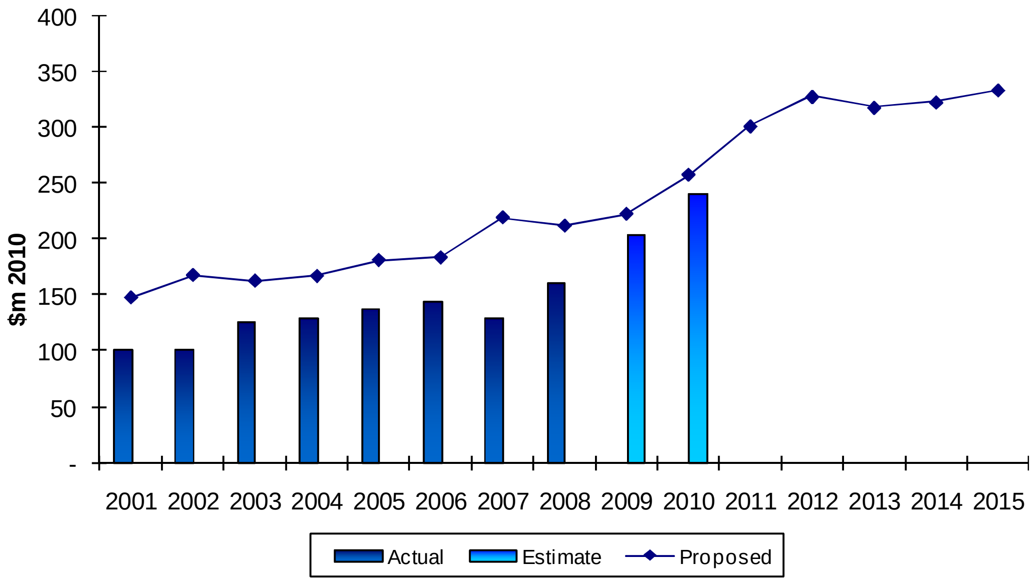
The Victorian DNSPs are proposing an increase of 120% in reliability and quality maintained (RQM) capex for the next Regulatory Control Period when compared against actual expenditure in the current Regulatory Control Period.

The DNSPs estimate that RQM capex for the 2006-10 regulatory control period will be $882 million. They are forecasting that this will increase to $1,602 million in the 2011-15 regulatory control period.

The DNSPs estimate that RQM capex for the 2006-10 regulatory control period is approximately 20% lower than their forecasts prepared for the 2006 EDPR, $1094 million.

The following chart provides a summary of RQM capex for the Victorian DNSPs. The chart shows a relatively consistent trending up of actual expenditure, with the 2009 and 2010 estimates showing a more significant increase above this trend.

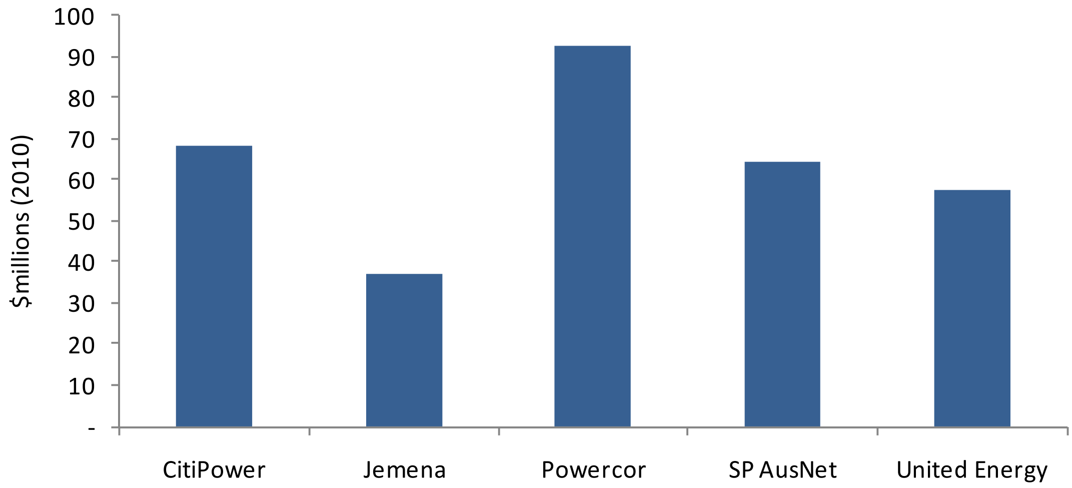
Figure 20 - Victorian Reliability and Quality Maintained



From 2001 to 2008, the DNSPs have significantly over forecast their RQM capex requirements. The forecast expenditures for the next regulatory control period are significantly greater than current levels of expenditure.

There was a high degree of variation in the overall RQM capex levels proposed by the DNSPs, which is not strictly in accordance with the relative scale of the networks. The following chart shows the average annual capex proposed by the DNSPs for the next control period.

Figure 21 - DNSP average RQM proposed capex



This variation however can be explained, at least mostly, by variations in the allocations of various types of project. Predominantly, this category captures age/condition driven replacement expenditure. However, there are some variations in how the DNSPs have allocated some major project and programs. The main examples of this are:

- Powercor and SP AusNet are both proposing very significant new programs to replace aged conductors, $100 million for Powercor and $55 million for SP AusNet. Powercor has included this program in the RQM category, but SP AusNet has included this in the ESL category.
- CitiPower are proposing a large project ($75 million) to mitigate fault levels. This sort of project could be considered an augmentation as the replacement is driven by the need to upgrade the existing fault rating of assets (or add assets to reduce fault levels); however, this project has been allocated to the RQM category.

There is significant variability in the scale of the increases proposed by the DNSPs, as shown in the table below. Jemena is seeking the greatest level of increase at 198%, while Powercor is seeking the least at 87%.

Table 11 - Proposed RQM capex increases

DNSP	% increase[18]
CitiPower	161%
Jemena	198%
Powercor	87%
SP AusNet	103%
United Energy	124%
Victoria	**120%**

For review purposes, a number of the SP AusNet replacement programs that had been allocated to the environmental, safety and legal category were transferred to the RQM category. This was because these programs were driven by the age/condition of the assets, of which SP AusNet had used age models to estimate the scale.

These transfers amounted to approximately $100 million, and covered replacement programs for HV fuses, cross-arms, overhead conductors and overhead line insulators. These transfers are not included in the charts and tables in this overview section, but are included in the discussions that follow.

4.3.2 The RQM activity code review

An important aspect of the RQM review conducted by Nuttall Consulting concerns the changes from current expenditure, whereby a starting assumption is that current expenditure levels can be considered representative of prudent and efficient expenditure.

The RIN templates do not provide an appropriate disaggregation to conduct such a review. Furthermore, the DNSPs have indicated during discussions that the historical allocation to the RIN categories may not be robust.

For this reason, the DNSPs were requested to provide a breakdown of historical and forecast expenditure in the RQM category, based upon their activity code definitions used in their financial systems.

The analysis of the RQM expenditure conducted by Nuttall Consulting has been largely based upon this breakdown (termed the RQM activity code review). The DNSPs' activity code breakdown, to a large extent, can be mapped to the asset group categorisation, used in the repex models (see Section 3.2.3).

The only DNSP where we found its disaggregation to be relatively course was SP AusNet. For SP AusNet it has been more difficult to get a consistent view of expenditure trends at the asset level. However, we still consider that the information we have been provided is sufficient to gauge the major drivers.

[18] Increases are based on a comparison with the most recent 3 years (2006-2008) of actual RQM capital expenditure.

A more detailed discussion of the activity code review undertaken for each DNSP is provided in respective DNSP Appendices A to E.

4.3.3 Projects and programs driving the increases

Through the RQM activity code review, we have identified a number of projects and programs for each DNSP that are the main reasons for the proposed increases.

Table 12 illustrates the scale of the increase due to the asset groups used in our repex modelling. This table indicates the following assets that are having the greatest influence on the proposed increases:

- zone substation circuit breakers and power transformers (and other associated plant) across all the DNSPs
- a proposed pre-emptive conductor replacement program for Powercor and SP AusNet, and to a lesser degree Jemena
- zone substation secondary systems replacement for Citipower, Powercor and SP AusNet
- pole top replacement (i.e. cross-arms) for Jemena and United Energy
- pole replacement for Jemena
- CitiPower's fault level mitigation project.

Table 13 shows the various methodologies that have been applied by the DNSPs to produce the forecast. For low volume / high cost plant, such as the zone substation circuit breakers and transformers, detailed condition based economic and risk analysis have been applied. However for other high volume /low cost items simpler approaches have been used, involving age-based models, trending historical rates, and assuming known quantities based upon known issues. Generally, unit costs are assumed based upon historical unit costs or specific cost estimates.

With regard to the more significant increases, important points to note on the methodologies are as follows:

Zone substation circuit breakers and power transformers

All DNSPs have used a condition based approach to determine the specific circuit breakers and power transformers proposed for replacement. In the case of Citipower, Powercor and SP AusNet this has involved a quantitative risk based approach that has valued the risks due to asset failure, based upon predicted failure rates and associated consequences. These risks have then been used via a form of NPV analysis to determine the optimum replacement program.

For Jemena and United Energy a simpler process has been used. For transformers, this has involved the use of condition information to estimate the technical remaining life of the transformers. This has then been used to determine the timing, with some adjustments for other known issues. For circuit breakers, a risk analysis has been performed; however, this analysis does not attempt to place an economic value on the risks.

Overhead Conductors

A range of approaches have been applied for forecasting conductor replacements. Only SP AusNet has undertaken some form of economic analysis, based upon historical failure rates and an age-based replacement criteria. For the other DNSPs various types of age-based models have been applied.

Poles and pole tops

Two types of approach have been used to forecast poles and pole top replacements. Citipower and Powercor have trended historical rates of replacement. The other three DNSPs have used age-based models. These models appear to be similar in philosophy to the repex model used in our review (i.e. using age profile with an assumed asset life and unit cost to determine the forecast). In the case of Jemena and United Energy, we understand that the model is the same as that used for the 2001 and 2006 EDPR (i.e. the replacement model supplied by PB Power – the PB age-based model).

Other assets

Various approaches have been used across the other categories. Jemena and United Energy have often used the PB age-based model. SP AusNet mainly uses internal probabilistic age-based models. Citipower and Powercor on the other hand have generally trended historical rates and assumed quantities.

Citipower fault mitigation project

The Citipower fault mitigation project has been determined through an independent technical assessment. The project however does not have any supporting economic evaluation.

Table 12 – assets driving proposed increases

Asset	Citipower	Powercor	SP AusNet	Jemena	United Energy
Poles	Moderate	Low	Low	**High**	Low
Pole top structures	Low	Low	*Moderate*	**High**	**High**
Overhead conductors	Low	**High – conductor replacement program**	***High - conductor and insulator replacement program***	**High**	High
Underground cables	Moderate	*Low*	Low	High	Low
Zone substation switchgear	**High**	**High**	**High**	**High**	**High**
Distribution transformers	High	Low	*Moderate*	Moderate	*Low*
Power transformers	**High**	**High**	**High**	**High**	**High**
SCADA, network control, protection, secondary	**High**	**High**	**High**	Low	Low
Service lines	High	High	*Moderate*	Low	Moderate
Zone substation - other	***High***	***High***	**High**	***High***	***High***
Distribution SWGR	High	High	*Moderate*	Low	*Low*
Other	**High - Fault Level Mitigation project**				

Key:

Low - <30% increase; Moderate - 30% to 100% increase; High - >100% increase
Bold text indicates asset forms a major component of the overall increase
Italic text indicates that this is an estimate by Nuttall Consulting due to the lack of disaggregation in the activity code definitions.

Table 13 – methodologies used to produce forecasts

Asset	Citipower	Powercor	SP AusNet	Jemena	United Energy
Poles	Historical rates	Historical rates	Age based model	Age based model	Age based model
Pole top structures	Historical rates	Historical rates	Age based model	Age based model	Age based model
Overhead conductors	Various – historical rates, engineering judgment, known issues and quantities	Simple age based model	Economic analysis, based upon failure rates and asset age	Age based model, and known quantities	Age based model
Underground cables	Various – historical rates, engineering judgment, known issues and quantities	Various – age based model, historical rates, engineering judgment	*Unclear, but not material*	Age based model	Age based model
Zone substation switchgear	condition based, quantitative economic/risk assessment	condition based, quantitative economic/risk assessment	condition based, quantitative economic/risk assessment	Pseudo-quantitative risk assessment	Pseudo-quantitative risk assessment
Distribution transformers	Historical rates and engineering judgement	Historical rates and engineering judgement		Age based model	
Power transformers	condition based, quantitative economic/risk assessment	condition based, quantitative economic/risk assessment	condition based, quantitative economic/risk assessment	condition based modelling of end of life	condition based modelling of end of life
SCADA, network control, protection, secondary	Various - risk assessment, historical rates, known issues and volumes	Various - risk assessment, historical rates, known issues and volumes	Various	Age based model	Age based model
Service lines	Age based model	Age based model	Age based model	Historical rates and known quantities	Known quantities
Zone substation - other	Various	Various	Various	Various	Various
Distribution SWGR	Various –known issues and quantities, historical rates	Various – historical rates	Age based model	Various – age based model, historical rates, known issues and quantities	Various – age based model, historical rates, known issues and quantities
Other	Technical study				

4.3.4 Nuttall Consulting review findings

Based upon our review, we do not consider that any of the DNSPs have adequately demonstrated that the proposed increases in RQM capex are prudent and efficient.

Generally, Nuttall Consulting does not have any issue with the philosophy of the methodologies applied by the DNSP. It has also reviewed the documentation provided in support of the proposals (e.g. asset management plans) and sees no reason to consider that the identified issues and associated risks do not exist.

However, given that in many cases the models are forecasting significant increases over historical replacement expenditure and volumes, we do not consider that the DNSPs have adequately demonstrated that the model inputs and assumptions are “fit for purpose” in terms of enabling a “bottom-up” build that is a reasonable estimator of overall prudent and efficient expenditure. In this regard, we do not consider that the DNSPs have demonstrated that rigorous approaches have been applied to calibrate the model for this purpose.

Furthermore, with regard to identified asset issues in the documentation and the various pre-emptive replacement programs that are proposed, there is little detail on how the DNSPs have actually managed the risks over the current period, how these risks will change moving into and through the next, and why it is justified that these risks must be removed. Given that these risks presently exist, and therefore, it seems reasonable to assume that they are being prudently and efficiently managed, it seems reasonable to assume there may not be a positive net benefit in removing these risks, at least to the scale proposed.

With regard to the more significant increases, important findings of our review are as follows:

- *Zone substation circuit breakers and power transformers*

  We consider that the condition based, quantitative economic/risk modelling that Citipower, Powercor and SP AusNet have applied are a contemporary and rigorous approach to predicting replacement needs for transformers and circuit breakers. However, based upon our review of these models, we do not consider that the DNSPs have adequately demonstrated that the probability of failures and consequences that these models predict reasonably reflect actual historical outcomes. In this regard, in a number of cases, it appears that the models may be overstating failure probabilities. It has also not been demonstrated how the range of options considered have appropriately recognised the specific matters driving the risks.

  For Jemena and United Energy, the validity of the predictive nature of the model is not fully supported from the information provided. For transformers, condition data suggests the transformers may have remaining life in excess of that predicted by the model. For circuit breakers, the model prioritises replacements, but does not provide any relative scale of the risks. Furthermore, other issues and associated risks are a significant factor in defining the timing and scale of the proposed projects, but there is no economic evaluation to support this view.

- *Overhead Conductors*

  It is clear that the main risk that is being mitigated by the proposed conductor replacement program concerns bushfires. Without this risk, it does not appear that this program would be economically justified. However, the DNSPs have not demonstrated that their condition assessment can reliably target the conductor that requires replacement or that the age-based criteria they have assumed to estimate the quantities for replacement is a reasonable estimator. It is understood that the ESV have undertaken a testing exercise, but the findings of this were not available at the time of drafting.

  Given the significance of this matter and its relationship with recommendations that may result from the Royal Commission on the 2008/9 bushfires, Nuttall Consulting considers that this program should be “ring fenced” and re-considered following the Royal Commission’s findings.

- *Other assets*

  In a number of cases, the age-based models applied by the DNSPs have forecast a step change in expenditure. Generally, we do not consider that the DNSPs have demonstrated that these increases are reasonable, rather they appear to be a calibration issue (i.e. a life or unit cost has been assumed that is not reflective of historical practices).

- *Citipower fault level mitigation project*

  The Citipower fault level mitigation program is a very significant ($75 million) new project proposed to commence in 2011. However, no economic analysis has been provided that demonstrates that the project scope and timing are required. It is not clearly evident from the information provided that the project will be needed at all in the next period. Given this lack of a robust economic argument for the project, we are not recommending any allowance for this project. In our opinion, there should be sufficient expenditure within our overall recommendation to allow CitiPower to manage its fault levels, possibly via the continuation of its current operational approaches where deemed prudent and efficient.

Based upon our review, and considering the findings of our repex modelling and the past overestimation of RQM requirements, we consider that the RQM allowance should be based upon the recent historical levels with some additional allowance for the aging of the network. We consider that the results of our repex modelling can be used as a reasonable estimate of the increases required due to the aging.

Based upon this review, the following table indicates our estimate of the RQM allowances for each DNSP.

It is important to note that this is an estimate only, and the AER may need to make adjustments based upon its findings on other matters such as overheads, and labour and material escalators.

Table 14 – Summary of RQM capex recommendations

	$millions (2010)				
	2011	2012	2013	2014	2015
CitiPower - proposed	56.1	69.4	63.8	69.8	83.0
CitiPower - recommended	**34.7**	**39.5**	**42.1**	**47.7**	**52.6**
Powercor - proposed	87.4	89.5	94.4	95.2	97.5
Powercor - recommended	**50.7**	**52.5**	**54.5**	**56.6**	**58.7**
Jemena - proposed	35.9	33.8	34.0	39.9	42.6
Jemena - recommended	**14.4**	**15.4**	**15.5**	**15.9**	**16.7**
SP AusNet - proposed[19]	82.7	95.1	92.1	82.1	70.6
SP AusNet - recommended	**49.5**	**52.4**	**54.8**	**57.5**	**60.3**
United Energy - proposed	62.8	60.2	58.7	52.9	54.1
United Energy - recommended	**35.3**	**31.7**	**28.5**	**31.2**	**33.5**

4.4 Environmental, Safety and Legal

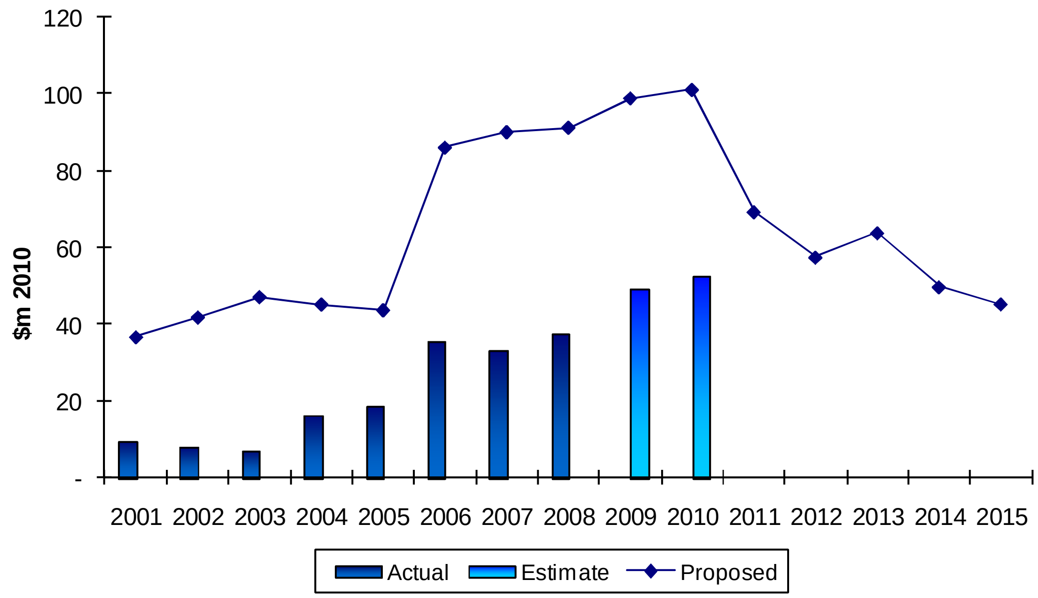
The Victorian DNSPs are proposing an increase of 61% in Environmental, Safety and Legal capex for the next Regulatory Control Period when compared against actual expenditure in the current Regulatory Control Period. The DNSPs estimate that Environmental, Safety and Legal capital expenditure for the 2006-10 regulatory control period will be $208 million. It is forecasting that this will increase to $285 million in the 2011-15 regulatory control period.

For the 2006 EDPR, the Victorian DNSPs proposed Environmental, Safety and Legal expenditure of $467 million. The resultant actual expenditure for this period is forecast to be $208 million.

The following chart provides a summary of Environmental, Safety and Legal capex for the Victorian DNSPs.

[19] This amount includes RQM plus identified transfers from ESL.

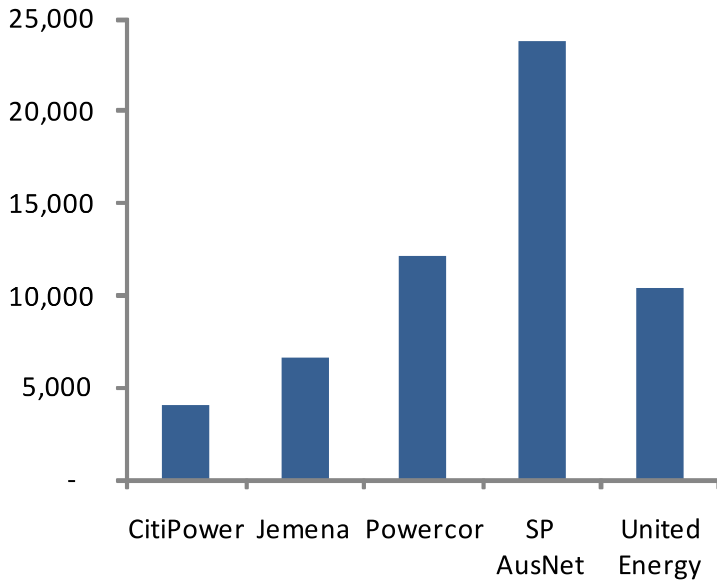
Figure 22 - Victorian Environmental, Safety and Legal capex



From 2001 to 2008, the DNSPs have significantly over forecast their Environmental, Safety and Legal capex requirements. The forecast expenditures for the next regulatory control period are significantly greater than current levels of expenditure, although they are more in line with the overall trend in Environmental, Safety and Legal capex.

There was a high degree of variation in the overall Environmental, Safety and Legal capex levels proposed by the DNSPs. The following chart shows the average annual capex proposed by the DNSPs for the next control period.

Figure 23 - DNSP average ESL proposed capex ($000)



Nuttall Consulting has not undertaken an audit of the allocation and categorisation practices of the DNSPs. However, from an overview perspective, it appears that the sort of costs that are captured by the DNSPs in this category varies considerably. This variability argues against undertaking any benchmark comparisons at the overall Environmental, Safety and Legal level.

There is significant variability in the scale of the increases proposed by the DNSPs. CitiPower is seeking the greatest level of increase at 160%, while Jemena is seeking the least at 12%. It should be noted that CitiPower's current expenditure levels in Environmental, Safety and Legal are the lowest of the Victorian DNSPs.

Table 15 - Proposed Environmental, Safety and Legal capex increases

DNSP	% increase[20]
CitiPower	160%
Jemena	12%
Powercor	50%
SP AusNet	107%
United Energy	22%
Victoria	**61%**

The DNSPs have identified a range of projects for increasing Environmental, Safety and Legal capex. There was very little consistency between the DNSPs in terms of the drivers that they considered would be resulting in increasing expenditures. The exceptions to this were the CitiPower and Powercor proposals that had a number of items in common.

The range of projects for increasing Environmental, Safety and Legal capex proposed by the DNSPs included:

- noise control
- containment and drainage of oil in zone substations
- asbestos management
- ESMS
- bushfire management
- managing powerline easements in Victorian National Parks
- infrastructure security
- Neutral screen services
- Ground fault neutralisers.

Each of these drivers is assessed in more detail in the respective DNSP specific appendices.

In general, the identified projects fell into two categories: whether the project was based on an existing driver, obligation or regulation, or whether there had been a change to the project driver regulation or obligation. The project groupings are identified below.

1 New or changed drivers, regulations or obligations

[20] Increased based on comparison with most recent 3 years of actual Environmental, Safety and Legal capital expenditure

a. ESMS

b. bushfire management

c. managing powerline easements in Victorian National parks

d. ground fault neutralisers.

2 Existing drivers, regulations or obligations

a. noise control

b. containment and drainage of oil in zone substations

c. asbestos management

d. infrastructure security

e. neutral screen services.

In the cases of the existing drivers, regulations or obligations, the DNSPs were generally unable to provide evidence that substantiated an increase in expenditures above and beyond the current levels. In most cases, the obligations for these projects have existed for many years and had been identified by the DNSPs in the 2001 and 2006 EDPR submissions.

The new or changed drivers, regulations or obligations projects were individually assessed. In general, the drivers for these expenditure changes were agreed, although the resulting increases in expenditures being sought by the DNSPs were relatively small.

In the case of the ground fault neutralisers, the DNSP identified that the project had a short payback period (less than 5 years). The DNSPs did not quantify the benefits of the project, so it was not possible to assess the proposed benefits. The project was not recommended for inclusion in the forecast allowances and the DNPSs are therefore able to take advantage of the overall net benefit of the project.

A general concern in assessing the information provided by the DNSPs was the lack of information concerning the benefits and associated advantages of the proposed programs. In most cases, it was considered highly likely that additional benefits would accrue through the implementation of the DNSP proposed programs, however these benefits were almost uniformly not acknowledged or quantified by the DNSPs.

It is recognised that these benefits may be hard to quantify in some cases. Safety and some environmental advantages may be hard to quantify. On the other hand, opex and reliability benefits are more easy to identify and measure.

The lack of recognition of these side benefits represents a consistent bias in the process and hinders the identification of the efficient level of capex.

On the basis of the information provided by the DNSPs, it was generally considered reasonable to accept the efficient costs that have been recently incurred by the DNSPs as the basis for forecasting the required Environmental, Safety and Legal expenditure for the next Regulatory Control Period.

Table 16 - Recommended ESL capex

	$millions (2010)				
	2011	2012	2013	2014	2015
CitiPower - proposed	4.4	4.0	4.1	3.9	4.1
CitiPower - recommended	**1.5**	**1.5**	**1.5**	**1.5**	**1.5**
Powercor - proposed	15.0	10.8	12.4	11.7	10.7
Powercor - recommended	**7.1**	**7.1**	**7.1**	**7.1**	**7.1**
Jemena - proposed	5.8	9.2	7.3	5.5	5.1
Jemena - recommended			***not part of targeted review***		
SP AusNet - proposed[21]	3.8	3.9	3.7	3.4	3.5
SP AusNet - recommended	**1.1**	**1.1**	**1.2**	**1.2**	**1.2**
United Energy - proposed	16.1	9.3	11.4	8.0	7.5
United Energy - recommended	**7.2**	**7.2**	**7.2**	**7.2**	**7.2**

The recommended Environmental, Safety and Legal capex for the above DNSPs is based on the average actual expenditures incurred in the previous 5 years exclusive of indexation and escalation.

With regard to Jemena, it was agreed with the AER that Nuttall Consulting would not undertake a detailed assessment of this category given the modest proposed increase and the low significance on overall capex.

4.5 SCADA and Network Control

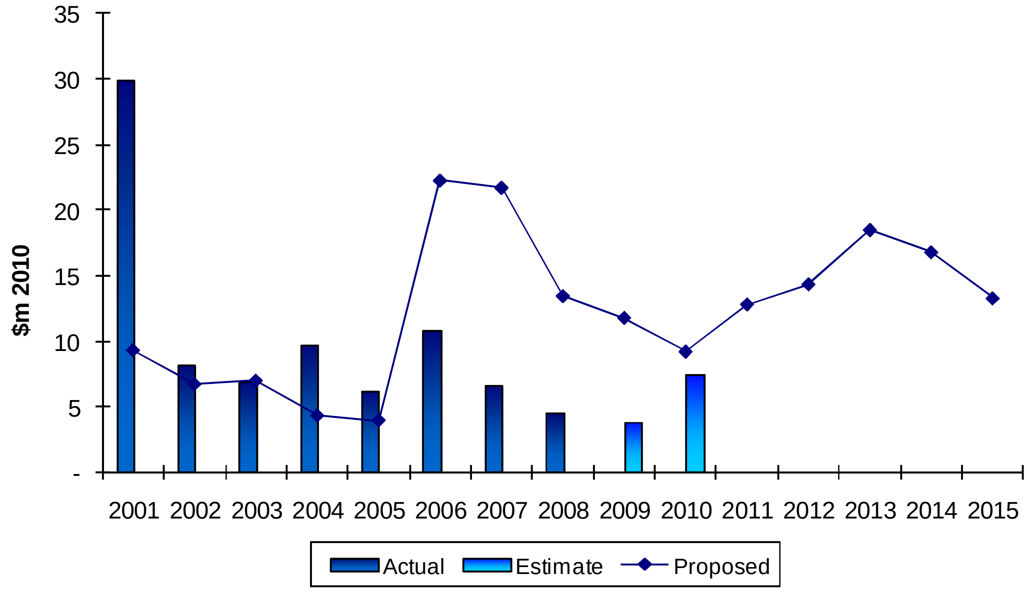
The Victorian DNSPs are proposing an increase of 106% in SCADA and Network Control capex for the next Regulatory Control Period when compared against actual expenditure in the current Regulatory Control Period. The DNSPs estimate that SCADA and Network Control capital expenditure for the 2006-10 regulatory control period will be $33.4 million. It is forecasting that this will increase to $75.6 million in the 2011-15 regulatory control period.

For the 2006 EDPR, the Victorian DNSPs proposed SCADA and Network Control expenditure of $78.3 million. The resultant actual expenditure for this period is forecast to be $33.4 million.

The following chart provides a summary of SCADA and Network Control capex for the Victorian DNSPs.

[21] This amount includes the transfers from ESL to RQM.

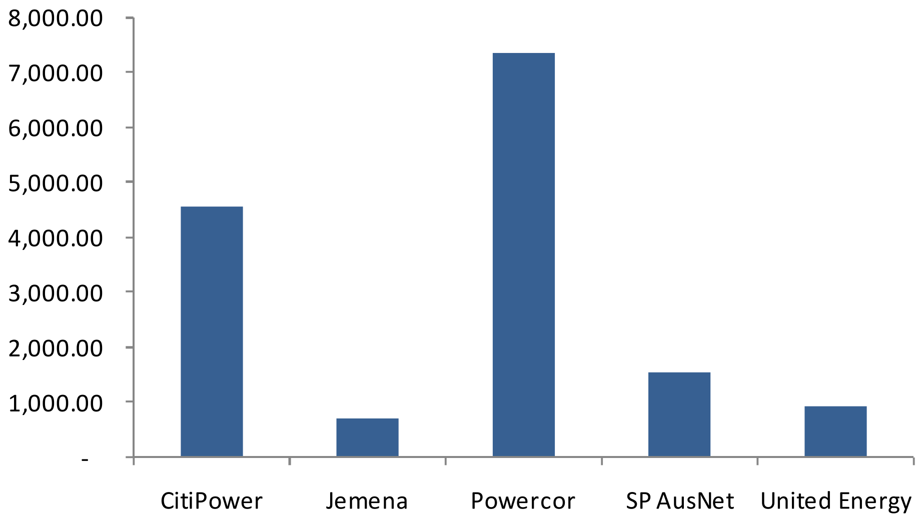
Figure 24 - Victorian SCADA and Network Control capex



From 2006 to 2008, the DNSPs have significantly over forecast their SCADA and Network Control capex requirements. Prior to this date, the proposed expenditures were closer to actuals or under-forecast. The forecast expenditures for the next regulatory control period are significantly greater than current levels of expenditure.

The following chart shows the average annual capex proposed by the DNSPs for the next control period.

Figure 25 - DNSP average SCADA and Network Control proposed capex ($000)



Nuttall Consulting has not undertaken an audit of the allocation and categorisation practices of the DNSPs. However, from an overview perspective, it appears that the sort of costs that are captured by the DNSPs in this category varies considerably. This variability argues against undertaking any benchmark comparisons at the overall SCADA and Network Control level.

There is significant variability in the scale of the increases proposed by the DNSPs. Powercor and CitiPower are seeking the greatest level of increases at over 700%, while SP AusNet and Jemena are proposing reduced levels of future expenditure. It should be noted that CitiPower's current expenditure levels in SCADA and Network Control are the lowest of the Victorian DNSPs.

Table 17 - Proposed SCADA and Network Control capex increases

DNSP	% increase[22]
CitiPower	703%
Jemena	-34%
Powercor	831%
SP AusNet	-68%
United Energy	-[23]
Victoria	**106%**

Based on the increases (or decreases) proposed above, it was agreed with the AER that the Nuttall Consulting review should target the CitiPower, Powercor and Jemena proposals for a more detailed assessment.

These three DNSPs identified a range of projects for increasing SCADA and Network Control capex. There was very little consistency between the DNSPs in terms of the drivers that they considered would be resulting in increasing expenditures. The exceptions to this were the CitiPower and Powercor proposals that had a number of items in common.

The range of projects for increasing SCADA and Network Control capex proposed by the DNSPs included:

- temperature and oil pressure monitoring
- allocation for development initiatives
- feeder automation
- integrated zone substation security
- replacement/enhancement of the station RTUs.

Each of these drivers is assessed in more detail in the DNSP specific appendices.

There was a degree of overlap in some proposals with the non-system IT category. Some projects were discussed in one category, but had costs allocated to another.

For a number of the SCADA and Network Control assessments, the DNSPs did not provide any cost information or any quantitative assessment of benefits. As such, it is difficult to determine whether these projects represent prudent or efficient expenditure.

[22] Increased based on comparison with most recent 3 years of actual Environmental, Safety and Legal capital expenditure

[23] United Energy reported no expenditure in the SCADA and Network Control category between 2001 and 2008 inclusive.

Many of the proposed programs would also have impacts on opex and system reliability. These impacts do not appear to be considered by the DNSPs.

In the absence of any defined benefit, Nuttall Consulting was unable to conclude that a number of the projects were prudent from a timing perspective or that they were efficiently targeted.

In some cases, there was a high degree of similarity between the project descriptions provided for the 2005 EDPR process and those of the current review. Where the level of actual expenditure in the current regulatory period was well below the level proposed by the DNSPs Nuttall Consulting considered this to suggest scope for deferral and efficiencies.

The DNSPs did not identify any new or changed regulations or obligations that would require a significant step change in SCADA and Network Control capex. As such, Nuttall Consulting recommended that the existing level of SCADA and Network Control capex represents an efficient expenditure level for CitiPower and Powercor. Jemena's proposed SCADA and Network Control expenditures were considered to be prudent and efficient.

The following table provides the recommended SCADA and Network Control capex levels for the three DNSPs reviewed in detail.

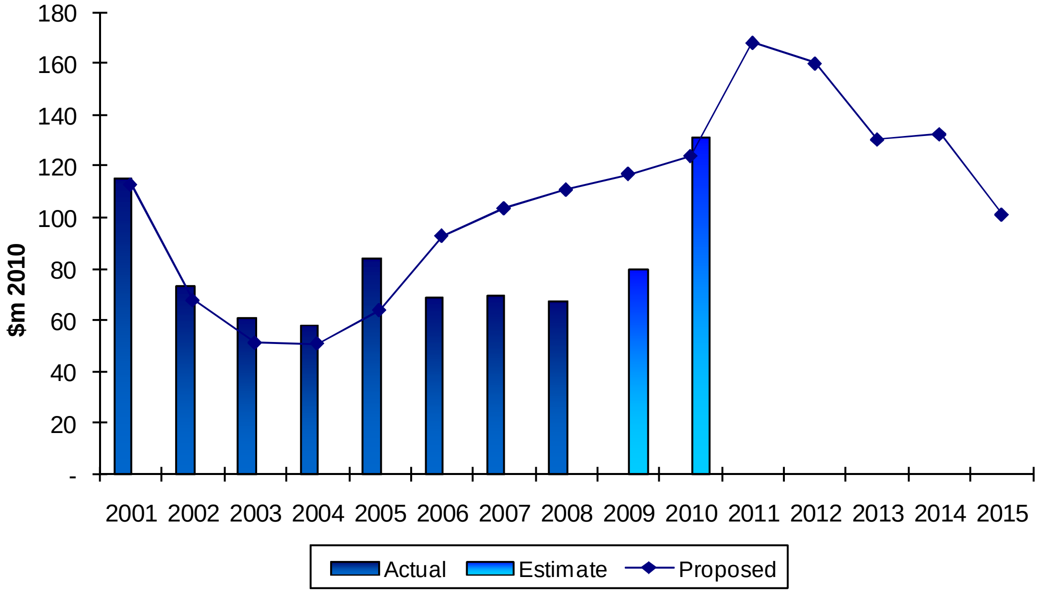
Table 18 - Recommended SCADA and Network Control capex

	$millions (2010)				
	2011	2012	2013	2014	2015
CitiPower - proposed	4.6	4.3	4.6	4.7	4.8
CitiPower - recommended	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**
Powercor - proposed	6.8	7.4	7.6	7.5	7.5
Powercor - recommended	**2.8**	**2.8**	**2.8**	**2.8**	**2.8**
Jemena - proposed	0.8	1.2	1.2	0.3	0.0
Jemena - recommended	**0.8**	**1.2**	**1.2**	**0.3**	**0.0**
SP AusNet - proposed	0.6	0.8	1.2	4.3	1.0
SP AusNet - recommended			***not part of targeted review***		
United Energy - proposed	0.0	0.7	3.9	0.0	0.0
United Energy - recommended			***not part of targeted review***		

4.6 Non-network

Victorian DNSPs are proposing to increase their non-network capex by 100% from current levels. The following figure provides a summary of the Victorian DNSPs non-system related capex.

Figure 26 - Victorian Non-Network Capex



The DNSPs have estimated that Non-Network Asset capital expenditure for the 2006-10 regulatory control period will be $418 million ($2010). It is forecasting that this will increase to $692 million ($2010) in the 2011-15 regulatory control period.

Historically the level of non-network capex that was proposed was relatively similar with actual incurred capex. The accuracy of the forecasts in the 2006 EDPR deteriorated with average actual expenditure remaining relatively stable, despite increasing forecasts.

The DNSPs are forecasting a significant increase in non-network capex in 2010 and for the next control period. This level of estimated and forecast expenditure is not consistent with the overall trends of the last 10 years.

Non-system capex is reported in two distinct categories: IT and "other". The DNSPs IT capex proposals are discussed at the aggregate level in the following section. Individual DNSP IT capex is discussed in the company specific appendices.

Non-system other capex was not considered by Nuttall Consulting as part of this review with the exception of Jemena. The review of the Jemena non-network other capex is provided in the Jemena specific appendix of this report.

4.6.1 Non-network - general IT

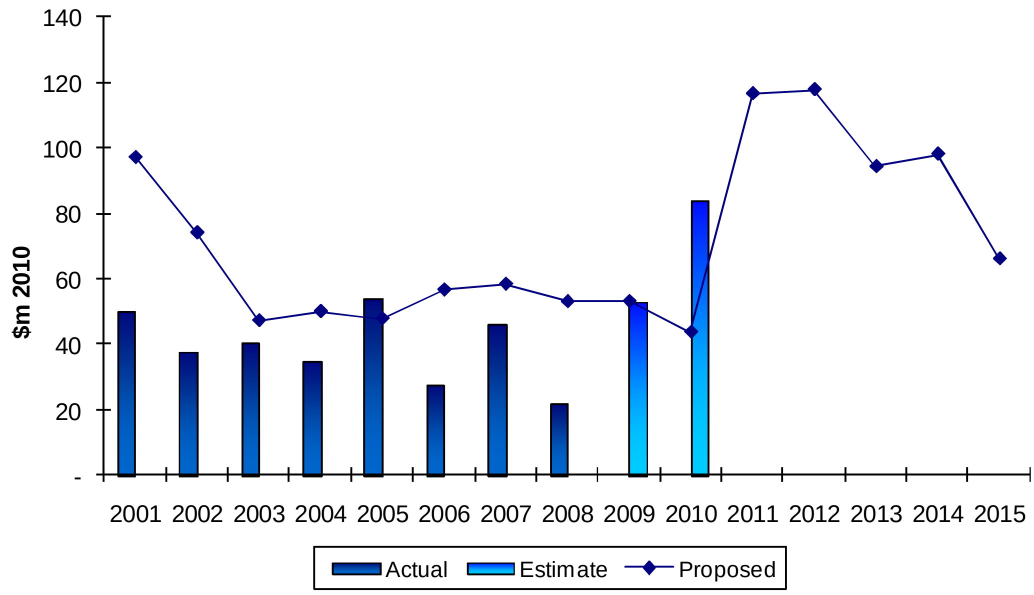
The Victorian DNSPs are proposing an increase of 206% in non-network IT capex for the next Regulatory Control Period when compared against actual expenditure in the current Regulatory Control Period. The DNSPs estimate that non-network IT capital expenditure for the 2006-10 regulatory control period will be $234 million[24]. It is forecast that this will increase to $493 million in the 2011-15 regulatory control period.

For the 2006 EDPR, the Victorian DNSPs proposed Environmental, Safety and Legal expenditure of $265 million. The resultant actual expenditure for this period is forecast to be $234 million.

[24] IT expenditure is forecast to increase significantly in the remaining years of the current control period.

The following chart provides a summary of non-network IT capex for the Victorian DNSPs.

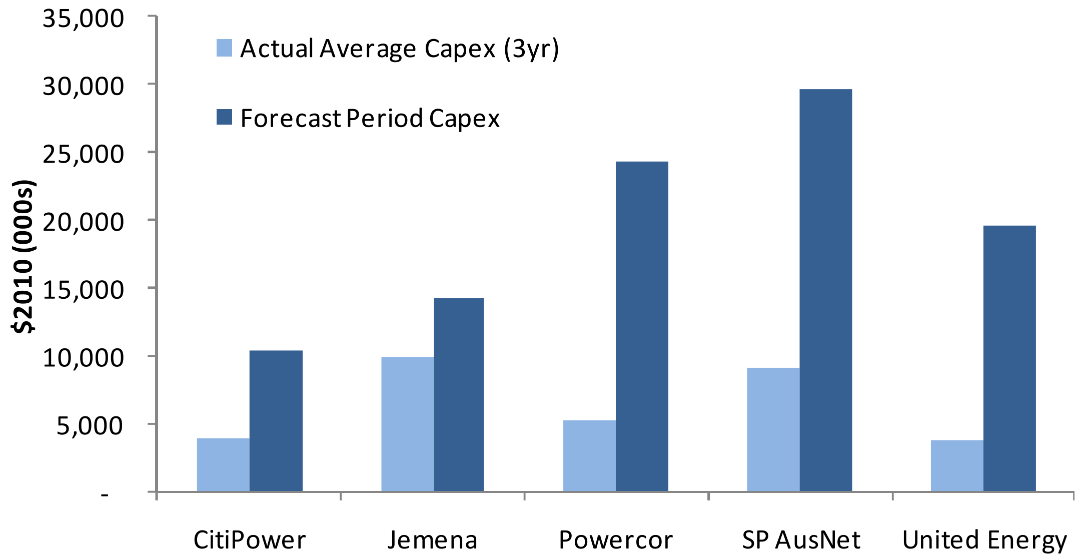
Figure 27 - Victorian non-network IT capex



From 2001 to 2008, the DNSPs have generally over forecast their non-network IT capex requirements. The exception to this is SP AusNet who have significantly overspent on their original forecast[25]. The forecast expenditures for the next regulatory control period are significantly greater than current levels of expenditure, and do not appear to be in line with the overall trend in non-network IT capex.

There was a high degree of variation in the overall non-network IT capex levels proposed by the DNSPs. The following chart shows the average annual capex proposed by the DNSPs for the next control period as well as the current period actuals (3 years).

Figure 28 - DNSP average non-network IT proposed capex ($000)



[25] Jemena was overspent in 2006 and 2007, but is underspent in aggregate.

There is significant variability in the scale of the increases proposed by the DNSPs. United Energy is seeking the greatest level of increase at 416%, while Jemena is seeking the least at 45%.

Table 19 - Proposed non-network IT capex increases

DNSP	% increase[26]
CitiPower	163%
Jemena	45%
Powercor	358%
SP AusNet	224%
United Energy	416%
Victoria	**206%**

Background

The AER asset category, “non-network assets – IT”, comprises expenditure associated with:

1. Server IT systems located inside dedicated Data Centres, consisting of hardware and software for running enterprise systems such as GIS, AM/FM, CIS, OMS, CRM, SAP, PeopleSoft, SCADA, etc.
2. Desktop IT systems consisting of hardware and software licenses that are used by DNSP staff.

Each DNSP has adopted different purchase strategies, with some utilising capital expenditure and others utilising operating expenditure (e.g. leasing). It was determined that due to these different approaches it is not feasible to benchmark the DNSPs in relation to their proposed IT spends in a meaningful way.

The scope of the review was limited to the proposed capital expenditure with a targeted analysis on particular expenditures.

Desktop systems are now essentially a commodity and the cost around them are well known and understood. Each DNSP submitted reasonable costs for ongoing upgrades of their desktop systems and we considered that these costs should be allowed.

IT systems for any business are mission critical. This is highlighted by the operational requirement for real-time information, responding to alarms and events as well as regulatory and financial reporting requirements.

The IT systems can be divided into two areas:-

1. server systems
2. desktop systems

[26] Increased based on comparison with most recent 3 years of actual Environmental, Safety and Legal capital expenditure

Server systems are dedicated computer and storage mediums located in specially designed data centres. These data centres have appropriate power and cooling capabilities to operate the hardware that greatly exceeds the power and cooling requirements of a typical desktop computer. Desktop computers[27] typically operate an application that then connect to the Server system, in architecture originally known as client-server computing. This has evolved over time so that the position of the client and server has become more complex.

There is nothing constant about Information technology; it is rapidly evolving and a highly competitive field. Once software and hardware systems are implemented they are quickly superseded by newer solutions that can potentially deliver the same capability for a lower cost. The nature of evolution of technology is that the commissioning and decommissioning of live to legacy systems is a never ending process. Ultimately IT managers and the businesses must make decisions based upon the best information available. Even client/server computing itself is changing with new architectures known as “thin computing”, “infrastructure as a service (IaaS)”, “software as a service (SaaS)”, and “cloud computing” are actively challenging these long establish practices.

There is one technology that has over the last decade fundamentally altered the IT landscape - providing capabilities that promise to greatly simplify and resolve many of these so called “lifecycle” issues. This technology has been shown to also substantially reduce operating costs such as electricity and cooling.

This technology is called “virtualisation” and it allows nearly identical “virtual” computers to be deployed in minutes, rather than the months typically required for traditional physical computers. Likewise, it allows the virtual machines to be decommissioned very simply; by just turning them off. As a result, no physical hardware needs to be removed from the data centre. There have been numerous studies and real world examples where virtualisation has delivered substantial cost saving whilst substantially increasing efficiencies, increasing agility and delivering operational savings.

Virtualisation removes the dependency on the physical world of computers, networks and cablings and instead replaces it with a virtual world, where these components can be moved around with points and clicks. It allows virtual servers (running applications) to be moved around between physical hardware easily, simply and usually while they are operating (known as “live migration”). For example with an enterprise class virtualisation environment, it would be possible to move a production system from one data centre to another data centre, with little if any outage to the business or end-user and at relatively low cost.

Agility

IT Agility is defined as the capability to rapidly and cost effectively adapt to change. In the IT sense, it refers to ability to deploy new Compute and Storage resources quickly (in a number of days) by either:

1 increasing utilisation of current Compute and/or Storage resources

2 incrementally expanding Computer and/or Storage resources to meet the requirement.

[27] Including mobile computing solutions.

Each DNSP has reported that there were many unexpected events during the last regulatory period that altered their plans and in many cases resulted in planned IT expenditures being deferred. Some of these delays were due to internal drivers, some delays due to external events.

Most projects submitted by the DNSPs for the next control period are “system upgrades”, where the underlying software is considered too old and needs to be replaced or upgraded to the latest supported level. In most cases, this involves a hardware upgrade as well as the physical replacement of the machine In these cases the DNSP has submitted a detailed business case for each upgrade and a supporting justification that is basically a wholesale replacement of the system.

When queried, many of the DNSPs submitted a detailed IT Architecture or Strategy document that identified the precise steps to be undertaken given the current known facts around these planned projects. Many of the strategy documents did not discuss or mention agility or the intention to provide their business with a flexible architecture that would be able to respond to the changing needs to the business.

Many of the DNSPs argued that any change brought about by external factors cannot be anticipated in terms of the need for more Compute and Storage resources.

It is our argument that an efficient DNSP, would recognise that there are many unknowns in operating a DNSP business in the current business, regulatory and customer environment. This would therefore require a flexible or agile IT architecture that would be able to more readily accommodate a reasonable level of change, before a major capital investment is required. For example, when deploying a new Compute or Storage platform a business may deploy infrastructure that would meet the projected capacity but would also be capable of being incrementally expanding at relatively low cost. Real world examples include only deploying partially populated Blade Chassis’ or partially populated Storage Arrays. Additional Blades and storage devices could be added quickly, simply and cheaply and would not require additional power or space in Data Centres.

Virtualisation offers a key IT infrastructure agility, the ability to better utilise hardware whilst not compromising security. Nuttall Consulting considers, that an efficient DNSP would develop an “agile” compute platform that could be incrementally expanded at relatively low cost whilst being based around a virtualisation product that would deliver:

1. High availability – allowing single processes to move between different physical machines in the advent of physical failure.
2. Enhanced Disaster Recovery – allowing production application and servers to be brought up easily and simply in case of a disaster replacing lower priority applications and servers like test and development.
3. Portability – the ability to move applications and servers from old to the new physical servers, simply and easily
4. Live Migration – move applications and servers whilst online between physical hardware and different data centres.

It is our view that such an agile architecture represents best practice and is commonly adopted by many organisations in Australia and overseas. The original concept of IT agility, known as the “Agile Manifesto” was first published in 2001 by seventeen IT industry leaders who saw the need for lighter alternatives to the traditional heavyweight methodologies of IT software development and management. The concept is now mainstream and is known as "agile computing", "agile software development" or "RAD – rapid application development". In 2005, a report by Gartner[28] concluded that "by 2009 automated approaches to supporting RDM will enable a reduction in the cost of AD (Application Development) quality by 30 percent (0.8 probability)". Another Gartner research paper[29] states that "for an enterprise to be agile, its data center must be agile, too" to meet business requirements.

The lack of agility in IT infrastructure has two impacts to any large business (including DNSPs):

1 Business projects that have IT infrastructure requirements cannot be completed due to lack of capacity or capability to expand the IT infrastructure to meet the business need. This can be mitigated by building new infrastructure, such as constructing a new data centre that will incur a much higher cost and resulting in an **overspend** of the originally proposed IT Capital expenditure.

2 IT projects such as IT infrastructure upgrades cannot be completed, due to the impact the change has upon the business or the amount of change the business can absorb (so called "change fatigue") becomes unmanageable. Therefore expenditure is deferred because it is "too hard" and resulting in an **overspend** of the originally proposed IT Capital expenditure.

Given that historical capital spend has not matched the DNSP forecasts, we believe that all the DNSPs have IT infrastructures that are too static and not sufficiently agile. Whilst the individual projects proposed by the DNSPs may be justified as being prudent and efficient, the historical inability to deliver them indicates that the projects are hampered by the lack of flexibility of the underlying IT infrastructure. Examples include; a lack of Compute, power, space, cooling, data centre and storage capacity. Resolving these issues, either becomes increasingly complex, too expensive (because it is no longer prudent) or too disruptive to continue and thus the project ends up being deferred or abandoned.

Whilst the DNSPs have provided numerous reasons for the deferment of individual projects, we believe that a fundamental and common issue is lack of "agility" in their IT infrastructure. This is evident with the large increase in the number of data centres. These data centres require large capital expenditures to design and build. Most DNSPs are intending to consolidate their data centres, which is also a large and costly undertaking, unless an agile IT infrastructure has been put in place.

If the DNSPs are permitted to continue to operate in a "non-agile" way then DNSPs will be able to claim large scale expenditure for the next round of upgrades in the following regulatory period (2015-2020) and beyond. The DNSPs should be encouraged to adopt a flexible Computer and Storage platform, on which applications (databases, CIS, etc) can be added independent of the underlying Compute and Storage platform. This approach is referred to as IaaS ("Infrastructure as a Service") delivery.

[28] Gartner RAS Core Research Note G00126310, Matt Light, 18 April 2005, R1741 03232007

[29] Achieving Agility: The Data Center Is the Foundation, ID Number: G00138154e underlying

The DNSPs have submitted significant capital expenditure increases, this is separate and additional to the expenditure allowed under the AMI process. Given that the fundamental requirements of the IT systems of the DNSPs have only incrementally changed, we would argue that only an incremental cost should be allowed for an efficient DNSP who would incrementally improve the capability of their systems and be able to migrate to new hardware platforms simply and easily.

Approach

Each DNSP provided detailed cost justification and detailed documentation for each of their proposed IT projects. Many also included detailed third-party (independent) assessments of their projects.

The information supplied by the DNSPs identified that they have currently not delivered on all the IT projects that were originally proposed for the current regulatory period. Typical reasons for the deferment or elimination of these projects was due to internal factors such as lack of resources and/or ability to absorb change ("Change Fatigue") and new external requirements such as AMI.

We utilised audited figures from 2004-2008 (adjusted for inflation) for historical spend and compared them with the DNSPs proposed spend for the same period. The historical proposed and actual IT expenditure levels for the DNSPs between 2004-2008, are shown below.

Table 20 - Non-network - IT variations

Non-network – IT	Costs (2010 $M)				
	SP Ausnet	Jemena	CitiPower	Powercor	United Energy
Proposed Expenditure 2004-2008	21.1	55.0	60.3	75.7	53.6
Actual Expenditure 2004 - 2008[30]	65.1	41.0	30.5	32.0	34.8
Variation	44.0	-14.0	-29.8	-43.7	-18.8
% Variation	309%	75%	51%	42%	65%

This difference between what the DNSPs proposed and what was actually spent demonstrates the forecasting methodology adopted by the DNSPs is not accurate. Given that the DNSPs have not addressed this inaccuracy in their proposals for the next regulatory period, it is reasonable to assume that a similar degree of variability may result.

One of the biggest forecasting variations relates to SP AusNet who have overspent on their proposed IT capex by over 300%. However, SP AusNet had proposed a level of IT capex for the current period that was more than 80% lower than the other DNSPs. All other DNSPs are underspent against their previous forecasts.

Based on our review, we have formed a view about the amount of change that each business would be able to tolerate and the agility of the underlying IT architecture to support change introduced by these projects. For IT architectures that were less agile, we believe that they will be less capable of delivery than more agile architectures.

1 In order to assess the efficiency of the underlying IT architecture we have conceptually split our discussion into three areas for each DNSP:

a. Compute Platform - the actually hardware and operating system on which the application or database operates

b. Storage Platform – the media that offers transitional or permanent storage of data

c. Network (or Connectivity) – the infrastructure that connects the Compute and Storage platforms together.

Many of the DNSPs intended to make significant changes to their Compute and Storage platforms in the next control period. In general, little change was proposed for Network or connectivity infrastructure[31]. Nuttall Consulting has concentrated our discussion and analysis on the Compute Platform since this is the key agility area that allows IT to deliver projects for its business.

[30] Includes previous 5 years of audited expenditure (2004-2008).

[31] In the non-network IT category, although some network connectivity costs are captured in other capex categories (i.e. SCADA and Network Control).

2 The projects proposed by each DNSP were examined, including supporting documents, project approval processes and IT strategy documentation. We discuss our findings for each business in the following sections.

Advanced Metering Infrastructure

The DNSPs are required to implement Advanced Metering Infrastructure (AMI) that will provide smart meters to all Victorian households and small businesses over the next four years. The costs for the AMI project have been assessed through a different process and these costs are required to be ring-fenced from the EDPR process.

For the DNSPs, the implementation of the AMI project creates more challenges, with certain functionality required to be delivered, the additional data collected to be stored and managed. To what level each DNSP leverages the AMI data to improve their business processes and deliver operational efficiencies is unknown at this time.

All DNSPs submitted that any delays in the AMI project will not impact their proposed capital expenditure as submitted under this process and in many cases stated that AMI was completely separate from this current operations both in terms of business sense (separate business unit) and physically (operated in a different data centre).

From an IT infrastructure perspective, AMI requires storage capacity, effecting the Storage Platform and additional Compute requirements to process the additional data. As a result, under a separate AMI expenditure allocation the DNSPs have generally taken the opportunity to replace or augment their Storage platform and utilise new data centre space for additional Compute resources. The additional data provided by AMI, may allow opportunities for the DNSPs to augment and improve their service offerings, future integration and leverage off the additional information.

An investigation into the areas of potential overlap or double-counting between the existing AMI expenditure allowance and the DNSPs' proposals has been undertaken as part of the Nuttall Consulting review of capex. These investigations compared the IT expenditures already allowed for under the AMI process against the IT expenditures within the DNSPs' proposals.

Based upon these investigations, we have found no evidence of overlap or double–counting between the EDPR proposals and the AMI project.

Included in these investigations was the assessment of projects identified by a number of DNSPs that leveraged off AMI (i.e. the use of data made available through the AMI roll-out to provide additional benefits to the DNSPs and to customers).

Whist we agree that there should be benefits through these "AMI leveraging projects", and these benefits may well outweigh the additional costs, we do not consider that the DNSPs have:

- adequately quantified all of the costs and benefits that may accrue through the use of the AMI data, and defined these in terms of those provided for through existing incentive mechanisms (e.g. STPIS, EBSS) and those external to these schemes
- adequately demonstrated that their proposed expenditure represents only the incremental level above that available through the existing incentive mechanisms.

Therefore, in the absence of the above items, we do not consider that the DNSPs should be allowed the proposed expenditure.

Further details of our investigations on the interaction of the DNSPs' proposals with AMI are provided in Appendix K.

Summary capex recommendations

The following table provides the recommended Non-network general IT capex for the Victorian DNSPs.

Table 21 - Recommended non-network general IT capex

	$millions (2010)				
	2011	2012	2013	2014	2015
CitiPower - proposed	9.6	8.7	9.5	13.7	10.8
CitiPower - recommended	**5.6**	**5.6**	**5.6**	**5.6**	**5.6**
Powercor - proposed	25.3	21.5	21.3	30.0	23.6
Powercor - recommended	**13.7**	**13.7**	**13.7**	**13.7**	**13.7**
Jemena - proposed	20.2	21.1	17.2	6.6	6.8
Jemena - recommended	**11.7**	**11.7**	**11.7**	**11.7**	**11.7**
SP AusNet - proposed	32.3	38.1	28.2	31.9	17.9
SP AusNet - recommended	**15.0**	**15.0**	**15.0**	**15.0**	**15.0**
United Energy - proposed	29.2	28.3	18.1	15.9	7.1
United Energy - recommended	**19.7**	**19.7**	**19.7**	**19.7**	**19.7**

5 Summary capex findings and recommendations

Recent actual capital expenditure of the Victorian DNSPs compares favourably with other NEM states, and the individual DNSPs. This suggests that the Victorian DNSPs currently have the lowest cost bases in the NEM.

For the next regulatory period (2011-2015), the Victorian DNSPs are forecasting a significant increase in capital expenditure. The average net increase ranges from 72% for Powercor to 156% for SP AusNet over the average actual expenditure between 2006 and 2008.

Capital expenditure has been trending up over the current and previous periods; however, the DNSPs' forecast increase is well above this trend. Importantly, all DNSPs are also forecasting that a significant component of the increase will occur as a step change in expenditure levels at the commencement of the next period (2011).

For the last two EDPRs in Victoria (2001 EDPR and 2006 EDPR), all DNSPs forecast higher levels of capital expenditure than they have incurred. For the 2006 EDPR, the over-forecast is estimated to range from 13% for SP AusNet to 30% for United Energy. Interestingly, for most DNSPs, the accuracy of their forecast in the first half of the current period is as poor – if not poorer – than for the 2nd half of the period.

Given the good recent comparative performance of the Victorian DNSPs with other NEM DNSPs, but the very significant proposed increases, it was agreed with the AER that the Nuttall Consulting review would be based upon the following two principles:

1 recent actual capital expenditure can be considered to reasonably represent the efficient cost base

2 the onus is on the DNSP to appropriately demonstrate that their proposed increase can be reasonably considered prudent and efficient.

Nuttall Consulting has undertaken a high-level review of the DNSPs' expenditure and the basis for the increases, presented in the DNSPs' proposals. This analysis has also included replacement expenditure modelling using data supplied by the DNSPs; the findings of which were that expenditure on age/condition driven replacement should be relatively consistent with the historical trend.

Based upon the findings of our high-level review, we have also conducted a detailed review of "targeted" matters, including specific project and programs, which form the DNSPs' processes and plans that underlie their proposed capital expenditure. A particular focus of this review has been those matters that are driving the proposed increases in expenditure. The matters for the targeted review were discussed and agreed with the AER.

Based upon the materiality of the proposed increases, the detailed review has focused on[32]:

- Reinforcement expenditure for each DNSP - in terms of the methodology adopted to prepare the forecasts and a selection of targeted projects and programs
- Reliability and Quality Maintained (RQM) expenditure for each DNSP - in terms of the methodology adopted to prepare the forecasts and a selection of targeted projects and programs
- Environmental, Safety and Legal (ESL) expenditure for the majority of DNSPs – in terms of the most significant programs resulting in proposed increases in expenditure
- various other expenditure categories depending on the DNSP - in terms of the most significant programs resulting in proposed increases in expenditure.

To conduct this review, Nuttall Consulting has reviewed relevant documents provided by the DNSPs to support their proposals, held meetings with the DNSPs, and made a number of additional information requests.

Based upon the findings of our review (high-level and detailed), we do not consider that any of the DNSPs have adequately demonstrated that their proposed expenditure increases can be considered prudent and efficient. This view is based upon concerns we have with:

- the DNSPs justification for the variations from past forecasts
- the lack of substantiation of the overall changes to risk levels through the proposed plans
- the lack of evidence that many of models used to develop the forecasts can be considered “fit for purpose”, in terms of producing forecast appropriate for regulatory purposes
- numerous areas where we considered overestimation could be occurring
- lack of recognition of synergies or benefits between individual projects and programs.

In general, we consider that the plans proposed by the DNSPs are reasonable at an internal level to define likely future network needs, work levels, and associated expenditure. However, we consider that as the plans advance through the DNSPs’ capital governance processes significant reductions will occur, resulting in a) the deferral of some projects, b) the selection of more efficient solutions, or c) the decision not to undertake certain projects at all.

Given the following:

- the good historical comparative performance of the DNSPs to other states
- the relatively consistent historical expenditure trend

[32] It has been agreed with the AER that Nuttall Consulting would not review expenditure on customer connections as this would be reviewed by the AER.

- the past overestimation of the DNSPs forecasts
- the findings of repex modelling, which support expenditure being in line with the historical trend
- the findings of targeted detailed reviews, which also support expenditure being in line with the historical trend,

we consider that a reasonable estimate of prudent and efficient capex should be relatively consistent with the recent historical level with some modest allowance for increasing needs due to the aging of the network and further demand growth.

We have developed an capital expenditure forecast that we consider reasonably represents a prudent and efficient level that allows the DNSPs to meet their obligations, based upon:

- adjustments to the DNSPs' RQM forecasts to ensure they are consistent with the historical expenditure levels with increases as suggest by our replacement modelling
- adjustments to the DNSPs' reinforcement forecasts to ensure they are consistent with the historical expenditure levels with increases based upon our probabilistic analysis of the project reviewed (i.e. the likelihood that projects and expenditure will occur as proposed by the DNSPs)
- adjustments to the ESL expenditure, based upon the lack of substantiation by the DNSPs that the increases were justified, which brings it more in line with historical levels
- adjustments to other expenditure categories, based upon the lack of substantiation by the DNSPs that the increases were justified, which brings it more in line with historical levels.

Our recommended capex adjustments (excluding new customer connections) are summarised in the tables below[33]. These adjustments represent:

- 40% reduction on the DNSP proposals, ranging from 49% for Jemena to 34% for United Energy
- 35% average increase on the actual expenditure over 2006 to 2008, ranging from 87% increase for CitiPower to a 15% increase for Jemena
- 13% average increase on the current period, ranging from a 47% increase for CitiPower to a 4% reduction for SP AusNet.

[33] These figures are approximate only due to the targeting exercise, which means that Nuttall Consulting has not reviewed certain expenditure categories of some DNSPs. In these cases, we have substituted the DNSP's proposed expenditure in place of our recommendation.

Table 22 – Summary of reinforcement capex recommendations

	$millions (2010)				
	2011	2012	2013	2014	2015
CitiPower - proposed	132.7	149.1	160.9	159.0	153.5
CitiPower - recommended	**91.8**	**89.8**	**97.4**	**73.9**	**79.7**
Powercor - proposed	204.6	202.8	215.1	230.3	226.9
Powercor - recommended	**123.7**	**129.3**	**133.4**	**138.9**	**144.5**
Jemena - proposed	111.4	114.4	105.2	91.4	91.8
Jemena - recommended	**49.0**	**53.7**	**53.8**	**52.6**	**54.3**
SP AusNet - proposed	197.1	232.1	210.3	212.3	184.5
SP AusNet - recommended	**110.4**	**114.1**	**120.7**	**131.3**	**135.7**
United Energy - proposed	157.3	147.3	142.1	126.2	105.9
United Energy - recommended	**88.4**	**89.9**	**88.8**	**90.3**	**93.8**
Total - proposed	803.2	845.7	833.6	819.2	762.7
Total - recommended	**463.4**	**476.8**	**494.1**	**487.1**	**508.0**

Table 23 – Estimated recommended capex adjustments

DNSP	% reduction	% increase 2006-2008 actuals	% increase 2006-2010 estimate
CitiPower	43%	87%[34]	47%
Powercor	38%	20%	17%
Jemena	49%	15%	1%
SP AusNet	41%	32%	-4%
United Energy	34%	46%	16%
Victoria	**40%**	**35%**	**13%**

It is important to note that the recommended capex allowance has been developed at a capex category level, but the overall view has been formed from both “top-down” and “bottom-up” assessments. As such, the recommendation should be viewed in its entirety. As history has shown, external events and further DNSP analysis and planning may result in significant variations at the project and capex category levels. The DNSPs will continue to manage capex expenditure as they best see fit and are in no way constrained to adhere to individual capex category allowances.

Therefore, if the DNSPs challenge this recommendation, it will be important that they demonstrate why they cannot manage the overall risks with the overall recommendation. Focusing only on the matters raised in the detailed reviews may not adequately address this matter.

[34] The greater increase accepted for CitiPower is due to two very costly projects that obtained approval in the current regulatory period, but a large portion of the costs will be incurred in the next.

Finally, on this point, it is worth noting that our recommendation could be considered conservative, as it has been produced as an aggregate of individual category estimates without further adjustments. It may be reasonable to expect that greater levels of capital and operational synergies may be realised as the overall expenditure needs increase.

Important caveat associated with our recommendation

This recommendation excludes allowances for new bushfire driven programs. For example, the pre-emptive replacement of conductors. These matters and others are currently under the consideration of the Bushfire Royal Commission. The AER will need to re-consider these matters following the findings of the Royal Commission.

There are also a number of matters that are not part of the Nuttall Consulting review that will have a material impact upon the overall level of capex that is allowed by the AER. These matters include the assessment of labour and materials escalation.

6 Appendix A - CitiPower review

The CitiPower and Powercor franchises are both owned by the same investment group and share management and executive services. The CitiPower and Powercor proposals share a great deal in common including structure and significant areas of content. There are also areas of differentiation between the proposals; specifically in relation to individual projects and programs.

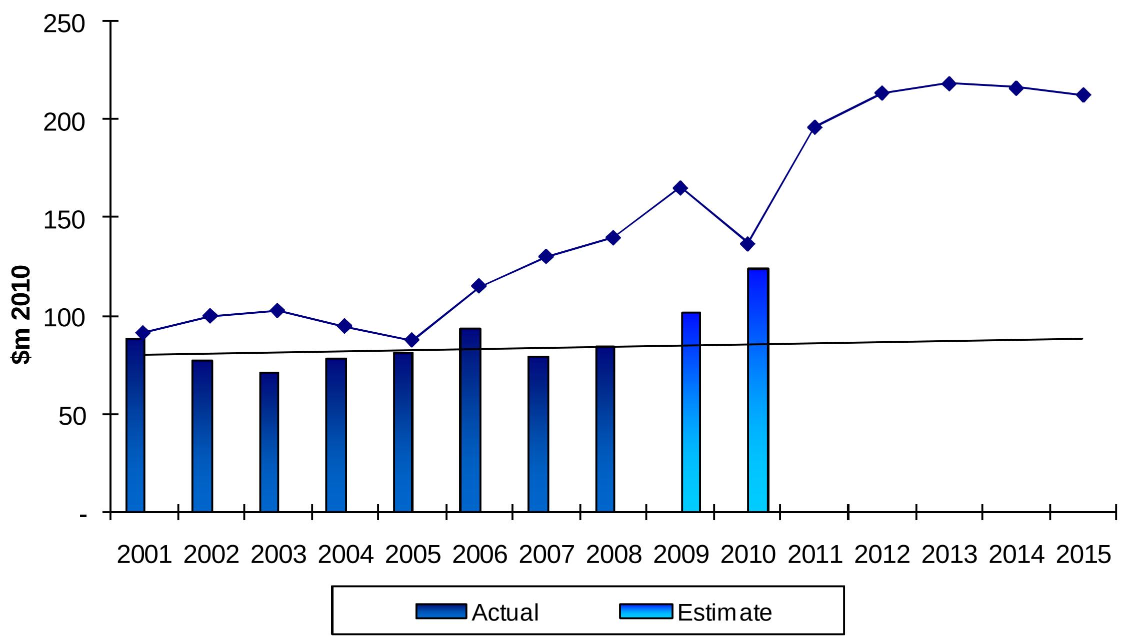
6.1 Overall capex

Overall capex is forecast to increase by 146% over actual expenditures in the current period. The main areas where capex is forecast to increase are reinforcement, reliability and quality maintained and new connections.

The following chart provides a summary of the overall capex figures for CitiPower. Key aspects of this chart include:

- CitiPower has consistently spent less than they proposed in the 2001 and 2006 EDPRs
- CitiPower is proposing a future level of capex that is much is significantly higher than the historical levels of expenditure and is not consistent with the historical trend in capex.

Figure 29 - CitiPower Capex Summary



CitiPower argues that comparisons at the capex category level with the ESC allowances set for the current period are not relevant. They state that the manner in which the category allowances were established makes them invalid for comparison.

The CitiPower proposal provides a high-level discussion of the overall capex allowance compared with overall actual expenditure for the period. The expenditure for the first two years of the regulatory period is significantly below the regulatory allowance with 2008 expenditure being slightly higher than the allowance. CitiPower identify the deferral of two major projects as the reasons for the historical underspend.

The proposal provides very little description of how the forecasts were actually developed, although a significant amount of information about current business processes is provided.

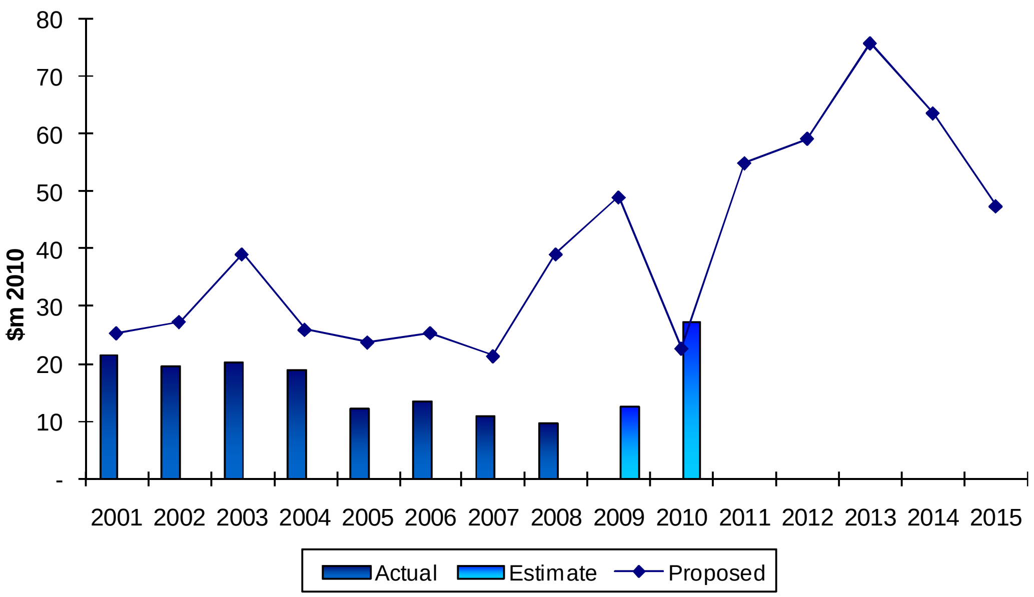
The CitiPower proposal provides a deliverability plan as to how they intend to resource to meet the forecast capex. The attachments to the proposal also provide a reasonable level of detail on the asset management processes, project approval processes and governance frameworks.

6.2 Reinforcement

CitiPower is proposing a reinforcement program that is 420% greater than actual expenditures in the current Regulatory Control Period. CitiPower estimates that its reinforcement capital expenditure for the 2006-10 regulatory control period will be $75 million ($2010). It is forecasting that this will increase to $300 million ($2010) in the 2011-15 regulatory control period.

The following chart provides a summary of reinforcement capex for CitiPower.

Figure 30 - CitiPower Reinforcement Capex Summary



This chart indicates that CitiPower’s reinforcement expenditure has been trending down over the previous and current regulatory periods, but is estimated to increase significantly from 2010. The 2001 and 2006 EDPR forecasts prepared by CitiPower were significantly over the actual expenditure incurred. This is most notable for the 2006 EDPR, where actual expenditure (2006-2008) has been only 40% of the forecast.

The variation between the CitiPower forecast and the estimated expenditure in the current period and the proposed increase in the next period can be explained, at least in part, by two very significant projects (in capex terms).

- The **Metro 2012 project** ($19 million in the current period and $48 million in the next) is associated with the need to increase the capacity of the CBD network. The overall project involves the development of a terminal station (i.e. transmission connection point) in the next period. Only expenditure associated with the distribution elements of this project are covered in Citipower's capex proposal. The distribution elements of this project were included in Citipower's regulatory test for the terminal station, which it undertook in the current period to justify the overall development. Citipower now considers that anticipated costs for the distribution elements have increased by around 20% from that applied in the regulatory test.
- The **CBD security project** ($7 million in the current period and $69 million in the next) is required to improve the security of supply in the CBD – essentially, increasing this from *N-1* to *N-1 secure*. This project was evaluated by the ESC during the current period, although most of the expenditure is needed in the next. ESC considered that this project passed the AER's regulatory test and revised the Victorian Distribution Code to place obligations on CitiPower to undertake the project. Citipower now considers that anticipated costs for the project have increased by around 10% from that considered by the ESC to be efficient. It is important to note that this project requires the Metro 2012 project to be in place to realise the increased security.

The main elements of both of these projects were included in Citipower's forecast associated with the 2006 EDPR, and explain the peak in forecast expenditure in 2008 and 2009. However, due to delays in the terminal stations development and through the ESC's review of the CBD security project, these projects have been deferred to the next period.

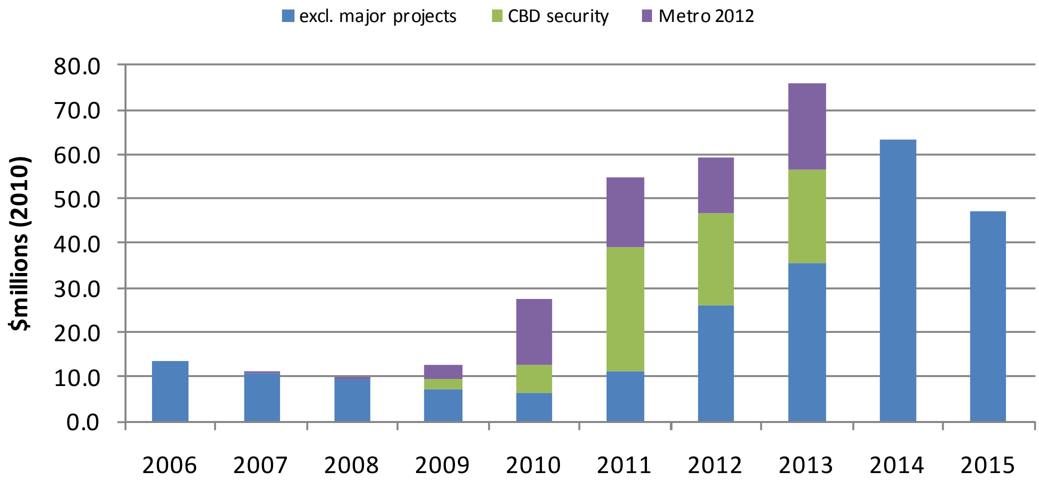
Citipower also now considers that the cost for these projects has increased significantly in real terms, by about 20% and 10% for the Metro 2012 project and CBD security project respectively.

The chart below shows the significance of the two major projects on CitiPower's reinforcement capex in the current and next periods. This indicates how these two projects result in a proposed step increase in expenditure over 2010 to 2013, but that the underlying trend in reinforcement expenditure is still forecast to increase very significantly.

Citipower's proposal indicates that this is required to maintain zone substation security levels, in the face of the anticipated demand growth[35].

[35] Pg 87, CitiPower proposal.

Figure 31 – CitiPower's major project reinforcement capex



6.2.1 Forecasting methodology

CitiPower has developed its reinforcement plans based upon a bottom-up build of individual network needs and projects to address these needs. CitiPower considers that these plans have been developed largely using the actual planning processes it applied in practice. However, due to their proposed timing, many projects will not have been through the full evaluations and justifications that would be required for approval.

The majority of these plans are developed via the risk evaluation approach CitiPower applies at the sub-transmission level.

This approach determines annual load at risk of not being supplied (i.e. under normal and outage conditions) and the annual duration of this risk. Future predictions of these measures are calculated using a number of key input assumptions, most notably:

- the 50% probability of exceedance maximum demand forecast
- a load profile based upon the average of the actual 2001 to 2005 profiles.

Citipower then uses internal criteria to define the trigger point when a network augmentation should be considered. These criteria are summarised as follows:

- For multiple transformer switched zone substations, load must not be above 110% of the N-1 cyclic rating of the substation for longer than 120 hours per year (assuming a suitable load shedding scheme is in place or can be installed).
- For the CBD zone substations, loading must remain within the N-1 cyclic rating of the substation (i.e. load at risk is not allowed).
- For looped sub-transmission lines, N-1 contingency loading must not exceed 110% of the rating of the sub-transmission line for more than 120 hours per year. This constraint is raised to 120% of the rating of the sub-transmission line for more than 240 hours per year if a dynamic line monitoring system is used.
- For the supply to inner Melbourne CBD zone substations, including BQ, FR, JA, LQ, MP, VM and WA, the meshed sub-transmission line network supplying these substations should be able to continue to supply these substations in the event of

an N-1 contingency and be reconfigured within 30 minutes to be able to supply customers in the event of an N-2 contingency.

- For the remaining meshed CBD sub-transmission lines, N-1 contingency loading must not exceed 110% of the rating of the sub-transmission line for more than 120 hours per year.

6.2.2 Nuttall Consulting detailed review

6.2.2.1 Process

Nuttall Consulting's detailed review of CitiPower's reinforcement expenditure has included a review of its forecasting methodology and a number of specific projects. The general process applied by Nuttall Consulting in conducting its review of CitiPower's reinforcement expenditure is summarised in Section 4.2 of this report.

The projects reviewed included:

- The CBD security project
- The Metro 2012 project
- Various 11 kV feeder works
- Three zone substation transformer upgrade projects

Key CitiPower documents, in addition to CitiPower's proposal, included in this review included:

- C0028 – Electricity network augmentation planning and guidelines
- C0029 - CitiPower Asset Management Framework 2009
- C0043 – PB CitiPower Energy at Risk and Growth related capex
- C0075 - 2008 Distribution System Planning Report
- 2009 Distribution System Planning report

Other documentation specific to the projects under review is identified in the sections below.

6.2.2.2 Findings on methodology

Overall, we consider that CitiPower's methodology is reasonable for developing capital plans for internal purposes. In this regard, the process should result in the identification of network needs, a list of projects to address these needs, and expenditure projections for the medium-term management of the network. In turn, this process results in a relatively comprehensive list of individual network needs and projects that can be monitored and developed further through the next period.

However, we do not consider that this largely "bottom-up" based process has been shown to be "fit for purpose" in terms of being a reasonable unbiased estimator for future prudent and efficient expenditure at the aggregate level. In particular, we do not consider that such a process adequately allows for the further optimisation of projects and synergies between projects that will occur as the individual projects and the overall capital plans advance through the capital governance process.

It is accepted that in some circumstances these processes will result in some projects being advanced or their scopes increased. However, in our view, the more detailed evaluation and justification associated with the project approval within the governance process will most likely result in overall expenditure being less than the simple summation of the project plans, as applied by CitiPower to determine its reinforcement expenditure.

Related to the points above, we also have a number of concerns with specific key input assumptions, which we consider may be overly conservative at this point in the planning process (i.e. they may, on average, overstate risks). This concerns the load profile and the internal planning criteria assumed by CitiPower in its probabilistic planning process.

With regard to the load profile, we consider that CitiPower's approach of basing this upon the average load profile over of the 5-year period from 2001 to 2005 may materially overstate the risks.

This view is based upon the fact that maximum demand has been growing at a significantly greater rate than energy since before 2000, and this is expected to continue throughout the next period. This results in the load profile becoming more "peaky" over time near the peak demand condition. This in turn means that predictions of energy at risk, or the durations of demand at risk, based upon assumed load profiles that have been developed from significantly earlier years may overstate these measures.

Our analysis of actual Victorian load profiles from 1999/2000 to 2007/08 suggests that this overestimate may be material (see Appendix J), possibly overstating the energy at risk in the next period by over 100%. This could result in projects being advanced by up to 3 years, depending on the rate of load growth.

It is accepted that the use of a 50% probability of exceedance maximum demand may understate expected risks. As such, there could be some argument that these two matters trade off somewhat. However, given the sensitivity to risks of the assumed maximum demand condition is well known in the industry, we consider it reasonable to assume that the optimism in this assumption is inherently allowed for in CitiPower's evaluations. Therefore, we do not consider that this matter should affect our findings on the conservatism in the load profile assumed.

With regard to the criteria CitiPower adopts as the trigger time for augmentations, we see no reason to consider that these are not appropriate for internal planning purposes (i.e. to initiate more detailed analysis and evaluation). However, for the purpose of generating the plans for the regulatory proposal, particularly in the context of its bottom-up build methodology, we consider that plans should still be demonstrably economic in their timing. In this regard, it should be clear that the benefits through the reductions in the energy not served to customers, out-weighs the costs of the project. We consider that this is in accordance with the principles of the NER, and the ESC's and Citipower's past regulatory test processes for major projects. We also consider that this is relevant to CitiPower's HV feeder augmentations.

To assess the significance of this issue, we have assessed matters within the project reviews to determine whether the timing of the projects is economically optimal. It is worth noting here that the general findings on this matter were that the criteria tended to bring forward projects from their optimal timing.

It is worth noting that Nuttall Consulting has not considered CitiPower's distribution substation and LV methodology in any detail, due to the lower materiality of these elements on CitiPower's overall reinforcement plans.

6.2.2.3 Project reviews

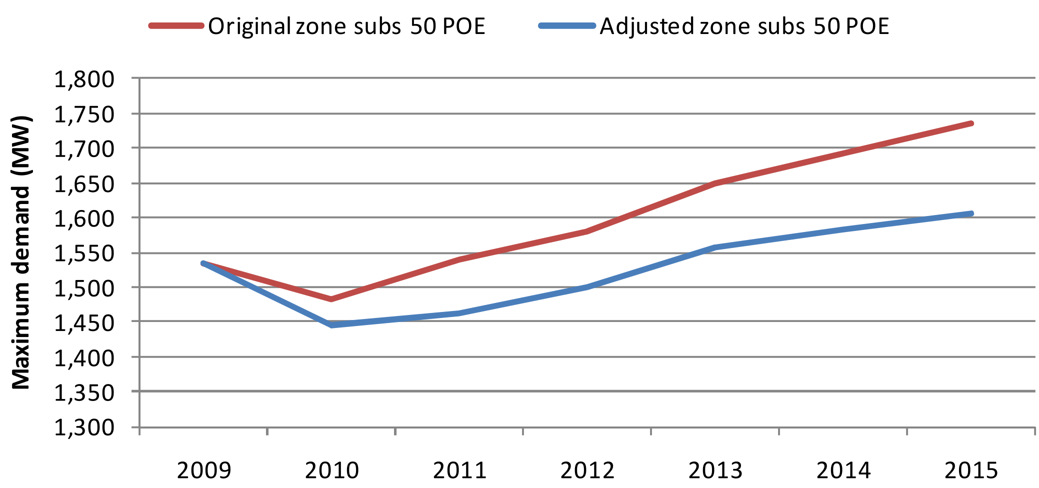
As noted in Section 4.2.4, the aim of the Nuttall Consulting review has been to determine the likelihood that the project expenditure will be required as proposed by CitiPower. We consider that this is a reasonable approach to account for the likely consequences of the governance processes and the other specific methodological concerns discussed above.

An additional input to our review has been the findings of the AER's review of CitiPower's load forecasts. Of particular relevance to our review are the maximum demand forecasts. The AER's findings here were that CitiPower has overstated the growth in maximum demand.

A comparison of the CitiPower maximum demand forecast and the AER's view is shown in the chart below. This chart indicates that the AER's adjustments result in maximum demand levels being delayed by 2 to 3 years.

It is important to note that we have not been able to analyse the effect of these adjustments in detail. However, we have attempted to allow for these to some degree in our assessment of the likelihood of the projects. We would recommend however that the AER requires CitiPower to more comprehensively reassess its plans in light of these load forecast findings to more accurately determine their effect.

Figure 32 – CitiPower maximum demand forecast



The following summarises the main findings for the projects reviewed.

6.2.2.4 11 kV feeder works (CBD security and Metro 2012 link projects)

Cost: 30 million ($2009)

Completion: 2015

The works associated with this project are related to the CBD security and Metro 2012 projects. The works cover a range of feeder projects to allow pre and post contingent transfers of load between various CBD zone substations.

Based upon our assessment, we consider that approximately half of the works (by value) are associated with realising the increased security of the CBD Security of Supply project.

For these works, it is noted that the ESC decision on the CBD security project supports that 11 kV feeder works were required to realise the full improvements in the security levels. However, the subsequent revision to the Distribution Code is unclear as to what flexibility CitiPower has in altering these plans.

It is clear that the cost for these works was not included in the regulatory test submitted to the ESC. It also appears that the inclusion of these costs may result in a material deferment of the overall project, in terms of the time when the project maximises the net benefits. It is also worth noting that in our opinion the regulatory test documents and the ESC decision does not clearly demonstrate whether a staged development of the overall CBD security project would result in significantly greater net benefits. Such an analysis may well indicate that the security related 11 kV feeder works should also be staged to realise these benefits.

As such, we do not consider that there is a clear demonstration that the security related 11 kV feeder elements are all required.

With regard to the other portion of these 11 kV feeder works, based upon our assessment these works appear to be required primarily for capacity reasons. To gauge the economic benefit of these works, we have evaluated the reduction in the expected energy not supplied through these projects[36]. Based upon our analysis, we do not consider that the benefits would be sufficient to justify the works until after the next regulatory period.

With regard to alternative options, given the extent of the transfers required, it is also considered that other lower cost options may be found to be preferred following more rigorous economic analysis. For example, we consider it reasonable to assume that an option involving the advancement of the development of the existing W switching station into a 66/11 kV zone substation could be found to be the preferred option following a more detailed evaluation.

Based upon the above, we consider that expenditure associated with these works has a low probability (33%) of being required as proposed by CitiPower.

6.2.2.5 3rd Transformer at BQ zone substation

Cost: 5.12 million ($2009)

Completion: 2015

The works associated with this project are related to the Metro 2012 projects. The works include the development of a 3rd transformer and capacitor banks at the BQ substation. It is our understanding that these works are included in the overall Metro 2012 project costs.

[36] Based upon the energy at risk spreadsheets provided by CitiPower.

It is important to note that they do not appear to have been included in CitiPower's original regulatory test associated with this development. The scope change issue will be discussed further below in the assessment of the Metro 2012 project.

The primary need for this project appears to be driven by the load transfers to BQ that will result from the 11 kV feeder transfers above. Given that we consider only a low probability that the 11 kV feeder works will be required in the next period, we consider there is an equally low probability that the 3rd transformer at BQ will be required.

Even if we allow for the transfer necessary to only allow the increased security to be achieved plus the other transfers to BQ through the Metro 2012 project, we do not consider that there is a clear case that the energy at risk is sufficient to economically justify these works in the next period.

As also noted above on the 11 kV feeder works, we consider that there are alternatives (such as the advancement of the W switching station conversion) that may be found to be lower in cost following more detailed analysis of the options.

Based upon the above, we consider that expenditure associated with these works has a low probability (33%) of being required as proposed by CitiPower.

It is also worth noting that the need for the additional cable to BQ, which is also within the Metro 2012 project, has not been formally reviewed. However, given the findings presented here, it may well be that this cable will not be justified at the time proposed by CitiPower.

6.2.2.6 3rd transformer at SB zone substation

Cost: 3.6 million ($2009)

Completion: 2015

The works associated with this project are related to the CBD security and Metro 2012 projects. The works include the development of a 3rd transformer at the existing SB zone substation.

As with the 3rd transformer at BQ discussed above, the primary need for this project appears to be driven by the load transfers to SB that will result from the 11 kV feeder transfers above. Given that we consider only a low probability that these works will be required in the next period, we consider there is an equally low probability that these works will be required.

It is worth noting however that even if we allow for the proposed transfer, we do not consider that there is a clear case that the energy at risk is sufficient to economically justify these works in the next period.

As also noted above on the 11 kV feeder works, we also consider that there are alternatives (such as the advancement of the W switching station conversion) that may be found to be lower in cost following more detailed analysis of the options.

Based upon the above, we consider that expenditure associated with these works has a low probability (33%) of being required as proposed by CitiPower.

6.2.2.7 Docklands area zone substation upgrade

Cost: 22.1 million ($2009)

Completion: 2014

This project involves the upgrade of the existing 22/11 kV DA zone substation to a high capacity 66/11 kV CBD style zone substation. This project also includes the upgrade of the existing 22 kV line that supplies the DA substation to 66 kV. The key driver for this project is the projected loading at the existing substation.

Based upon our analysis of CitiPower's energy at risk calculations for the existing substation, they only marginally support the timing of this project near the end of the period. Given the point made above on the load profile assumed by CitiPower, we would expect that this timing may well be optimally deferred.

Furthermore, with regard to the reasonable option, we do not consider that CitiPower has adequately demonstrated that it has considered all reasonable options. In our opinion, there are other lower cost options that may be justified through more detailed analysis. In particular, we considered that an additional option involving the establishment of a second 66/11kV zone substation in the Docklands area, supplied from Fishermans Bend Terminal Station (FBTS) could be a reasonable option that may maximise the net benefits.

Finally, we do not consider that CitiPower has adequately demonstrated that its cost for the proposed project can be considered a reasonable estimate of the efficient costs for the project. Based upon our assessment, we consider that the CitiPower estimate is considerably higher than our estimate for the project[37].

Based upon the above, we consider that expenditure associated with these works has a moderate probability (50%) of being required as proposed by CitiPower.

6.2.2.8 CBD Security of supply and Metro 2012 projects

Our review of the CBD security project and Metro 2012 project has been treated differently to the other projects discussed above. As noted in the introduction, both of these projects have been through an external approval process: the CBD security through the ESC detailed review process and the major portion of the Metro 2012 project through the public regulatory test.

As such, we have not considered the need for these two projects in our review. Instead, we have only reviewed the justification for the cost increases from the previous amounts that have been proposed by CitiPower. In real terms, these increases are approximately 10% for the CBD security project and 20% for the Metro 2012 project.

For both projects, we have requested detailed costing spreadsheets and supporting reports[38]. However, for both projects we have received no additional information from that provided in response to the AER's RIN.

[37] Based upon a high-level scope for this project, we determined the direct costs to be around 10-13 million (with an outdoor 66 kV switchyard) compared to an equivalent estimate of 16 million by CitiPower.

[38] Request made in email to CitiPower, dated 18/1/10.

CitiPower's proposal indicates that the original costs were based upon a high-level function scope and internal cost estimates. The increases have resulted from further scoping and quotes for similar projects.

In the case of the CBD security project, it is important to note that the ESC undertook a detailed assessment of its view of a reasonable estimate of efficient costs. This assessment largely agreed with CitiPower's original estimate, with some minor reductions.

Given this fact and the lack of detailed substantiation of the increase, we consider that CitiPower should only be allowed the ESC original estimate for the efficient cost, with adjustments for labour and material escalations.

It is also worth noting that, as discussed above on the 11 kV feeder projects, we consider there is some uncertainty as to how bound CitiPower is to undertake the project as planned, and to what extent it can change its plans if cost increases change the findings of the regulatory test. Given the proposed increases, we do not consider it has been clearly demonstrated that the timing of the project, allowing for the cost increase, would maximise the net benefits. Nonetheless, we recognise that the AER may be required to treat the need for the project as a compliance issue, and therefore, are not recommending further reductions.

With regard to the Metro 2012 project, it does appear from the original regulatory test analysis that the increased cost would still justify the project at the proposed time. However, we consider that CitiPower has not adequately demonstrated that the cost increases can be considered a reasonable estimate of the efficient costs. Moreover, given the findings on the 3rd transformer at BQ discussed above, which appear to be a scope increase from the original project that underwent the regulatory test, we do not consider that that these scope increases are justified.

Based upon the above, we consider that CitiPower should only be allowed the base-case estimate used in the regulatory test as the reasonable estimate for the efficient cost, with adjustments for labour and material escalations.

In both cases, if the cost increases are to be accepted, we consider that CitiPower would need to provide detailed cost build-ups of the project, clearly indicating where the costs have increased and the basis for the increases. The onus should also be placed in CitiPower to adequately demonstrate why it considers that these costs can be considered a reasonable estimate of efficient costs. This should include evidence of its own analysis that it has undertaken to arrive at that position.

6.2.3 Overall findings

Based upon our review, we do not consider that CitiPower has adequately demonstrated that its proposed increases in reinforcement expenditure are reasonable. Moreover, we consider that significant reductions to the proposed plans will occur as the plans pass through the governance processes and more detailed evaluations and justifications are undertaken. In our opinion, a reasonable estimate will be more in line with the trend, with some adjustment to allow for the CBD security and Metro 2012 projects.

This view is based upon a number of findings from our project reviews, which draw upon our high-level expenditure analysis and the findings of the methodology reviews.

Firstly, the timing of the projects reviewed did not appear to be economically justified, in terms of the benefits through the reduction in energy at risk. Only one project reviewed (the Docklands Area upgrade), which was planned for 2014, was marginal in this respect. However, given we consider that CitiPower has used a conservative load profile in its assessments, we consider there is a reasonable possibility that this project will be deferred also.

Secondly, there were some projects (i.e. elements of the HV feeder projects) of which the main need appears to be the increased security of supply (i.e. related to the CDB security project). Although it is clear that the need for these works was referred to in the ESC review, the costs do not appear to have been included in regulatory tests or the plan for these defined through the Distribution Code obligation. We do not consider that Citipower has adequately demonstrated that the inclusion of these elements is appropriate. On their own, they do not appear to be economically justified in terms of the energy at risk benefits they realise.

Finally, in most cases, there appears to be other lower cost options, not considered in detail by Citipower, that we consider may have a reasonable probability that they may be found to be the preferred option.

It is also worth noting that the findings of the AER's review of CitiPower's maximum demand forecast also supports the view that many projects may be optimally deferred, particularly those towards the end of the period.

Using the approach discussed in Section 4.2, we have developed a forecast of the reinforcement expenditure using:

- the weighted average probability from the project reviews (38%) to determine the reasonable estimate to total expenditure
- a constant growth rate assuming a notional 2008 base-line, derived from the average of the historical 2006-2008 expenditure

Based upon this process, we have estimated the CitiPower reinforcement expenditure in the next period (ex the CBD security project and Metro 2012 project) will be 39% of the CitiPower proposal and the expenditure growth rate from historical levels will be 5.7%.

For the CBD security and Metro 2012 projects, we do not consider that CitiPower has adequately demonstrated that its proposed cost increases are reasonable. In the case of the CBD security project, we consider that these project costs should be adjusted back to the costs approved through the ESC's review – suitably adjusted for labour and material escalations. For the Metro 2012 project, we consider that these costs should be adjusted back to the base case estimate assumed in its regulatory test – once again, suitably adjusted for labour and material escalation.

Our estimate of CitiPower's reinforcement capex is shown in Figure 33 and Table 24 below. It is important to note that this should be considered as an estimate only. The AER may need to make further adjustments to allow for its findings on the other matters, such as overheads and labour and material escalation, which are not accurately allowed for here.

Figure 33 – CitiPower reinforcement capex recommendation

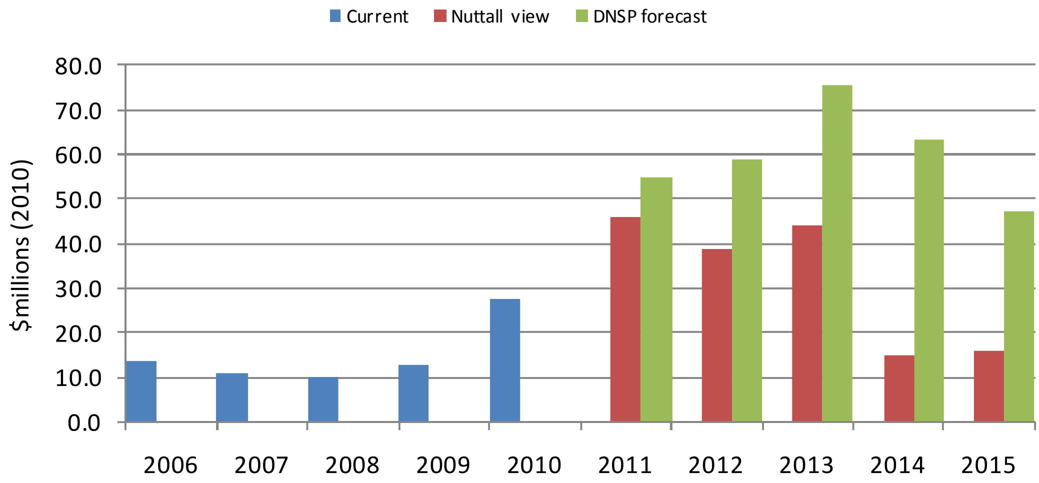


Table 24 – CitiPower reinforcement capex recommendation

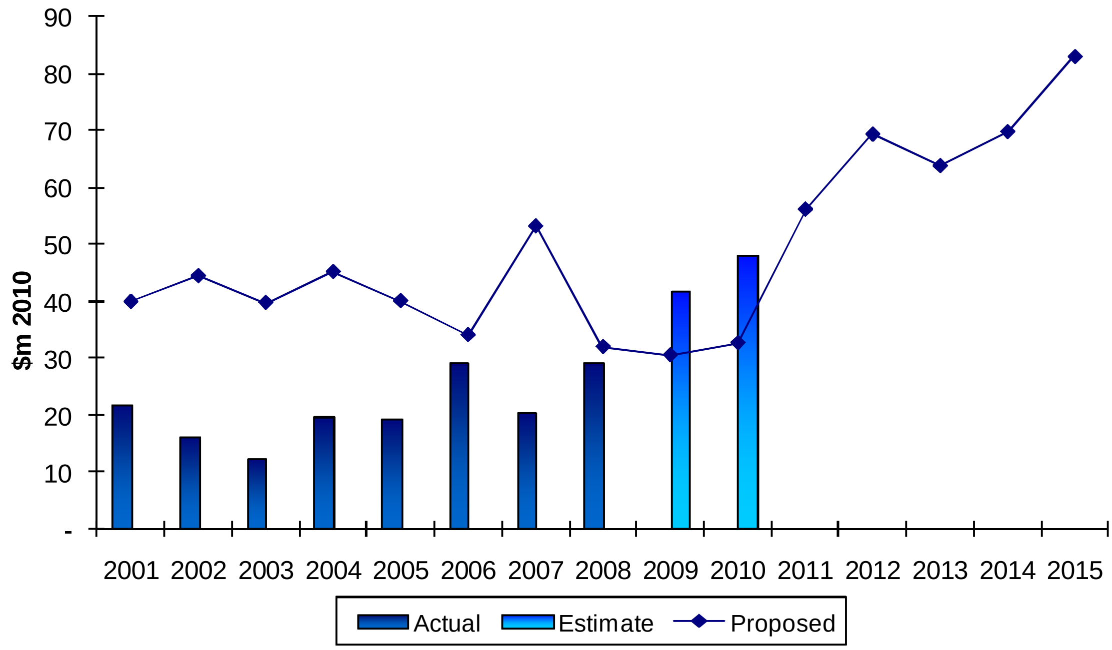
	$millions (2010)				
	2011	2012	2013	2014	2015
CitiPower - proposed	54.8	59.1	75.7	63.5	47.4
CitiPower - recommended	**45.7**	**38.3**	**43.7**	**14.6**	**15.3**

6.3 Reliability and quality maintained

CitiPower is proposing an increase of 161% in reliability and quality maintained capex for the next Regulatory Control Period when compared against actual expenditure in the current Regulatory Control Period. CitiPower estimates that its Reliability and Quality Maintained capital expenditure for the 2006-10 regulatory control period will be $168 million ($2010). It is forecasting that this will increase to $342 million ($2010) in the 2011-15 regulatory control period.

The following chart provides a summary of reliability and quality maintained capex for CitiPower.

Figure 34 - CitiPower Reliability and Quality Maintained Capex



CitiPower states that they use RCM[39] for small value assets and CBRM[40] for high value assets as the primary asset replacement approaches (note: some assets outside of this framework).

The proposal notes that failure rates (poles and cross-arms) were not used to forecast expenditure, although other analysis/modelling was used to support the forecast (e.g. independent modelling - PB model for WARL[41]).

The methodology provided in the CitiPower proposal for developing reliability and quality maintained capex focuses on real-life processes, not the methodology used to develop the expenditure forecast. The proposal states "*CitiPower does not have any software based replacement models. It uses the RCM and CBRM methodologies to manage and maintain its network assets to ensure that network performance is maintained within acceptable risk levels*."

6.3.1 Overview of activity code review

Explanation of expenditure profile – trends and major drivers of increases

Table 25 - Summary of CitiPower RQM expenditure

Average per annum expenditure ($2010)			% increase (from 2006-2008)	
2006-2008	2009-2010	2011-2012	2009-2010	2011-2015
26.2	44.9	68.4	71%	161%

[39] Reliability Centred Maintenance
[40] Condition Based Reliability Maintenance
[41] Weighted Average Remaining Life

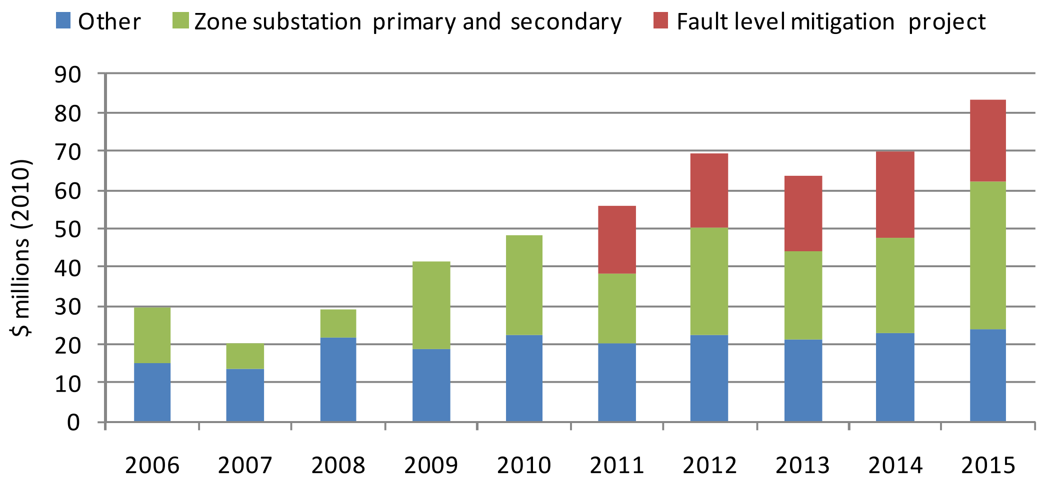
As indicated in Table 25, CitiPower are proposing a significant increase in RQM expenditure from 2009. There are two major drivers of this increase:

3 **Fault level mitigation project**. The first is a proposed new project to mitigate the high fault levels in the CitiPower network. This project is proposed to commence at the beginning of the next period, and continue throughout the period.

4 **Zone substation replacements**. The second is due to the largely age/condition based replacement of zone substation primary and secondary assets, namely the HV circuit breakers, power transformers and protection relays. The level of replacement of these asset types is forecast to increase significantly from 2009, and is forecast to remain at significant levels throughout the next period.

The effect of these two matters on the RQM expenditure profile is shown in Figure 35. This figure indicates that the underlying expenditure is far more in trend with historical levels.

Figure 35 - CitiPower RQM expenditure profile



The breakdown of the 2011-2015 RQM expenditure increase (from 2006-2008 levels) is shown in Table 26. These activity codes are ranked in terms of significance, based upon the proportion of total RQM expenditure.

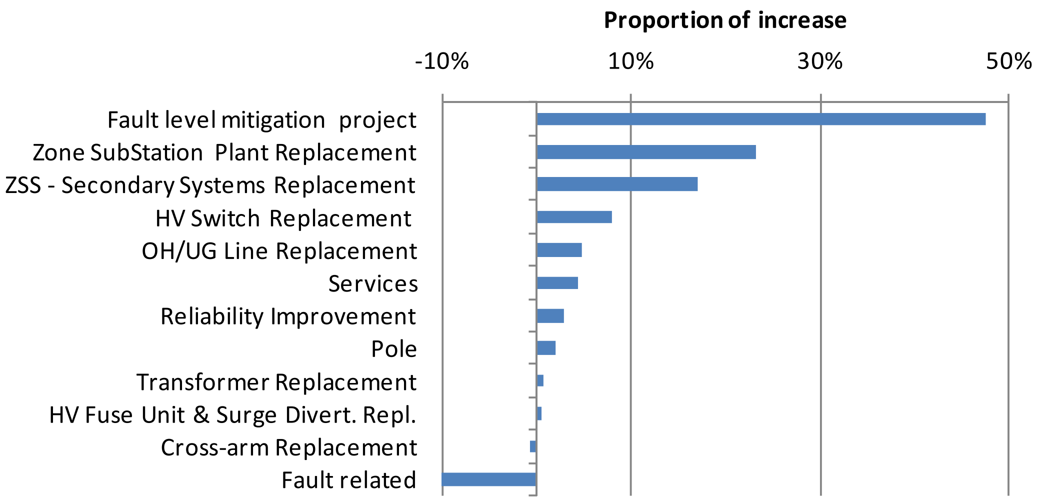
Table 26 - Activity Code summary

Activity Code	Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
	2006-08	2009-10	2011-15		90-10	11-15
Fault level mitigation project	0.0	0.0	20.1	29%	n/a	n/a
Zone Sub Plant Replacement	8.3	21.1	18.0	26%	155%	118%
ZSS - Secondary Systems Replacement	1.0	3.3	8.1	12%	228%	718%
OH/UG Line Replacement	4.0	3.4	6.0	9%	-14%	51%

Activity Code	Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
	2006-08	2009-10	2011-15		90-10	11-15
HV Switch Replacement	0.9	3.4	4.2	6%	296%	391%
Pole	1.9	2.3	2.8	4%	20%	47%
Cross-arm Replacement	2.9	2.1	2.6	4%	-27%	-11%
Fault related	6.7	6.2	2.3	3%	-8%	-65%
Services	0.4	2.0	2.2	3%	430%	491%
Reliability Improvement	0.0	0.6	1.2	2%	n/a	n/a
Transformer Replacement	0.2	0.4	0.5	1%	114%	195%
HV Fuse Unit & Surge Divert Repl	0.1	0.2	0.3	0%	144%	388%
Other	0.0	0.0	0.0	0%	n/a	n/a
Grand Total	**26.23**	**44.95**	**68.41**	**100%**	**71%**	**161%**

The breakdown into activity codes of the proposed increase in expenditure for the next period (compared to the average of 2006-2008) is shown in Figure 36. This clearly illustrates that the fault level mitigation project is the major contributor to the proposed increase, with zone substation primary and secondary plant and equipment also contributing significant portions.

Figure 36 - CitiPower activity code



6.3.2 Fault level mitigation project

Activity code and expenditure summary

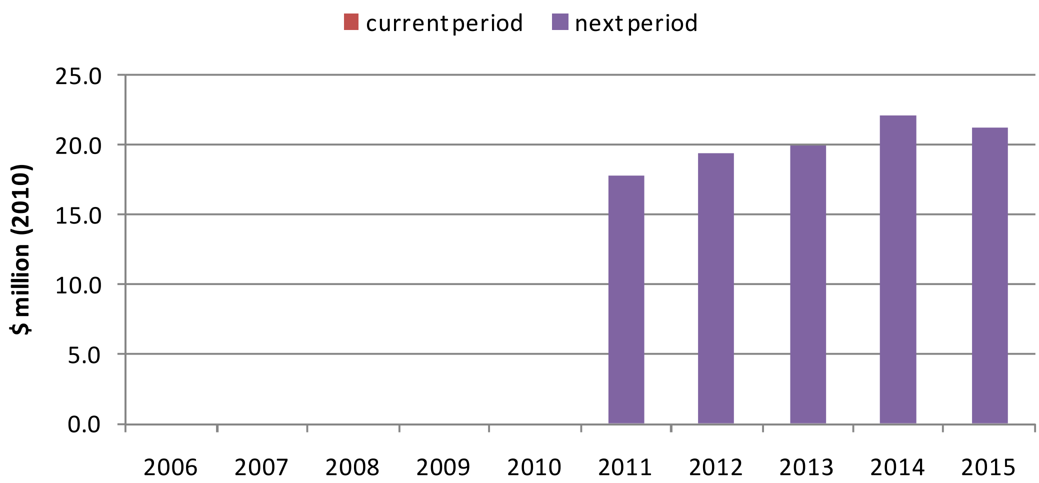
CitiPower do not have a separate activity code for the fault level mitigation project (FLM project). The proposed costs for this project are allocated between two activity codes: OH OH/UG Line Replacement and Zone Sub Plant Replacement. However, to aid in the discussion, we have removed the fault level mitigation project costs from these codes and considered them separately here.

Table 27 and Figure 37 provide an overview of the expenditure in this category. This indicates that this project represents 29% of the total RQM expenditure in the next period, with expenditure at a significant level throughout the period.

Table 27 Overview of expenditure for the fault level mitigation project

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
0.0	0.0	20.1	29%	n/a	Na

Figure 37 - Expenditure profile for the fault level mitigation project



Forecasting methodology and rationale

The FLM project is a new project that CitiPower is proposing to undertake in the next period. CitiPower considers that the project is needed to allow it to keep fault levels on its network to within plant ratings.

Presently, CitiPower operates it network with a number of open points to ensure fault levels are maintained within rating. Although CitiPower has used this approach recently to manage this issue, it does not consider that this is a long-term solution. In this regard, CitiPower notes: "opening selected circuit breakers in this manner can potentially undermine the security of the network and increase supply interruptions"[42].

[42] See explanation for activity code 157 "Maintaining Fault levels", provided in CitiPower email, dated 26/2/10

CitiPower has sourced an independent assessment of solutions to this issue (the SKM reports)[43]. This assessment has considered the options to remove the operational restrictions of the existing network[44].

The assessment considered a number of options, and recommended an option, which involved installing series reactors within terminal stations and replacing key plant and equipment at a number of zone substations. CitiPower has used this recommendation to prepare its expenditure estimate for the project.

Nuttall Consulting views

Nuttall Consulting considers that CitiPower's present strategy of opening circuit breakers to manage fault level is an accepted fault level mitigation option. In support of this view, Nuttall Consulting understands that this approach is used elsewhere, in particular in a number of places on the Victorian transmission network. It is also accepted that this approach may result in some degradation of security and increased supply interruption risks.

However, whether this or another more costly option is appropriate is an economic consideration i.e. the costs associated with the fault level mitigation action need to be balanced against the changes to risks. In this regard, it is assumed that the previous action of opening breakers was considered the prudent and efficient approach at that time to manage fault levels. Similarly, the benefits of removing these restrictions must outweigh the costs.

It is noted that the CitiPower proposal references an ESCV letter that indicates there may be a possibility that CitiPower's operational practices may not be strictly in accordance with the Victorian Distribution Code[45]. However, the context of this view by the ESCV is not clear, and, given our views above, we do not consider that this view warrants that we should consider the need for this project to be a strict compliance issues rather than an economic test.

Nuttall Consulting has reviewed the SKM reports and sees no reason to consider that the options are unreasonable, and may constitute long-term solutions to managing fault levels.

However, the SKM report (and associated CitiPower documentation) does not provide any economic analysis or detailed project schedules that show that the overall project and its timing is optimal (e.g. it would pass a market benefits test).

Given the significance of the proposed project (i.e. $75 million over 5 years), we consider it reasonable to expect that rigorous analysis of this form would be undertaken to justify the need for this project. We also consider that this expectation is in accordance with the ESC views during the 2006 EDPR on the CDB security project, where it required evidence that this project would pass the market benefits limb of the regulatory test.

We consider this is particularly important for this project, given the following:

[43] See CitiPower documents: C0002 and C0186

[44] The assessment also considered the works required to allow for the increased fault level infeed from increased levels of embedded generation in the Citipower network. The costs associated with these works have been allocated to the New Customer connection category, and are not discussed further in this section.

[45] Pg 108, CitiPower proposal.

- The optimal timing for the work, including the optimal schedule, may be heavily influenced by the most significant risks due to specific operational limitations and specific places where embedded generation is most likely to connect.
- The relationship of the proposed works with other network needs (i.e. age, condition and capacity driven plant replacements) is not clear, and as such, it is not clear how much further optimisation is possible. It is noted that this point was raised in the SKM report[46].
- The relationship and optimality of the transmission and distribution fault mitigation plans is not clear. This would require a more thorough and transparent analysis of the transmission/distribution joint planning issues, clearly indicating the available options and optimal plan for all parties.

In the absence of this type of evaluation and justification, we consider that an allowance for this project should be removed, as there remains a significant possibility that the works may not be justified in the next period.

6.3.3 Zone substation plant replacement[47]

Activity code and expenditure summary

The zone substation plant replacement activity code broadly covers the aged/condition based replacement of primary plant within the zone substations. A major portion of this expenditure in the next period is due to the proposed replacement of power transformers and HV circuit breakers (HV CB).

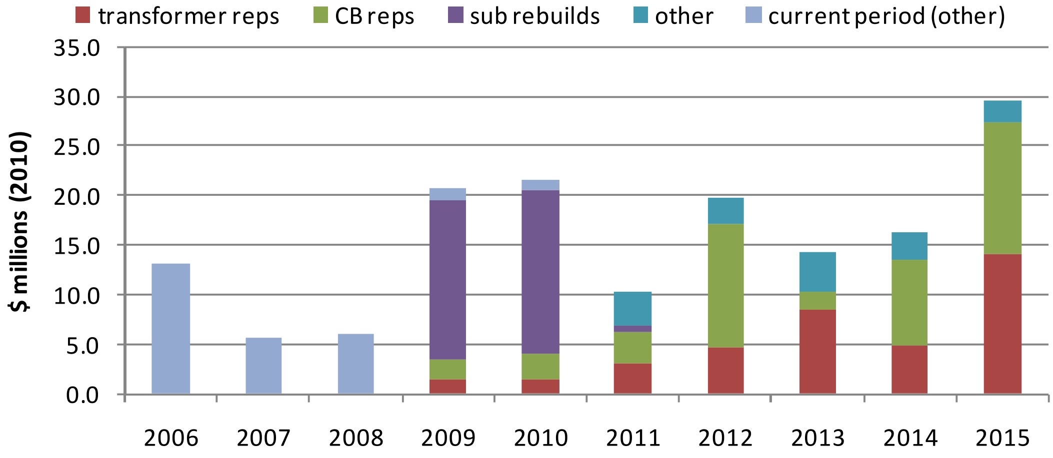
Table 28 and Figure 38 provide an overview of the expenditure in this category. Figure 38 also indicates the proportion of expenditure on the transformer, HV CB replacements and substation rebuilds, which may include both transformer and CB replacements. This analysis indicates that this activity code represents 26% of the total RQM expenditure in the next period, with expenditure anticipated to significantly increase from historical levels in 2009. This increase is largely due to increased transformer and HV CB replacement activity, whereby prior to 2009 there were no transformer replacements and very few HV CB replacements.

Table 28 - Overview of expenditure for the zone substation plant replacement

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
8.3	21.1	18.0	26%	155%	118%

[46] Page 6, C002, SKM report, "Accommodating Distributed Generation in the CitiPower Network"
[47] It is worth noting that this activity code included approximately half of the FLM project costs. These costs have been excluded from the analysis and discussion presented in this subsection.

Figure 38 - Expenditure profile for the zone substation plant replacement



Forecasting methodology and rationale

The forecasts for the HV CB and transformer replacement are based upon quantitative risk modelling of the transformer and CB fleet. The modelling technique, known as Condition Based Risk Modelling (CBRM), has been developed by an independent consultancy, EA Technology, and used elsewhere nationally and internationally for forecasting replacement needs. CitiPower engaged EA Technology in 2008/09 to implement this approach for its transformers and CBs.

Key features of the approach are:

- the use of asset specific condition information (or assumptions if data is not available) and age information to determine probability of failure rates
- the illustration of the probability of failure in terms of a "Health Index" for each asset item, which EA considers allows a more meaningful comparison between asset items and asset types
- internal model to predict the degradation of condition and probability of failure as the asset ages
- failure consequence assumptions (in $ terms)
- risk predictions (in $ terms) based upon the probability of failure predictions and failure consequence
- NPV analysis of the risk costs and the replacement costs of each asset item to predict the optimal timing for replacement
- the ability to input asset specific interventions, such as refurbishments, which then adjust the condition and failure probability of those assets.

This modelling has resulted in 21 transformers being proposed for replacement in the next period under RQM, compared to two in the current period and zero between 2006 and 2008. With regard to HV circuit breakers, 233 circuit breakers of various types are planned for replacement at a number of locations through the next period, compared to 43 in the current period and only 6 between 2006 and 2008.

CitiPower has provided the spreadsheet models and an associated EA Technology report in support of its forecast.

Nuttall Consulting views

The Nuttall Consulting review of this category has focused on the transformer and CB replacement forecasts. Nuttall Consulting has reviewed the spreadsheet models and EA report on its CBRM approach that has been used to forecast transformer and HV CB replacement needs. The model is a contemporary approach to predicting replacement needs, and in principle at least, we see no reason to consider it is not appropriate for this purpose.

The important point here is that the model appears to be primarily an asset management tool that allows assets to be targeted and prioritised over the short to long term. It is expected however that following this modelling exercise far more detailed reviews and testing will occur prior to any replacements being approved.

The main issue for our review is then whether it is “fit for purpose” in terms of producing forecasts for regulatory purposes, or does it include some bias. Like any other modelling approach, this depends on the calibration and validation of the model. This is particularly important given that the model is forecasting such a significant step up in replacement qualities from recent historical levels.

Important matters, in the context of this model, are:

- the existing probability of failure and the ageing relationship used to predict the degradation with time – as noted above, for the CBRM approach this is transferred into a Health Index (HI) for each asset
- consequence assumptions which together with the probability of failure are used to determine risk profiles for each asset.

With regard to transformers, the CBRM model indicates that condition test data was used in developing the health index. The most relevant data appears to be DGA analysis test results. These results provided in the model indicated that all transformers were in a “fair” or better condition (i.e. an HI of 5 or less). This suggests a remaining life of at least 5 to 10 years.

However, much higher final HI values are determined through the model - and as such, much reduced remaining lives - for many of these assets due to the age of the transformers and various other factors. The increased HI also appears to result in the degradation due to aging being much more rapid. However, it is not clear why these factors have such a significant influence on the predicted remaining life over the actual condition information obtained through testing.

For example, the highest health index based upon the DGA results is approximately five. For the age of that transformer, the health index is worse at 5.5. Then, based upon other multiplying factors associated with external condition and relationship of condition to age, the final output HI is 7.2. This places the transformer in much poorer health, and much closer to its end of life.

It is also noted that the number of major failures (i.e. those resulting in a significant disruption to supply) appears to be higher than historical levels for the asset population.

The major failure rate used within the model is based upon an EA estimate derived from international results. However, across the CitiPower's population, this may be overstating the risks of major failure. In this regard, the model assumes there will be a major transformer failure once in every 2 years; contradicting this the EA report indicates that no major failures have occurred over the last 5 years. The important point here is that it appears that the most significant component of risk is associated with network performance due to major failures (i.e. the value of loss of supply). As such, this factor may be overstating the risks associated with transformers.

For CBs, the health is largely based upon the age with various factors applied to adjust this for fleet condition and environment, etc. In effect, the health index and the rate of aging appear to be largely due to asset life assumptions for the various CB types. However, it is not clear how these lives were derived, although it is clear that the HI, probability of failure, and the aging, are sensitive to this assumption.

Similar to the concern above on assumed transformer major failure rates, the number of major failures for CBs predicted by the model appears to be much higher than recent levels on the CitiPower network. As with transformers, the most significant component of risk for CBs is due to the impact of major failures on network performance. The model major failure rate is based upon an EA estimate derived from international results. In this regard, the model assumes there will be a major CB failure across the population every year, with a catastrophic failure every 3.5 years (i.e. over the last 5 years, we would expect to have encountered 5 major distributive failures (i.e. resulting in significant loss of supply) and 1 to 2 catastrophic failures). However, the EA report states that "(t)o date, CitiPower have not experienced a significant number of failures of primary switchgear"[48].

For CBs, it is also not clear how CitiPower has derived the number of replacements from the model outputs. The CitiPower information indicates that it is based upon the number of CBs with a predicted health index greater than 6, but this does not reconcile with quantities provided elsewhere – i.e. the model appears to be less than the basis of the forecast.

Due to these issues and the general matter of proof of "fit for purpose", Nuttall Consulting has requested that CitiPower provide information indicating how it calibrated and validated the CBRM model. This requested an explanation in terms of recent historical failures and associated consequences.

Unfortunately, the CitiPower response[49] to this request has provided little additional and quantitative information that addresses our concerns. The response does indicate that workshops were held with EA and actual data was reviewed. However, we have not been provided with any workings or outputs from these workshops.

CitiPower did provide a memorandum from EA on some of these matters, but this provided very little additional information that was not already available through the original report.

On the matter of the higher major failure rate, EA did discuss why a major failure rate of zero was inappropriate. However, we do not dispute that; clearly, assuming a zero major

[48] Pg 39, EA report

[49] Nuttall Consulting email, dated 15/2/10, and CitiPower response email, dated 26/2/10

failure rate would most likely be too optimistic. The issue in our opinion is why they did not determine that a rate below the general international rate was more appropriate, given the recent 5-year history.

Based upon the above concerns, and given the significant increase in replacement needs forecast through these models, we do not consider that CitiPower has adequately demonstrated that they are “fit for purpose”. In our opinion, this would require a far more substantial and quantitative analysis to appropriately and transparently demonstrate their suitability. This would require network level and sample asset level analysis that shows that the number of failures, probability of failure, the aging relationship, and the consequences, derived through the model are reasonable unbiased estimates of the replacement needs. Such an evaluation would need to take into account CitiPower's historical information, including failure statistics, asset condition monitoring results and risk mitigation measures.

At this stage, we consider there is considerable discretion to further optimise and defer much of the program proposed by CitiPower. It is impossible in a review of this form for us to undertake the type of analysis that would be required to determine an alternative detailed work plan. We do accept however that the aging of the network is imposing greater needs on the business, above those faced in the current period. On balance, we consider that an allowance based upon the actual expenditure in the current period, allowing for the further aging of the network is reasonable.

6.3.4 Zone substation Secondary Systems Replacement

Activity code and expenditure summary

The zone substation secondary systems replacement activity code largely covers the aged/condition based replacement of secondary systems within the zone substations.

A major portion of this expenditure in the next period is due to an ongoing program to replace aged relays. There are also a number of other ongoing programs, covering batteries and chargers, aged PLC units, age Quality of Supply meters, new control schemes for fault level management, and capacitor controller replacements.

There are also a large number of proposed new programs for the next period:

- replacing aged DC intertrip schemes
- installing new transformer inhibit schemes
- relay replacements due to terminal station rebuilds
- undertaking a number of protection reviews
- installing duplicate protection
- upgrading AC and DC supplies
- replacing aged switch controllers
- establishing VTs on some 66 kV lines
- control room modifications
- replacement of aged communications equipment

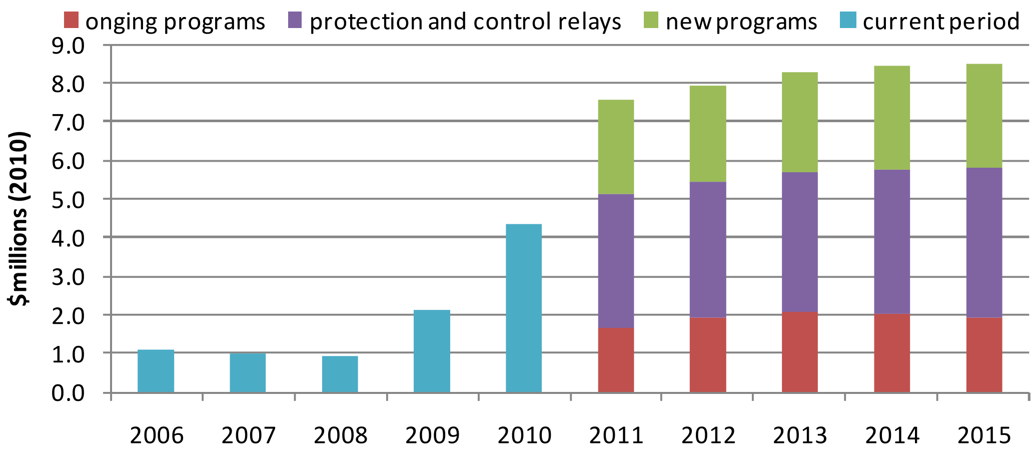
- installation of auto-reclose schemes.

Table 29 and Figure 39 provide an overview of the expenditure in this category. Figure 39 also indicates the proportion of expenditure on the aged relays, other ongoing programs, and the new programs. This analysis indicates that this activity code represents 12% of the total RQM expenditure in the next period, with expenditure anticipated to significantly increase from historical levels in 2009 to considerably higher levels by 2011.

Table 29 - Overview of expenditure for the zone substation secondary system replacements

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
1.0	3.3	8.1	12%	228%	718%

Figure 39 - Expenditure profile for the zone substation secondary system replacements



Forecasting methodology and rationale

CitiPower has provided some discussion on the relay replacement program[50]. This indicates that CitiPower has undertaken a risk assessment of its relay fleet and ranked each relay in terms of highest to lowest risk.

The forecast for the other ongoing programs are generally based upon an assumed volume per year multiplied by an assumed unit cost, or historical rates. The forecast of the new programs proposed for the next period appear to be based upon assumed volumes multiplied by an assumed unit cost.

Nuttall Consulting views

With regard to the large increase proposed to occur from 2009 to 2011, there is very little evidence provided by CitiPower to demonstrate that this increase is prudent and efficient.

With regard to the relay replacements, it is noted that the level of replacement in the next period does not appear to be significantly different to the level in 2007 and 2008[51]. As such, it is not clear why such an increase in expenditure is necessary.

[50] Relay replacement documents in the CitiPower email, dated 11/1/10

Furthermore, CitiPower has provided no information that justifies that the proposed increases are appropriate (i.e. in terms of demonstrating the benefit, through the reduction in risk, exceeds the large expenditure increases). Nuttall Consulting has requested the details of the relay risk assessments, including the quantities associated with the various priority levels and the relative scale of the risks in each priority. Nuttall Consulting has also requested information on the changes to existing risks if the program is deferred or spread over a longer period. This information is useful in demonstrating CitiPower's acceptance of existing risk levels and showing that there will be a net benefit in undertaking the replacement as planned or an alternative optimal replacement level. However, in both cases, CitiPower's response has not provided useful additional information[52].

Similarly, with the other ongoing and new programs, no economic analysis has been presented to demonstrate the prudency and efficiency of the increases.

With regard to the new programs, it appears that these are largely based upon issues (and associated risks) that were known and tolerated during the current period. As such, although we see no reason to consider that the issues and associated risks are not real, given they are being currently managed, it is not clear why such a large increase in expenditure is required to begin to address so many matters. In the absence of evidence to the contrary, it must also be assumed that the undertaking of such a program would have a similarly significant step change in the risks that CitiPower currently face, and have accepted in the current period.

Based upon the lack of evidence that CitiPower’s proposed expenditure increase is prudent and efficient, we consider that a reasonable estimate would be based upon the existing levels with some allowance for an increasing expenditure based upon the aging of the network.

6.3.5 Overhead and underground line replacement

Activity code and expenditure summary

The overhead and underground line replacement activity code broadly covers the aged/condition based replacement of overhead line conductors and insulators, and underground cables and associated underground equipment (e.g. joints, terminations, link boxes etc). A major portion of this expenditure in the next period is due to the proposed replacement of HV and LV cables, and associated joints and terminations.

Table 30 and Figure 40 provide an overview of the expenditure in this category. Figure 40 also indicates the proportion of expenditure in the next period on ongoing programs, new programs, and where this is unknown. This analysis indicates that this activity code represents 9% of the total RQM expenditure in the next period, with expenditure anticipated to significantly increase from historical levels in 2009. This increase appears to be largely due to increases in the ongoing programs.

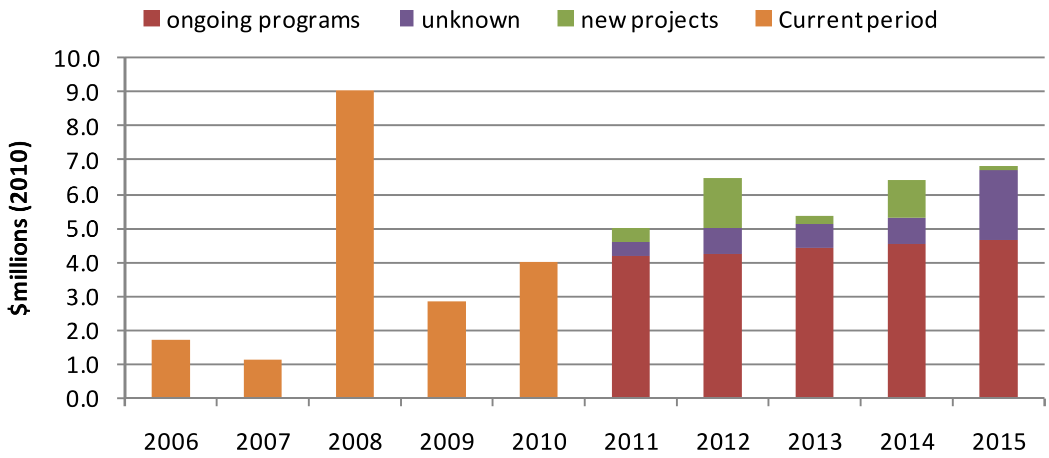
The spike in expenditure in 2008 is understood to relate to a specific 22 kV cable replacement project that occurred in that year.

[51] Methodology documents provided in email, dated 26/2/10, indicate that 85 and 65 relays were replaced in 2007 and 2008 respectively. Citipower is planning to replace 65 per annum in the next period.
[52] Q6 response, in Citipower letter, dated 26/2/10

Table 30 - Overview of expenditure for overhead and underground line replacement

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
4.0	3.4	6.0	9%	-14%	51%

Figure 40 - Expenditure profile for overhead and underground line replacement



Forecasting methodology and rationale

The CitiPower information indicates that the forecasts for the ongoing programs were based upon historical rates and engineering judgment. The expenditure forecasts for the new projects are based upon known issues and estimates of the volume and unit cost estimates.

Nuttall Consulting views

Nuttall Consulting has reviewed the information provided by CitiPower to support the expenditure forecast associated with this activity code. However, there is little information to justify the scale of the sharp increase that is proposed from 2006-2008 levels. In particular, the CitiPower information indicates that the forecast for the ongoing programs are largely based upon historical rates. As such, it is not clear why such a significant ramp-up has been identified through this approach.

All that said, our replacement modelling is forecasting a significant increase in the expenditure levels for these asset categories. These forecast increases are broadly in accordance with CitiPower's forecast, and as such, we consider this to be reasonable.

6.3.6 HV Switch Replacement

Activity code and expenditure summary

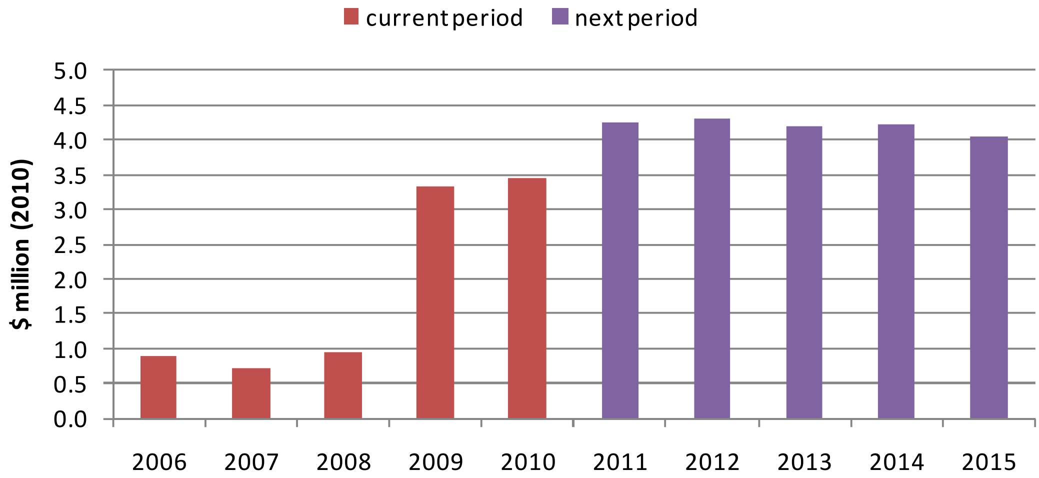
The HV switch replacement activity code broadly covers the aged/condition based replacement of HV and LV switchgear. A major portion of this expenditure in the next period is due to the proposed replacement of a particular type of LV circuit breaker (Nilsen air circuit breakers).

Table 31 and Figure 41 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents 6% of the total RQM expenditure in the next period, with expenditure anticipated to significantly increase from historical levels in 2009. This increase appears to be largely due to the commencement of a number of programs at that time.

Table 31 - Overview of expenditure for the HV switch replacements

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
0.9	3.4	4.2	6%	296%	391%

Figure 41 - Expenditure profile for the HV switch replacements



Forecasting methodology and rationale

The forecasts in this category are generally developed from known volumes associated with known issues of the particular asset type. The expenditure is estimated from a modern equivalent unit cost.

For example, the Nilsen LV circuit breakers are being replaced as that asset type has had two major failures, resulting in substation fires and the evacuation of the associated CBD building in which they were located. As a result, CitiPower is proposing the replacement of this type by the end of the next period. CitiPower has indicated that it has undertaken a risk assessment of the locations of these breakers to determine the priority order for replacement.

Nuttall Consulting views

CitiPower has provided asset management plans associated with the majority of this activity code. Nuttall Consulting has reviewed these documents. Although, we see no reason to doubt the issues raised by CitiPower, and consider it reasonable to consider that they do impose risks on CitiPower, this alone does not justify the need for such a substantial expenditure increase.

No quantitative risk and economic analysis has been provided to justify the scale of the programs and the associated sharp increase that is proposed from 2006-2008 levels.

Nuttall Consulting has requested information on the changes to existing risks if the programs are deferred or spread over a longer period. This information would be useful in demonstrating CitiPower's acceptance of existing risk levels and showing that there will be a net benefit in undertaking the replacement as planned or an alternative optimal replacement level. However, CitiPower's response on these matters has not provided useful additional information[53].

For example, the information indicates that the two LV circuit breaker's failures occurred in 2005 and 2007, as such, it is not clear why such a significant step increase is warranted in the next period. The CitiPower response on why the project could not be spread over a longer period, simpley states that risk would increase. However, it does not discuss this in the context of the risks it is willing to accept in the current period, and how these will change in the next if the program is undertaken as planned or extended over a longer period.

Based upon the lack of evidence that CitiPower's proposed expenditure increase is prudent and efficient, we consider that a reasonable estimate would be based upon the existing levels with some allowance for an increasing expenditure based upon the aging of the network.

6.3.7 Service Replacement

Activity code and expenditure summary

The service activity code broadly covers the aged/condition based replacement of customer service lines and cables. This made up of two main programs: neutral screen (aerial) services and other condition based service replacements.

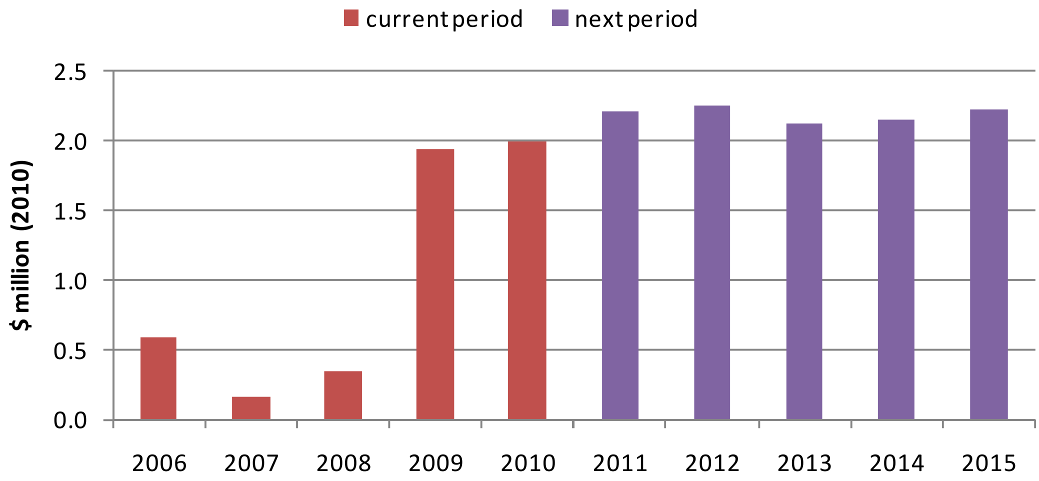
Table 32 and Figure 42 provide an overview of the expenditure in this category. Figure 38 also indicates the proportion of expenditure on the transformer, HV CB replacements and substation rebuilds, which may include both transformer and CB replacements. This analysis indicates that this activity code represents only 3% of the total RQM expenditure in the next period, but with expenditure anticipated to significantly increase from historical levels in 2009.

Table 32 - Overview of expenditure for the service replacements

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
0.4	2.0	2.2	3%	430%	491%

[53] Q3 and Q4 responses in Citipower letter, dated 26/2/10

Figure 42 - Expenditure profile for the service replacements



Forecasting methodology and rationale

CitiPower has provided some discussion on its methodology applied for this category[54]. This indicates that CitiPower has forecast the volume of replacement via a simple age based model to determine annual volumes – essentially dividing the total number of services by an assumed 60-year life. Certain minor adjustments are then made to allow for replacements that may occur in other activity codes. Unit costs are assumed based upon typical costs.

Nuttall Consulting views

The main factors raised in the CitiPower documents as a need for the increase in expenditure, in addition to an aging asset base, are a change in the inspection criteria and the removal of an exemption for full compliance with a vegetation clearance obligation. However, in both these cases, CitiPower's rationale for its estimate of the increase due to these changes is not clear. There is little information presented that supports the scale of the increase, and it could be that it would be far more modest than indicated.

Allowing for CitiPower's proposed increases due to these reasons, these appear to justify only a modest increase in expenditure of around 50%, rather than the nearly 500% proposed by CitiPower.

Given the lack of substantiation of such a significant increase, and the uncertainty as to the impact of the proposed changes, we see no reason to consider that an expenditure allowance based upon the historical trend with a gradual increase to allow for the aging of the network would not be a reasonable estimate for this category.

6.3.8 Reliability

Activity code and expenditure summary

The reliability activity code broadly covers work to address worst served customers.

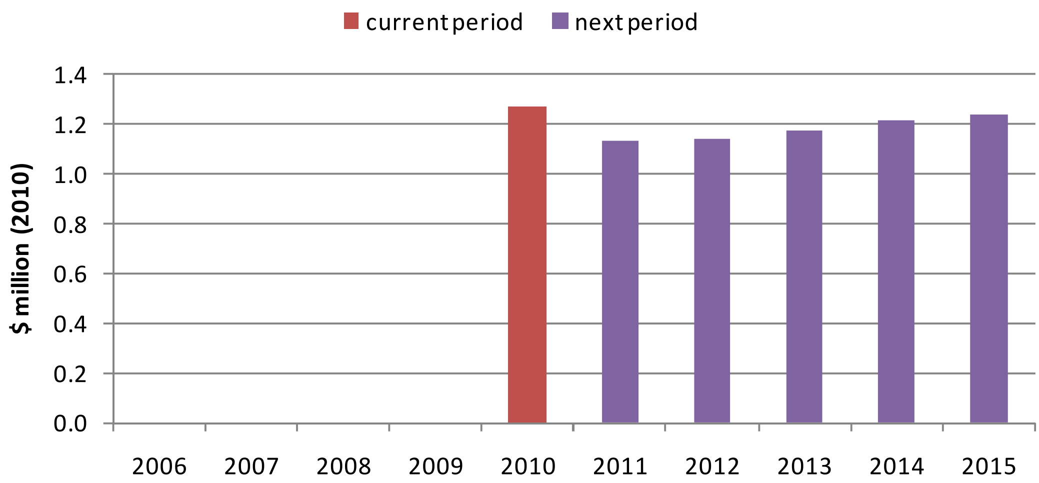
[54] Activity Code 152 and 153 documents, provided in CitiPower email dated 26/2/10

Table 33 and Figure 43 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents only 2% of the total RQM expenditure in the next period, with forecast expenditure stepping up from a zero level in 2010.

Table 33 - Overview of expenditure for reliability

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
0.0	0.6	1.2	2%	n/a	n/a

Figure 43 - Expenditure profile for reliability



Forecasting methodology and rationale

The CitiPower documentation[55] indicates that the reliability forecasts are based upon a range of assumed projects to address worst served customers.

Nuttall Consulting views

As expenditure is not captured to this activity code prior to 2010, it is not clear how similar works have been allocated historically. However, assuming that similar works in the current period have been captured in the other RQM activity codes, we consider that there should already be some allowance for these proposed works in other activity code allowances.

6.3.9 Pole Replacement

Activity code and expenditure summary

The pole replacement activity code broadly covers the age/condition based replacement of poles, including pole staking and pole treatments.

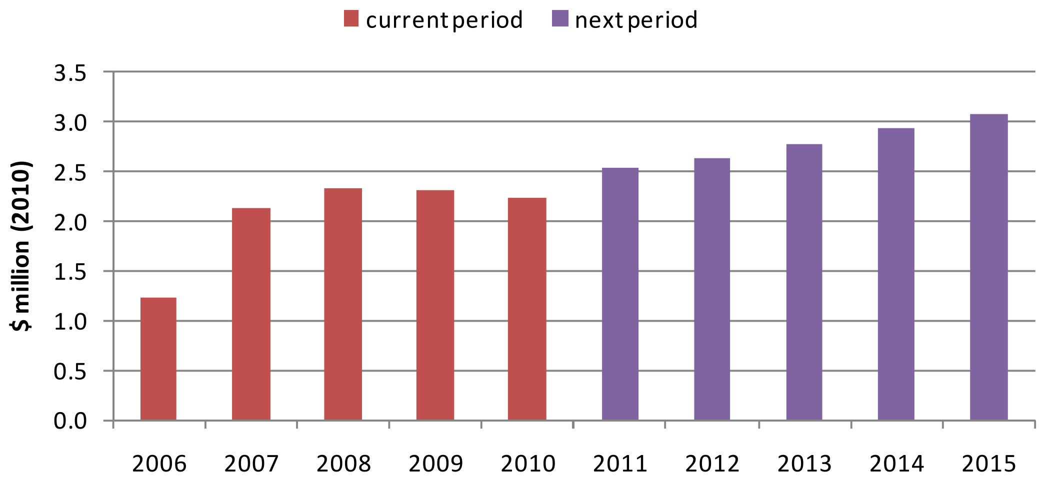
Table 34 and Figure 44 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents only 4% of the total RQM expenditure in the next period, with forecast expenditure broadly on trend with historical levels.

[55] Pole related activity Codes, provided in CitiPower email, dated 26/2/10

Table 34 - Overview of expenditure for pole replacements

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
1.9	2.3	2.8	4%	20%	47%

Figure 44 - Expenditure profile for pole replacements



Forecasting methodology and rationale

The CitiPower documentation[56] indicates that the pole forecasts are based upon historical replacement rates with an incremental annual increase.

Nuttall Consulting views

Expenditure on pole replacements (including staking and treatments) appears to be broadly in line with the historical trend. There is a small step increase in 2011, but this may be due to the reduced pole replacements estimated for 2009 and 2010.

Given the low materiality of this activity code and the proposed increase, which is broadly in line with our replacement modelling, we consider that this estimate is reasonable.

6.3.10 Transformer Replacement

Activity code and expenditure summary

The transformer activity code covers the age/condition based replacement of distribution transformers.

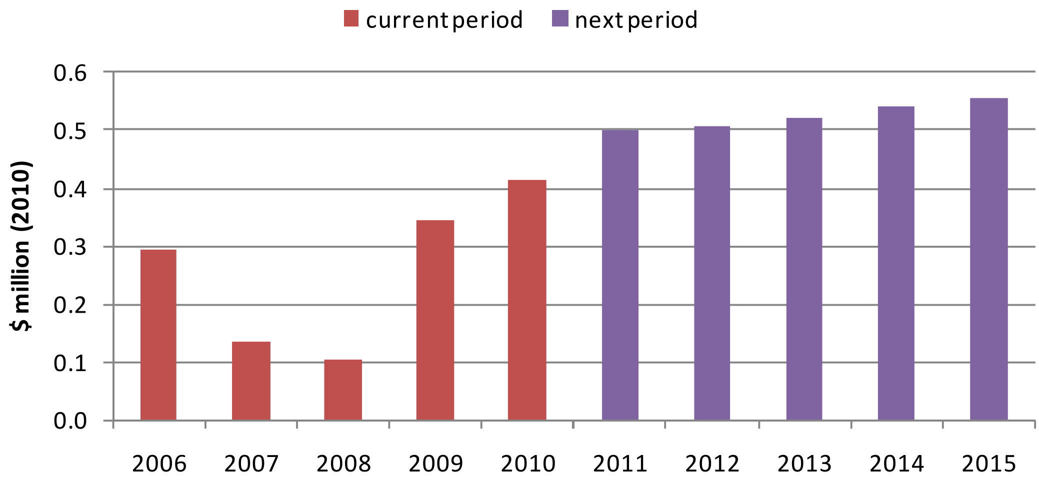
Table 35 and Figure 45 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents only 1% of the total RQM expenditure in the next period, but CitiPower is proposing a fairly significant step increase in expenditure from 2008 levels.

[56] Pole related activity Codes, provided in CitiPower email, dated 26/2/10

Table 35 - Overview of expenditure for transformer replacements

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
0.2	0.4	0.5	1%	114%	195%

Figure 45 - Expenditure profile for transformer replacements



Forecasting methodology and rationale

The CitiPower documentation[57] indicates that the transformer replacement forecast is based upon engineering judgment of historical replacement rates – although the precise methodology is not clear.

Nuttall Consulting views

The CitiPower documentation does not explain why such a large increase in expenditure is forecast from 2008 levels. Further, given that the CitiPower methodology is based upon historical unit rates and does not suggest that these are expected to increase significantly, we see no reason to allow more than the average recent historical level with some allowance for an aging population.

6.3.11 Cross arm Replacement

Activity code and expenditure summary

The cross arm replacement activity code covers the age/condition based replacement of this asset.

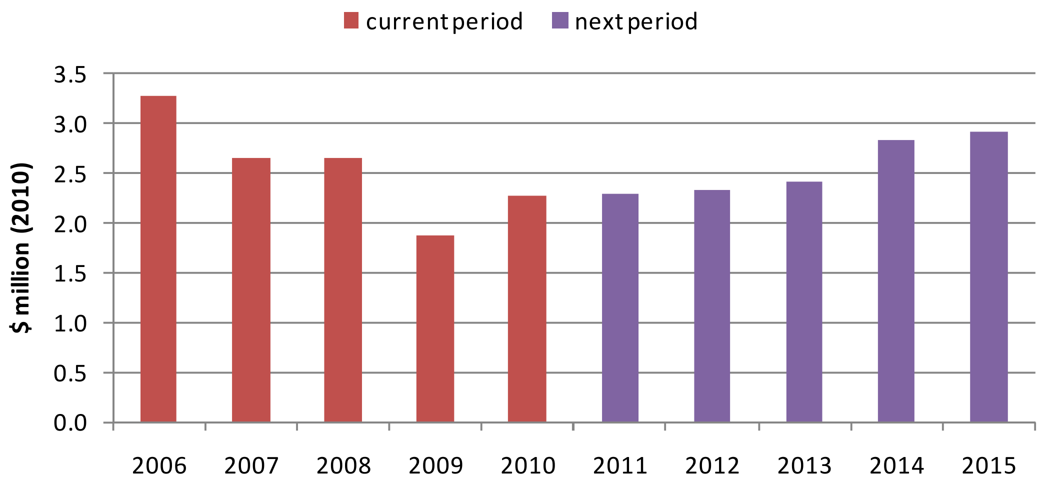
Table 36 and Figure 46 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents only 4% of the total RQM expenditure in the next period, with forecast expenditure broadly on trend with historical levels.

[57] Distribution transformer related activity Codes, provided in CitiPower email, dated 26/2/10

Table 36 - Overview of expenditure for cross arm replacements

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
2.9	2.1	2.6	4%	-27%	-11%

Figure 46 - Expenditure profile for cross arm replacements



Forecasting methodology and rationale

The CitiPower documentation[58] indicates that the cross arm forecasts are based upon historical replacement rates with an incremental annual increase.

Nuttall Consulting views

Expenditure on cross arm replacements appears to be broadly in line with the historical trend. There is a small step increase in 2010, but given previous replacement numbers, this does not appear to be unjustified.

Given the low materiality of this activity code and the proposed increase, which is broadly in line with our replacement modelling, we consider that this estimate is reasonable.

6.3.12 Fault Replacement

Activity code and expenditure summary

The fault replacement category covers three CitiPower activity codes that capture fault related asset replacements. This may be due to age/condition related failure or other causes.

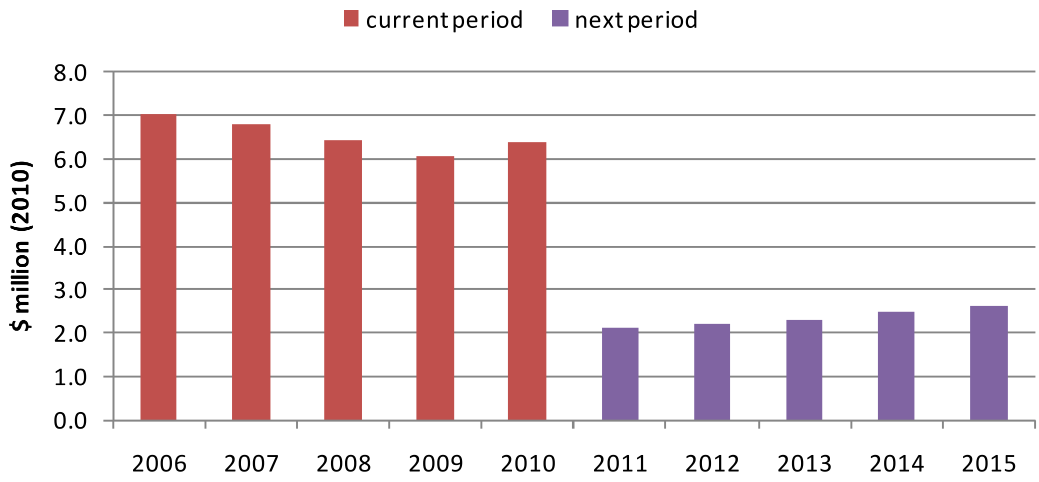
Table 37 and Figure 47 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents only 3% of the total RQM expenditure in the next period, with forecast expenditure reducing significantly in the next period.

[58] Cross-arm related activity Codes, provided in CitiPower email, dated 26/2/10

Table 37 - Overview of expenditure for fault replacements

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
6.7	6.2	2.3	3%	-8%	-65%

Figure 47 - Expenditure profile for fault replacements



Forecasting methodology and rationale

The CitiPower documentation[59] indicates that the fault replacement forecasts are based upon historical replacement rates, but the methodology is not clear.

Nuttall Consulting views

The reason for the proposed reduction in this category is not clear. Without operating and replacement policies changing significantly, it is not clear why this expenditure would drop so considerably.

Given the approach we have applied in other categories to place expenditure on trend, we consider that it is reasonable to allow for expenditure in this category to be at the historical level, with some additional allowance for the aging of the network.

6.3.13 HV fuse and surge diverters Replacement

Activity code and expenditure summary

The HV fuse and surge diverters (HVFSD) activity code broadly covers the aged/condition based replacement of these assets and some other HV and LV devices.

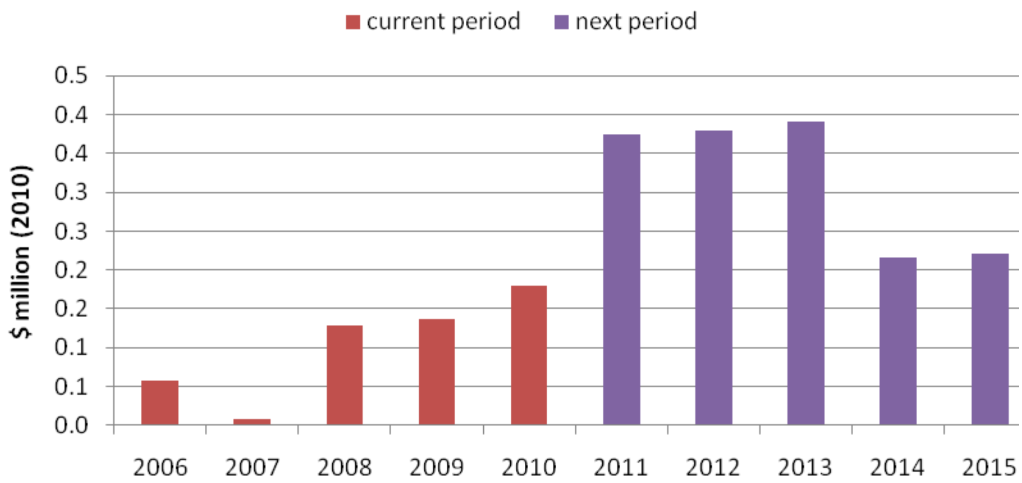
Table 38 and Figure 48 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents a very small portion of the total RQM expenditure in the next period, but CitiPower is proposing a fairly significant step increase in expenditure from 2008 levels.

[59] Fault related activity Codes, provided in CitiPower email, dated 26/2/10

Table 38 - Overview of expenditure for HVFSD replacements

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
0.1	0.2	0.3	0%	144%	388%

Figure 48 - Expenditure profile for HVSFD replacements



Forecasting methodology and rationale

The CitiPower documentation[60] indicates that the HVFSD forecast is based upon a range of very small programs. The main increase appears to be based upon a new program to replace aged fault indicators. Other expenditure appears to be related to ongoing programs, with the forecast based upon historical rates.

Nuttall Consulting views

Due to the relatively immaterial expenditure in this category, Nuttall Consulting has not considered this in any detail. However, based upon findings of the other categories, it appears reasonable to assume that a trending of expenditure from historical levels, allowing for the aging of the network, may adequately represent the expenditure requirements for this category also.

6.3.14 Overall findings

The above has shown that the proposed increase in RQM expenditure in the next period is mainly due to a new project to mitigate fault levels and the age/condition related replacements of zone substation assets. A number of other asset types are also proposed to have significant increases in expenditure over historical levels.

Based upon our review, we do not consider that CitiPower has adequately demonstrated that the increases are prudent and efficient.

The fault mitigation program is a very significant ($75 million) new project proposed to commence in 2011. However, no economic analysis has been provided that demonstrates

[60] Related Activity Code discussions, provided in CitiPower email, dated 26/2/10

that the project scope and timing are required. It is not evident from the information provided whether the project will be needed at all in the next period. Given the lack of a robust economic argument for the project, we are not recommending any allowance for this project.

For the age/condition based replacements, only the zone substation transformer and circuit breaker replacement programs have some form of quantitative economic and risk analysis. However, there is little evidence that this has been calibrated to CitiPower's circumstances, and as such, it may be significantly overstating replacement needs.

For other assets, the basis for the increase appears to be due to known issues and associated risks that are being reduced. This particularly concerns increases in relay replacements, HV/LV switchgear and underground cables.

In these case, we do not doubt that the issues and associated risks exist, but it has not been demonstrated how CitiPower is presently managing these matters – presumably in a prudent and efficient manner – and how the risk will change over time. As such, it is not evident that the scale of the increase is required.

Nuttall Consulting has requested information on the changes to existing risks if the programs are deferred or spread over a longer period. This information would be useful in demonstrating CitiPower's acceptance of existing risk levels and showing that there will be a net benefit in undertaking the replacement as planned or an alternative optimal replacement level. However, CitiPower's response on these matters has not provided useful additional information[61].

Based upon the above, we consider that the RQM allowance should be based upon the recent historical levels of RQM expenditure with some additional allowance for the aging of the network. The recommended RQM expenditure is shown in Table 39. The basis for these recommendations is indicated in Table 40.

It is important to note that this recommendation must be considered in the broader context of the overall capex. We would fully expect that at the activity code level, actual expenditure may differ considerably as circumstances change and the full capital governance process is applied.

It is also important to note that this recommendations should be considered as an estimate only. The AER may need to make further adjustments to allow for its findings on the other matters, such as overhead and labour and material escalation, which are not accurately allowed for here.

Table 39 – CitiPower RQM capex recommendation

	$thousands (2010)				
	2011	2012	2013	2014	2015
Proposed	56,099	69,357	63,795	69,781	83,030
Recommended	**34,738**	**39,485**	**42,145**	**47,734**	**52,611**

[61] Refer to Q6 response, CitiPower letter, dated 26/2/10

Table 40 – CitiPower activity code based adjustments

Activity code	Nuttall Consulting view
Cross-arm Replacement	Accepted
Fault level mitigation project	Rejected – no allowance
Fault related	Rejected - allowance based upon average 2006-2008, with increase based upon repex model findings
HV Fuse Unit & Surge Divert. Repl.	Rejected - allowance based upon average 2006-2008, with increase based upon repex model findings
HV Switch Replacement	Rejected - allowance based upon average 2006-2008, with increase based upon repex model findings
OH/UG Line Replacement	Accepted
Pole	Accepted
Reliability Improvement	Rejected – no allowance
Services	Rejected - allowance based upon average 2006-2008, with increase based upon repex model findings
Transformer Replacement	Rejected - allowance based upon average 2006-2008, with increase based upon repex model findings
Zone Substation Plant Replacement	Rejected - allowance based upon average 2006-2008, with increase based upon repex model findings
ZSS - Secondary Systems Replacement	Rejected - allowance based upon average 2006-2008, with increase based upon repex model findings

6.4 Environmental, Safety and Legal

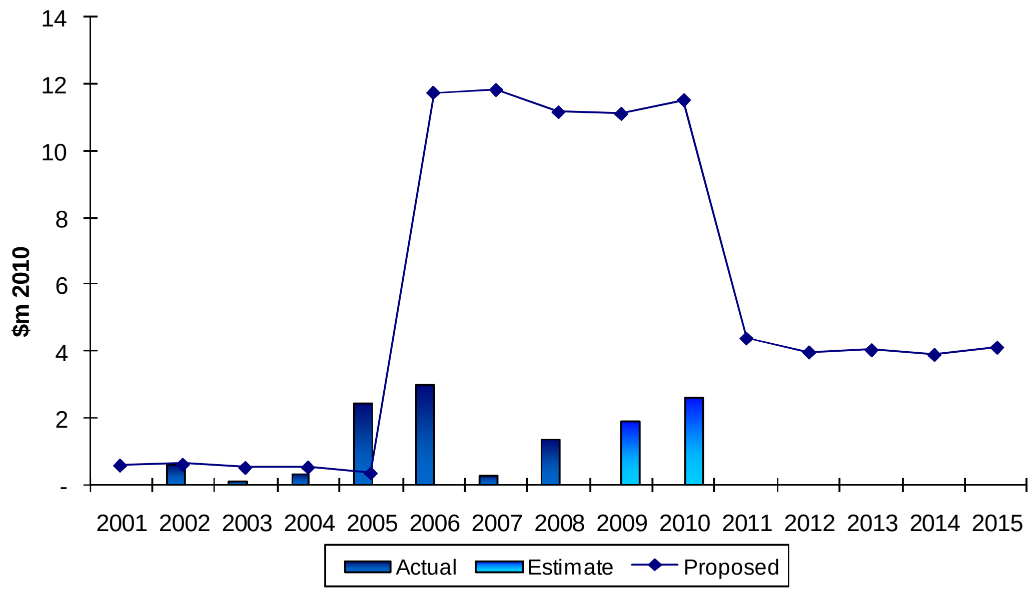
CitiPower is proposing an increase of 160% in Environmental, Safety and Legal capex for the next Regulatory Control Period when compared against actual expenditure in the current Regulatory Control Period. CitiPower estimates that its' Environmental, Safety and Legal capital expenditure for the 2006-10 regulatory control period will be $9.2 million. It is forecasting that this will increase to $20.5 million in the 2011-15 regulatory control period.

For the 2006 EDPR, CitiPower proposed Environmental, Safety and Legal expenditure of $57 million. The resultant actual expenditure for this period is forecast to be $9 million[62].

The following chart provides a summary of Environmental, Safety and Legal capex for CitiPower.

[62] Including 2009 and 2010 estimates.

Figure 49 - CitiPower Environmental, Safety and Legal capex



The CitiPower proposal identifies the key environmental issues that require management as:

- noise control
- containment and drainage of oil in zone substations
- asbestos management
- ESMS.

Each of these issues is considered below.

6.4.1 Noise control

The CitiPower proposal identifies the 1997 State Environmental Protection Policy (SEPP) as the primary legal instrument in relation to regulating the impact of noise emissions from CitiPower assets. CitiPower state that they have voluntarily created an Environment Improvement Plan (EIP) to assist in complying with the SEPP. The CitiPower proposal identifies that the "*main driver of (the) increase in Environmental, Safety and Legal capital expenditure over the 2011-15 regulatory control period is expenditure on the mitigation of noise at zone substations*".

Noise control is a long-term consideration for all DNSPs:

- In their proposal to the 2001 EDPR process[63], CitiPower stated that: "*Capital expenditure (is) required to ensure on-going compliance with relevant environmental regulations includes the following: ... Various noise mitigation works at zone substations and distribution substations*."

[63] 2001 Distribution Price Review Submission, Chapter 2.8.

- In their proposal to the 2006 EDPR process[64], CitiPower stated that: "*Capital investment of $15.2M to improve environmental outcomes, including a reduction in substation noise exceedance by 50 per cent*" and "*CitiPower has supplied the Environment Protection Authority (EPA) with its Environmental Improvement Program describing the management of excessive noise from its substations. Over the period 2006-10 it is anticipated that the total noise exceedance from zone substations will reduce by 50 per cent.*"

In 2005, CitiPower argued against any reductions to the proposed noise program[65]. CitiPower stated that the "*number of noise complaints registered by CitiPower is growing steadily and it is anticipated that 2005 will result in more than double the complaints registered in 2002*". CitiPower stated that they had only forecast expenditure for 50 per cent of the zone substations that are substantially exceeding the EPA noise standard.

Despite the forecast doubling of noise complaints and only targeting half of the exceeding substations, resulting Environmental, Safety and Legal expenditure levels remained significantly below proposal forecasts.

CitiPower state that four sites are currently in substantial non-compliance with the noise obligations.

CitiPower has not provided any information to suggest that the obligations for noise control have changed or are anticipated to change. On this basis, it appears reasonable to assume that noise control remains a continuing works program and that future expenditures should be consistent with historical expenditure trends.

6.4.2 Oil containment

CitiPower has identified a number of existing regulatory and legislative obligations that relate to the containment and drainage of oil filled equipment. CitiPower state that they have developed Oil Containment Guidelines to assist it in complying with these obligations. These Guidelines provide a basis for CitiPower's ten year work program for upgrading or replacing oil bunds at zone substations and retrofitting drainage at zone substations.

Oil containment is a long-term consideration for all DNSPs:

- In their proposal to the 2001 EDPR process[66], CitiPower stated that: "*Capital expenditure (is) required to ensure on-going compliance with relevant environmental regulations includes the following: ... Installation of best practice integrated transformer bunding and stormwater systems at zone substations, to enable oil containment and stormwater treatment*"
- In their proposal to the 2006 EDPR process[67], CitiPower stated that: "*Capital expenditure required to ensure compliance is maintained with the relevant environmental regulations includes the following: installation of best practice*

[64] CitiPower's Submission to the Essential Services Commission – 2006 Price Review, Chapter 6.
[65] CitiPower Expenditure Response - v1.10, Chapter 6.
[66] 2001 Distribution Price Review Submission, Chapter 2.8.
[67] CitiPower's Submission to the Essential Services Commission – 2006 Price Review, Chapter 6.

integrated transformer bunding and stormwater systems at zone substations to enable oil containment and stormwater treatment".

CitiPower has not provided any information to suggest that the obligations for oil containment and drainage have changed or are anticipated to change. On this basis, it appears reasonable to assume that oil containment and drainage remains a continuing works program and that future expenditures should be consistent with historical expenditure trends.

6.4.3 Asbestos management

CitiPower has identified that the Occupational Health and Safety (OHS) Regulations 2007 (OHS Regulations) and the Environment Protection (Industrial Waste Resource) Regulations 2009 regulate the storage and disposal of asbestos materials. CitiPower states that is has established an Asbestos Management Manual - 14-25-M0004 to assist it in complying with asbestos related obligations.

Asbestos management is a long-term obligation for all DNSPs.

CitiPower has not provided any information to suggest that the obligations for asbestos management have changed or are anticipated to change. On this basis, it appears reasonable to assume that asbestos management remains a continuing works program and that future expenditures should be consistent with historical expenditure trends.

6.4.4 ESMS

CitiPower has identified the Electrical Safety Act (Victoria) 1998, the Electricity Safety (Network Assets) Regulations 1999 and the Electrical Safety Amendment Act 2007 as major regulatory obligations.

These safety regulations represent a long-term consideration for all DNSPs. In their proposal to the 2006 EDPR process[68], CitiPower stated that:

- "*CitiPower is committed to the ongoing safety of its network and the workplace and has developed an Electricity Safety Management Scheme (ESMS) to ensure appropriate safety outcomes are achieved. However, uncertainty about the actual compliance requirements under new regulations means that estimates of the necessary capital investment range from $20-140M. CitiPower will continue to work with the Office of the Chief Electrical Inspector (OCEI), the Commission and Government to resolve this issue*."

In their proposal for the next Regulatory Control Period, CitiPower state that "*Forecast expenditure in the next regulatory control period is based on the current average cost of undertaking the program of works in the 2006-10 regulatory control period. The works program for the 2011-15 regulatory control period is derived from CitiPower's existing safety management plans and will largely reflect a continuation of the work program in the current regulatory control period.*"

On this basis, it appears reasonable to assume that safety management remains a continuing works program and that future expenditures should be consistent with historical expenditure trends.

[68] CitiPower's Submission to the Essential Services Commission – 2006 Price Review, Chapter 6.

6.4.5 Environmental, Safety and Legal summary

The historical forecasts for Environmental, Safety and Legal have proven to be inaccurate with significant levels of over-forecasting. In addition, there is a significant difference between the forecasts for the next control period and current levels of expenditure. On this basis it would not be reasonable to simply accept the forecasts for the next control period as being accurate.

The issues identified by CitiPower as driving the change in Environmental, Safety and Legal expenditure have been part of the operating environment for many years and have clearly been considered in the previous Environmental, Safety and Legal forecasts.

CitiPower has not identified any changes in these obligations that impact the next Regulatory Control Period.

A key assumption of the CitiPower proposal is that they are an efficient operator. The benchmarking undertaken by Nuttall Consulting and the historical expenditures of CitiPower tend to support this assumption.

On the basis of the information provided by CitiPower, it is reasonable to accept the efficient costs that have been recently incurred by the DNSP as the basis for forecasting the required Environmental, Safety and Legal expenditure for the next Regulatory Control Period.

Table 41 - Recommended CitiPower ESL capex

CitiPower	Costs (2010 $M)				
Environmental, Safety and Legal	2011	2012	2013	2014	2015
Recommended Expenditure	1.510	1.510	1.510	1.510	1.510

The recommended Environmental, Safety and Legal capex for CitiPower is based on the average actual expenditures incurred in the previous 5 years exclusive of indexation and escalation.

6.5 SCADA and Network Control

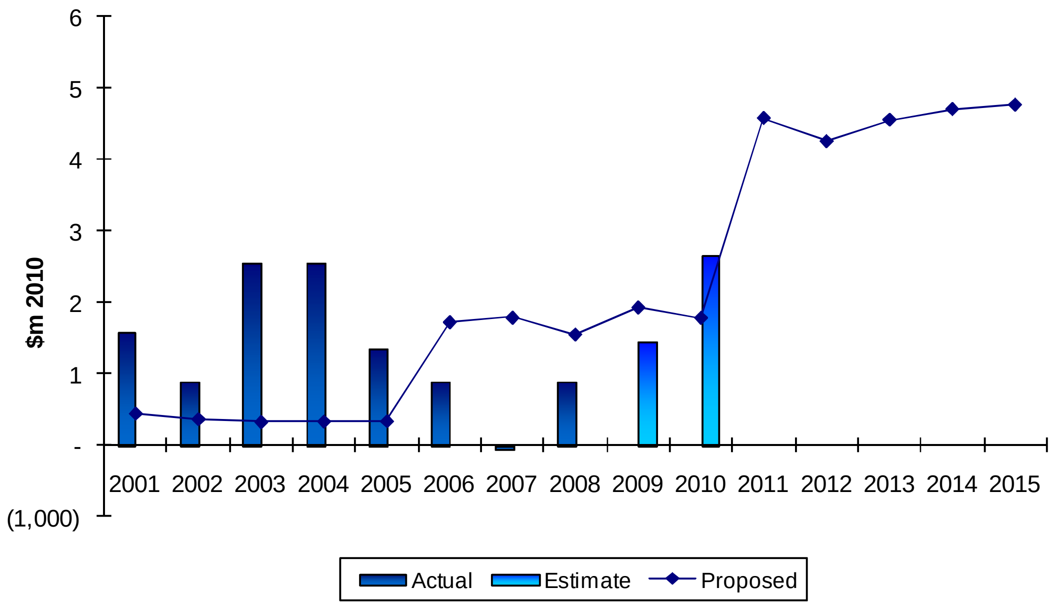
CitiPower is proposing an increase of over 700% in SCADA and Network Control capex for the next Regulatory Control Period when compared against actual expenditure in the current Regulatory Control Period. CitiPower estimates that its' SCADA and Network Control capital expenditure for the 2006-10 regulatory control period will be $5.8 million. It is forecasting that this will increase to $22.8 million in the 2011-15 regulatory control period.

For the 2006 EDPR, CitiPower proposed SCADA and Network Control expenditure of $8.8 million. The resultant actual expenditure for this period is forecast to be $5.8 million[69].

The following chart provides a summary of Environmental, Safety and Legal capex for CitiPower.

[69] Including 2009 and 2010 estimates.

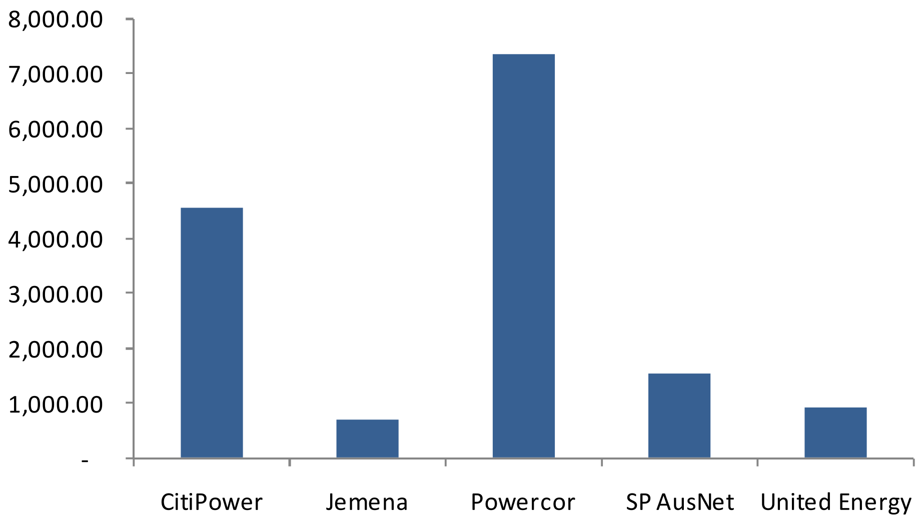
Figure 50 - CitiPower SCADA and Network Control capex



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 $1.3 million per annum. This is an average spend of less than one third of that proposed for the next Regulatory Control Period.

The CitiPower proposed SCADA and Network Control appears significantly higher than that proposed by other DNSPs for the next control period with the exception of Powercor. The following chart provides the average annual proposed capex for SCADA and Network Control for the next control period.

Figure 51 - Forecast SCADA and Network Control



The above chart shows that the proposed SCADA and Network Control capex for CitiPower and Powercor is significantly higher than that proposed by the other Victorian DNSPs. SCADA and Network Control expenditures for CitiPower and Powercor over the last 3 years are consistent with the proposed levels for Jemena, SP AusNet and United Energy. The factors driving the increased capex are considered below.

The CitiPower proposal identifies the key programs for the 2011-15 period as:

- continuation of the installation of new protection and control communications infrastructure
- installation of Distribution Management System (DMS) field devices
- increased substation monitoring and automation investments.

The DMS program identified above is not included in the SCADA and Network Control proposed expenditure, but is captured in the proposed IT capex. For this reason, it is assessed in the CitiPower IT capex section of this report.

New programs proposed by CitiPower to commence in the next regulatory period[70] include:

- Cable oil pressure monitoring
- Allocation for development initiatives
- Cable temperature monitoring
- Ethernet rollout and RTU Conversions to DNP
- Feeder automation
- Human machine interface (HMI) in zone substations
- Implementation of distribution management system (DMS) field devices
- Improved earth fault pre-emptive detection on underground cables
- Install IEC61850 communications
- Installation of remote monitored fault indicators on the overhead network
- Plant condition monitoring solutions
- Transformer monitoring solutions - oil, fans and pumps
- Upgrade swipe card system
- Weather stations
- Zone substation cameras - asset management and security

Continuing programs with increased expenditure in next regulatory period:

- Enhanced zone substation monitoring via SCADA
- Install Ethernet PLC at existing indoor distribution substations
- New fibre allowance

In its 2005 EDPR submission, CitiPower proposed capital expenditure of $7 million[71], for areas of network control other than the SCADA master station, including:

[70] Note: CitiPower states that some of these projects may commence in 2010.

- replacement of aged communications equipment located in CitiPower's zone substations, including remote terminal units
- upgrading zone substation monitoring and control systems, associated with the introduction of "smart protection relays"
- additional SCADA data security and security monitoring for the safety of the network
- replacement of aged remote fault monitoring units in the CBD high voltage feeder network.

Noting that the proposed DMS expenditure is captured in the non-system IT category, there appears to be a high degree of similarity between the major projects in 2005 and the current proposal. The CitiPower proposal does not discuss the overlap between the previous and proposed projects.

CitiPower states that they have already commenced the installation of new protection and control communications infrastructure. This suggests that the increased substation monitoring and automation investments represent the majority of the step change in proposed expenditure.

CitiPower provides some supporting information for these projects in chapter 28 of its proposal. This chapter was structured in response to the RIN requirements and included a section for each project on "Costs and benefits of each option considered". These sections did not provide any cost information or any quantitative assessment of benefits. As such, it is difficult to determine whether these project represent prudent or efficient expenditure.

CitiPower provided additional supporting material for the new and increased projects listed above. This information did not describe any quantitative benefits or advantages of the proposed programs. Many of the proposed programs would also have impacts on opex and system reliability. These impacts do not appear to be considered by CitiPower.

In the absence of any defined benefit, it is not possible to conclude that the projects are prudent from a timing perspective or that they are efficiently targeted.

There is a high degree similarity between the project descriptions provided for the 2005 EDPR process and those of the current review. In addition, the level of actual expenditure in the current regulatory period is well below the level proposed by CitiPower. This suggests that there is scope for deferral and efficiencies in the current and proposed programs.

CitiPower has not identified any new or changed regulations or obligations that require a significant step change in SCADA and Network Control capex. As such, Nuttall Consulting recommends that the existing level of SCADA and Network Control capex represents an efficient expenditure level.

[71] $2006

Table 42 - Recommended CitiPower SCADA and Network Control capex

CitiPower	Costs (2010 $M)				
Environmental, Safety and Legal	2011	2012	2013	2014	2015
Recommended Expenditure	1.124	1.124	1.124	1.124	1.124

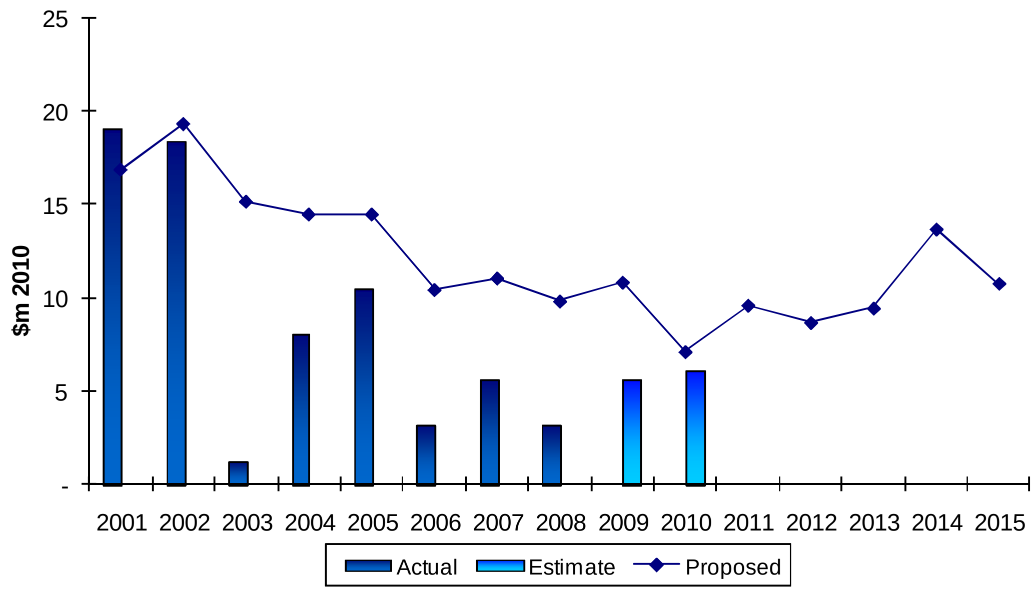
The recommended SCADA and Network Control capex for CitiPower is based on the average actual expenditures incurred in the previous 5 years exclusive of indexation and escalation.

6.6 Non-network general – IT

CitiPower submitted IT capital expenditure of $52.2 million over the forthcoming regulatory control period, which represents an increase of 71% in capital expenditure from audited historical expenditure ($30.5 million).). Major proposed IT capital projects include CIS replacement, leveraging off the AMI project and increasing the utilisation of mobile computing in the field.

During 2004-2008, CitiPower underspent their IT capital expenditure from a proposed of $60.3 million to actual audited spending of $30.5 million including deferrals of project like the CIS replacement.

Figure 52 - CitiPower proposed vs actual IT capex



CitiPower and Powercor are related parties and each holds a separate electricity distribution licence for a defined geographical electricity distribution area in Victoria. The Distribution Networks are jointly managed and operated by Powercor Australia and CitiPower personnel and systems. Under the Cost Sharing Agreement, defined overhead costs incurred by Powercor Australia and CitiPower are apportioned between each respective business. CHED Services provides both CitiPower and Powercor with specialist corporate services including: the Chief Executive Officer; Finance; the Company Secretary and Legal; Human Resources; Corporate Affairs; Regulation; Customer Services; Information Technology; and Office Administration; and under the Metering Services Agreement a number of metering services.

CitiPower submitted that their distribution network is unique amongst Australian electricity networks being the smallest whilst having the highest load density. As a result, CitiPower submitted that their capital expenditure being characterised by relatively few, but very large high capacity network extensions and connections. However, in terms of IT, CitiPower is not in a unique situation and therefore requirement should be consistent with other DNSPs. As CitiPower and Powercor operate under a cost sharing agreement, the cost submitted are not the actual estimation of costs, but CitiPower share of those costs as determined by the agreement. To assist us with the analysis, we combined the CitiPower and Powercor submissions to review the actual proposed costs:

Table 43 - Proposed CitiPower and Powercor non-network general IT capex

CitiPower & Powercor	Costs (2010 $M)				
Non-network general – IT	2011	2012	2013	2014	2015
CitiPower – Proposed	9.6	8.7	9.5	13.7	10.8
Powercor – Proposed	25.3	21.5	21.3	30.0	23.7
Total	34.9	30.2	30.8	43.7	34.5

The CitiPower proportion of the costs is between 37-46% of the total costs, accounting for its smaller number of end-users under the cost sharing agreement.

CitiPower submitted that "significant IT resources were diverted to preparing system readiness for the rollout of AMI" that resulted in previously proposed expenditure being deferred. This could also indicate a lack of flexibility and agility in the underlying IT systems. CitiPower also submitted that the main factors driving increased IT capital expenditure are:

1 Increases in baseline costs – this increase is required in order to support the existing suite of IT applications

2 New applications and systems – this increase in costs is associated with extending and replacing the existing suite of applications to meet the increasing business requirements.

CitiPower is currently replacing legacy Telstra PAPL (Permitted Attached Private Lines) with fibre optic and modern Ethernet networking for zone substation control and monitoring plus remote monitoring of distribution infrastructure via SCADA. CitiPower is intending to extend its SCADA operations with Distribution Management System (DMS) field devices that integrate with the existing Geographic Information System (GIS). This expenditure is classified as IT expenditure rather than part of distribution network, since it is regarded as part of CitiPower's IT assets. We make no comment on the classification of expenditure by the DNSP.

CitiPower will commence installing DMS field devices once the DMS infrastructure is in place (expected to be end of 2011).

CitiPower was an early adopter of x86 virtualisation (running both Windows and Linux) and is actively seeking to upgrade this infrastructure to latest levels as recommended by the vendor. CitiPower stated that limitation around "application support" for virtualisation, limited currently levels of adoption.

CitiPower's IT capital cost expenditure gradually increases from around $9 million per year until major upgrades and changes are expected for 2014 and 2015 incurring larger costs in the range of $11 million to $14 million. In our opinion, CitiPower has not fully considered the complexity of the totality of works that they are contemplating and the amount of change they can absorb, given the lack of agility in the IT environment. This is further demonstrated by their historical underspending of proposed IT capital expenditure. We consider it more likely that CitiPower will take considerably longer to complete these projects and that any projects in 2014 and 2015 are likely to be deferred or even abandoned for other alternatives. Therefore, we recommend that first three years of capital cost be spread over five years.

Table 44 - Recommended CitiPower non-network general IT capex

CitiPower	Costs (2010 $M)				
Non-network general – IT	2011	2012	2013	2014	2015
Proposed Expenditure	9.6	8.7	9.5	13.7	10.8
Recommended Expenditure	5.6	5.6	5.6	5.6	5.6

6.7 Non-network general other

CitiPower's proposed expenditure in the "non-network general – other" category represents only a small percentage (2%) of the total net capex in the next period, and only a very small portion of the proposed expenditure increase (1%).

Given the low significance of this expenditure, it was agreed with the AER that Nuttall Consulting would not undertake a detailed review of this category.

7 Appendix B - Jemena findings

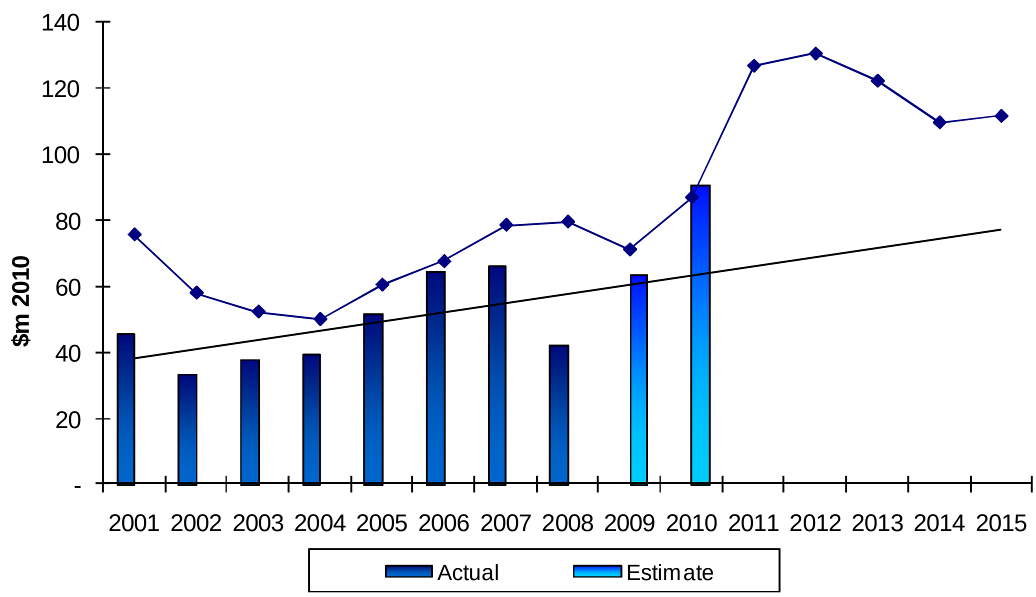
7.1 Overall capex

Overall capex is forecast to increase by 108% over actual expenditures in the current period. The main areas where capex is forecast to increase are reinforcement and reliability and quality maintained.

The following chart provides a summary of the overall capex figures for Jemena. Key aspects of this chart include:

- Jemena has consistently spent less than they proposed in the 2001 and 2006 EDPRs
- Jemena is proposing a future level of capex that is significantly higher than the historical levels of expenditure and is not consistent with the historical trend in capex.

Figure 53 – Jemena Capex Summary

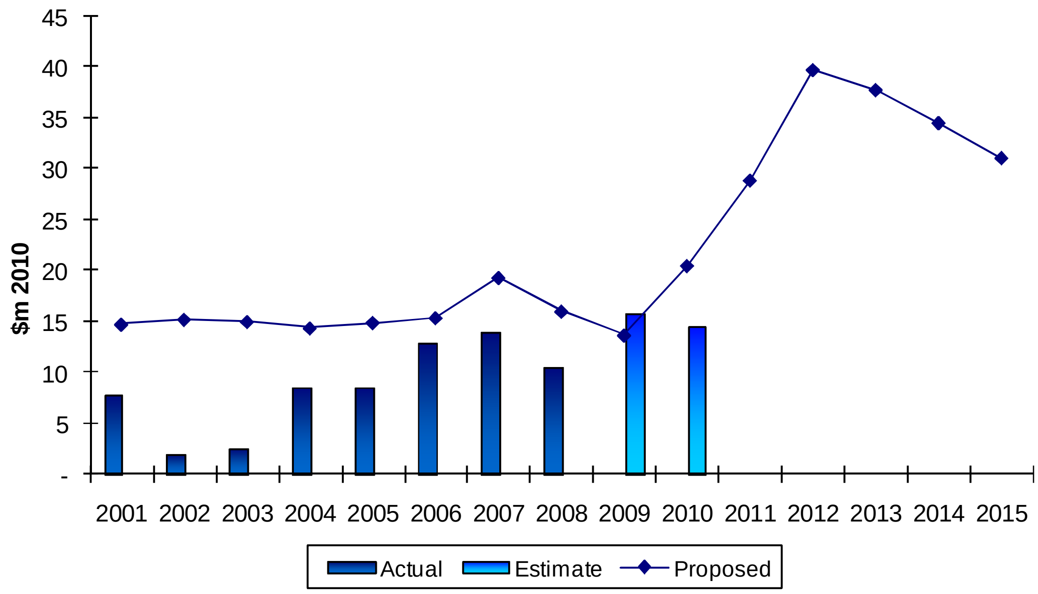


7.2 Reinforcement

Jemena is proposing a reinforcement program that is 175% greater than actual expenditures in the current Regulatory Control Period. Jemena estimates that its reinforcement capital expenditure for the 2006-10 regulatory control period will be $68 million ($2010). It is forecasting that this will increase to $172 million ($2010) in the 2011-15 regulatory control period.

The following chart provides a summary of reinforcement capex for Jemena.

Figure 54 - Jemena Reinforcement Capex Summary



This chart indicates that Jemena's reinforcement expenditure has been trending over the previous and current regulatory periods. Jemena has forecast that there will be a significant step increase in reinforcement expenditure in 2011 and 2012, and then expenditure will trend down, albeit to still greater levels than historically.

The 2001 EDPR forecasts prepared by Jemena was significantly over the actual expenditure incurred. The 2006 EDPR forecast is still in excess of the actual expenditure, but not to the level in the previous period. Interestingly, the level of over-forecast is not lower in the early years of the forecast, which is counterintuitive to what would be expected.

Jemena's proposal indicates a number of factors driving the proposed increase reinforcement expenditure, including:

- demand growth
- localised overloads in distribution substations and the LV network
- high utilisation and reducing level of spare capacity in the sub-transmission and distribution network.

7.2.1 Forecasting methodology

Jemena has developed its reinforcement plans largely based upon a bottom-up build of individual network needs and projects to address these needs. Jemena considers that these plans have been developed using the actual planning processes it applies in practice. However, due to their proposed timing, many projects will not have been through the full evaluations and justifications that would be required for approval.

A major portion of these plans is developed via the risk evaluation approach Jemena applies at the sub-transmission level. This approach is similar to the full probabilistic planning approach that is applied at transmission level in Victoria. This approach assigns an economic value to the expected energy that will not be served to customers (often related to the probability of network outages) and then balances this against the capital cost to reduce these risks, to ensure capital projects are economically justified.

Future predictions of the value of the expected energy not supplied are calculated using a number of key input assumptions, most notably:

- the 50% probability of exceedance maximum demand forecast
- a load profile, based upon the actual load profile for 1999/00
- a value of customer reliability (VCR) based upon the Victorian average- Jemena considers that this is reasonably reflective of its customer base
- transformer outage rates based upon those used for assessing transmission connection augmentations.

It is worth noting that detailed probabilistic assessments, based upon these assumptions, do not appear to have been undertaken at this stage on all projects. In these cases, engineering judgement has been applied to determine the timing. Nonetheless, where relevant, this judgement considers the forecast level of energy at risk.

For distribution feeders, Jemena applies a more deterministic approach that considers the loading of feeders, their rating and the load transfer capability. The plans however are still built up from individually identified needs.

For distribution substations, Jemena applies a pseudo “bottom-up” approach, whereby the quantity of distribution transformers requiring upgrading is calculated at an aggregate level. This process involves estimating the future maximum demands of the transformer population, based upon customer types and metering information associated with individual substations. The number of transformers requiring upgrading is then determined based upon the quantity with a predicted maximum demand above a function of the transformer rating. The expenditure is calculated based upon the quantity at various standard sizes and a unit cost for that size.

It is important to note that the methodology associated with the distribution substation is based upon a new pre-emptive upgrade program that has been commenced in the current period. Prior to this, distribution transformers would generally be replaced in a reactive fashion.

7.2.2 Nuttall Consulting detailed review

7.2.2.1 Process

Nuttall Consulting’s detailed review of Jemena’s reinforcement expenditure has included a review of its forecasting methodology and a number of specific projects. The general process applied by Nuttall Consulting in conducting its review of Jemena’s reinforcement expenditure is summarised in Section 4.2 of this report.

The projects reviewed included:

- Preston area voltage conversions, including the new East Preston and Preston zone substations
- Pascoe vale transformer upgrade

- Tullamarine new zone substation
- Craigieburn new zone substation (plus associated land purchases)
- TTS-CN-CS-TTS 66 kV line re-conductor
- KTS-MAT-AW-PV-KTS 66kV loop re-conductor and later splitting
- Distribution substation upgrades.

Key Jemena documents, in addition to Jemena's proposal, included in this review included:

- Appendix 9.1 of the Jemena Proposal – Network Asset Management Plan
- 2009 Distribution System Planning report
- Appendix 11.28 of the Jemena Proposal – Network Planning Guidelines.

Other documentation specific to the projects under review are identified in the sections below.

7.2.2.2 Findings on methodology

Overall, we consider that Jemena's methodology is reasonable for developing capital plans for internal purposes. In this regard, the process should result in the identification of network needs, a list of projects to address these needs, and expenditure projections for the medium-term management of the network. In turn, this process results in a relatively comprehensive list of individual network needs and projects that can be monitored and developed further through the next period.

However, we do not consider that this largely "bottom-up" based process has been shown to be "fit for purpose" in terms of being a reasonable unbiased estimator for future prudent and efficient expenditure at the aggregate level. In particular, we do not consider that such a process adequately allows for the further optimisation of projects and synergies between projects that will occur as the individual projects and the overall capital plans advance through the capital governance process.

It is accepted that in some circumstances these processes will result in some projects being advanced or their scopes increased. However, in our view, the more detailed evaluation and justification associated with the project approval within the governance process will most likely result in overall expenditure being less than the simple summation of the project plans, as applied by Jemena to determine its reinforcement expenditure.

Related to the points above, we also have a significant concern that Jemena's use of a load profile based upon the 1999/200 actual profile may materially overstate the risks.

This view is based upon the fact that maximum demand has been growing at a significantly greater rate than energy since before 2000, and this is expected to continue throughout the next period. This results in the load profile becoming more "peaky" over time near the peak demand condition. This in turn means that predictions of energy at risk based upon an assumed load profiles, developed from significantly earlier years, may overstate these measures.

Our analysis of actual Victorian load profiles from 1999/2000 to 2007/08 suggests that this overestimate may be material (see Appendix J), possibly overstating the energy at risk in the next period by over 100%. This could result in projects being advanced by up to 3 years from their optimal date, depending on the rate of load growth.

It is accepted that the use of a 50% probability of exceedance maximum demand may understate expected risks. As such, there could be some argument that these two matters trade off somewhat. However, given the sensitivity to risks of the assumed maximum demand condition is well known in the industry, we consider it reasonable to assume that the optimism in this assumption is inherently allowed for in Jemena's evaluations. Therefore, we do not consider that this matter should affect our findings on the conservatism in the load profile assumed.

Issues associated with the distribution substation methodology will be discussed in the project reviews below.

7.2.2.3 Project reviews

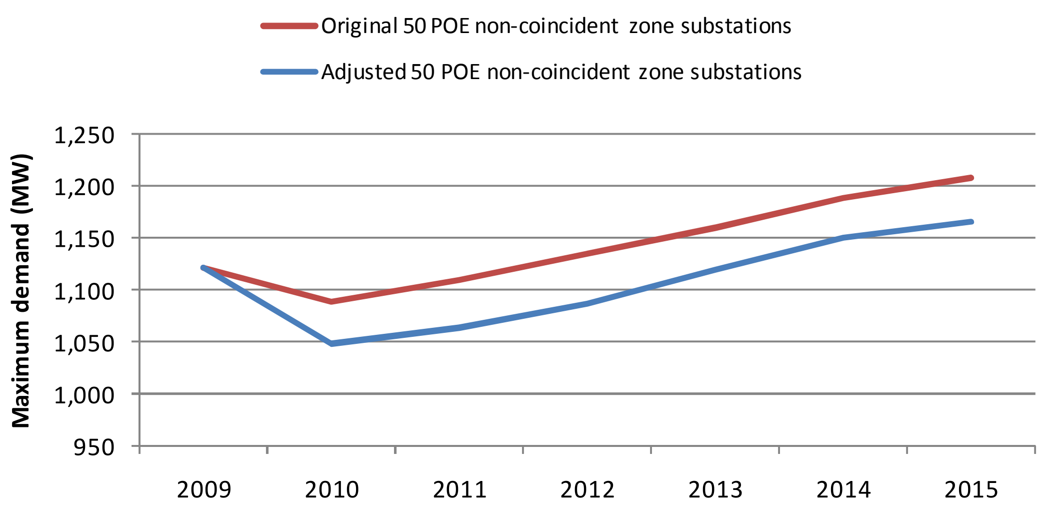
As noted in Section 4.2.4, the aim of the Nuttall Consulting review has been to determine the likelihood that the project expenditure will be required as proposed by Jemena. We consider that this is a reasonable approach to account for the likely consequences of the governance processes and the other specific methodological concerns discussed above.

An additional input to our review has been the findings of the AER's review of Jemena's load forecasts. Of particular relevance to our review are the maximum demand forecasts. The AER's findings here were that Jemena has overstated the growth in maximum demand.

A comparison of the Jemena maximum demand forecast and the AER's view is shown in the chart below. This chart indicates that the AER's adjustments result in maximum demand levels being delayed by around 1 to 2 years.

It is important to note that we have not been able to analyse the affect of these adjustments in detail. However, we have attempted to allow for these to some degree in our assessment of the likelihood of the projects. We would recommend however that the AER requires Jemena to reassess its plans more comprehensively in light of these load forecast findings to determine their effects.

Figure 55 – Jemena's maximum demand forecast



The following summarises the main findings for the projects reviewed.

7.2.2.4 East Preston and Preston new zone substations (voltage conversion strategy)

Cost:23 million

Completion: East Preston 2012 and Preston 2015

This project involves the establishment of two new zone substations at East Preston and Preston. This project is associated with Jemena's strategy to upgrade to the existing 6.6 kV voltage level in the Preston area to 22 kV. This strategy will result in significant increases in the network capacity in this area to cater for anticipated load growth.

Although the projects are assigned to the reinforcement category, the actual timing of the project is driven primarily by Jemena's views on the age and condition of the existing 6.6 kV assets[72]. Only the existing Preston zone substation has load at risk. However, provided load transfers can be managed, possibly via some additional augmentation work, there does not appear to be sufficient load at risk to justify the projects in the next period.

The main rationale for the proposed timing is to develop East Preston first. Following this, load from Preston can be transferred to this new substation in order that the new Preston substation can be developed, prior to the failure of the existing assets at Preston. Jemena is predicting that this will occur around 2014.

With regard to the condition of the existing 6.6 kV assets at East Preston and Preston (i.e. transformers and circuit breakers), Jemena's life cycle plans indicate that only the switchgear at Preston is currently anticipated to require replacement in the next period (2014). Other assets are timed for 2017 to 2024. As such, it appears that it is Jemena's view of the condition of the switchgear that is the primary driver for the timing of the project.

Based upon the information available, we do not consider that Jemena has adequately demonstrated that its views on the likely failure date for these assets is reasonable. Furthermore, given the range of replacement dates for these assets, we consider that there is a good possibility that Jemena will be able to manage the existing assets past 2014. As such, we consider that there is a reasonable possibility that further analysis of these projects will result in a more optimal staging of the projects, and the likely deferral of some elements.

Finally, we consider that Jemena's cost for the Preston projects is on the high side of a reasonable range. We have estimate this project cost to be around $13 million, compared to Jemena's estimate of $18 million.

Based upon the above, we consider that expenditure associated with these works has a moderate probability (50%) of being required as proposed by Jemena.

7.2.2.5 Pascoe vale transformer upgrade

Cost: 4.3 million

Completion: 2011

[72] Discussed in Appendix 11.30 of the Jemena Proposal – Preston area strategic plan.

This project involves the replacement of the existing three transformers with two transformers of a higher aggregate capacity.

The existing Pascoe Vale zone substation will have some load at risk in the next period. However, this does not appear to be sufficient to justify the planned project and timing.

The primary driver for the timing of this project appears to be the anticipated condition of the existing switchgear and transformers at Pascoe Vale. In this regard, the switchgear is considered to be in poor condition by Jemena, and is planned for replacement in the next period (this project has been assigned to the RQM category). However, although the existing transformers are old, Jemena's life cycle plans indicate they are not planned for replacement until 2018-2024. As such, it appears that the condition of the switchgear is the primary factor defining the timing of this project.

However, as noted in the RQM section below, we have reviewed the condition information for the Pascoe Vale switchgear, and although we accept it is in poor condition, there does appear to be some flexibility in the timing. If the replacement will result in the advancement of such a significant project, it is reasonable to expect that it is more likely that the switchgear replacements will be economically delayed (i.e. more risk will be required to justify the project).

Even setting aside this issue, given the relatively better condition of the transformers, we consider that there is a reasonable possibility that further analysis will result in the deferral of the project or its re-scoping.

Based upon the above, this project has been assigned a moderate to high probability (70%) of occurring as planned.

7.2.2.6 Tullamarine new zone substation

Cost: 10.3 million

Completion: 2012

This project involves the establishment of a new zone substation at Tullamarine. This project is driven by load at risk at the exiting Airport West zone substation and various issues with distribution feeder loading.

Jemena has provided energy at risk calculations and economic analysis for this project, which do support its timing. However, given the scale of this project, the point above on the load profile used in these calculations, and the AER's findings on Jemena's load forecast, we consider that there is a reasonable possibility that the project scope may be further optimised, resulting in the deferral of the new substation works.

As such, this project has been assigned a moderate probability (50%) of occurring as planned.

7.2.2.7 Craigieburn new zone substation

Cost: 13 million

Completion: 2016

This project involves the establishment of a new zone substation at Craigieburn. This project is driven by load at risk at the exiting Somerton zone substation and various issues with distribution feeder loading.

However, we have a number of concerns with the timing of this project.

Firstly, Jemena's energy at risks calculations justifying this project do not appear to allow for other anticipated works that may reduce the level of load at risk at Somerton, specifically the upgrade of the Coolaroo transformer. Furthermore, given the point above on the load profile used in these calculations, and the AER's findings on Jemena's load forecast, we consider there is a reasonable possibility that the project will be deferred.

Secondly, we consider that Jemena's cost for this project is on the high side of a reasonable range. We have estimated this project cost to be around $10 million.

Finally, and to a lesser degree, we also consider that Jemena has not adequately demonstrated that a 3rd transformer at Coolaroo may not be a lower cost reasonable alternative.

Based upon the above, this project has been assigned a low probability (33%) of occurring as planned.

7.2.2.8 TTS-CN-CS-TTS 66 kV line re-conductor

Cost: 0.96 million

Completion: 2012

This project involves the re-conductoring of sections of the existing TTS-CN-CS-TTS 66 kV line. This project is driven by load at risk due to an outage of a section of the existing line.

Jemena's energy at risk calculations and preferred option appears reasonable, and justifies the selection and timing of the project. However, given the point above on the load profile used in these calculations, and the AER's findings on Jemena's load forecast, we consider there is a reasonable possibility that the project will be deferred.

This project has been assigned a moderate to high probability (70%) of occurring as planned.

7.2.2.9 KTS-MAT-AW-PV-KTS 66kV loop re-conductor and later splitting

Cost: 0.5 million and 1.8 million

Completion: 2011 and 2015

This project involves the re-conductoring of sections of the existing KTS-MAT-AW-PV-KTS 66 kV line followed by a later project to split the loop. This project is driven by load at risk due to an outage of a section of the existing line.

The options considered by Jemena appear reasonable. However, we do not consider that Jemena has clearly demonstrated that the value of the risks is sufficient to justify the timing of this project. Based upon our assessment of these risks, using Jemena's assumptions, we consider that the project may be optimally deferred by 1 to 2 years. Furthermore, given the point above on the load profile used in these calculations, and the AER's findings on Jemena's load forecast, we consider there is a reasonable possibility that the project will be deferred even further.

Based upon the above, this project has been assigned a low probability (33%) of occurring as planned.

7.2.2.10 Distribution upgrade program

Cost: 60 million

Completion: 2011-2015

This program involves the upgrade of the distribution transformers (and associated LV works). The key driver for this project is the projected loading at the distribution transformers.

The key factor resulting in the proposed increased expenditure for this program is the move to a pro-active upgrade program. The aim here is to replace the transformers before they fail, improving the reliability of the network and reducing safety risks.

However, we do not consider that Jemena has adequately demonstrated that this program is economically justified, in terms of actually realising the anticipated benefits. In particular, we do not consider that the DNSPs have provided sufficient evidence to show that the program can adequately target specific transformers, such that it will reduce the transformer failure rate sufficiently. The important point here is that Jemena does not meter load at the distribution transformer; it has to estimate the loading at a particular transformer via customer metering data. Furthermore, determining when a distribution transformer may fail is more problematic than power transformers, as detailed condition information is not available.

It is also worth noting that we also consider that a delay until the AMI roll-out may allow information from these meters to be used to more accurately determine transformer loadings and target transformers. We also note that the STPIS provides some incentive and reward for undertaking these programs if it will be improving reliability.

Based upon the above, the distribution transformer upgrade program has been assigned a low probability (30%) of occurring as planned. This probability has been assigned to allow for the existing levels of upgrades, with some allowance for the escalation in volumes due to demand growth.

7.2.3 Overall findings

Based upon our review, we do not consider that Jemena has adequately demonstrated that its proposed increases in reinforcement expenditure are reasonable. Moreover, we consider that significant reductions to the proposed plans will occur as the plans pass through the governance processes and more detailed evaluations and justifications are undertaken. In our opinion, a reasonable estimate will be more in line with the historical trend.

This view is based upon a number of findings from our project reviews, which draw upon our high-level expenditure analysis and the findings of the methodology reviews.

Firstly, for a number of the projects reviewed (e.g. the Preston area voltage upgrade), the main driver of the timing of the project was the age/condition of existing assets. Without this issue, it appears that the EENS and capacity issues would not require the scale of augmentation at the proposed time. For these projects, we have reviewed the condition information available in the relevant asset life cycle plans. In our opinion, based upon the information available, there did not appear to be a compelling case that the projects were required at the proposed time. There still appears significant discretion in the timing of these projects.

Secondly, in many cases, the timing of the projects reviewed did not appear to be economically justified, in terms of the benefits through the reduction in EENS. Furthermore, given the point made above on the demand profile assumed by Jemena and the AER's findings on Jemena's demand forecast, we consider there is a reasonable possibility that many projects could be deferred.

Thirdly, in some cases there appeared to be other lower cost options, not considered in detail by Jemena, that we consider may have a reasonable probability that they may be found to be the preferred option.

Finally, with regard to the distribution transformer upgrade program, we do not consider that Jemena has adequately demonstrated that the pro-active upgrade program will realise the benefits that are predicted for the reasons outlined above.

Using the approach discussed in Section 4.2, we have developed a forecast of the reinforcement expenditure using:

- the weighted average probability from the project reviews to determine the reasonable estimate of the total expenditure
- a constant growth rate assuming a notional 2008 base-line, derived from the average of the historical 2006-2008 expenditure.

Based upon this process, we have estimated the Jemena reinforcement expenditure in the next period will be 38% of the Jemena proposal and the expenditure growth rate from historical levels will be 7.4%.

Our estimate of Jemena's reinforcement capex is shown in Figure 33 and Table 24 below. It is important to note that this should be considered as an estimate only. The AER may need to make further adjustments to allow for its findings on the other matters, such as overheads and labour and material escalation, which are not accurately allowed for here.

Figure 56 – Jemena reinforcement capex recommendation

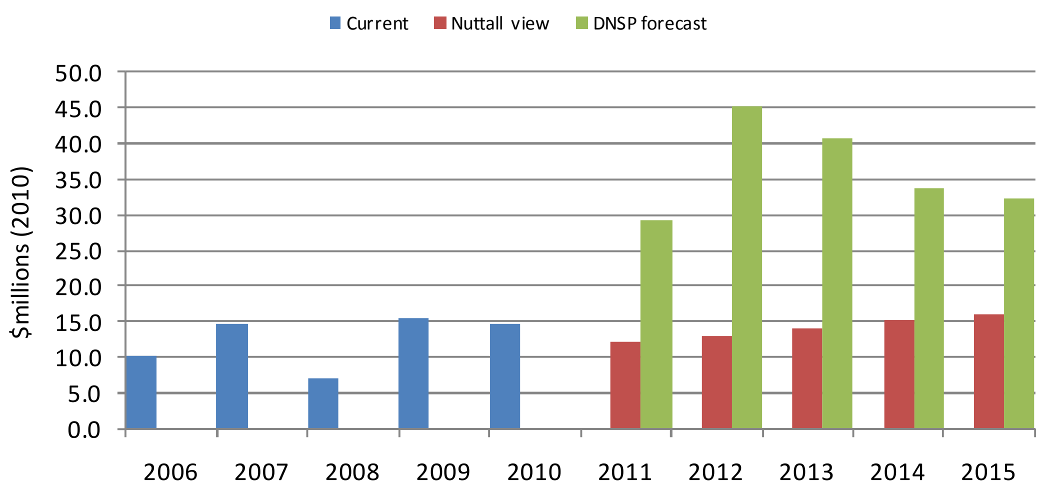


Table 45 – Jemena reinforcement capex recommendation

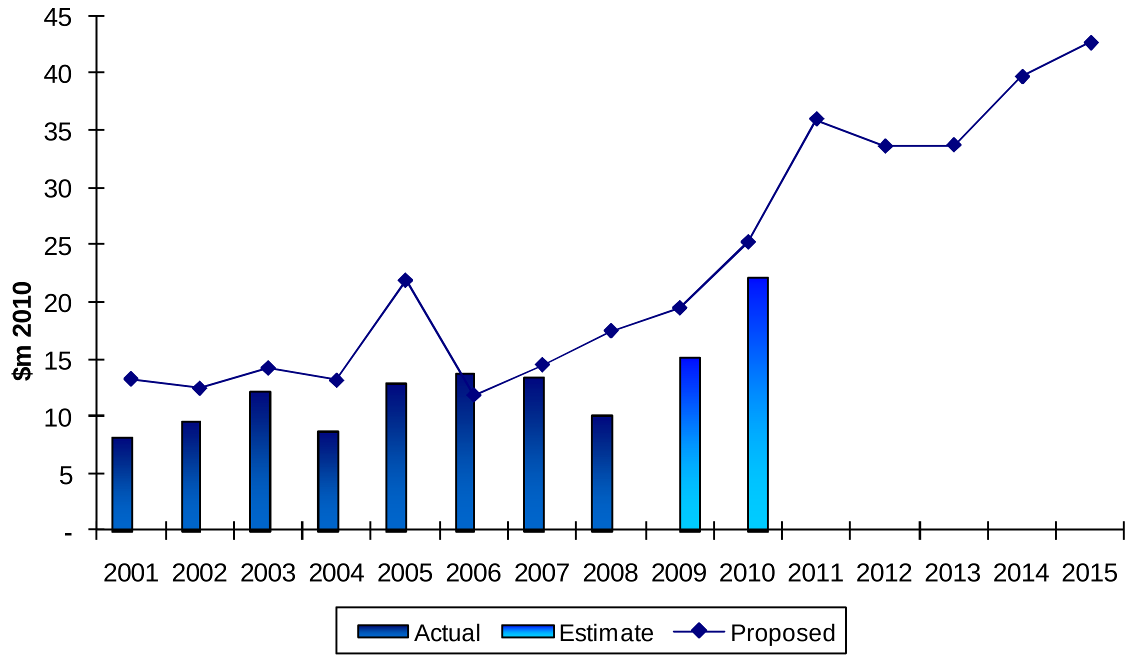
	$millions (2010)				
	2011	2012	2013	2014	2015
Jemena - proposed	29.4	46.1	41.6	35.1	32.8
Jemena - recommended	**12.2**	**13.1**	**14.1**	**15.1**	**16.2**

7.3 Reliability and quality maintained

Jemena is proposing an increase of 198% in reliability and quality maintained capex for the next Regulatory Control Period when compared against actual expenditure in the current Regulatory Control Period. Jemena estimates that its Reliability and Quality Maintained capital expenditure for the 2006-10 regulatory control period will be $75 million ($2010). It is forecasting that this will increase to $185 million ($2010) in the 2011-15 regulatory control period.

The following chart provides a summary of reliability and quality maintained capex for Jemena. This indicates that the trend in actual expenditure is relatively flat, with a significant increase estimated for 2009 and then 2010. It also indicates that Jemena has historically over-forecast RQM expenditure.

Figure 57 – Jemena RQM capex



7.3.1 Overview of activity code review

Explanation of expenditure profile – trends and major drivers of increases

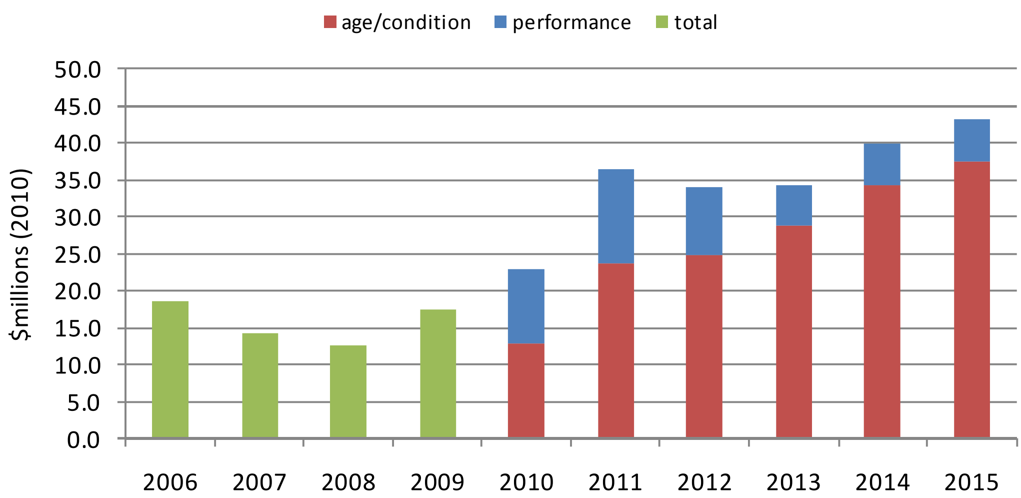
Table 46 - Summary of Jemena RQM expenditure

Average per annum expenditure ($2010)			% increase (from 2006-2008)	
2006-2008	2009-2010	2011-2012	2009-2010	2011-2015
15.1	20.0	37.2	33%	147%

As indicated in Table 46, Jemena are proposing a significant increase in RQM expenditure from 2011. The increase is mainly driven by two factors: increased age/condition related asset replacement and the need for a number of performance related programs to maintain reliability and quality to the target levels. Jemena considers that the additional performance works are required due to two factors: the degradation expected in the next period through climate change and degradation in asset failure rates that have occurred historically.

The breakdown of expenditure into the age/condition and performance drivers is shown in Figure 58. It is worth noting that this breakdown is not available prior to 2010. This figure indicates that the performance related expenditure appears to be resulting a in step increase in 2010. The underlying age/condition driven expenditure is stepping up in 2011, with a significant annual increase from that time.

Figure 58 - Jemena RQM expenditure profile



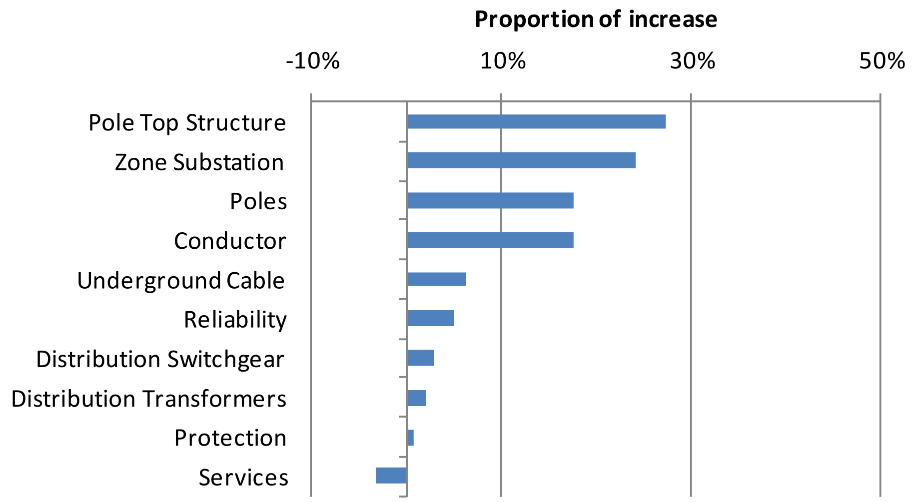
The breakdown of the 2011-2015 RQM expenditure into Jemena's activity codes is shown in Table 47. These activity codes are ranked in terms of significance, based upon the proportion of total RQM expenditure.

Table 47 - Activity Code summary

Activity Code	Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
	2006-08	2009-10	2011-15		90-10	11-15
Pole Top Structure	2.8	3.1	8.9	24%	10%	214%
Zone Substation	1.9	2.0	7.2	19%	7%	286%
Poles	1.4	1.9	5.3	14%	37%	287%
Conductor	0.7	2.2	4.6	12%	217%	567%
Distribution Switchgear	2.6	2.2	3.2	9%	-15%	24%
Protection	2.6	3.7	2.8	7%	44%	6%
Underground Cable	0.5	0.6	1.9	5%	22%	267%
Reliability	0.7	1.7	1.8	5%	153%	162%
Distribution Transformers	0.5	1.0	0.9	3%	96%	89%
Services	1.4	1.6	0.7	2%	11%	-50%
Total	**15.1**	**20.0**	**37.2**	**100%**	**33%**	**147%**

The breakdown of the proposed increase in expenditure for the next period (compared to the average of 2006-2008) into activity codes is shown in Figure 59. This illustrates that the expenditure on pole top structures, zone substations, poles and conductors are the major contributor to the proposed increase.

Figure 59 - Jemena activity code proportion of increase



In the review of expenditure in the individual activity codes that follows, the expenditure profiles will be considered from a "business as usual" perspective. As such, it will be assumed that climate change and the need to allow for performance degradation are no more significant than the business has faced in its recent history. This matter will be addressed further in the summarising section.

It is also worth noting that for a number of asset types, Jemena has used a proprietary age based replacement model to develop the volume forecasts. This model is similar in philosophy to the repex model discussed here. However, it uses a deterministic replacement life and condition assumptions to adjust the anticipated life of assets. The model had been developed for Jemena by PB Associates for the previous revenue review. It is also basically the same as the model that the ESC used in its 2001 EDPR.

Jemena has updated this model with revised input data for its model exercise for this revenue proposal. In the discussions that follow, this model will be called the PB replacement model.

7.3.2 Pole top structures

Activity code and expenditure summary

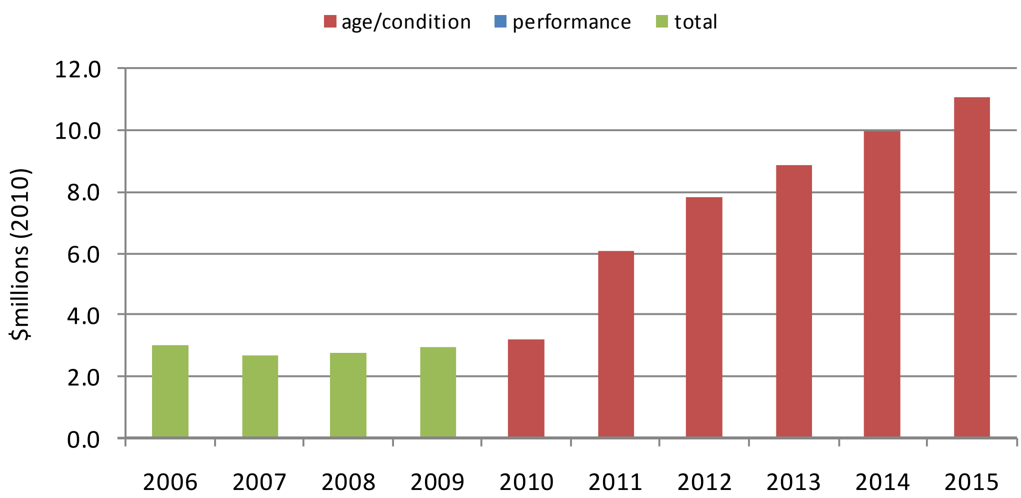
The pole top structure activity code covers the age/condition based replacement of these assets i.e. cross arms.

Table 48 and Figure 60 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents 24% of the total RQM expenditure in the next period, with expenditure forecast to step up significantly in 2011 and then increase at a fairly significant rate well in excess of the historical trend.

Table 48 Overview of expenditure for pole top structure replacements

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
2.8	3.1	8.9	24%	10%	214%

Figure 60 - Expenditure profile for pole top structure replacements



Forecasting methodology and rationale

The Jemena forecast is mainly based upon two cross arm replacement programs.

The first is related to the condition based replacement of cross arms determined via the cyclical inspection program. Jemena has used the PB replacement model to forecast the replacement quantities for this program. The documentation indicates that the output of the model forecasts a large step increase that was then manually smoothed by Jemena.

The second program relates to cross-arm replacement to mitigate pole top fire. This is an ongoing program and relates to the replacement of cross-arms in locations that are identified as having a history of pole top fires. This program represents approximately 16% of the replacement volume through the period.

Nuttall Consulting views

Given both these programs are ongoing and there does not appear to be any change in replacement criteria then it is not clear why such a significant step increase is required in 2011 or the rate of increase from that point on is so steep. Jemena considers the forecast numbers are in line with historical notification rates and the existing backlog of replacements, which is above the annual notification rate.

Nuttall Consulting is not in a position to dispute this information; however, in the absence of information to the contrary, it has to be assumed that the levels of backlog are being prudently managed, and as such, there is not a pressing need to have a step change in this level in 2011. Furthermore, this does not fully justify the large ramping of expenditure that is forecast through the period.

Based upon the above, Nuttall Consulting considers it is reasonable to assume that the pole top forecast should be based upon the historical trend with some allowance for the aging of the network, which based upon our repex modelling would be much less than presently forecast.

7.3.3 Zone substation

Activity code and expenditure summary

The zone substation activity code broadly covers the age/condition based replacement of primary plant within the zone substations. A major portion of this expenditure in the next period is due to the proposed replacement of power transformers and circuit breakers.

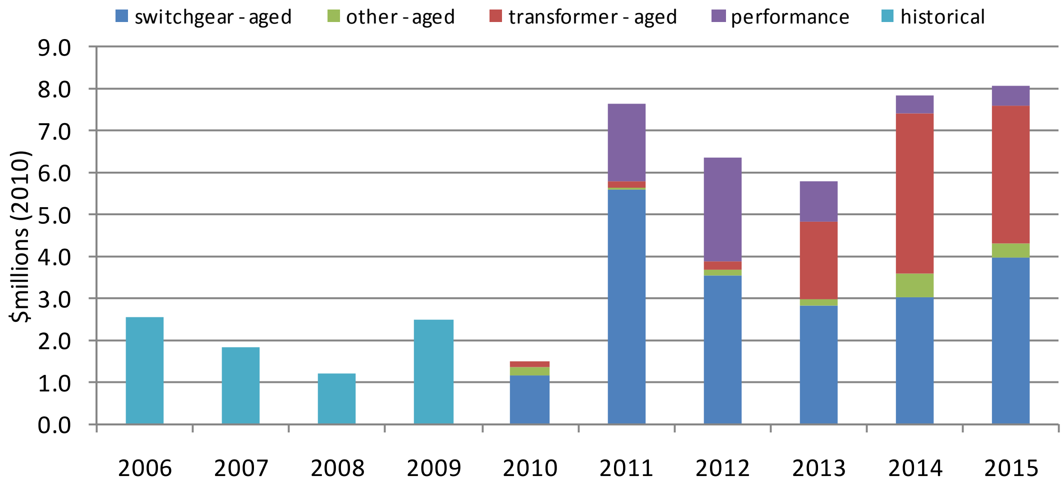
Table 49 and Figure 61 provide an overview of the expenditure in this category. Figure 61 also indicates the proportion of expenditure on the transformer and CB replacements and performance enhancements. The performance enhancements mainly include the upgrading of a transformer in 2012.

This analysis indicates that this activity code represents 19% of the total RQM expenditure in the next period, with expenditure stepping up significantly in 2011. This increase is largely due to increased transformer and HV CB replacement expenditure, and the performance enhancements.

Table 49 - Overview of expenditure for the zone substation plant replacement

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
1.9	2.0	7.2	19%	7%	286%

Figure 61 - Expenditure profile for the zone substation plant replacement



Forecasting methodology and rationale

The forecast in this category are mainly based on two methodologies relating to transformers and circuit breakers.

For transformers, expected replacement dates are prepared for the fleet based upon condition monitoring information. Various condition test results are used to assess the overall condition of the transformers. The primary test information for replacement timing however concerns the condition of the winding insulation. In this regard, test results that indicate the likelihood of a major failure of the transformer are used to determine which transformers should be targeted for replacement.

For the circuit breakers, a risk assessment has been performed to prioritise circuit breaker types for replacement. This assessment accounts for a number of factors; including the condition, age, performance and operational aspects of the circuit breaker type.

For both transformers and circuit breakers, engineering judgement is then used to develop the replacement program, based upon the other considerations e.g. augmentation requirements and other replacement needs. For the transformers, the issue of noise mitigation appears to be a significant factor that advanced the proposed timing.

This process has resulted in a number of transformers being proposed for replacement. Six transformers are being replaced under RQM in two locations: three in 2014 and three in 2015. One transformer is also proposed to be purchased as a spare in 2013, with its expenditure allocated to the RQM category.

Eighty-two circuit breakers of various types are planned for replacement at a number of locations through the next period. This compares to 74 in the current period, of which only 18 were replaced between 2006 to 2008 – all in 2008.

Nuttall Consulting views

Nuttall Consulting has focused its review on the transformer and circuit breaker forecasts, and associated methodology.

For transformers, Nuttall Consulting has reviewed the existing condition information detailed in the asset life cycle plans. Of particular note here is the degree of polymerisation (DP) estimate, which indicates that the transformers are at an advanced stage of aging (DP estimated value of 453 to 523), but they may still have around 5-10 years remaining life. This view appears to be supported by the proposed replacement dates, based upon the condition test, that are indicated in the asset life cycle plan (ALCP). Where by only one transformer is proposed for replacement in 2015, with all others at a later date.

As noted above, the main factor that appears to be advancing the works is the noise issue at the two locations where transformers are proposed for replacement. However, Jemena has not provided any analysis to support this position. Given that Jemena appears to consider that it can manage the noise issues until 2014 for one location and 2015 for the other, it is not evident why it cannot manage these matters for another year or so, without the risks increasing significantly, such that it can replace the transformers closer to their condition based life.

It is also noted that at one site, the plan is to rebuild the switchyard due to safety issues. However, as with the noise issue, it is not evident why it cannot manage these matters for another year or so, without these risks increasing significantly.

With regard to HV circuit breakers, Nuttall Consulting considers that Jemena's risk assessment is quite high-level, and does not allow risks to be readily compared from one element to another. As an example, it is not clear how well the risks deduced for the various factors can be compared against one another. Nuttall Consulting requested that Jemena explain how it has weighted the various factors to achieve comparability, but it appears from the response that this is still work in progress[73].

It is noted that the ALCP includes a summary of issues associated with certain switchgear, but does not provide any real detail of relevant matters for this review. Areas that Nuttall Consulting considers as missing include how the issues are being managed into the next period, how the risk will change in time from this period to the next, available options to mitigate the risk, and the evaluation that supports the proposed timing. Given this lack of justification for the scale of the plans, it is not clear why the replacement levels cannot be undertaken broadly in line with recent historical levels.

Condition test data has been provided for the switchgear at one location proposed for replacement in 2011[74]. This test data does support the view that much of the switchgear is near the end of its life. However, even here, the test data indicates that the condition of the worse switchgear is still only at the lower end of what Jemena considers the unacceptable range. There still appears from the Jemena information that there is some limited discretion in how Jemena may approach this issue.

Finally, based upon volume information provided by Jemena, it appears that switchgear replacement volumes are below those estimated for 2009 and 2010. Therefore, it is not clear why such a large increase in expenditure is required.

Based upon the above, Nuttall Consulting considers it is reasonable to assume that the zone substation forecast should be based upon the historical trend with some allowance for the aging of the network.

[73] Requested in email, dated 2/3/10. – response in email, dated 11/3/10

[74] See condition data for Pascoe Vale (PV) switchgear, Jemena email, dated 11/3/10

7.3.4 Pole Replacement

Activity code and expenditure summary

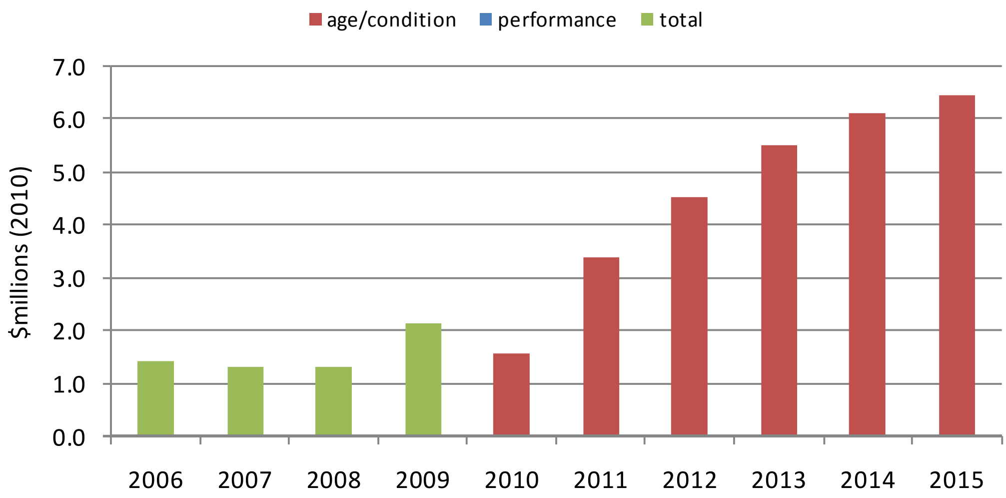
The pole replacement activity code broadly covers the age/condition based replacement of poles, including pole staking.

Table 50 and Figure 62 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents 14% of the total RQM expenditure in the next period, with expenditure forecast to step up significantly in 2011 and then increase at a fairly significant rate well in excess of the historical trend.

Table 50 - Overview of expenditure for pole replacements

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
1.4	1.9	5.3	14%	37%	287%

Figure 62 - Expenditure profile for pole replacements



Forecasting methodology and rationale

The Jemena forecast is mainly based upon two pole replacement programs.

The first is related to the condition based replacement of poles determined via the cyclical inspection program. Jemena has used the PB replacement model to forecast the replacement quantities for this program.

The second program relates to an undersized pole replacement program. This appears to be a proposed new program and relates to the replacement poles that are determined to be undersized for their intended purpose (based upon inspections). Jemena has estimated this quantity based upon information in their asset database. In this regard, it has been assumed that that all poles will be replaced over a 10-year period, with a constant number of 560 each year. It is worth noting that this is an estimate only, whether the poles are undersized will be determined through the inspections. This program represents approximately 30 to 45% of the replacement volume through the period.

Nuttall Consulting views

Then are two issues with the Jemena forecast. Firstly, the large step increase appears to be driven by the proposed new undersized replacement program. This proposal appears to be driven by 3 pole failures during the 2008 storm conditions. Other than this 2008 outcome, there does not appear to be any other substantiation of the need for this new program. Given that this issue would have been known for some time, and the risk accepted, it is difficult to determine whether this program is warranted at all. Even if it is the case then it is not clear whether Jemena's estimate is reasonable. For example, we would expect some prioritisation and opportunistic replacement to occur such that the number of replacements would be less than estimated by Jemena.

The second issue concerns the large rate of increase of expenditure. This increase appears to be driven by the increase predicted by the PB replacement model. The increase however is significantly higher than historical levels, which is far more constant.

Based upon the above, in the absence of more robust analysis to justify the scale of the new program and the expenditure ramp rate, Nuttall Consulting considers it is reasonable to assume that the pole forecast should be based upon the historical trend with some allowance for the aging of the network. Based upon our repex modelling this would be much less than presently forecast.

7.3.5 Conductor replacement

Activity code and expenditure summary

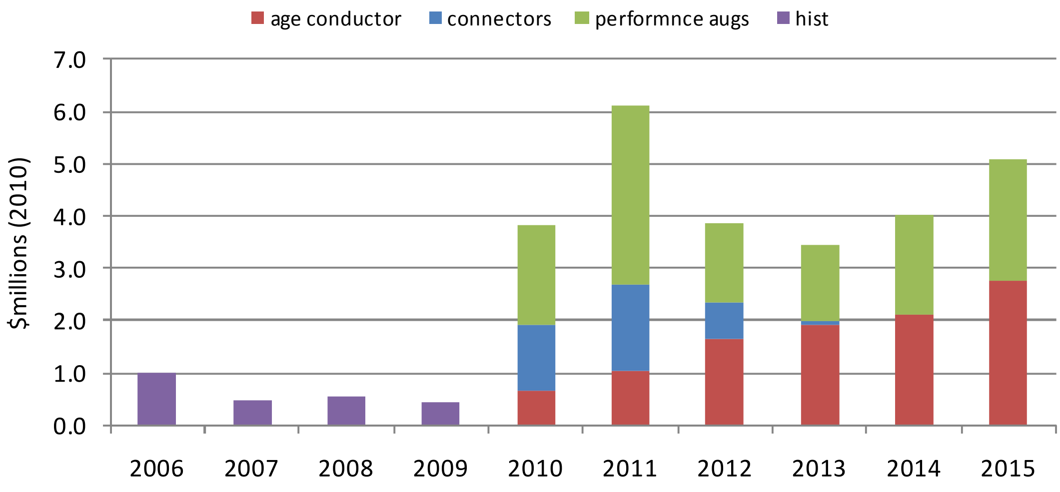
The conductor activity code covers expenditure on overhead line conductors and associated connecting equipment. This category includes the age/condition based replacement of conductors, a proactive connector replacement program, and a range of other projects that appear to be largely augmentations. Both the connector program and other projects are considered performance related by Jemena.

Table 51 and Figure 63 provide an overview of the expenditure in this category. Figure 63 also shows the expenditure breakdown into the three groups identified above. This analysis indicates that this activity code represents 12% of the total RQM expenditure in the next period, with expenditure anticipated to significantly increase from historical levels in 2010.

Table 51 - Overview of expenditure for conductor replacement

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
0.7	2.2	4.6	12%	217%	567%

Figure 63 - Expenditure profile for conductor replacement



Forecasting methodology and rationale

The age/condition based conductor replacement program appears to be a new program to replace conductors, based upon aerial inspection techniques. Jemena has forecast the quantity based upon the PB replacement model.

The connector replacement program is an ongoing program, running from 2009 to 2012. The Jemena information indicates that the majority of the connectors will be replaced in 2010 and 2011.

The other performance works appear to be based upon a series of identified projects to improve performance.

Nuttall Consulting views

With regard to the conductor replacement program, based upon the volume of information provided by Jemena, it appears that Jemena is assuming that its proposed inspection techniques will result in a significant step increase in conductor replacement levels. However, at this stage, it is not clear to us if this will occur. The Jemena documentation indicated that 26km was identified in 2006 following similar inspections, although it appears that a far lower level was replaced and was ramped down during the period, not up.

With regard to the connector program, the majority of the program appears to be planned to occur in the 2-year period 2010 and 2011. It is not clear from the information provided, what the justification is for such a small window, and what flexibility Jemena has to manage the risks associated with this program by extending the plan over a longer period. Given it has managed these issues throughout the current period, and has only undertaken a limited level of connector replacement in 2009, it seems reasonable to assume that Jemena can undertake this program over a longer period. It is also noted that this program is classed as a performance enhancement, as such, it is not clear if this program can be considered "business as usual".

Based upon the above, we see no reason to allow more than the average recent historical level with some allowance for an aging population. In our opinion, this should account for the likely outcome of a proactive conductor inspection program.

With regard to the works to enhance performance, these will be discussed further in the summarising section.

7.3.6 Underground cable

Activity code and expenditure summary

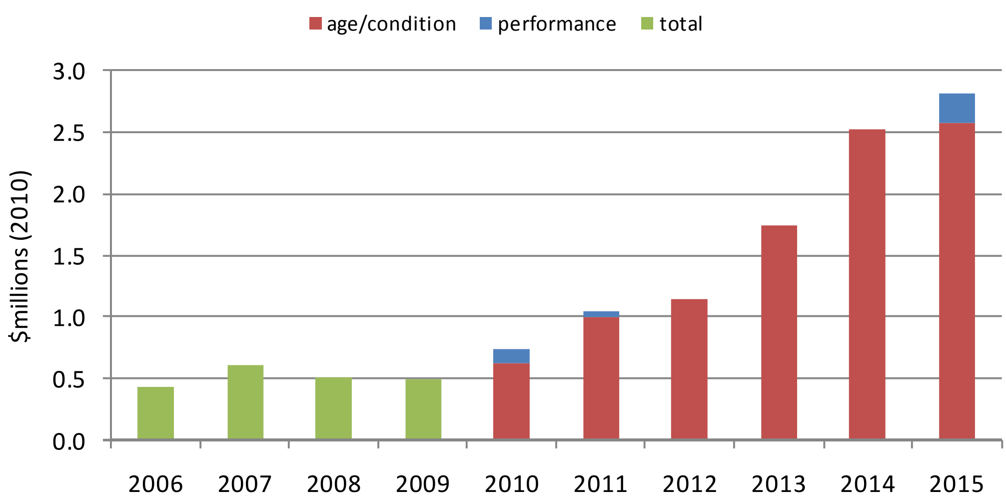
The underground cable activity code broadly covers the age/condition based replacement of underground cables and associated underground equipment (e.g. joints, terminations, link boxes etc).

Table 52 and Figure 64 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents 5% of the total RQM expenditure in the next period, with expenditure anticipated to significantly increase from historical levels in 2010. This increase appears to be largely due to increases in the replacement of cable joints and terminations in the first few years and cable replacement in the later years.

Table 52 - Overview of expenditure for underground cable replacement

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
0.5	0.6	1.9	5%	22%	267%

Figure 64 - Expenditure profile for underground cable replacement



Forecasting methodology and rationale

The Jemena information indicates that the forecasts for the cable replacements are based upon the PB replacement model and joint and terminations are based upon historical failure rates.

Nuttall Consulting views

Nuttall Consulting has reviewed the information provided by Jemena to support the expenditure forecast associated with this activity code. However, there is little information to justify the scale of the sharp increase that is proposed from 2010.

For joint and terminals, which appears to be a significant portion of the expenditure in 2011 and 2012 (approx. 75%), as these are based upon historical rates, there does not appear to be a significant justification for such an increase from historical levels.

For cables, the Jemena forecast appears to be based upon cable replacement quantities well below historical levels in 2011 and 2012. Given the point above on joint and terminations, this does not support the need for an increase in expenditure for these years. The forecast cable replacement quantities however are increasing significantly in 2013 to 2015, to levels that are 500% to 1000% above the historical level (2006-2008). Based upon our replacement modelling, such a dramatic increase is not justified.

It is noted that Jemena has indicated that it is intending to introduce a new condition monitoring technique, but we do not consider that this alone is sufficient to justify such an increase. At this stage, there is little justification provided by Jemena that the introduction of this monitoring will result in any significant increase to the quantities of cable replacement – although it is accepted that it may reduce the failure rate.

Based upon these findings, we see no reason to allow more than the average recent historical level with some allowance for an aging population.

7.3.7 Reliability

Activity code and expenditure summary

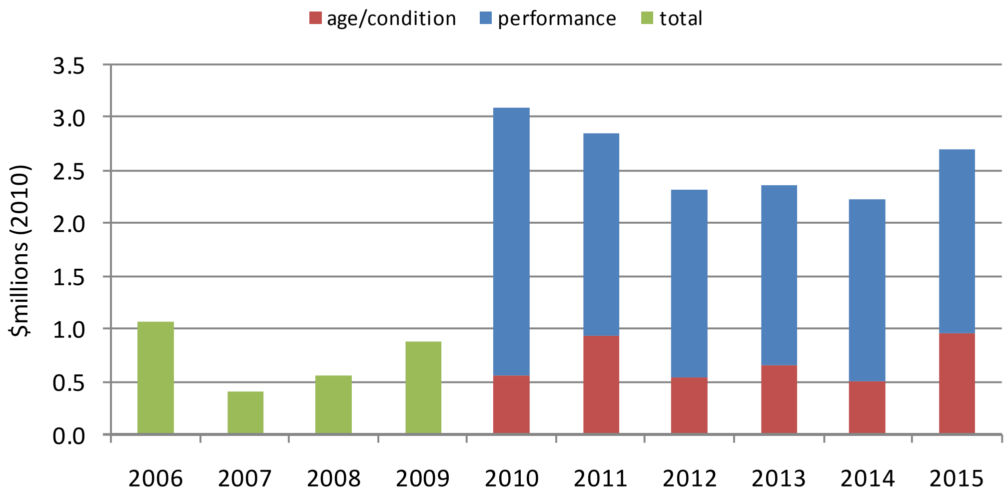
The reliability activity code broadly covers works to address reliability issues on the network.

Table 53 and Figure 65 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents only 5% of the total RQM expenditure in the next period, with forecast expenditure proposed to increase significantly in 2010.

Table 53 - Overview of expenditure for reliability

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
0.7	1.7	1.8	5%	153%	162%

Figure 65 - Expenditure profile for reliability



Forecasting methodology and rationale

The Jemena documentation indicates that the reliability forecasts are based upon a range of assumed projects to maintain reliability and quality of supply at the target level.

Nuttall Consulting views

The detailed justification for the projects in this category is not clear from the Jemena documentation, particularly with respect to their impact on reliability in the context of the significant increases in expenditure proposed elsewhere. However, assuming that the matters affecting reliability in the current period are largely similar to those in the next (i.e. "business as usual") and in the absence of a more detailed and quantitative justification for the expenditure increase, we consider that an allowance based upon the historical level is reasonable.

The matter of performance related expenditure to maintain reliability will be discussed further in the summarising section.

7.3.8 Distribution switchgear

Activity code and expenditure summary

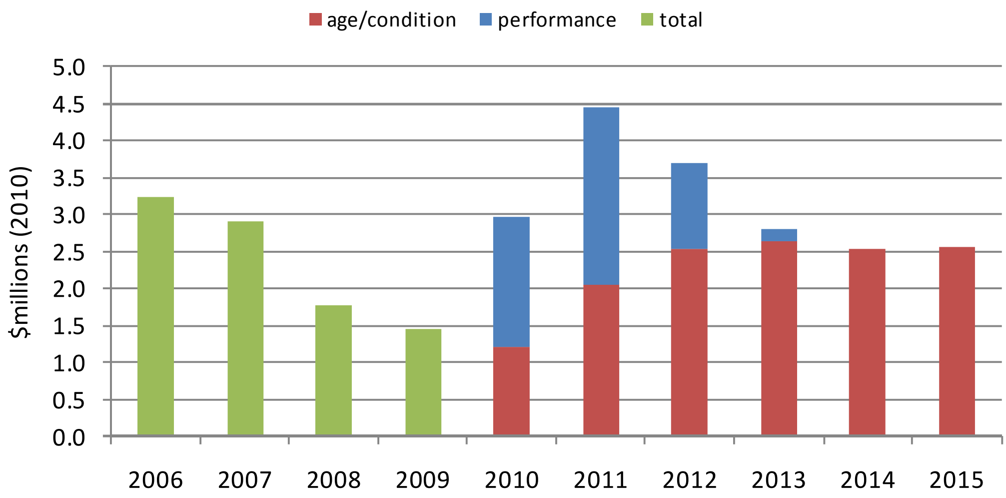
The distribution switchgear activity code broadly covers the age/condition based replacement of HV and LV switchgear. The performance work mainly covers a surge diverter replacement program.

Table 54 and Figure 66 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents 9% of the total RQM expenditure in the next period, with expenditure anticipated to significantly increase from recent historical levels in 2010 – although this appears to be due to the performance related works.

Table 54 - Overview of expenditure for the distribution switchgear replacement

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
2.6	2.2	3.2	9%	-15%	24%

Figure 66 - Expenditure profile for the distribution switchgear replacement



Forecasting methodology and rationale

The Jemena documentation indicates that the forecasts for HV switchgear are based upon a number of methods:

- assumed failure rates for air break switches, based upon a new proposed inspection program
- the PB model for fuse replacement quantities
- knowledge and engineering judgement to estimate distribution substation switchgear replacements, based upon a new proposed inspection manual
- knowledge of the types of surge diverters that are programmed for replacement.

Nuttall Consulting views

It is noted that expenditure in this category has been ramping down during the current period, but the age/condition based replacement is then forecast to increase significantly. This increase however is close to the average 2006 to 2008 levels.

Although we have not investigated the reasons for this profile in detail, given the aging of the network, we do not consider that the proposed age/condition based expenditure is unreasonable.

7.3.9 Distribution transformers

Activity code and expenditure summary

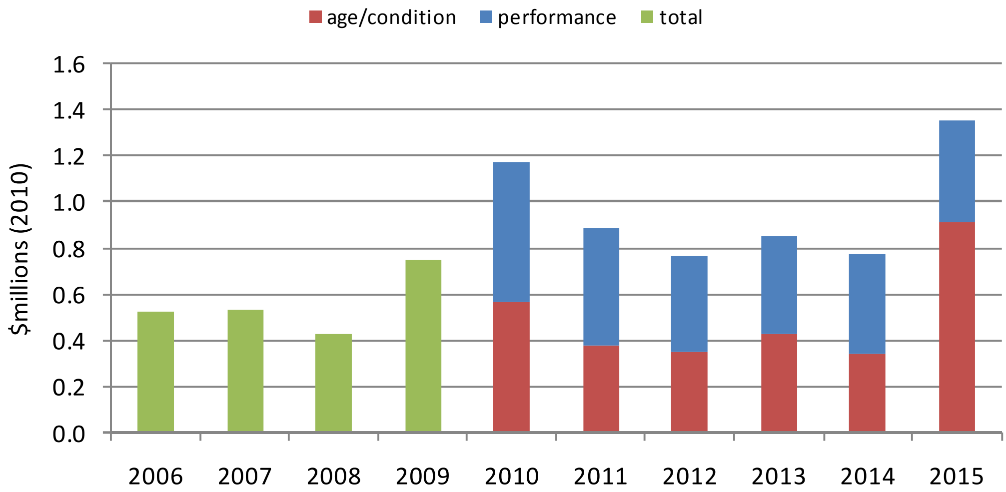
The distribution transformer activity code covers the age/condition based replacement of distribution transformers, with some additional allowance for performance related works.

Table 55 and Figure 67 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents only 3% of the total RQM expenditure in the next period, with age/condition based expenditure below average 2006-2008 levels in the next period.

Table 55 - Overview of expenditure for distribution transformer replacements

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
0.5	1.0	0.9	3%	96%	89%

Figure 67 - Expenditure profile for distribution transformer replacements



Forecasting methodology and rationale

The Jemena documentation indicates that the PB model has been used to forecast quantities of distribution transformer age/condition based replacements.

The methodology used to determine the performance related works is not clear.

Nuttall Consulting views

As noted above, age/condition based expenditure in this activity code appears to be broadly in line with the average during the 2006-2008 period, with a spike forecast for 2015. This spike appears to be due to an assumed doubling of transformer replacements in this year. The reason for this is not clear, but it is assumed that it may be a spike through the PB model, due to its deterministic replacement approach.

Other than the 2015 year, we consider that this estimate is reasonable. For 2015, we consider that this should be brought in line with the preceding years. Given this issue, we recommend using the replacement model to derive the profile.

7.3.10 Protection

Activity code and expenditure summary

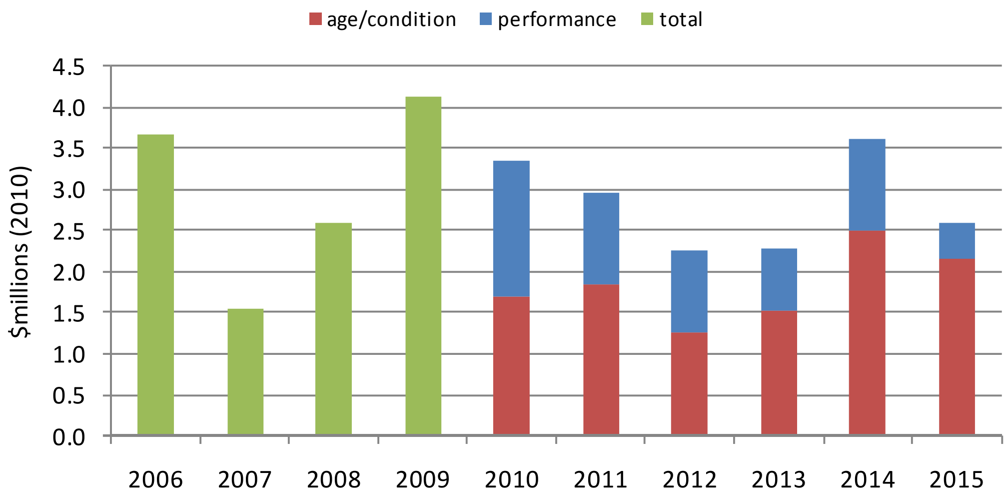
The protection activity code largely covers the age/condition based replacement of protection relays and some other secondary systems. It also includes a range of performance works.

Table 56 and Figure 68 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents 7% of the total RQM expenditure in the next period, with age/condition based expenditure at relatively low levels compared to average historical levels.

Table 56 - Overview of expenditure for the protection replacements

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
2.6	3.7	2.8	7%	44%	6%

Figure 68 - Expenditure profile for the protection replacements



Forecasting methodology and rationale

The Jemena document indicates that the relay replacement program has been forecast based upon installation age. It is also noted that DC systems are also forecast based upon installation age. In both cases, however the detail of this methodology is not clear

Nuttall Consulting views

Although the methodology for producing this age/condition based forecast is not clear, given that expenditure is at the lower level of expenditure in the current period, Nuttall Consulting does not consider the estimate is unreasonable. As such, we have not investigated this category in any detail.

7.3.11 Services

Activity code and expenditure summary

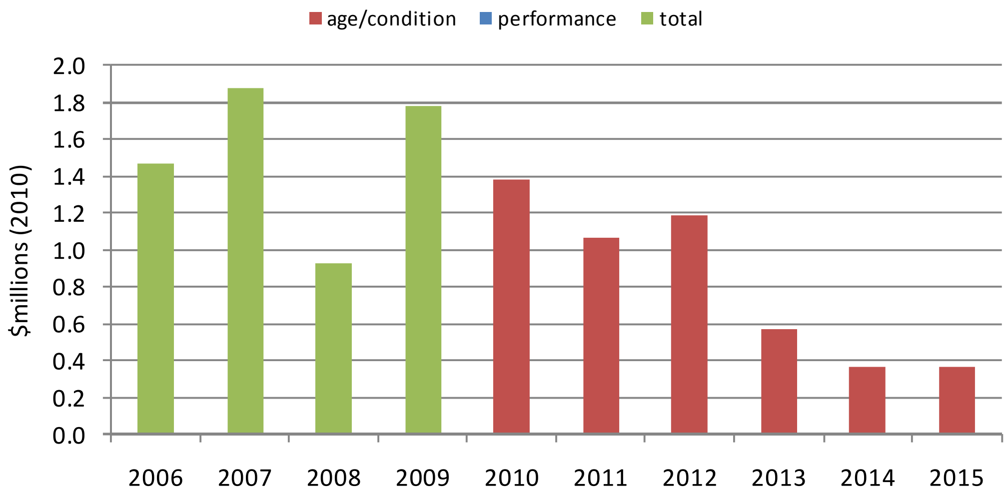
The service activity codes broadly cover the age/condition based replacement of customer service lines and cables.

Table 57 and Figure 69 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents only 2% of the total RQM expenditure in the next period, with expenditure anticipated to trend down in the next period.

Table 57 - Overview of expenditure for the service replacements

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
1.4	1.6	0.7	2%	11%	-50%

Figure 69 - Expenditure profile for the service replacements



Forecasting methodology and rationale

The Jemena documentation indicates that these forecasts are based upon historical and known program rates.

Nuttall Consulting views

Given that expenditure is forecast to trend down significantly in the next period, Nuttall Consulting does not consider the estimate is unreasonable. As such, we have not investigated this category in any detail.

7.3.12 Overall findings

The above has shown that the proposed increase in RQM expenditure in the next period is mainly driven by two factors: increased age/condition related asset replacement and the need for a number of performance related programs to maintain reliability and quality to the target levels. Jemena consider that the additional performance works are required due to two factors: the degradation expected in the next period through climate change and degradation in asset failure rates that have occurred historically.

With regard to the increase driven by climate change, the AER has instructed Nuttall Consulting that it does not consider that Jemena's approach is appropriate, and as such, the AER intends to reject claims for expenditure increases based upon climate change, including those in the RQM category.

With regard to other performance enhancement projects, Jemena has not provided detailed evaluation of the changes to reliability due to its proposed program.

Furthermore, based upon our "business as usual" approach, it is not clear why an allowance based upon increases to allow for the aging of the network plus an allowance for the historical level of reliability/quality related expenditure is not appropriate.

With regard to the age/condition based replacements, it is obvious that Jemena is proposing to undertake increased levels of replacement and introduce a number of new pre-emptive replacement programs. However, Jemena has not provided any economic analysis that demonstrates that the increases are prudent and efficient. It is also worth noting that, as the aim of some of the pre-emptive programs is to improve performance, the STPIS may be an appropriate mechanism for funding such changes.

It is noted that in some cases, a replacement model has been used to determine quantities for replacement (the PB model). However, in the cases where this appears to be forecasting replacement levels much higher than existing levels, Jemena's justification for the increase does not appear to be reasonable.

For other assets, the basis for the increase appears to be due to known issues and associated risks, which are discussed in the asset "life cycle management plans". However, in these cases, we do not doubt that the issues and associated risks exist, but it has not been demonstrated how Jemena is presently managing these matters – presumably in a prudent and efficient manner – and how the risk will change over time. As such, it is not evident that the scale of the increase is required.

Based upon our review, we do not consider that Jemena has adequately demonstrated that the increases are prudent and efficient. We consider that the RQM allowance should be based upon the recent historical levels of RQM expenditure with some additional allowance for the aging of the network.

The recommended RQM expenditure is shown in Table 58. The basis for these recommendations is indicated in Table 59.

It is important to note that this recommendation must be considered in the broader context of the overall capex. We would fully expect that at the activity code level, actual expenditure may differ considerably as circumstances change and the full capital governance process is applied.

It is also important to note that this recommendation should be considered as an estimate only. The AER may need to make further adjustments to allow for its findings on the other matters, such as overhead and labour and material escalation, which are not accurately allowed for here.

Table 58 – Jemena recommended RQM capex

	$thousands (2010)				
Activity code	2011	2012	2013	2014	2015
Proposed	35,938	33,779	33,963	39,918	42,648
Recommended	**14,437**	**15,445**	**15,487**	**15,868**	**16,724**

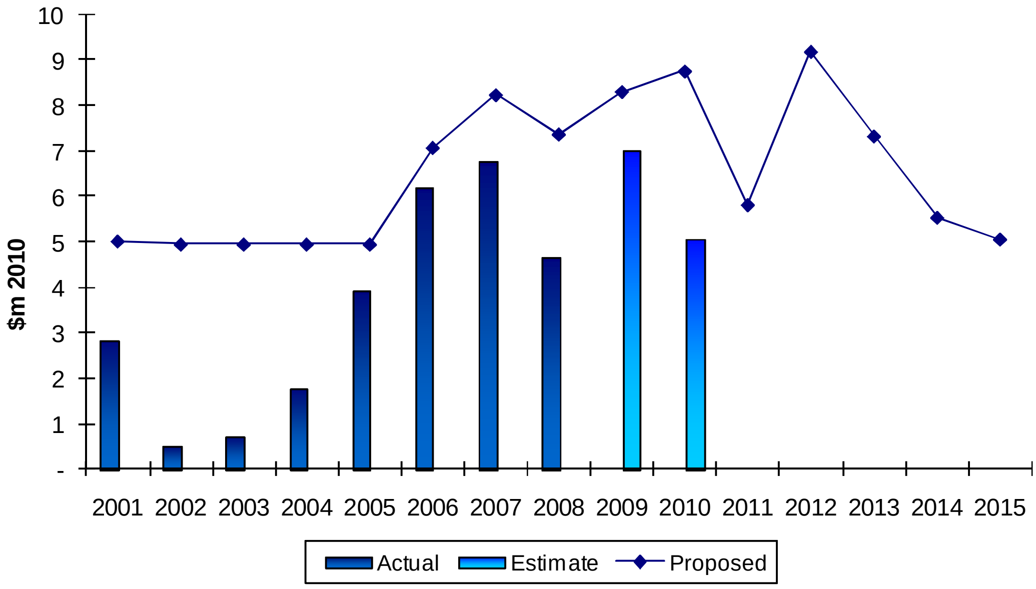
Table 59 – Jemena activity code based adjustments

Activity code	Nuttall Consulting view
Poles	Rejected - allowance based upon average 2006-2008, with increase based upon repex model findings
Pole Top Structure	Rejected - allowance based upon average 2006-2008, with increase based upon repex model findings
Conductor	Rejected - allowance based upon average 2006-2008, with increase based upon repex model findings
Distribution Transformers	Rejected - allowance based upon average 2006-2008, with increase based upon repex model findings
Underground Cable	Rejected - allowance based upon average 2006-2008, with increase based upon repex model findings
Zone Substation	Rejected - allowance based upon average 2006-2008, with increase based upon repex model findings
Protection	Rejected - allowance based upon average 2006-2008, with increase based upon repex model findings
Distribution Switchgear	Accepted (age/condition only)
Services	Accepted
Reliability Maintained (performance)	Rejected - allowance based upon average 2006-2008, with increase based upon repex model findings

7.4 Environmental, Safety and Legal

Jemena estimates that its Environmental, Safety and Legal capital expenditure for the 2006-10 regulatory control period will be $29.7 million ($2010). It is forecasting that this will increase to $32.9 million ($2010) in the 2011-15 regulatory control period.

Figure 70 – Jemena ESL expenditure



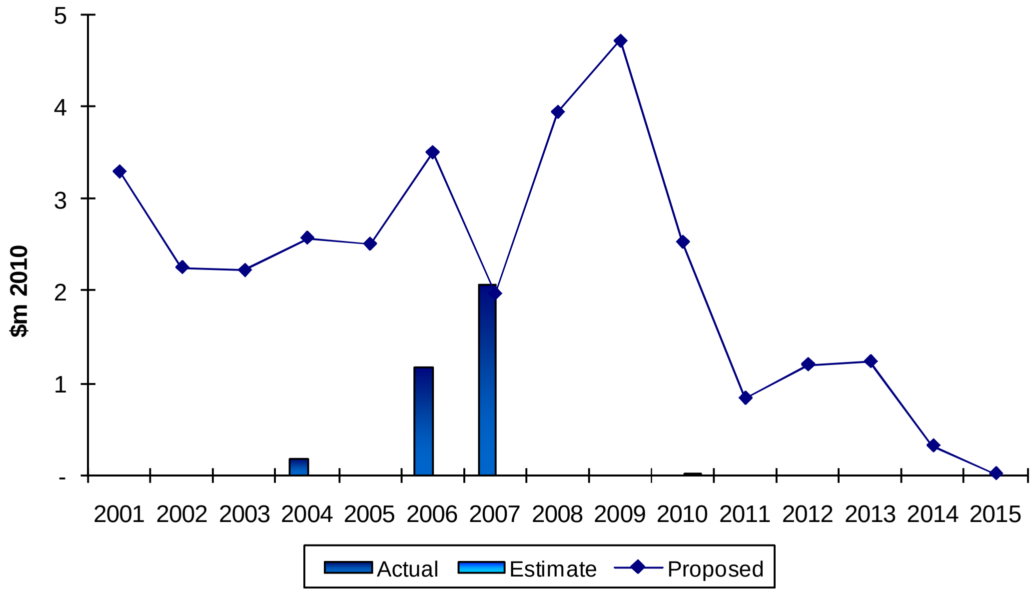
Given the modest proposed increase and the low significance on overall capex, it was agreed with the AER that Nuttall Consulting would not undertake a detailed review of this category.

7.5 SCADA and Network Control

Jemena is proposing expenditures of $3.5 million relating to SCADA and Network Control in the next control period. This level of expenditure is relatively consistent with expenditure in the current control period, although the nature of historical expenditure is more sporadic (i.e. lumpier).

The expenditures proposed by Jemena for the 2001 and 2006 EDPRs appear to have been significantly underspent in the respective periods. The proposed expenditure for the next control period appears to be significantly closer to actual historical trends.

Figure 71 - Jemena proposed and actual SCADA and Network Control capex



The Jemena SCADA system includes a central master station and remote terminal units (RTUs) which measure critical system parameters such as voltages, currents and plant status/condition and then interprets and displays this data to operational personnel in the Jemena control centre.

The expenditure allowances proposed by Jemena cover the works at the zone substations including the provision of an integrated zone substation security system, enhancement of the station RTU for smart network applications, and support services. The proposed works include the Zone Substation Integrated Security (electronic security) project. This project continues the security improvement projects that have been undertaken by Jemena in the current control and is also linked with other security projects being undertaken in the Environmental, Safety and Legal category.

Information provided by Jemena identifies that the project is consistent with the regulatory obligations and internal risk assessment processes.

The capex requirement for the central master station is addressed in the non-network IT section of this review (below).

The expenditure proposed by Jemena for the next control period is less than the current (3 year) average annual expenditure. The overall level of SCADA and Network Control expenditure is also less than the average Victorian spend in this category - noting the potential for differing categorisations between DNSPs.

Nuttall Consulting considers that the overall level of SCADA and Network Control capex proposed by Jemena for the next control period is reasonable.

Table 60 - Recommended CitiPower SCADA and Network Control capex

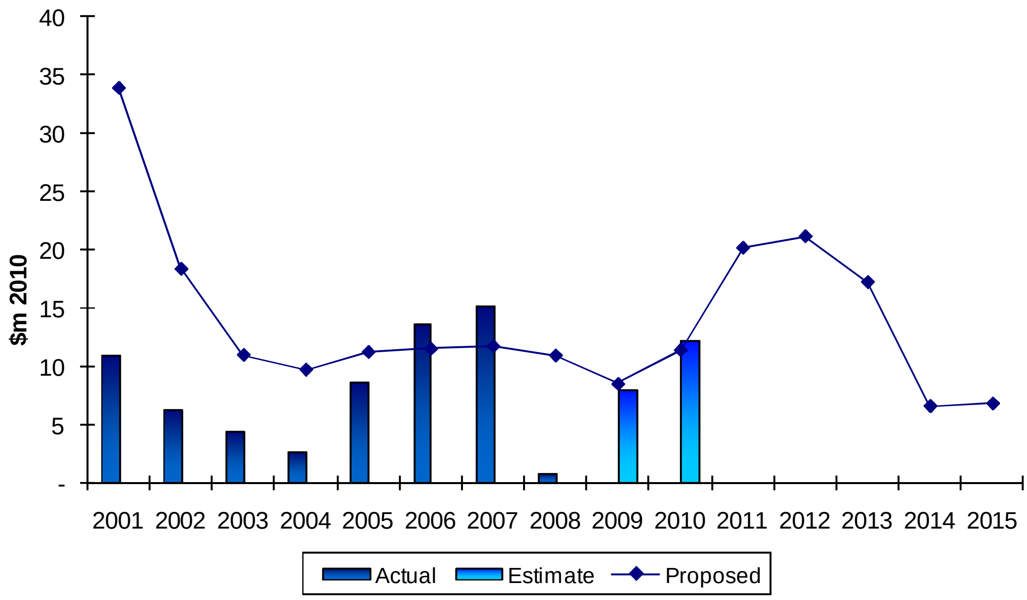
Jemena	Costs (2010 $M)				
Environmental, Safety and Legal	2011	2012	2013	2014	2015
Recommended Expenditure	0.833	1.198	1.231	0.317	0.014

7.6 Non-network – general IT

Jemena submitted IT capital expenditure at $71.9 million over the forthcoming regulatory control period, which represents an increase of 75% in capital expenditure from audited historical expenditure ($41.0 million). Major proposed IT capital projects include replacing its SAP enterprise asset management system and building a disaster recovery data centre, and establishing a geographical information system (GIS).

During 2004-2008, Jemena underspent their IT capital expenditure from a proposed of $55.0 million to actual audited spending of $41.0 million including deferrals of project like DMS, VMS and some SAP models which were impacted by AMI.

Figure 72 - Jemena proposed vs actual IT capex



Ownership changes have meant that the Compute, Storage and Network platform were not acquired as part of the sale process. As a result Jemena's IT infrastructure has had to be largely renewed post separation from AGL. This has resulted in Jemena incurring significant expense and major disruption. EB Services (IT service provider to Jemena) developed an IT planning document in late 2009 with a number of recommendations including:

1 moving the Compute Platform towards Blades

2 review of the Storage Platform provider

3 review of the Backup software and storage media provider.

Most of these recommendations were driven by synergies with other areas of the Jemena IT environment. These proposals appear to be reasonable decisions based upon the information provided. However, providing agility and flexibility to the business does not appear to be major consideration for Jemena.

Jemena included $5.7 million for the new data centre project and provided detailed information and justification which we found to be reasonable and efficient given the static nature of the IT environment. We do believe, that if Jemena had a more agile IT environment they would be able to achieve the migration to the data centre at substantially less cost, by fully utilising virtualisation technology. The lack of enterprise level virtualisation means that there are substantial transition costs including IT Infrastructure removal from the facilities, transport, labour and associated costs from the current data centres to the new data centres.

Jemena IT capital cost expenditure ramps up substantially to around $20 million for three years and then reduces to around $7 million for the last two years of the next control period. This reflects Jemena's desire to deliver most projects within 3 years, including data centres moves and applications upgrades. In our opinion, the Jemena information and documentation does not adequately recognise the complexity of what is being contemplated and the amount of change they can absorb, given the lack of agility in the IT environment. We consider it more likely that Jemena will take five years (potentially longer) to complete these projects and that any projects in 2014 and 2015 are likely to be deferred until after 2015. Therefore, we recommend that first three years of capital cost be allocated over five years and that the final two years of capital cost not be considered in the next control period.

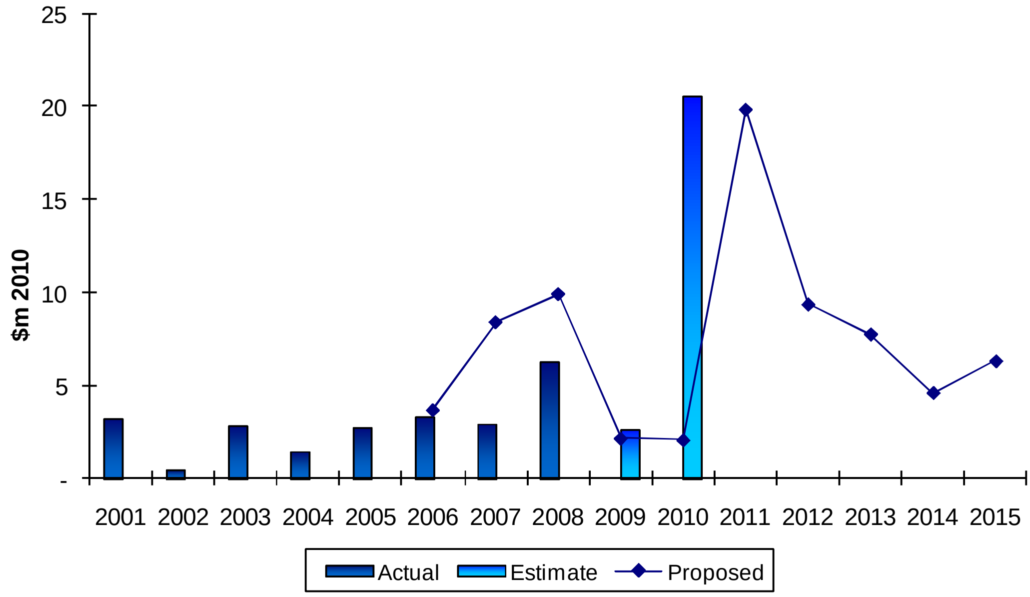
Table 61 - Recommended Jemena non-network general IT capex

Jemena	Costs (2010 $M)				
Non-network general – IT	2011	2012	2013	2014	2015
Proposed Expenditure	20.2	21.1	17.2	6.6	6.8
Recommended Expenditure	11.7	11.7	11.7	11.7	11.7

7.7 Non-network general other

Jemena estimates that its Non-Network - general capital expenditure for the 2006-10 regulatory control period will be $35.9 million ($2010). It is forecasting that this will increase to $47.9 million ($2010) in the 2011-15 regulatory control period.

Figure 73 - Jemena proposed and actual non-network general capex



The majority of non-network general expenditure identified by Jemena relates to land purchases and an office/depot relocation. Nuttall Consulting considers that the land purchases are network related as they are for future zone substations. On this basis, the following expenditures are recommended for removal from the Non-network - general category and will be considered in the reinforcement category.

Table 62 - Jemena Non-Network -General - land purchases and relocations capex ($2009 millions)

Description	2011	2012	2013	2014	2015	Period Total
Total	0.6	6.3	3.8	0.6	1.7	13.1

More than half of the proposed expenditure in this category for the next control period relates to the Sunshine depot relocation/merger project.

Jemena has proposed expenditure for the redevelopment of its two work depots currently located at Broadmeadows and Sunshine. The proposed redevelopment targets the establishment of a single Melbourne North site which would service Jemena's network. Jemena states that the proposal is to optimise Jemena's performance and that the options were considered against the following requirements[75]:

- OHS&E – overcome the current operational concerns and deficiencies with the Broadmeadows site
- Operational – achieve operational efficiencies, performance improvements and the right amenity in the right location to attract and retain staff
- Capacity – the need to accommodate the scope and specifications of the Broadmeadows and Sunshine operations, including integration of JEN related staff

[75] Jemena Electricity Networks regulatory proposal - 30 November 2009, P121 and 122.

currently at Mt Waverley and Clayton and the capacity to support forecast network growth.

This project has arisen due to the potential expiration of the lease of the Sunshine Depot facility with City West Water; operational issues associated with the Broadmeadows site including asbestos and site constraints; and the need to provide for future expansion.

Jemena has advised Nuttall Consulting that the draft Broadmeadows business case has not gained internal approval.[76]

Jemena appointed GHD Australia Pty Ltd ("GHD") to review the Jemena Network Asset Management Plan (NAMP) and associated capex forecasts prepared by Jemena. The purpose of the review was for GHD to provide an opinion as to the compliance of Jemena's capex proposal with the requirements of the National Electricity Law and Rules. This review identified that the depot merger project was not sufficiently justified: "*The Broadmeadows – Sunshine Depot Relocation/Merger project, while having an established need, has not sufficiently demonstrated the benefits of the specific proposal through identifying Opex efficiencies and potential performance improvements from the consolidation.*"[77]

In addition, opportunities for opex savings have not been quantified. Other performance benefits such as improved customer response, have also not been quantified. The decision to relocate some staff from other Jemena locations is also not adequately justified.

On this basis, it is reasonable to consider that the project may likely proceed at some time in the future, although the timing and associated benefits of the project are not adequately considered. On this basis, the proposed depot relocation expenditure is not sufficiently justified for the next control period.

The remainder of the Jemena capex proposed in the non-network - general category relates to "SCADA and Network Control", "tools and test equipment" and "vehicles". Nuttall Consulting has reviewed these expenditures at the gross level and considers that the expenditures are required, and that they are consistent with existing levels.

Table 63 - Recommended Jemena Non-network General capex

Jemena	Costs (2010 $M)				
Non-network General	2011	2012	2013	2014	2015
Recommended Expenditure	4.076	3,092	3,959	4,008	4,600

[76] Jemena provided a draft business case relating to the depot relocation and merger. This document has not been provided to the Jemena board. The timing of the provision of this document was such that it has not been considered in this draft report.

[77] GHD: Independent Review of Jemena Electricity Networks (Vic) capital expenditure forecasts - 30 November 2009, P2.

8 Appendix C - Powercor

The CitiPower and Powercor franchises are both owned by the same investment group and share management and executive services. The CitiPower and Powercor proposals share a great deal in common including structure and significant areas of content. There are also areas of differentiation between the proposals; specifically in relation to individual projects and programs.

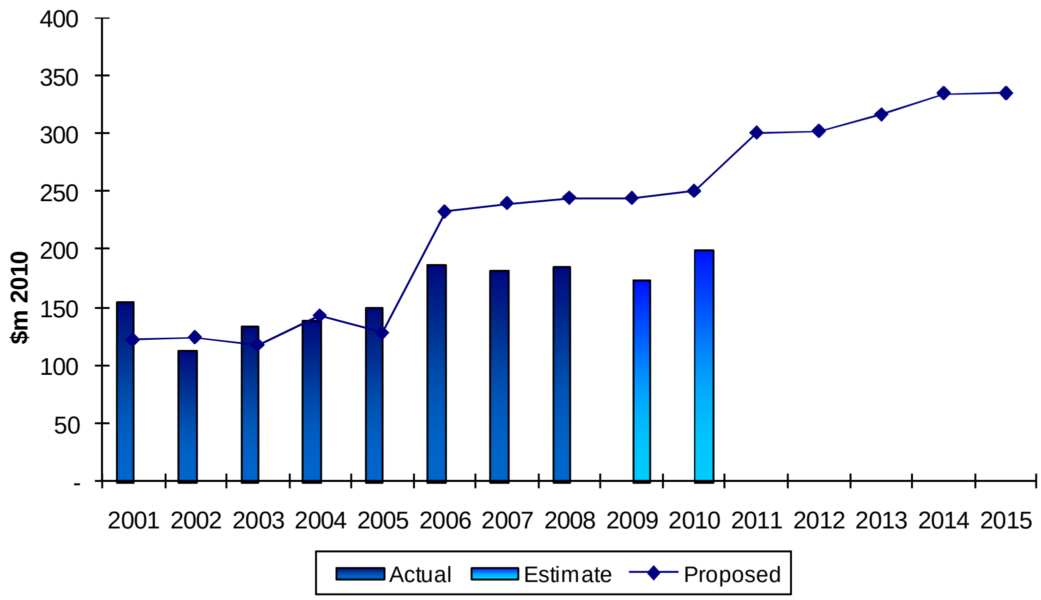
8.1 Overall capex

Overall capex is forecast to increase by 72% over actual expenditures in the current period. The main areas where capex is forecast to increase are reinforcement, reliability and quality maintained, new connections, and non-network IT.

The following chart provides a summary of the overall capex figures for Powercor. Key aspects of this chart include:

- Powercor has consistently spent less than they proposed in the 2006 EDPR
- Powercor has consistently spent less than the allowances in the 2006 EDPR
- Powercor is proposing a future level of capex that is much is significantly higher than the historical levels of expenditure and is not consistent with the historical trend in capex.

Figure 74 - Powercor Capex Summary



Powercor argues that comparisons at the capex category level with the ESC allowances set for the current period are not relevant. They state that the manner in which the category allowances were established makes them invalid for comparison.

The Powercor proposal provides a high-level discussion of the overall capex allowance compared with overall actual expenditure for the period. The expenditure for the first two years of the regulatory period is significantly below the regulatory allowance with 2008 expenditure being slightly higher than the allowance. Powercor identify the deferral of two major projects as the reasons for the historical underspend.

The proposal provides very little description of how the forecasts were actually developed, although a significant amount of information about current business processes is provided.

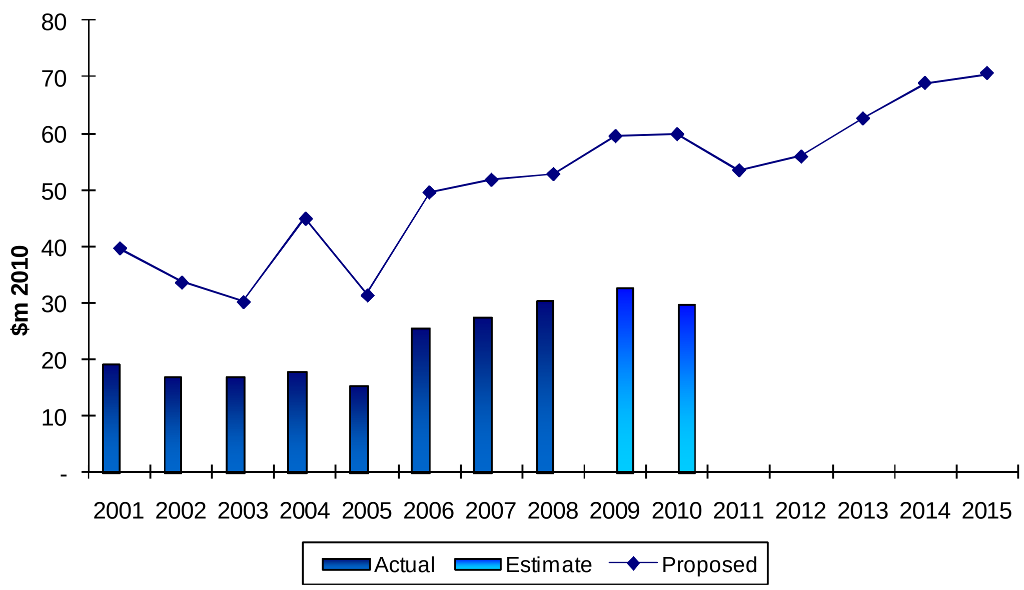
The Powercor proposal provides a deliverability plan as to how they intend to resource to meet the forecast capex. The attachments to the proposal also provide a reasonable level of detail on the asset management processes, project approval processes and governance frameworks.

8.2 Reinforcement

Powercor is proposing a reinforcement program that is 124% greater than actual expenditures in the current Regulatory Control Period. Powercor estimates that its reinforcement capital expenditure for the 2006-10 regulatory control period will be $146 million ($2010). It is forecasting that this will increase to $311 million ($2010) in the 2011-15 regulatory control period.

The following chart provides a summary of reinforcement capex for Powercor.

Figure 75 - Powercor Reinforcement Capex Summary



This chart indicates that Powercor's reinforcement expenditure has been trending up, particularly over the current regulatory periods, but is estimated to have a significant step increase in 2011. The 2001 and 2006 EDPR forecasts prepared by Powercor were significantly over the actual expenditure incurred. This is most notable for the 2006 EDPR, where actual expenditure (2006-2008) has been only 53% of the forecast. Interestingly, the 2011-2015 forecast is on trend with Powercor's previous forecasts, which have been significantly above actual expenditure levels.

Powercor has advised that the underspend on its forecast "*is largely because some of the major projects identified when preparing its expenditure forecast were assessed as not being required due to changes in circumstances or scope during the current regulatory control period*"[78]. Specific reasons given include reductions in anticipated growth in particular areas, implementation of load management programs, revisions to asset ratings, changes to project scopes.

Powercor's proposal indicates that the increase in expenditure above current levels is required to maintain zone substation security levels, in the face of the anticipated demand growth[79].

8.2.1 Forecasting methodology

Powercor has developed its reinforcement plans based upon a bottom-up build of individual network needs and projects to address these needs. Powercor considers that these plans have been developed largely using the actual planning processes it applied in practice. However, due to their proposed timing, many projects will not have been through the full evaluations and justifications that would be required for approval.

A major portion of these plans is developed via the risk evaluation approach Powercor applies at the sub-transmission level.

This approach determines annual load at risk of not being supplied (i.e. under normal and outage conditions) and the annual duration of this risk. Future predictions of these measures are calculated using a number of key input assumptions, most notably:

- the 50% probability of exceedance maximum demand forecast
- a load profile, based upon the actual load profile for 2008/09.

Powercor then uses internal criteria to define the trigger point when a network augmentation should be considered. These criteria are summarised as follows:

- For single transformer zone substations, load at risk is only tolerated up to a loading of 15 MVA.
- For the multiple banked transformer zone substations, loading is allowed to exceed the N-1 cyclic rating of the substation for up to no more than 120 hours per annum. Powercor will convert these to a switched substation when the load exceed to 20 MVA.
- For the multiple switched transformer zone substations, loading is allowed to exceed the N-1 cyclic rating of the substation for up to no more than 120 hours per annum, provided suitable protection is in place.
- For rural radial sub-transmission lines, N-1 contingency loading must not exceed 110% of the rating of the sub-transmission line for more than 80 hours per year.

[78] Advised in response to Q2.3 of Nuttall Consulting questions in its guidance paper, provided by CitiPower on 11/1/10
[79] Pg 85, Powercor proposal.

This constraint is raised to 120% of the rating of the sub-transmission line for more than 160 hours per year if a dynamic line monitoring system is used. However, the forecast loading on the line must not exceed 15 MVA.

- For looped sub-transmission lines, N-1 contingency loading must not exceed 110% of the rating of the sub-transmission line for more than 120 hours per year. This constraint is raised to 120% of the rating of the sub-transmission line for more than 240 hours per year if a dynamic line monitoring system is used.
- For distribution feeders, loading is allowed up to specified limits depending on the type of feeder (i.e. rural, urban, CBD, and radial or looped). The limit is generally set at a level to allow load transfers between feeders, without exceeding thermal ratings and voltage criteria.

It is noted that there is little information on the method adopted by Powercor to forecast distribution substation and LV augmentations. However, Powercor is not forecasting an increase in these areas. As such, we have not considered these matters in detail.

8.2.2 Nuttall Consulting detailed review

8.2.2.1 Process

Nuttall Consulting's detailed review of Powercor's reinforcement expenditure has included a review of its forecasting methodology and a number of specific projects. The general process applied by Nuttall Consulting in conducting its review of Powercor's reinforcement expenditure is summarised in Section 4.2 of this report.

The projects reviewed included:

- The Eagle Hawk zone substation upgrade
- The Gisborne new zone substation
- The BETS-CTN 66 kV line upgrade
- The GLE upgrade
- GTS 66 kV lines upgrade
- NKA-CBE 66 kV line upgrade.

Key Powercor documents, in addition to Powercor's proposal, included in this review are:

- P0028 – Electricity network augmentation planning and guidelines
- P0029 - Powercor Asset Management Framework 2009
- P0043 – PB Powercor Energy at Risk and Growth related capex
- P0075 - 2008 Distribution System Planning Report
- 2009 Distribution System Planning Report (2009 DSPR)

Other documentation specific to the projects under review is identified in the sections below.

8.2.2.2 Findings on methodology

Overall, we consider that Powercor's methodology is reasonable for developing capital plans for internal purposes. In this regard, the process should result in the identification of network needs, a list of projects to address these needs, and expenditure projections for the medium-term management of the network. In turn, this process results in a relatively comprehensive list of individual network needs and projects that can be monitored and developed further through the next period.

However, we do not consider that this largely "bottom-up" based process has been shown to be "fit for purpose" in terms of being a reasonable unbiased estimator for future prudent and efficient expenditure at the aggregate level. In particular, we do not consider that such a process adequately allows for the further optimisation of projects and synergies between projects that will occur as the individual projects and the overall capital plans advance through the capital governance process.

It is accepted that in some circumstances these processes will result in some projects being advanced or their scopes increased. However, in our view, the more detailed evaluation and justification associated with the project approval within the governance process will most likely result in overall expenditure being less than the simple summation of the project plans, as applied by Powercor to determine its reinforcement expenditure.

Related to the points above, we also have a number of concerns with specific key input assumptions, which we consider may be overly conservative at this point in the planning process (i.e. they may, on average, overstate risks). This concerns the load profile and the internal planning criteria assumed by Powercor in its probabilistic planning process.

With regard to the load profile, we consider that Powercor's approach of basing this upon the 2008/09 load profile may materially overstate the risks. It is our understanding that this year is non-typical as it had a number of extended periods of hot weather. As such, it has a flatter profile around the peak period than a typical (50% PoE) year would have. Therefore, such a profile may over state energy at risk or the duration associated with the risk.

It is accepted that the use of a 50% probability of exceedance maximum demand may understate expected risks. As such, there could be some argument that these two matters trade off somewhat. However, given the sensitivity to risks of the assumed maximum demand condition is well known in the industry, we consider it reasonable to assume that the optimism in this assumption is inherently allowed for in Powercor's evaluations. Therefore, we do not consider that this matter should affect our findings on the conservatism in the assumed load profile.

With regard to the criteria Powercor adopts as the trigger time for augmentations, we see no reason to consider that these are not appropriate for internal planning purposes (i.e. to initiate more detailed analysis and evaluation). However, for the purposes of generating the plans for the regulatory proposal, particularly in the context of its bottom-up build methodology, we consider that plans should still be demonstrably economic in their timing. In this regard, it should be clear that the benefits, through the reduction in the energy not served to customers, out-weighs the costs of the project. We consider that this is in accordance with the principles of the NER. We also consider that this is relevant to Powercor's HV feeder augmentations.

To assess the significance of this matter, we have evaluated this within the project reviews to determine whether the timing of the projects is economically optimal. It is worth noting here that the general findings on this matter were that the criteria tended to bring forward projects from their optimal timing.

8.2.2.3 Project reviews

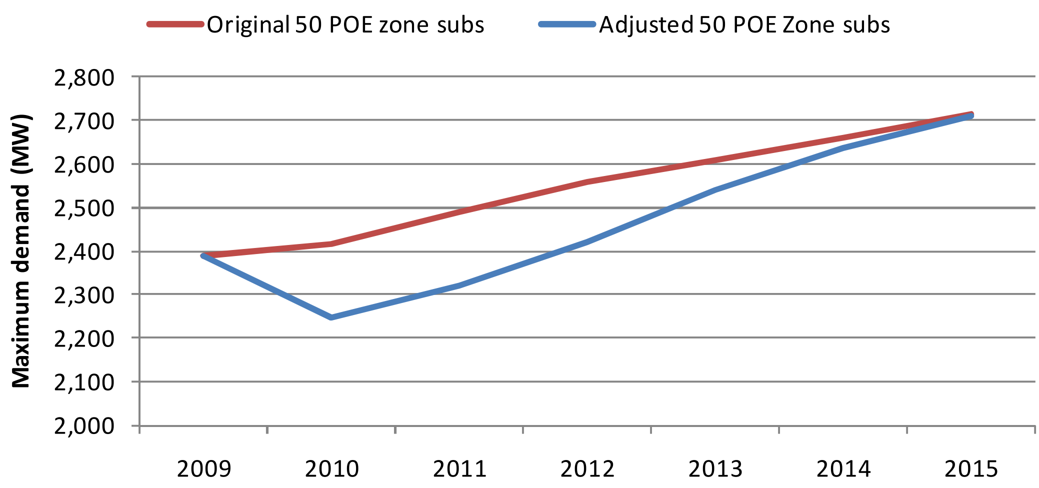
As noted in Section 4.2.4, the aim of the Nuttall Consulting review has been to determine the likelihood that the project expenditure will be required as proposed by Powercor. We consider that this is a reasonable approach to account for the likely consequences of the governance processes and the other specific methodology concerns discussed above.

An additional input to our review has been the findings of the AER's review of Powercor's load forecasts. Of particular relevance to our review is the maximum demand forecast. The AER's findings here were that Powercor has overstated the growth in maximum demand.

A comparison of the Powercor maximum demand forecast and the AER's view is shown in the chart below. This chart indicates that the AER's adjustments result in maximum demand levels being delayed by 2 to 3 years, particularly in the 1st 3 years of the next period.

It is important to note that we have not been able to analyse the effect of these adjustments in detail. However, we have attempted to allow for these to some degree in our assessment of the likelihood of the projects. We would recommend however that the AER require Powercor to reassess its plans more comprehensively in light of these load forecast findings to determine their effects.

Figure 76 – Powercor maximum demand forecast



The following summarises the main findings for the projects reviewed.

8.2.2.4 Eagle Hawk Zone substation upgrade

Cost: 3.5 million ($2009)

Completion: 2012

This project involves the upgrade of the existing substation to install a 3rd 66/22 kV transformer and a 3rd 22 kV bus. The key driver for this project is the projected loading at the existing substation and the internal planning criteria to upgrade to a fully switched substation when loading exceeds 20 MVA.

Based upon our analysis of Powercor's energy at risk calculations for the existing substation, the timing appears reasonable. Furthermore, the options considered and the cost of the preferred option also appears reasonable.

However, given the point made above on the load profile assumed by Powercor and the AER's findings on the maximum demand forecast, we consider that there is a reasonable possibility that this project may be optimally deferred.

Based upon the above, we consider that expenditure associated with these works has a moderate to high probability (70%) of being required as proposed by Powercor.

8.2.2.5 Gisborne new zone substation

Cost: 9.7 million ($2009)

Completion: 2012

This project involves the establishment of a new zone substation at Gisborne. The key driver for this project is the projected loading at the existing Woodend zone substation and an associated 66 kV transmission line.

We have a number of concerns with the timing and scope of this project. Firstly, we do not consider it clear that Powercor's energy at risk calculations support the timing of the project. The predicted level of energy at risk at the Woodend zone substation would not be sufficient to economically justify the project until nearer the end of the next period. Unfortunately, with the information available it is not clear what affect the line overload has on risk levels; however, we do not consider that it should be sufficient to advance the project to the proposed time. Moreover, the findings of the AER's review of Powercor's load forecast also support the view that the project will be deferred. Finally, given the point above on the load profile assumed, we consider that it may well be deferred even beyond the next period.

In addition to the points above, we do not consider that Powercor has adequately demonstrated that it has considered all reasonable options. In our opinion, there are other lower cost options that may be justified through more detailed analysis. In particular, we considered that an additional option involving the first stage of a switching station at Gisborne could be a reasonable option that may maximise the net benefits.

Based upon the above, this project has been assigned a low probability (33%) of occurring as planned.

8.2.2.6 BETS-CTN 66 kV line upgrade

Cost: 15.7 million ($2009)

Completion: staged from 2011-2015

This project involves the staged upgrade of the existing radial 66 kV line from BETS to CTN. The key drivers for this project are loading and voltage stability issues on the existing line, and Powercor's internal criteria to only allow loading up to 20 MVA on radial lines.

Based upon our review of the information provided, we consider that the energy at risk justifies undertaking some form of augmentation to address the energy at risk. However, given the findings of the AER's review of Powercor's load forecast, we consider that this project may be deferred.

Furthermore, we do not consider that Powercor has adequately demonstrated that it has considered all reasonable options, particularly with regard to the timeframe of the staged upgrade. In our opinion, there may be other lower cost options that may be justified through more detailed analysis. These options may be linked with the staged upgrade of the line, effectively deferring some stages, such as the installation of reactive compensation; or alternatives such as the construction of a new line from KGTS to CTN.

Based upon the above, this project has been assigned a moderate probability (50%) of occurring as planned.

8.2.2.7 GLE zone substation upgrade

Cost: 6.4 million

Completion: staged from 2014-2015

This project involves the upgrade of the existing GLE zone substation by replacing the existing transformers with higher rated units. The key drivers for this project is the energy at risk at the existing GLE zone substations.

Based upon our review of the information provided, we do not consider that the energy at risk clearly and economically justifies the project at the proposed time. The energy at risk indicated in Powercor's 2009 DSPR does appear to justify the project, but it is not clear whether this adequately allows for the available load transfers. Furthermore, given the points made above on the conservatism in the assumed load profile, we consider that there is a reasonable case that this project will be optimally deferred, even if the stated energy at risk is marginal.

Based upon the above, this project has been assigned a moderate probability (50%) of occurring as planned.

8.2.2.8 GTS 66 kV line upgrades

Cost: 9.6 million

Completion: 2011-2013

This project involves the upgrade of various lines that connect GTS to various zone substations. The key driver for this project is the projected loading at GTS and various existing lines.

The project is associated with the GTS upgrade project that has undergone a regulatory test. However, detailed analysis specific to these upgrades has not been clearly presented in the regulatory test documentation. Nonetheless, the energy at risk calculations associated with the regulatory test support the timing of this project and the options appear reasonable.

However, given the point above on the load profile assumed by Powercor and the AER's findings on Powercor's maximum demand forecasts, we consider there is still a reasonable possibility that this project may be optimally deferred given its timing in the 1st half of the next period.

Based upon the above, this project has been assigned a high probability (90%) of occurring as planned.

8.2.2.9 NKA-CBE 66 kV line upgrade

Cost: 9.2 million ($2009)

Completion: staged from 2015

This project involves the establishment of a second line to the Cobram East zone substation (CBE) from the Numurkah zone substation (NKA). Presently, CBE is supplied by a radial line from NKA. The key drivers for this project are the energy at risk at CBE, and Powercor's internal criteria to only allow loading up to 20 MVA on radial lines.

Based upon our review of the information provided, it is accepted that the projected load at CBE will be high for a radially supplied load (i.e. above 40 MVA), and therefore, there is a reasonable likelihood that expenditure will be required in the next period as proposed by Powercor.

Nonetheless, we still consider that Powercor has not clearly demonstrated that the energy at risk and alternatives considered, allowing for all interim measures, are sufficient to justify the project.

On these matters, Powecor's 2009 DSPR indicates that the risks will be managed prior to the construction of the new line by measures such as load transfers and emergency generation. However, there is no detail of the impact that these measures will have on the risks, and importantly, to what extent the risks will subsequently change from those presently accepted.

Furthermore, Powercor's proposal indicates that an alternative solution it considered was to transfer load away from CBE via the construction of three new 22 kV feeders[80]. The proposal indicates that cost-benefit analysis undertaken by Powercor found that this alternative was higher cost than the second 66 kV line, but this analysis has not been provided by Powercor. Given the scale of the project and the relatively low load growth at CBE, we consider it reasonable to consider that a smaller scale 22 kV transfer project (e.g. a single 22 kV feeder) may be found to be sufficient to defer the 66 kV line option following more detailed economic analysis, which also allows for the affect of the risk mitigation measures.

Based upon the above, we consider that there is still a reasonable possibility that this project will be deferred or its scale reduced. Therefore, this project has been assigned a moderate to high probability (70%) of occurring as planned.

[80] Associated project discussion in Chapter 28 of the Powercor proposal

8.2.3 Overall findings

Based upon our review, we do not consider that Powercor has adequately demonstrated that its proposed increases in reinforcement expenditure are reasonable. Moreover, we consider that significant reductions to the proposed plans will occur as the plans pass through the governance processes and more detailed evaluations and justifications are undertaken. In our opinion, a reasonable estimate will be more in line with the historical trend.

This view is based upon a number of findings from our project reviews, which draw upon our high-level expenditure analysis and the findings of the methodology reviews.

Firstly, in a number of cases, the project timing was not clearly economically justified. Given the point made above on the demand profile used by Powercor, we consider there is a reasonable possibility that some projects may be deferred.

Secondly, the findings of the AER's review of Powercor's maximum demand forecast also supports the view that many projects may be optimally deferred, particularly those in the 1st half of the next period.

Finally, in some cases, there also appears to be other lower cost options, not considered in detail by Powercor, that we considered may have a reasonably probability that they may be found to be the preferred option.

Using the approach discussed in Section 4.2, we have developed a forecast of the reinforcement expenditure using:

- the weighted average probability from the project reviews to determine the reasonable estimate to total expenditure
- a constant growth rate assuming a notional 2008 base-line, derived from the average of the historical 2006-2008 expenditure.

Based upon this process, we have estimated the Powercor reinforcement expenditure in the next period (ex the CBD security project and Metro 2012 project) will be 62% of the Powercor proposal and the expenditure growth rate from historical levels will be 8.3%.

Our estimate of the Powercor's reinforcement capex is shown in Figure 33 and Table 24 below. It is important to note that this should be considered as an estimate only. The AER may need to make further adjustments to allow for its findings on the other matters, such as overheads and labour and material escalation, which are not accurately allowed for here.

Figure 77 – Powercor reinforcement capex recommendation

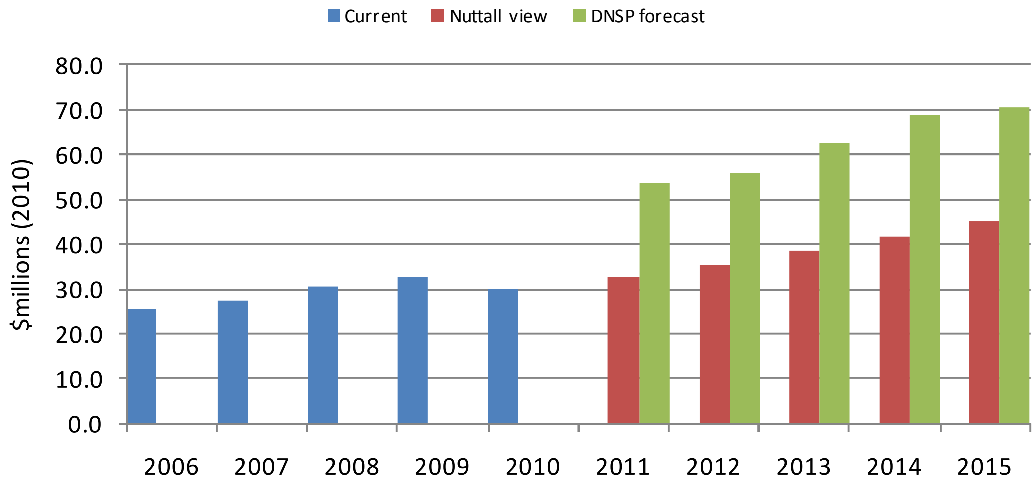


Table 64 – Powercor reinforcement capex recommendation

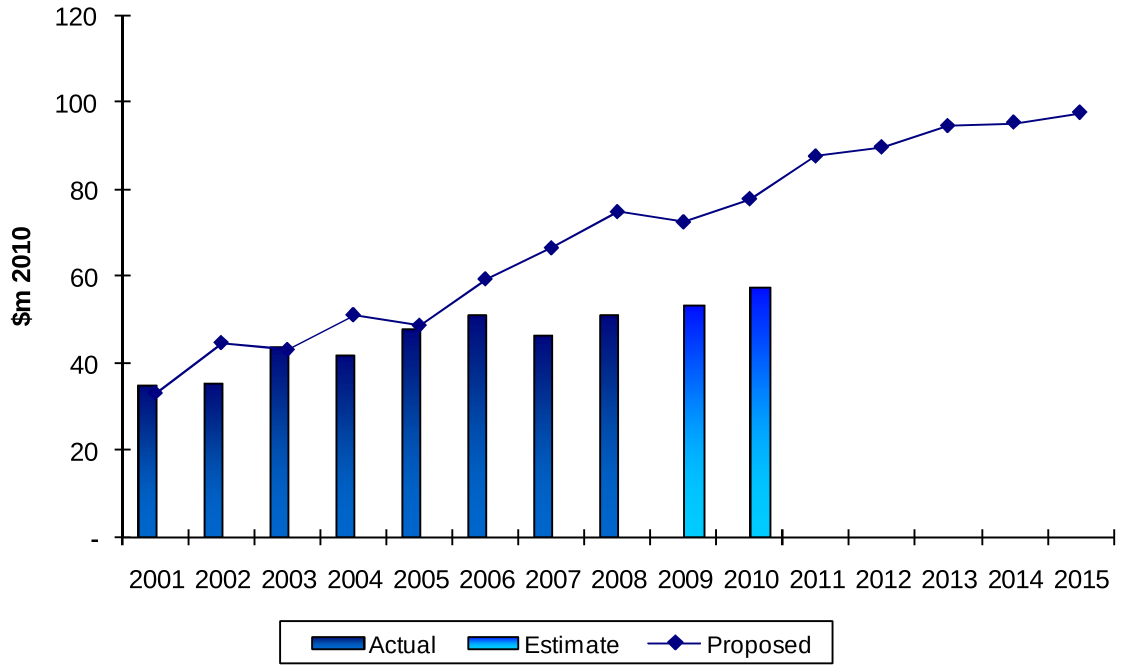
	$millions (2010)				
	2011	2012	2013	2014	2015
Powercor - proposed	53.4	55.9	62.6	68.8	70.6
Powercor - recommended	**32.7**	**35.4**	**38.4**	**41.6**	**45.0**

8.3 Reliability and quality maintained

Powercor is proposing an increase of 87% in reliability and quality maintained capex for the next Regulatory Control Period when compared against actual expenditure in the current Regulatory Control Period. Powercor estimates that its Reliability and Quality Maintained capital expenditure for the 2006-10 regulatory control period will be $260 million ($2010). It is forecasting that this will increase to $464 million in the 2011-15 regulatory control period.

The following chart provides a summary of reliability and quality maintained capex for Powercor. This chart indicates a relatively modest increase in actual RQM expenditure, but a significant over-forecast of RQM expenditure in the previous period.

Figure 78 - Powercor Reliability and Quality Maintained Capex



8.3.1 Overview of activity code review

Explanation of expenditure profile – trends and major drivers of increases

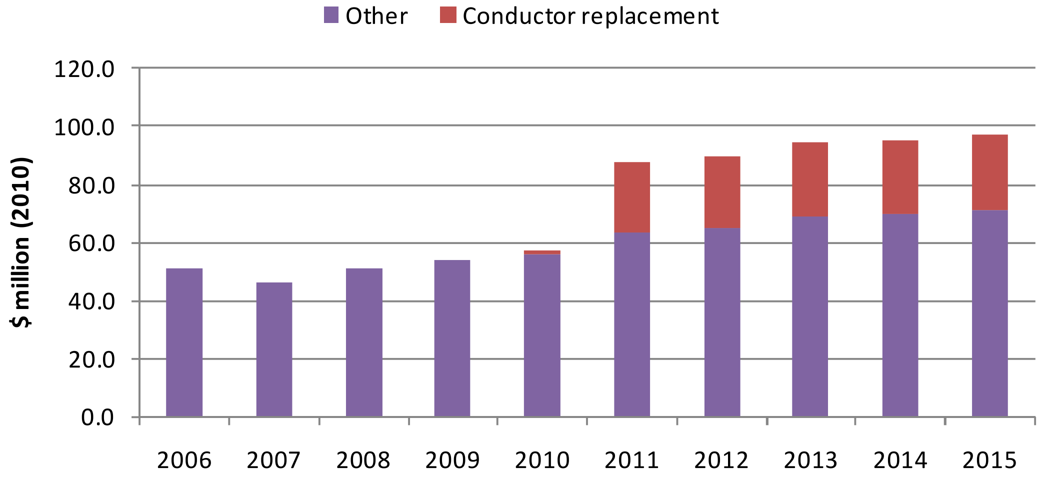
Table 65 - Summary of Powercor RQM expenditure

Average per annum expenditure ($2010)			% increase (from 2006-2008)	
2006-2008	2009-2010	2011-2012	2009-2010	2011-2015
49.6	55.6	92.8	12%	87%

As indicated in Table 65, Powercor are proposing a significant increase in RQM expenditure from 2011. The main reason for this increase is a proposed new conductor replacement program. This is due to commence in 2010 at a relatively low level, but then significantly step up in 2011 and continue for approximately 20 years. This program will be discussed further below.

The effect of this conductor replacement program on the overall RQM expenditure profile is shown in Figure 79. This figure indicates that the underlying expenditure is far more in trend with historical expenditure. This increase is also more in line with our replacement modelling for the Powercor network.

Figure 79 - Powercor RQM expenditure profile



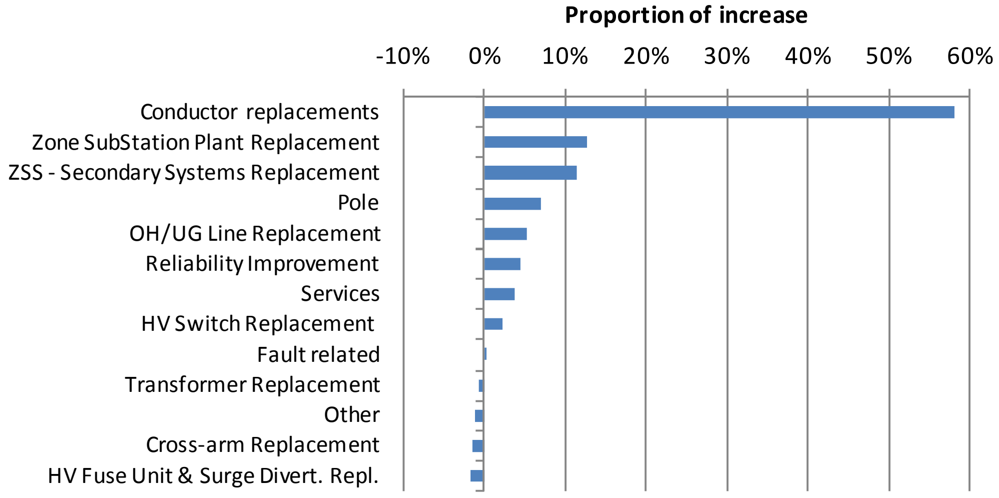
The breakdown of the 2011-2015 RQM expenditure into Powercor's activity codes is shown in Table 66. These activity codes are ranked in terms of significance, based upon the proportion of total RQM expenditure.

Table 66 - Activity Code summary

Activity Code	Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
	2006-08	2009-10	2011-15		90-10	11-15
Conductor replacements	0.0	0.9	25.1	27%	n/a	n/a
Pole	10.8	12.2	13.8	15%	13%	28%
Fault related	13.7	13.6	13.7	15%	0%	0%
Zone Sub Plant Replacement	3.4	5.2	8.8	9%	54%	160%
Cross-arm Replacement	8.8	7.1	8.2	9%	-20%	-7%
ZSS - Secondary Systems Replacement	2.9	4.5	7.8	8%	58%	172%
OH/UG Line Replacement	1.7	1.5	3.9	4%	-9%	134%
Services	1.6	3.5	3.2	3%	122%	106%
HV Fuse Unit & Surge Divert Repl	3.6	2.5	2.9	3%	-31%	-20%
Reliability Improvement	0.0	1.7	1.9	2%	n/a	n/a
HV Switch Replacement	0.4	1.0	1.4	1%	158%	243%
Transformer Replacement	1.6	1.2	1.3	1%	-23%	-20%
Other	1.2	0.6	0.7	1%	-52%	-40%
Grand Total	**49.6**	**55.6**	**92.8**	**100%**	**12%**	**87%**

The breakdown of the proposed increase in expenditure for the next period (compared to the average of 2006-2008) into activity codes is shown in Figure 80. This clearly illustrates that the new conductor replacement program is the major contributor to the proposed increase, with zone substation primary and secondary plant and equipment also contributing significant portions.

Figure 80 - Powercor activity code



8.3.2 Conductor replacement program

Activity code and expenditure summary

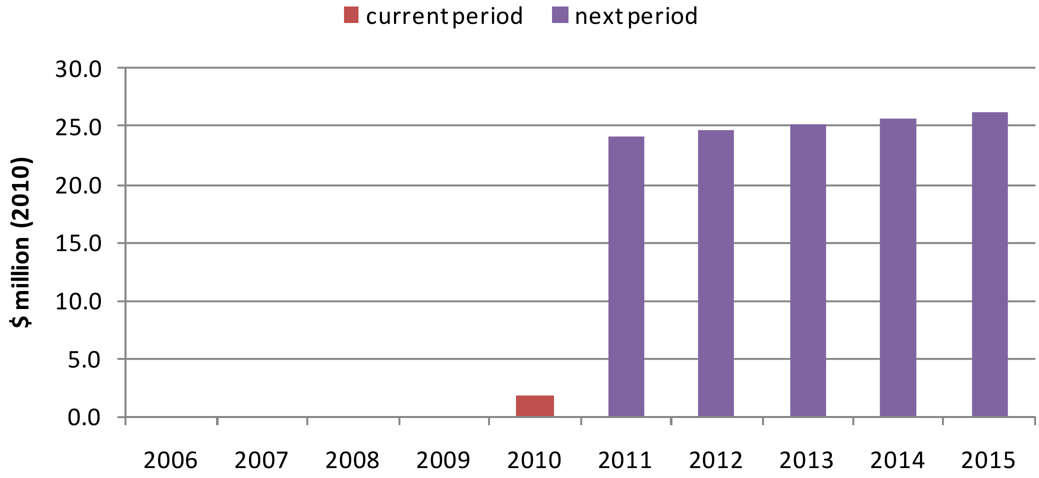
Powercor do not have a separate activity code for the conductor replacement program. The proposed costs for this project are allocated to the OH/UG Line Replacement activity code, which is discussed separately below. To aid in our discussion, we have removed the conductor replacement costs from this code and considered them separately here.

Table 67 and Figure 81 provide an overview of the expenditure in this category. This indicates that this project represent 27% of the total RQM expenditure in the next period, with expenditure at a significant level throughout the period.

Table 67 - Overview of expenditure for the conductor replacement program

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
0.0	0.9	25.1	27%	n/a	n/a

Figure 81 - Expenditure profile for the conductor replacement program



Forecasting methodology and rationale

Powercor has provided documentation on its proposed conductor replacement program[81]. The program is a pre-emptive condition based replacement program to replace aged conductors prior to their failure. The underlying driver for this program appears to be the safety issue, and in particular, fire risks (e.g. bushfire starts).

The methodology Powercor has applied to determine the expenditure allowance is a relatively simple age based calculation, which has assessed the quantity of conductor installed prior to 1970 and then proposed a long-term (i.e. 40 year) program to replace this conductor – assuming a constant amount in each year. A typical unit cost has been applied to determine the expenditure requirement. A reduction to this amount has been applied (approximately 25%) to allow for other factors that may drive the replacement of conductors in the future, such as augmentations.

Nuttall Consulting views

On the information provided, Powercor's modelling appears to be simplistic, and does not demonstrate that such a significant step change is warranted in 2010.

At this stage, it is not clear what testing Powercor has undertaken and how the results demonstrate that Powercor can accurately target conductors. Powercor has also not justified the criteria it should apply to estimate the prudent volume for the next period. It is understood that Energy Safe Victoria (ESV) has undertaken some testing, but at the stage of drafting this report, the findings of this testing are not known.

Furthermore, Powercor has not presented any risk assessments to support the prudency and efficiency of its proposed plan. It is noted that SP AusNet, who has a similar pre-emptive conductor replacement plan, appears to have undertaken analysis that is more thorough. The SP AusNet analysis indicated that the main risks are bushfire related, and without these, it is unlikely that a pre-emptive approach would be optimal at this time.

Therefore, due to the significance of this matter and its relationship with recommendations that may result from the Royal Commission on the 2008/9 bushfires,

[81] Asset Management Plan in emails, dated 24/12/10, and further data in email dated 26/2/10

Nuttall Consulting considers that this program should be "ring fenced" and re-considered following the Royal Commission's findings.

At this stage, given the uncertainty in how the conductor can be appropriately targeted to reduce risk, and hence the prudent criteria to develop the forecast, we consider that the expenditure allowance should be made based upon a "business as usual" view. As such, we do not consider any allowance should be made for this specific program at this time[82]. Nuttall Consulting considers the business should be provided an allowance that is based upon its present and historical approach to managing risks.

If an allowance for a pre-emptive conductor replacement program were to be made, irrespective of the Royal Commission's findings, then Powercor would need to demonstrate that:

- it has relevant test results that indicate it can target the appropriate conductors
- its criteria and methodology for producing a 5 year forecast are a reasonable estimate of the prudent and efficient replacement quantities and costs (i.e. it maximises the net benefits based upon some robust economic/risk evaluation)
- its plan and methodology are in accordance with ESV findings on these matters.

8.3.3 Zone substation plant replacement

Activity code and expenditure summary

The zone substation plant replacement activity code broadly covers the age/condition based replacement of primary plant within the zone substations. A major portion of this expenditure in the next period is due to the proposed replacement of power transformers and circuit breakers.

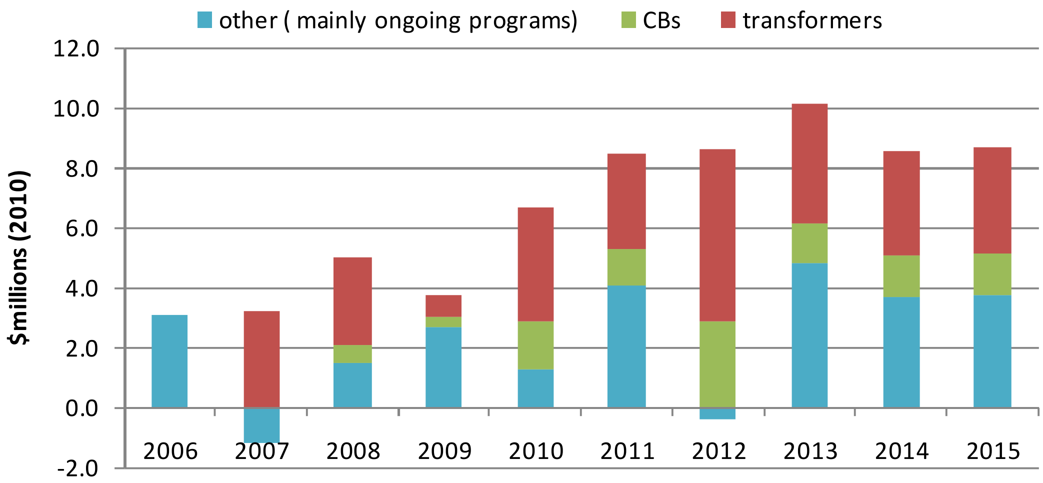
Table 68 and Figure 82 provide an overview of the expenditure in this category. Figure 82 also indicates the proportion of expenditure on the transformer and CB replacements. This analysis indicates that this activity code represents 9% of the total RQM expenditure in the next period, with expenditure ramping up fairly significantly through the current and next periods. This increase is largely due to increased transformer and HV CB replacement activity.

Table 68 - Overview of expenditure for the zone substation plant replacement

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
3.4	5.2	8.8	9%	54%	160%

82 It is worth noting that some allowance for conductor replacement can be allowed for in the OH/UG line replacement category, based upon a "business and usual" approach.

Figure 82 - Expenditure profile for the zone substation plant replacement



Forecasting methodology and rationale

The forecasts for the HV CB and transformer replacements are based upon the same quantitative risk modelling of the transformer and CB fleet that has been undertaken for CitiPower's equivalent assets. The modelling technique, known as Condition Based Risk Modelling (CBRM), has been developed by an independent consultancy, EA Technology, and used elsewhere nationally and internationally for forecasting replacement needs. Powercor engaged EA Technology in 2009 to implement this approach for its transformers and CBs.

Key features of the approach are:

- the use of asset specific condition information (or assumptions if data is not available) and age information to determine probability of failure rates
- the illustration of the probability of failure in terms of a "Health Index" for each asset item, which EA considers allows a more meaningful comparison between asset items and asset types
- internal model to predict the degradation of condition and probability of failure as the asset ages
- failure consequence assumptions (in $ terms)
- risk predictions (in $ terms) based upon the probability of failure predictions and the failure consequence
- NPV analysis of the risk costs and the replacement costs of each asset item to predict the optimal timing for replacement
- the ability to input asset specific interventions, such as refurbishments, which then adjust the condition and failure probability of those assets.

This modelling has resulted in nine transformers being proposed for replacement in the next period under RQM, compared to four in the current period, with three between 2006 and 2008. With regard to HV circuit breakers, 43 circuit breakers of various types are planned for replacement at a number of locations through the next period, compared to 27 in the current period, of which 16 were replaced between 2006 and 2008.

Powercor has provided the spreadsheet models and an associated EA Technology report in support of its forecast.

Nuttall Consulting views

The Nuttall Consulting review of this category has focused on the transformer and CB replacement forecasts. Given this modelling is the same as the CitiPower approach discussed in the previous section, many of the matters raised are also very similar.

Nuttall Consulting has reviewed the spreadsheet models and EA report on the CBRM approach that has been used to forecast transformer and HV CB replacement needs. The model is a contemporary approach to predicting replacement needs, and in principle at least, we see no reason to consider it is not appropriate for this purpose.

The important point here is that the model appears to be primarily an asset management tool that allows assets to be targeted and prioritised over the short to long term. It is expected however that following this modelling exercise, far more detailed review, testing and evaluation will occur prior to any replacements being approved.

The main issue for our review is then whether it is “fit for purpose” in terms of producing forecasts for regulatory purposes, or does it include some bias. Like any other modelling approach, this depends on the calibration and validation of the model. This is particularly important given that the model is forecasting such a significant step up in replacement qualities from recent historical levels.

Important matters, in the context of this model, are:

- the existing probability of failure and the ageing relationship used to predict the degradation with time and their relationships with asset condition and age – as noted above, for the CBRM approach this is transferred into a Health Index (HI) for each asset
- consequence assumptions, which together with the probability of failure are used to determine risk profiles for each asset.

With regard to transformers, the CBRM model indicates that condition test data was used in developing the health index. The most relevant appears to be the estimated degree of polymerisation (DP), which we consider primary condition information that indicates the impending failure of the transformers windings and associated remaining life. The model input data indicates that only one transformer is at its end of its technical life, based upon these estimates (i.e. a DP below 200). Four appear to be just entering an advanced aging zone (i.e. DP 290-330 - HI around 5). This may suggest around 5 to 10 years of remaining life. All others are well below this level (i.e. DP >390 - HI less than 5). This may suggest greater than 10 years of remaining life for these transformers.

The much higher final HI values in the model - and as such reduced remaining life - for many of these assets are due to the age of the transformers and various other factors. The increased HI also appears to result in the degradation due to aging also being much more rapid. However, it is not clear why these factors have such a significant influence on the predicted remaining life over the actual condition information obtained through testing.

It is also noted that the number of major failures (i.e. those resulting in a significant disruption to supply) appears to be higher than historical levels for the asset population. The major failure rate used within the model is based upon an EA estimate derived from international results. However, across the Powercor's population this may be overstating risks of major failure. In this regard, the model assumes there will be a major transformer failure once in every 1.5 years, but it is not clear from the Powercor documentation that this frequency of major failure is reasonabley close to that which has occurred over the last 5 years. The important point here is that it appears that the most significant component of risk is associated with network performance due to major failures (i.e. the value of loss of supply). As such, this factor may be overstating the risks associated with transformers.

For CBs, the health is largely based upon the age with various factors applied to adjust this for fleet condition and environment, etc. In effect, the health index and the rate of aging appear to be largely due to asset life assumptions for the various CB types. However, it is not clear how these lives were derived, although it is clear that the HI, probability of failure, and the aging, are sensitive to this assumption.

Similar to the concern above on assumed transformer major failure rates, the number of major failures for CBs predicted by the model appears to be much higher than recent levels on the Powercor network. As with transformers, the most significant component of risk for CBs is due to the impact of major failures on network performance. The model major failure rate is based upon an EA estimate derived from international results. In this regard, the model assumes there will be a major CB failure across the population every year, with a catastrophic failure every 3.5 years (i.e. over the last five years, we may have encountered five major distributive failures (i.e. resulting in significant loss of supply) and one to two catastrophic failures. As far as we can tell from the information provided, this has not occurred.

For CBs, it is also not clear how Powercor has derived the number of replacements from the model outputs. The Powercor information indicates that it is based upon the number of CBs with a predicted health index greater than 8, but this does not reconcile with quantities provided elsewhere.

Due to these issues and the general matter of proof of "fit for purpose", Nuttall Consulting has requested that Powercor provide information indicating how it calibrated and validated the CBRM model. This requested an explanation in terms of recent historical failures and associated consequences.

Unfortunately, the Powercor response to this request has provided little additional and quantitative information that addresses our concerns. The response does indicate that workshops were held with EA and actual data was reviewed. However, we have not been provided with any workings or outputs from these workshops.

Powercor did provide a memorandum from EA on some of these matters, but this provided very little additional information that was not already available through the original report.

On the matter of the higher major failure rate, EA did discuss why a failure rate of zero was inappropriate. However, we do not dispute that; clearly, assuming a zero major failure rate would most likely be too optimistic. The issue in our opinion is why they did not determine that a rate below the general international rate was not more appropriate, given the recent 5-year history.

Based upon the above concerns, given the significant increase in replacement needs, forecast through these models, we do not consider that Powercor has adequately demonstrated that they are “fit for purpose”. In our opinion, this would require a far more substantial and quantitative analysis to appropriately and transparently demonstrate their suitability. This would require network level and sample asset level analysis that shows that the number of failures, probability of failure, the aging relationship, and the consequences, derived through the model are reasonable unbiased estimates of the replacement needs. Such an evaluation would need to take into account Powercor’s historical information, including failure statistics, asset condition monitoring results and risk mitigation measures.

At this stage, we consider there is considerable discretion to further optimise and defer much of the program proposed by Powercor. It is impossible in a review of this form for us to undertake the type of analysis that would be required to determine an alternative detailed work plan. We do accept however that the aging of the network is imposing greater needs on the business, above those faced in the current period. On balance, we consider that an allowance based upon the current period actual, allowing for the further aging of the network is reasonable. This still allows a significant increase on 2006-2008 levels, and should allow for a number of transformer replacements, an increase in CB replacements and other works.

8.3.4 Zone substation Secondary Systems Replacement

Activity code and expenditure summary

The zone substation secondary Systems Replacement activity code largely covers the age/condition based replacement of secondary systems within the zone substations.

A major portion of this expenditure in the next period is due to an ongoing program to replace aged relays. There are also a number of other ongoing programs, covering batteries and chargers, aged PLC units, aged quality of supply meters, new control schemes for fault level management, and capacitor controller replacements.

There are also a large number of proposed new programs for the next period:

- replacing aged DC intertrip schemes
- installing new transformer inhibit schemes
- relay replacements due to terminal station rebuilds
- undertaking a number of protection reviews
- installing duplicate protection
- upgrading AC and DC supplies
- replacing aged switch controllers

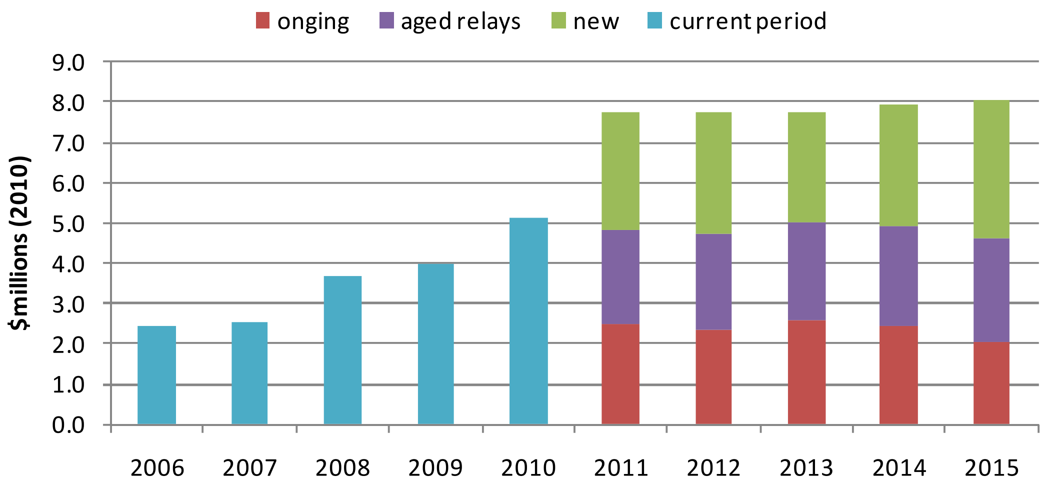
- establishing VTs on some 66 kV lines
- control room modifications
- replacement of aged communications equipment
- installation of auto-reclose schemes.

Table 69 and Figure 83 provide an overview of the expenditure in this category. Figure 83 also indicates the proportion of expenditure on the aged relays, other ongoing programs, and the new programs. This analysis indicates that this activity code represents 8% of the total RQM expenditure in the next period, with significant step increase in expenditure proposed for the commencement of the next period (2011).

Table 69 - Overview of expenditure for the zone substation secondary system replacements

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
2.9	4.5	7.8	8%	58%	172%

Figure 83 - Expenditure profile for the zone substation secondary system replacements



Forecasting methodology and rationale

Powercor has provided some discussion on the relay replacement program[83]. This indicates that Powercor has undertaken a risk assessment of its relay fleet and ranked each relay in terms of highest to lowest risk.

The forecast for the other ongoing programs are generally based upon an assumed volume per year multiplied by an assumed unit cost, or historical rates. The forecast of the new programs proposed for the next period appear to be based upon assumed volumes multiplied by an assumed unit cost.

Nuttall Consulting views

83 Relay documentation, in email, dated 24/12/09

With regard to the large step increase proposed to occur in 2011, there is very little evidence provided by Powercor to demonstrate that this increase is prudent and efficient.

With regard to the relay replacements, it is noted that the level of replacement in the next period is lower than the average level in the current period[84]. As such, it is not clear why such an increase in expenditure is necessary.

Similarly, with the other ongoing and new programs, no economic analysis has been presented to demonstrate the prudency and efficiency of the increases.

With regard to the new programs, it appears that these are largely based upon issues (and associated risks) that were known and tolerated during the current period. As such, although we see no reason to consider that the issues and associated risk are not material, given they are being currently managed, it is not clear why such a large increase in expenditure is required to begin to address so many matters. In the absence of evidence to the contrary, it must also be assumed that the undertaking of such a program would have a similarly significant step reduction in the risks that Powercor currently faces, and have accepted in the current period.

Based upon the lack of evidence that Powercor's proposed expenditure increase is prudent and efficient, we consider that a reasonable estimate would be based upon the existing levels with some allowance for an increasing expenditure based upon the aging of the network.

8.3.5 Overhead and underground line replacement

Activity code and expenditure summary

The overhead and underground line replacement activity code broadly covers the age/condition based replacement of overhead line conductors and insulators, and underground cable and associated underground equipments (e.g. joints, terminations, link boxes etc). A major portion of this expenditure in the next period is due to the proposed replacement of HV cables and associated joints and terminations.

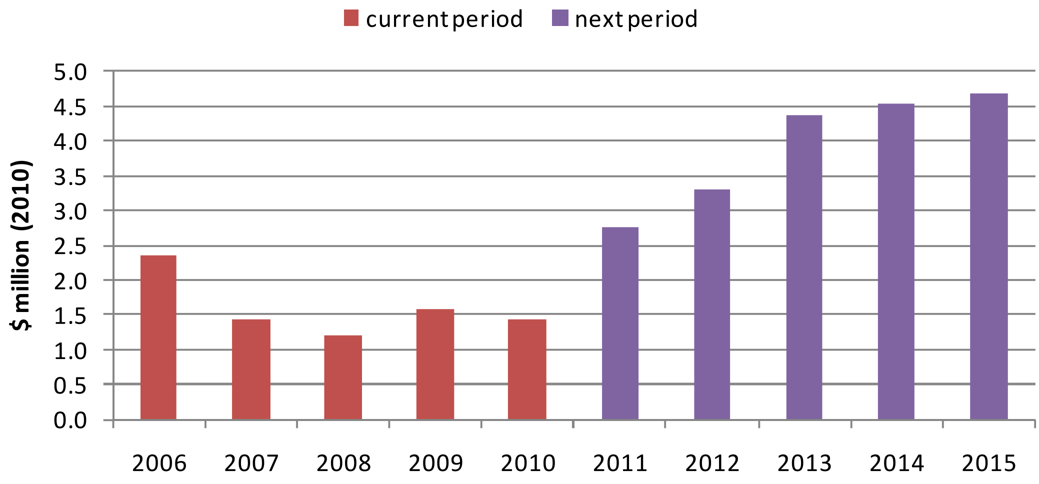
Table 70 and Figure 84 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents 4% of the total RQM expenditure in the next period, with expenditure anticipated to significantly increase from historical levels in 2011. This increase appears to be largely due to increases in the ongoing programs, particularly the HV cable replacement program.

Table 70 - Overview of expenditure for overhead and underground line replacement

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
1.7	1.5	3.9	4%	-9%	134%

[84] Documentation provided in email, dated 26/2/10, indicate that on average 77 relays were replaced annually in the current period. Powercor is planning to replace 55 per annum in the next period.

Figure 84 - Expenditure profile for overhead and underground line replacement



Forecasting methodology and rationale

The Powercor information indicates that the forecasts for the HV cables are based upon a fairly simple age based model that assumes a percentage of cable needs to be replaced at particular ages, between 25 and 40 years. The other ongoing programs were based upon a combination of historical rates and engineering judgment.

Nuttall Consulting views

Nuttall Consulting has reviewed the information provided by Powercor to support the expenditure forecast associated with this activity code. However, there is little information to justify the scale of the sharp increase that is proposed in 2011. In particular, it is not clear why Powercor considers its age based model to be reasonably representative of replacement needs, given the average age of replacement appears to be around 30 to 35 years, which is much lower than we would typically expect. Furthermore, as other ongoing programs appear to be based upon historical rates, it is not clear why these would be resulting in such a sharp upturn in expenditure.

Based upon these findings, we see no reason to allow more than the average recent historical level with some allowance for an aging population.

8.3.6 HV Switch Replacement

Activity code and expenditure summary

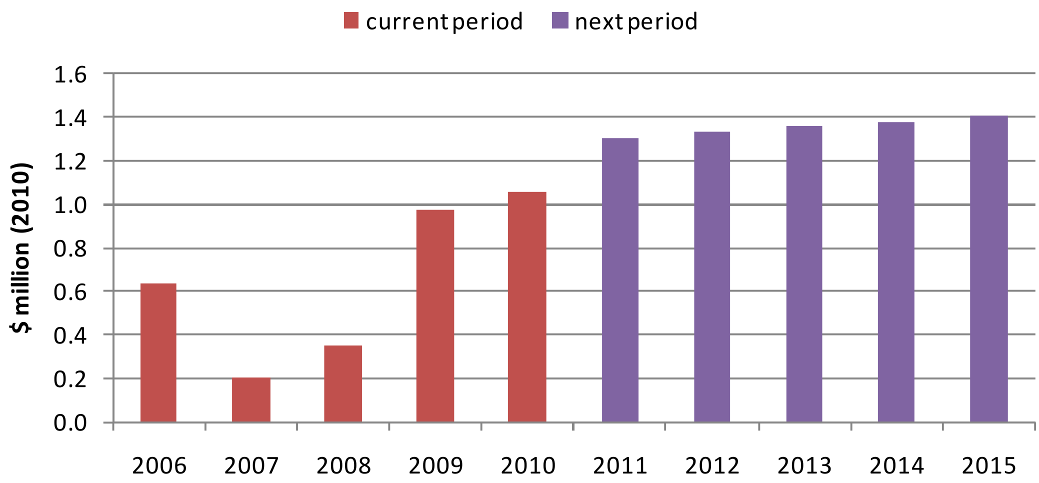
The HV switch replacement activity code broadly covers the age/condition based replacement of HV and LV switchgear. A major portion of this expenditure in the next period is due to the proposed replacement of HV air break switches.

Table 71 and Figure 85 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents 1% of the total RQM expenditure in the next period, with expenditure anticipated to significantly increase from historical levels in 2009.

Table 71 - Overview of expenditure for the HV switch replacement

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
0.4	1.0	1.4	1%	158%	243%

Figure 85 - Expenditure profile for the HV switch replacement



Forecasting methodology and rationale

The Powercor documentation indicates that forecasts in this activity code are based upon historical replacement activities.

Nuttall Consulting views

Nuttall Consulting has reviewed the information provided by Powercor to support the expenditure forecast associated with this activity code. However, there is little information to justify the scale of the sharp increase that is proposed in 2009. In particular, given that the expenditure appears to be based upon ongoing replacement programs of which the historical replacement activity is the main basis for the forecast, it is not clear why such a sharp upturn in expenditure is required.

Based upon these findings, we see no reason to allow more than the average recent historical level (i.e. from 2006-2008) with some allowance for an aging population.

8.3.7 Service Replacement

Activity code and expenditure summary

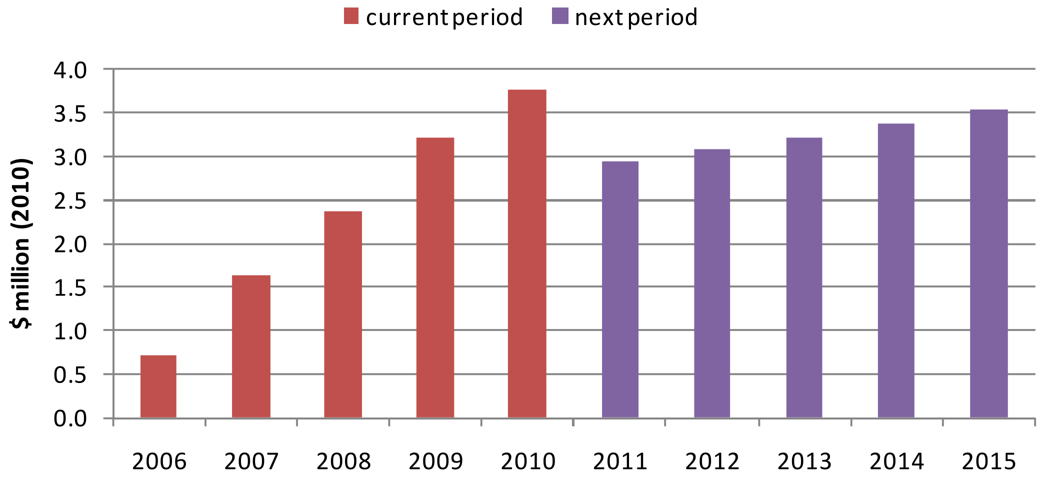
The service activity codes broadly cover the age/condition based replacement of customer service lines and cables. This made up of two main programs: neutral screen (aerial) services and other condition based service replacements.

Table 72 and Figure 86 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents only 3% of the total RQM expenditure in the next period, with expenditure anticipated to significantly trend up in the current period but reduce slightly in the next period.

Table 72 Overview of expenditure for the service replacements

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
1.6	3.5	3.2	3%	122%	106%

Figure 86 - Expenditure profile for the service replacements



Forecasting methodology and rationale

Powercor has provided some discussion on its methodology applied for this category[85]. This indicates that Powercor has forecast the volume of replacement via a simple age based model to determine annual volumes – essentially dividing the total number of services by an assumed 60-year life. Certain minor adjustments are then made to allow for replacements that may occur in other activity codes. Unit costs are assumed based upon typical costs.

Nuttall Consulting views

There is little information presented that supports the scale of the increase in the current period. The main factors raised in the Powercor documents as a justification for expenditure increases, in addition to an aging asset base, are a change in the inspection criteria and the removal of an exemption for full compliance with a vegetation clearance obligation. However, in both these cases, it is not clear how these have impacted the current period

That said, given that the next period appears to be broadly in line with the historical trend (2006-2008), the forecast for the next period is not unreasonable.

8.3.8 Reliability

Activity code and expenditure summary

[85] Related Activity Code documents in email, dated 26/2/10

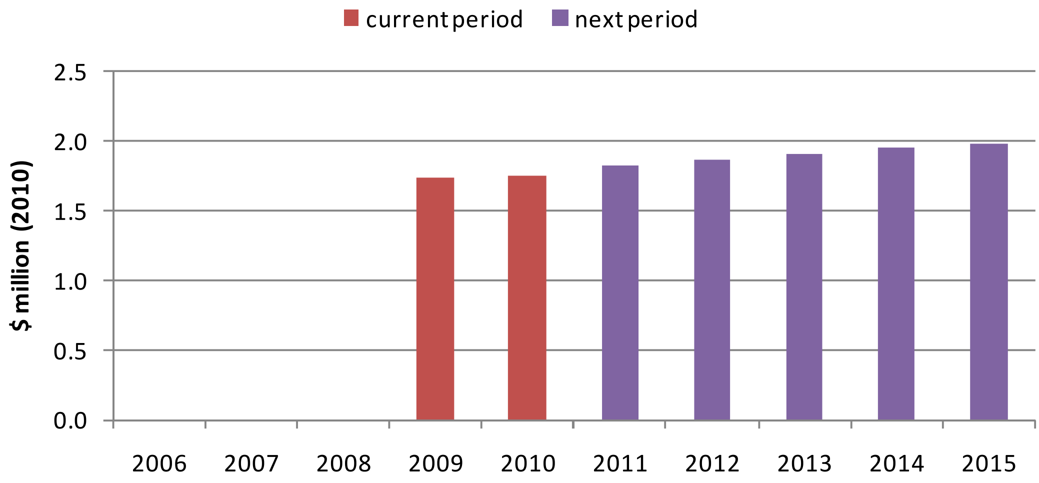
The reliability activity code broadly covers works to address worst served customers.

Table 73 and Figure 87 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents only 2% of the total RQM expenditure in the next period, with forecast expenditure stepping up from a zero level in 2009.

Table 73 - Overview of expenditure for reliability

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
0.0	1.7	1.9	2%	n/a	n/a

Figure 87 - Expenditure profile for reliability



Forecasting methodology and rationale

The Powercor documentation[86] indicates that the reliability forecasts are based upon a range of assumed projects to address worst served customers.

Nuttall Consulting views

There is limited information to justify the expenditure in this activity code.

Furthermore, as expenditure is not captured to this activity code prior to 2009, it is not clear how similar works have been allocated historically. However, assuming that similar works in the current period have been captured in the other RQM activity codes, we consider that there should already be some allowance for these proposed works in our suggested forecasts for other activity codes, which are predominantly based upon an extrapolation of the 2006-2008 costs.

8.3.9 Pole Replacement

Activity code and expenditure summary

The pole replacement activity code broadly covers the age/condition based replacement of poles, including pole staking and pole treatments.

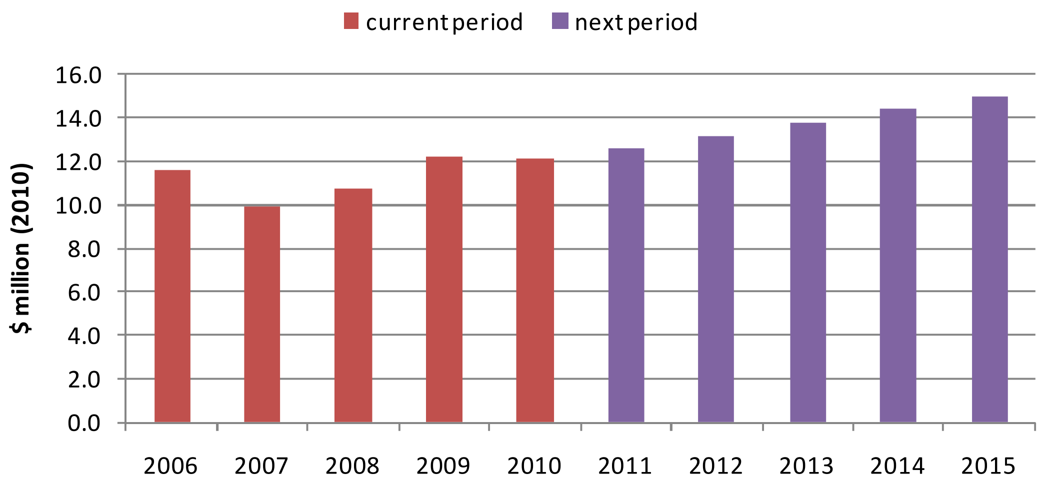
[86] Related Activity Code documents in email, dated 26/2/10

Table 74 and Figure 88 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents only 15% of the total RQM expenditure in the next period, with forecast expenditure broadly on trend with historical levels.

Table 74 - Overview of expenditure for pole replacements

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
10.8	12.2	13.8	15%	13%	28%

Figure 88 - Expenditure profile for pole replacements



Forecasting methodology and rationale

The Powercor documentation[87] indicates that the pole forecasts are based upon historical replacement rates with an incremental annual increase.

Nuttall Consulting views

Expenditure on pole replacements (including staking and treatments) appears to be broadly in line with the historical trend. There is a small step increase in 2009, but this does not appear to be that significant and does not appear to have a significant impact on the 2011 to 2015 forecast.

Given the modest proposed increase, which is broadly in line with our replacement modelling, we consider that this estimate is reasonable.

8.3.10 Transformer Replacement

Activity code and expenditure summary

The transformer activity code covers the age/condition based replacement of distribution transformers.

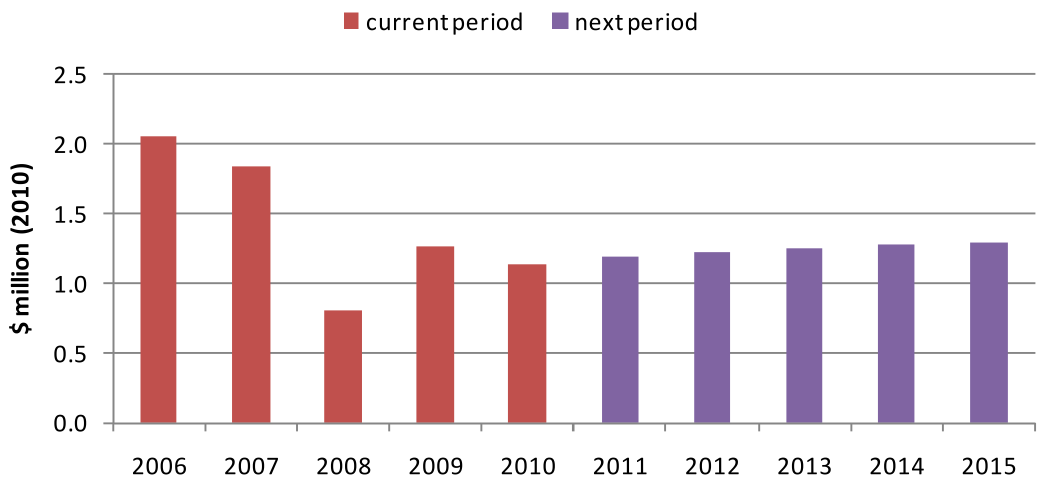
[87] Related Activity Code documents in email, dated 26/2/10

Table 75 and Figure 89 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents only 1% of the total RQM expenditure in the next period, with expenditure below average 2006-2008 level in the next period.

Table 75 - Overview of expenditure for transformer replacements

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
1.6	1.2	1.3	1%	-23%	-20%

Figure 89 - Expenditure profile for transformer replacements



Forecasting methodology and rationale

The Powercor documentation[88] indicates that the transformer replacement forecast is based upon engineering judgment of historical replacement rates – although the precise methodology is not clear.

Nuttall Consulting views

As noted above, expenditure in this activity code appears to be broadly in line with the average during the 2006-2008 period. Given this view and the low materiality of this activity code, we consider that this estimate is reasonable.

8.3.11 Cross arm Replacement

Activity code and expenditure summary

The cross arm replacement activity code covers the age/condition based replacement of this asset.

Table 76 and Figure 90 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents 9% of the total RQM expenditure in the next period, with forecast expenditure broadly on trend with historical levels.

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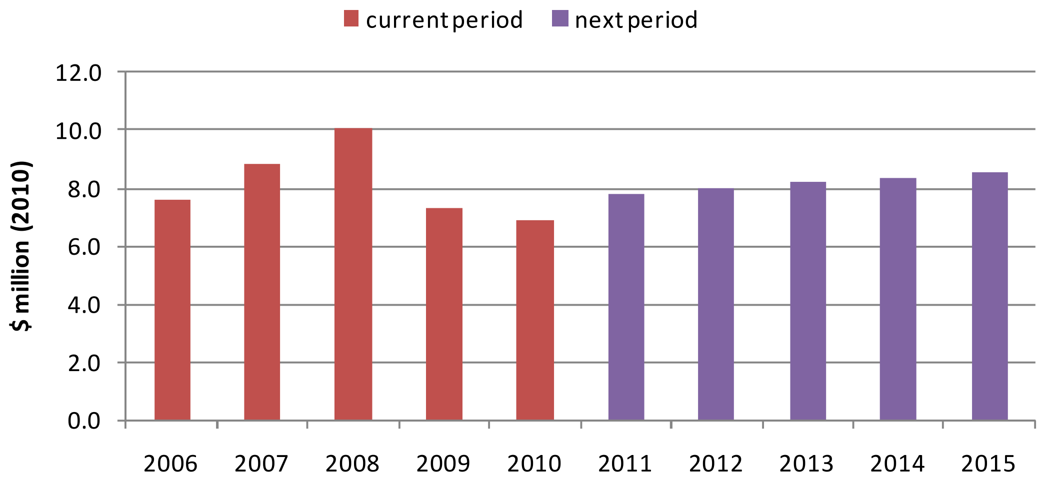
[88] Related Activity Code documents in email, dated 26/2/10

Table 76 - Overview of expenditure for cross arm replacements

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
8.8	7.1	8.2	9%	-20%	-7%

Figure 90 - Expenditure profile for cross arm replacements



Forecasting methodology and rationale

The Powercor documentation[89] indicates that the cross arm forecasts are based upon historical replacement rates with an incremental annual increase.

Nuttall Consulting views

Expenditure on cross arm replacements appears to be broadly in line with the historical trend. There is a small step increase in 2011, but based upon the previous replacement numbers, this does not appear to be unjustified.

Given these findings and the modest proposed annual increase, which is broadly in line with our replacement modelling, we consider that this estimate is reasonable.

8.3.12 Fault Replacement

Activity code and expenditure summary

The fault replacement category covers three Powercor activity codes that capture fault related asset replacements. This may be due to age/condition related failure or other causes.

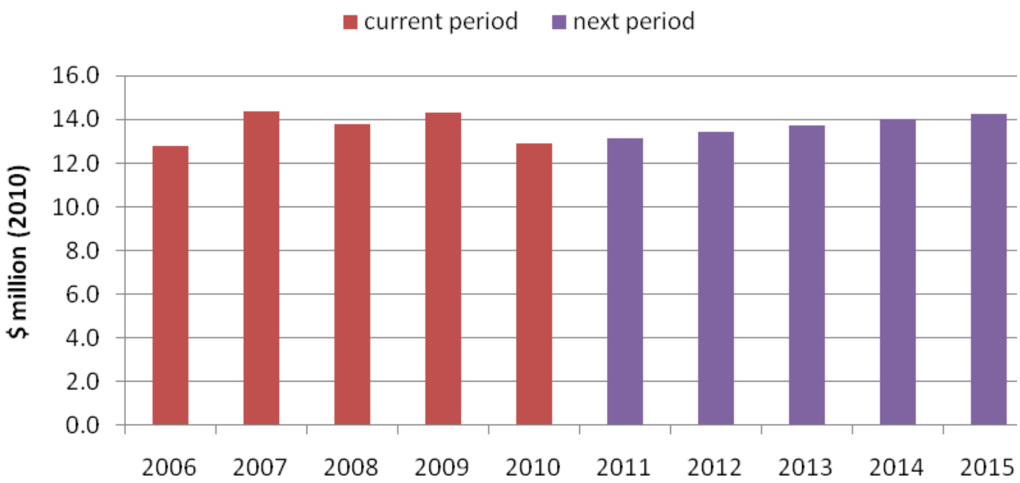
Table 77 and Figure 91 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents 15% of the total RQM expenditure in the next period, with forecast expenditure around the historical trend.

[89] Related Activity Code documents in email, dated 26/2/10

Table 77 - Overview of expenditure for fault replacements

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
13.7	13.6	13.7	15%	0%	0%

Figure 91 - Expenditure profile for fault replacements



Forecasting methodology and rationale

The Powercor documentation[90] indicates that the fault replacement forecasts are based upon historical replacement rates, but the methodology is not clear.

Nuttall Consulting views

Given that the 2011-2015 forecasts are similar to the 2006-2008 trend and no significant increase is being proposed, we consider this estimate reasonable.

8.3.13 HV fuse and surge diverter replacement

Activity code and expenditure summary

The HV fuse and surge diverters (HVFSD) activity code broadly covers the age/condition based replacement of these assets and some other HV and LV devices.

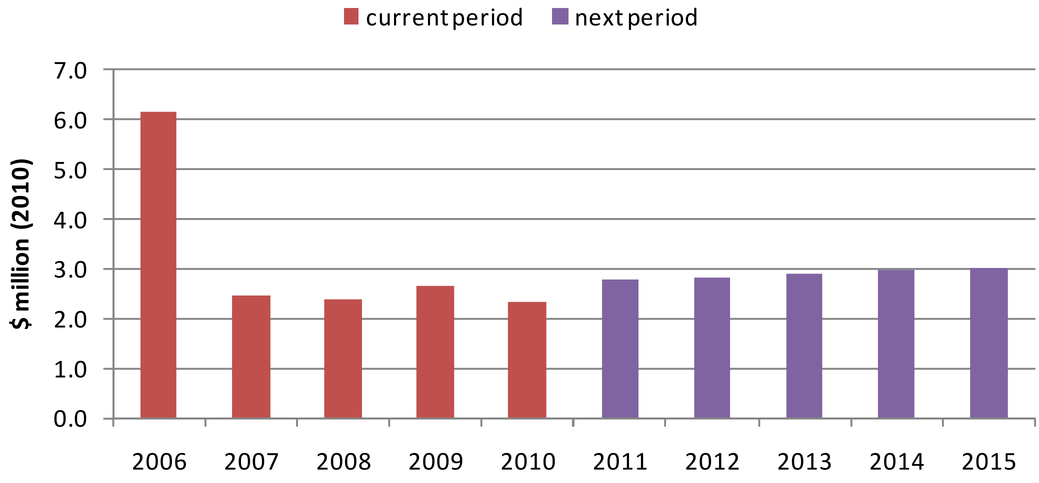
Table 78 and Figure 92 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents only 3% of the total RQM expenditure in the next period, with expenditure proposed for the next period close to the historical trend.

Table 78 - Overview of expenditure for HVFSD replacements

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
3.6	2.5	2.9	3%	-31%	-20%

[90] Related Activity Code documents in email, dated 26/2/10

Figure 92 - Expenditure profile for HVSFD replacements



Forecasting methodology and rationale

The Powercor documentation[91] indicates that the HVFSD expenditure forecast is mainly based upon two replacement programs: HV fuses and distribution surge diverters. The Powercor documentation indicates that both these programs have been forecast based upon historical rates and engineering judgement.

Nuttall Consulting views

Given that the 2011-2015 forecasts are similar to the 2007-2008 levels, with only a modest increase, we consider this estimate reasonable.

8.3.14 Other

Activity code and expenditure summary

The other activity codes cover replacement activities to mitigate TC interference and bird cover replacements, both of which Powercor captures costs in specific activity codes.

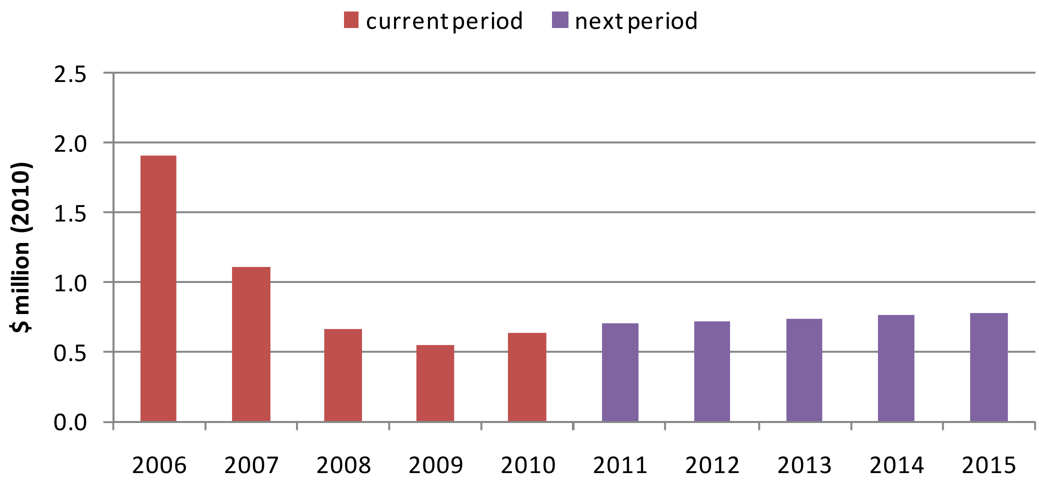
Table 79 and Figure 93 provide an overview of the expenditure in this category. This analysis indicates that this activity code represent only 1% of the total RQM expenditure in the next period, with forecast expenditure broadly in line with historical levels.

Table 79 - Overview of expenditure other replacements

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
1.2	0.6	0.7	1%	-52%	-40%

[91] Related Activity Code documents in email, dated 26/2/10

Figure 93 - Expenditure profile for other replacements



Forecasting methodology and rationale

The Powercor documentation[92] indicates that the 2011-2015 forecasts are based upon historical replacement rates.

Nuttall Consulting views

It is noted that expenditure was ramping down significantly between 2006 and 2008 and then is forecast to stabilise from this point on, rather than reduce further. However, we see no reason to consider that this is unreasonable. Therefore, given that the 2011-2015 forecasts are similar to the 2008 levels, we consider this estimate reasonable.

8.3.15 Overall findings

The above has shown that the proposed increase in RQM expenditure in the next period is mainly due to a new program to proactively replace age conductors. A number of other asset types are also proposed to have significant increases in expenditure over historical levels.

Based upon our review, we do not consider that Powercor has adequately demonstrated that the increases are prudent and efficient.

The conductor replacement program is a very significant ($100 million) new program proposed to commence in 2011. However, there is very little justification for the scale of this program. We are not recommending any additional allowance for this project. However, it does appear that a major driver of this new program may be reducing bushfire risks. Therefore, we are recommending that the expenditure for such a program is “ring fenced” for further review following the findings of the Royal Commission on the Victorian bushfires.

For the age/condition based replacements, only the zone substation transformer and circuit breaker replacement programs have some form of quantitative economic and risk analysis. However, there is little evidence that this has been calibrated to Powercor’s circumstances, and as such, it may be significantly overstating replacement needs.

[92] Related Activity Code documents in email, dated 26/2/10

For other assets, the basis for the increase appears to be due to known issues and associated risks that are being reduced. This particularly concerns increases in relay replacements, HV/LV switchgear and underground cables.

In these cases, we do not doubt that the issues and associated risks exist, but it has not been demonstrated how Powercor is presently managing these matters – presumably in a prudent and efficient manner – and how the risk will change over time. As such, it is not evident that the scale of the increase is required.

Based upon the above, we consider that the RQM allowance should be based upon the recent historical levels of RQM expenditure with some additional allowance for the aging of the network. The recommended RQM expenditure is shown in Table 80. The basis for these recommendations is indicated in Table 81.

It is important to note that this recommendation must be considered in the broader context of the overall capex. We would fully expect that at the activity code level, actual expenditure may differ considerably as circumstances change and the full capital governance process is applied.

It is also important to note that this recommendation should be considered as an estimate only. The AER may need to make further adjustments to allow for its findings on the other matters, such as overhead and labour and material escalation, which are not accurately allowed for here.

Table 80 – Powercor recommended RQM

	$thousands (2010)				
Activity code	2011	2012	2013	2014	2015
Proposed	87,428	89,526	94,428	95,203	97,493
Recommended	**50,708**	**52,506**	**54,482**	**56,586**	**58,699**

Table 81 – Powercor activity code based adjustments

Activity code	Nuttall Consulting view
Cross-arm Replacement	Accepted
Conductor replacement program	Rejected – no allowance
Fault related	Accepted
HV Fuse Unit & Surge Divert. Repl.	Accepted
HV Switch Replacement	Rejected - allowance based upon average 2006-2008, with increase based upon repex model findings
OH/UG Line Replacement	Rejected - allowance based upon average 2006-2008, with increase based upon repex model findings
Other	Accepted
Pole	Accepted
Reliability Improvement	Rejected – no allowance
Services	Accepted
Transformer Replacement	Accepted
Zone Substation Plant Replacement	Rejected - allowance based upon average 2006-2008, with increase based upon repex model findings
ZSS - Secondary Systems Replacement	Rejected - allowance based upon average 2006-2008, with increase based upon repex model findings

8.4 Environmental, Safety and Legal

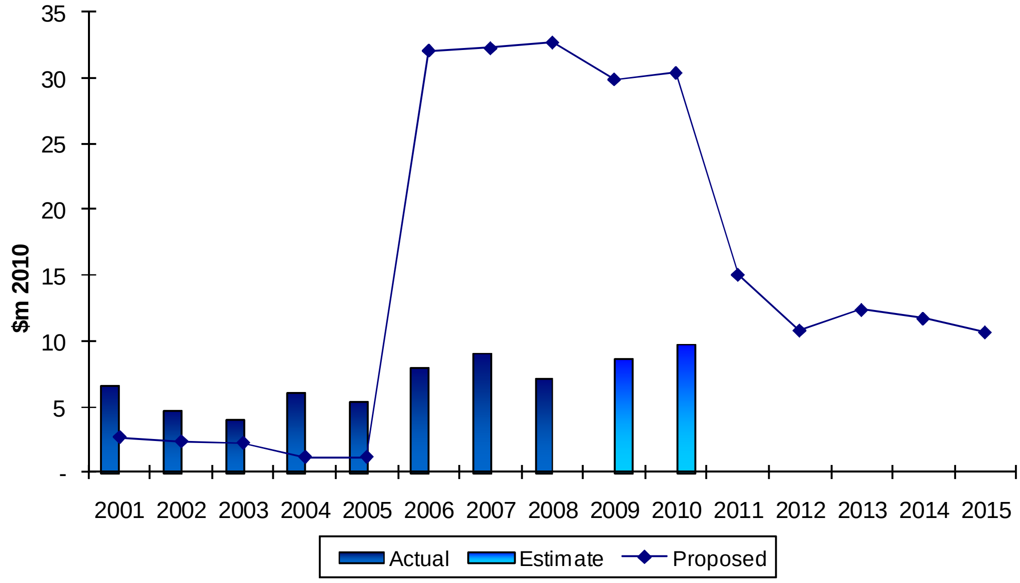
Powercor is proposing an increase of 50% in Environmental, Safety and Legal capex for the next Regulatory Control Period when compared against actual expenditure in the current Regulatory Control Period. Powercor estimates that its' Environmental, Safety and Legal capital expenditure for the 2006-10 regulatory control period will be $42.7 million. It is forecasting that this will increase to $60.5 million in the 2011-15 regulatory control period.

For the 2006 EDPR, Powercor proposed Environmental, Safety and Legal expenditure of $157.3 million. The resultant actual expenditure for this period is forecast to be $42.7 million[93].

The following chart provides a summary of Environmental, Safety and Legal capex for Powercor.

[93] Including 2009 and 2010 estimates.

Figure 94 - Powercor Environmental, Safety and Legal capex



The Powercor proposal identifies the key environmental issues that require management as:

- noise control
- bushfire management
- containment and drainage of oil in zone substations
- asbestos management
- managing powerline easements in Victorian National Parks
- ESMS.

Each of these issues is considered below.

8.4.1 Noise control

The Powercor proposal identifies the 1997 State Environmental Protection Policy (SEPP) as the primary legal instrument in relation to regulating the impact of noise emissions from Powercor assets. Powercor state that they have voluntarily created an Environment Improvement Plan (EIP) to assist in complying with the SEPP. The Powercor proposal identifies that the "*main driver of (the) increase in Environmental, Safety and Legal capital expenditure over the 2011-15 regulatory control period is expenditure on the mitigation of noise at zone substations*".

Noise control is a long-term consideration for all DNSPs.

Powercor state that four sites are currently in substantial non-compliance with the noise obligations.

Powercor states that "the levels of work are forecast to be consistent with the 2006-10 regulatory control period"[94]. On this basis, it appears reasonable to assume that noise

[94] Powercor Australia Ltd's Regulatory Proposal 2011-15, Chapter 5.7.4

control remains a continuing works program and that future expenditures should be consistent with historical expenditure trends.

8.4.2 Bushfire management

The Electricity Safety (Bushfire Mitigation) Regulations 2003 regulate Powercor's bushfire mitigation activities. Powercor Australia is required to submit annually a Bushfire Mitigation Strategic Plan to the Energy Safe Victoria which provides information on its bushfire mitigation activities.

Powercor is proposing to increase the volume of its bushfire mitigation capital expenditure activities in the 2011-15 regulatory control period due to land remapping by the Country Fire Authority. This will result in 10 per cent of low bushfire risk areas in rural areas being reclassified as high bushfire risk areas.

This change does impact Powercor as differing standards apply for low and high risk bushfire areas. Powercor has estimated that this change will increase capital expenditure in order to comply with the requirements of the Electricity Safety (Bushfire Mitigation) Regulations 2003, in particular costs associated with low voltage spreaders and bird covers.

Based on projected mapping provided by the CFA, it is estimated by Powercor that additional vegetation management costs of $0.5 million will be required over the period 2011-15. Forecast expenditure in the next regulatory control period is based on the current average unit cost of undertaking the physical works.

Nuttall Consulting considers that the additional expenditures are prudent and should be considered by the AER for inclusion in the allowed capex for the next control period. However, these costs may also be impacted by the outcomes of the Bushfire Royal Commission.

8.4.3 Oil containment

Powercor has identified a number of existing regulatory and legislative obligations that relate to the containment and drainage of oil filled equipment. Powercor state that they have developed Oil Containment Guidelines (Guidelines) to assist it in complying with these obligations. These Guidelines provide a basis for Powercor's ten year work program for upgrading or replacing oil bunds at zone substations and retrofitting drainage at zone substations.

Oil containment is a long-term consideration for all DNSPs and the existing set of regulations relating to oil management have been in existence for many years.

Powercor is proposing an annual expenditure of $100k for the next control period. This level of expenditure is consistent with actual expenditure in the current control period.

Powercor has not provided any information to suggest that the obligations for oil containment and drainage have changed or are anticipated to change. On this basis, it appears reasonable to assume that oil containment and drainage remains a continuing works program and that future expenditures should be consistent with historical expenditure trends. The expenditure proposed by Powercor for oil management for the next control period appears reasonable.

8.4.4 Asbestos management

Powercor has identified that the Occupational Health and Safety (OHS) Regulations 2007 (OHS Regulations) and the Environment Protection (Industrial Waste Resource) Regulations 2009 regulate the storage and disposal of asbestos materials. Powercor states that is has established an Asbestos Management Manual - 14-25-M0004 to assist it in complying with asbestos related obligations.

Asbestos management is a long-term obligation for all DNSPs. In their 1999 submission to the Essential Services Commission Powercor identified removal of asbestos as a major initiative for the 2001-2005 period[95].

Powercor was requested to provide additional information on the projected asbestos management costs and supporting documentation. No additional information was provided.

Powercor has not provided any information to suggest that the obligations for asbestos management have changed or are anticipated to change. On this basis, it appears reasonable to assume that asbestos management remains a continuing works program and that future expenditures should be consistent with historical expenditure trends.

8.4.5 Managing powerline easements in Victorian National Parks

The National Parks Act 1975 is managed by Parks Victoria and includes aspects relating to the management of utility assets within parks and the prevention of erosion of land, particularly in forested areas. In accordance with section 27A of the National Parks Act 1975, Parks Victoria has recently required Powercor Australia to enter into an agreement with it to, amongst other things:

- install fences and gates to prevent recreational and other unauthorised use along linear powerline easements and therefore prevent erosion and damage of this land; and
- build and maintain access tracks along powerline easements.

Powercor has stated that they will commence capital works resulting from this agreement in 2010.

The above requirements appear reasonable as Powercor has been required to undertake these works by Parks Victoria. However, Powercor has not provided any additional information to support this program and the program was not identified in Powercor's Environmental, Safety and Legal program and activity template list[96]. It is not clear whether this was an omission on the behalf of Powercor or whether the program had been removed.

In the absence of further information from Powercor it is not possible to recommend the inclusion of additional expenditures to address this program.

[95] 2001 Electricity Distribution Price Review Submission - 1 December 1999, Powercor, P65
[96] ESL program and activity template list v1.pdf, 9 March 2010

8.4.6 ESMS

Powercor has identified the Electrical Safety Act (Victoria) 1998, the Electricity Safety (Network Assets) Regulations 1999 and the Electrical Safety Amendment Act 2007 as major regulatory obligations.

These safety regulations represent a long-term consideration for all DNSPs.

In their proposal for the next Regulatory Control Period, Powercor state that "*Forecast expenditure in the next regulatory control period is based on the current average cost of undertaking the program of works in the 2006-10 regulatory control period. The works program for the 2011-15 regulatory control period is derived from Powercor's existing safety management plans and will largely reflect a continuation of the work program in the current regulatory control period.*"

On this basis, it appears reasonable to assume that safety management remains a continuing works program and that future expenditures should be consistent with historical expenditure trends.

8.4.7 Environmental, Safety and Legal summary

The historical forecasts for Environmental, Safety and Legal have proven to be inaccurate with significant levels of over-forecasting.

The issues identified by Powercor as driving Environmental, Safety and Legal expenditure have been part of the operating environment for many years and have clearly been considered in the previous Environmental, Safety and Legal forecasts.

Powercor has not identified any changes in these obligations that impact the next control period.

A key assumption of the Powercor proposal is that they are an efficient operator. The benchmarking undertaken by Nuttall Consulting and the historical expenditures of Powercor tend to support this assumption.

On this basis, it is reasonable to accept the efficient costs that have been recently incurred by the DNSP as the basis for forecasting the required Environmental, Safety and Legal expenditure for the next Regulatory Control Period.

Table 82 - Recommended Powercor Environmental, Safety and Legal capex

Powercor	Costs (2010 $M)				
Environmental, Safety and Legal	2011	2012	2013	2014	2015
Recommended Expenditure	7.12	7.12	7.12	7.12	7.12

The recommended Environmental, Safety and Legal capex for Powercor is based on the average actual expenditures incurred in the previous 5 years exclusive of indexation and escalation.

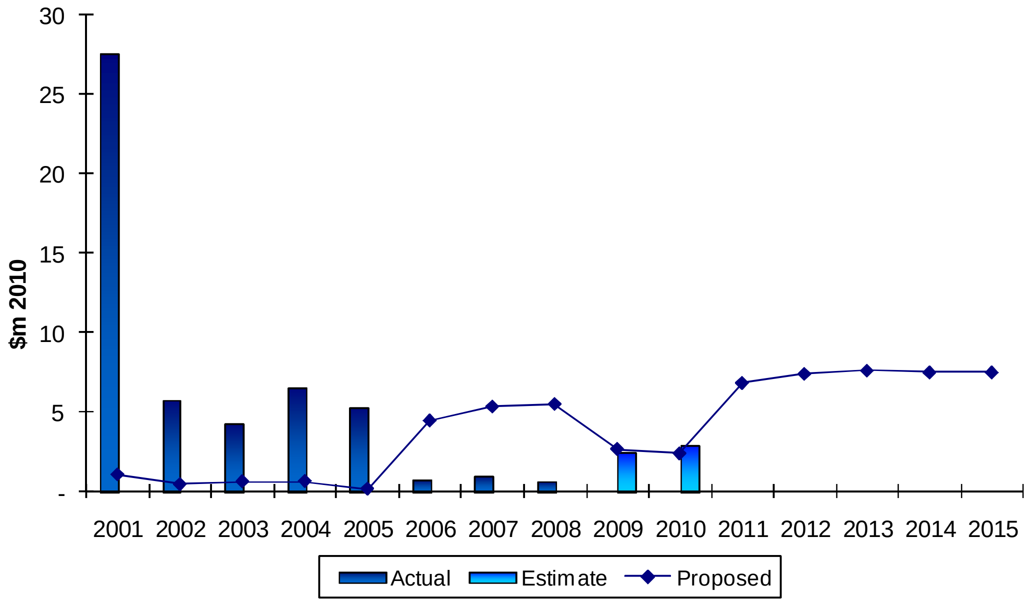
8.5 SCADA and Network Control

Powercor is proposing an increase of over 800% in SCADA and Network Control capex for the next Regulatory Control Period when compared against actual expenditure in the current Regulatory Control Period. Powercor estimates that its' SCADA and Network Control capital expenditure for the 2006-10 regulatory control period will be $7.6 million. It is forecasting that this will increase to $36.7 million in the 2011-15 regulatory control period.

For the 2006 EDPR, Powercor proposed SCADA and Network Control expenditure of $20.2 million. The resultant actual expenditure for this period is forecast to be $7.6 million[97].

The following chart provides a summary of SCADA and Network Control capex for Powercor.

Figure 95 - Powercor SCADA and Network Control capex



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 $6.5 million per annum., although almost half of this expenditure occurred in 2001.

The Powercor proposed SCADA and Network Control appears significantly higher than that proposed by other DNSPs for the next control period with the exception of CitiPower. The following chart provides the average annual proposed capex for SCADA and Network Control for the next control period.

[97] Including 2009 and 2010 estimates.

Figure 96 - Forecast SCADA and Network Control

The above chart shows that the proposed SCADA and Network Control capex for CitiPower and Powercor is significantly higher than that proposed by the other Victorian DNSPs. SCADA and Network Control expenditures for CitiPower and Powercor over the last 3 years are consistent with the proposed levels for Jemena, SP AusNet and United Energy. The factors driving the increased capex are considered below.

The Powercor proposal identifies the key programs for the 2011-15 period as:

- continuation of the installation of new protection and control communications infrastructure
- installation of Distribution Management System (DMS) field devices
- migration away from Trunk Mobile Radio (TMR) View to SCADA
- increased substation monitoring and automation investments.

Powercor states that "*Each of these initiatives has been started in the current regulatory control period, except the installation of DMS field devices*"[98]. The DMS program identified above is not included in the SCADA and Network Control proposed expenditure, but is captured in the proposed IT capex. For this reason, it is assessed in the Powercor IT capex section of this report.

In its 2005 EDPR submission, Powercor proposed capital expenditure of $20.2 million[99], for SCADA and network control, with key outcomes including:

- the rationalisation and integration of disparate and non-connected control centre operational systems;
- migration of SCADA services currently on the aging/obsolete supervisory network to Powercor Australia's fibre optic network;

[98] Powercor Australia LTD'S Regulatory Proposal 2011-15
[99] $2006

- continuing investment in sub-transmission (voltage and capacitor banks) and distribution (regulators) network monitoring and control;
- establishment of back-up SCADA communications links to zone substations on single contingency;
- migration to an alternate communications medium for both voice and distribution remote control devices in anticipation of Telstra's planned retirement of the trunk radio network; and
- improving the communications capacity and SCADA polling times to zone substations not included on the fibre optic network.

Noting that the proposed DMS expenditure is captured in the non-system IT category, there appears to be a high degree of overlap between the major projects in 2005 and the current proposal. The Powercor proposal does not discuss the overlap between the previous and proposed projects.

Powercor states that they have already commenced the installation of new protection and control communications infrastructure. This suggests that the increased substation monitoring and automation investments represent the majority of the step change in proposed expenditure.

The Powercor proposal identifies four major projects associated with SCADA[100]:

- Enhanced Zone Substation Monitoring and Control
- Station security monitoring
- Zone substation SCADA communications migration to DNP3.0
- Migration away from TMR View to SCADA.

Powercor provides supporting information for these projects in chapter 28 of its proposal. This chapter was structured in response to the RIN requirements and included a section for each project on "Costs and benefits of each option considered". These sections did not provide any cost information or any quantitative assessment of benefits. As such, it is difficult to determine whether these project represent prudent or efficient expenditure.

Following a request for a more detailed breakdown of the proposed SCADA and Network Control projects, Powercor provided a template set of information about 20 SCADA and Network Control projects. New programs proposed by Powercor to commence in the next regulatory period[101] include:

- Allocation for development initiatives
- Communications upgrade to PQM metres
- Human machine interface (HMI) in zone-substations
- Implementation of distribution management system (DMS) field devices
- Improved earth fault pre emptive detection on underground cables

[100] Excluding the DMS projects where proposed expenditures are reported in the IT category.
[101] Note: CitiPower states that some of these projects may commence in 2010.

- Installation of IEC61850 communications
- Plant condition monitoring solutions
- Installation of remote monitored fault indicators on the overhead network
- Transformer monitoring solutions - oil, fans and pumps
- Upgrade swipe card system
- Weather stations
- Zone substation cameras - asset management and security
- Zone substation SCADA communications migration to DNP3.0

Continuing programs with increased expenditure in next regulatory period:

- Automatic reclosers (ACRs) and SW migration from trunk mobile radio (TMR) View to SCADA
- Enhanced zone substation monitoring via SCADA
- Zone substation Ethernet deployment
- Feeder automation
- New fibre allowance
- Regulator (loop) monitoring and control program
- Rural communications and securing SCADA links to Western and Northern areas of its distribution area

In its 2005 EDPR submission, Powercor proposed capital expenditure of $7 million[102], for areas of network control other than the SCADA master station, including:

- replacement of aged communications equipment located in Powercor's zone substations, including remote terminal units
- upgrading zone substation monitoring and control systems, associated with the introduction of "smart protection relays"
- additional SCADA data security and security monitoring for the safety of the network
- replacement of aged remote fault monitoring units in the CBD high voltage feeder network.

Noting that the proposed DMS expenditure is captured in the non-system IT category, there appears to be a high degree of similarity between the major projects in 2005 and the current proposal. The Powercor proposal does not discuss the overlap between the previous and proposed projects.

Powercor states that they have already commenced the installation of new protection and control communications infrastructure. This suggests that the increased substation

[102] $2006

monitoring and automation investments represent the majority of the step change in proposed expenditure.

Powercor provides some supporting information for these projects in chapter 28 of its proposal. This chapter was structured in response to the RIN requirements and included a section for each project on "Costs and benefits of each option considered". These sections did not provide any cost information or any quantitative assessment of benefits. As such, it is difficult to determine whether these project represent prudent or efficient expenditure.

Powercor provided additional supporting material for the new and increased projects listed above. This information did not describe any quantitative benefits or advantages of the proposed programs. Many of the proposed programs would also have impacts on opex and system reliability. These impacts do not appear to be considered by Powercor.

In the absence of any defined benefit, it is not possible to conclude that the projects are prudent from a timing perspective or that they are efficiently targeted.

There is a high degree similarity between the project descriptions provided for the 2005 EDPR process and those of the current review. In addition, the level of actual expenditure in the current regulatory period is well below the level proposed by Powercor. This suggests that there is scope for deferral and efficiencies in the current and proposed programs.

Powercor has not identified any new or changed regulations or obligations that require a significant step change in SCADA and Network Control capex. As such, Nuttall Consulting recommends that the existing level of SCADA and Network Control capex represents an efficient expenditure level.

Table 83 - Recommended Powercor SCADA and Network Control capex

Powercor	Costs (2010 $M)				
SCADA and Network Control	2011	2012	2013	2014	2015
Recommended Expenditure	2.848	2.848	2.848	2.848	2.848

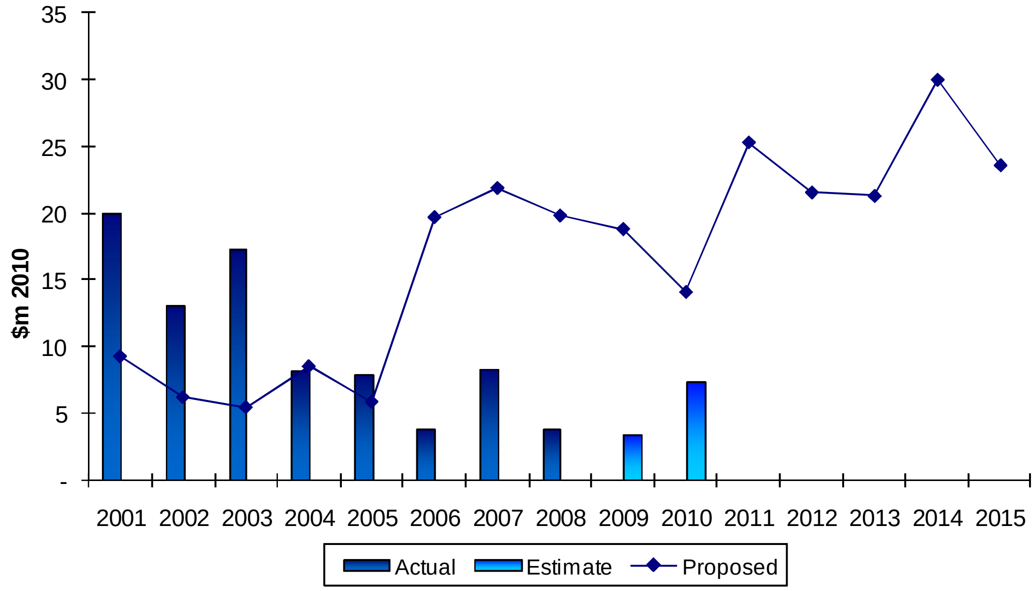
The recommended SCADA and Network Control capex for Powercor is based on the average actual expenditures incurred in the previous 5 years exclusive of indexation and escalation.

8.6 Non-network general - IT

Powercor submitted IT capital expenditure at $121.6 million over the forthcoming regulatory control period, which represents an increase of 281% in capital expenditure from audited historical expenditure ($32.0 million). Major proposed IT capital projects include CIS replacement, leveraging off the AMI project and increasing the utilisation of mobile computing in the field.

During 2004-2008, Powercor significantly underspent their IT capital expenditure from a proposed of $75.7 million to actual audited spending of $32.0 million including deferrals of project like the CIS replacement.

Figure 97 - Powercor proposed vs actual IT capex



CitiPower and Powercor are related parties and each holds a separate electricity distribution licence for a defined geographical electricity distribution area in Victoria. The Distribution Networks are jointly managed and operated by Powercor Australia and CitiPower personnel and systems. Under the Cost Sharing Agreement, defined overhead costs incurred by Powercor Australia and CitiPower are apportioned between each respective business. CHED Services provides both CitiPower and Powercor with specialist corporate services including: the Chief Executive Officer; Finance; the Company Secretary and Legal; Human Resources; Corporate Affairs; Regulation; Customer Services; Information Technology; and Office Administration; and under the Metering Services Agreement a number of metering services.

Powercor also submitted that "significant IT resources were diverted to preparing system readiness for the rollout of AMI" that resulted in previously proposed expenditure being deferred. This could also indicate a lack of flexibility and agility in the underlying IT systems.

Powercor is currently replacing legacy Telstra PAPL (Permitted Attached Private Lines) with fibre optic and modern Ethernet networking for zone substation control and monitoring plus remote monitoring of distribution infrastructure via SCADA. Powercor is intending to extend its SCADA operations with Distribution Management System (DMS) field devices that integrate with the existing Geographic Information System (GIS). This expenditure is classified as IT expenditure rather than part of distribution network, since it is regarded as part of Powercor's IT assets. We make no comment on the classification of expenditure by the DNSP. Powercor will commence installing DMS field devices once the DMS infrastructure is in place (expected to be end of 2011).

Powercor was an early adopter of x86 virtualisation (running both Windows and Linux) and is actively seeking to upgrade this infrastructure to latest levels as recommended by the vendor.

Powercor's IT capital cost expenditure gradually increases from around $22 million per year until major upgrades and changes are expected for 2014 and 2015 incurring larger costs in the range of $30M to $24 million. In our opinion, Powercor have not fully considered the complexity of what they are contemplating and the amount of change the business can absorb, given the lack of agility in the IT environment. This is further demonstrated by their historical underspending of proposed IT capital expenditure. We believe it more likely that Powercor will take longer than five years to complete these projects and that any projects in 2014 and 2015 are likely to be deferred or even abandoned for other alternatives. Therefore, we recommend that first three years of capital cost be spread over five years.

Table 84 - Recommended Powercor non-network general IT capex

Powercor	Costs (2010 $M)				
Non-network general – IT	2011	2012	2013	2014	2015
Proposed Expenditure	25.3	21.5	21.3	30.0	23.7
Recommended Expenditure	13.7	13.7	13.7	13.7	13.7

8.7 Non-network general - other

Powercor's proposed expenditure in the "non-network general – other" category represents only a small percentage (5%) of the total net capex in the next period, and is at a level relatively consistent with the current period.

Given the low significance of this expenditure, it was agreed with the AER that Nuttall Consulting would not undertake a detailed review of this category.

9 Appendix D - SP AusNet review

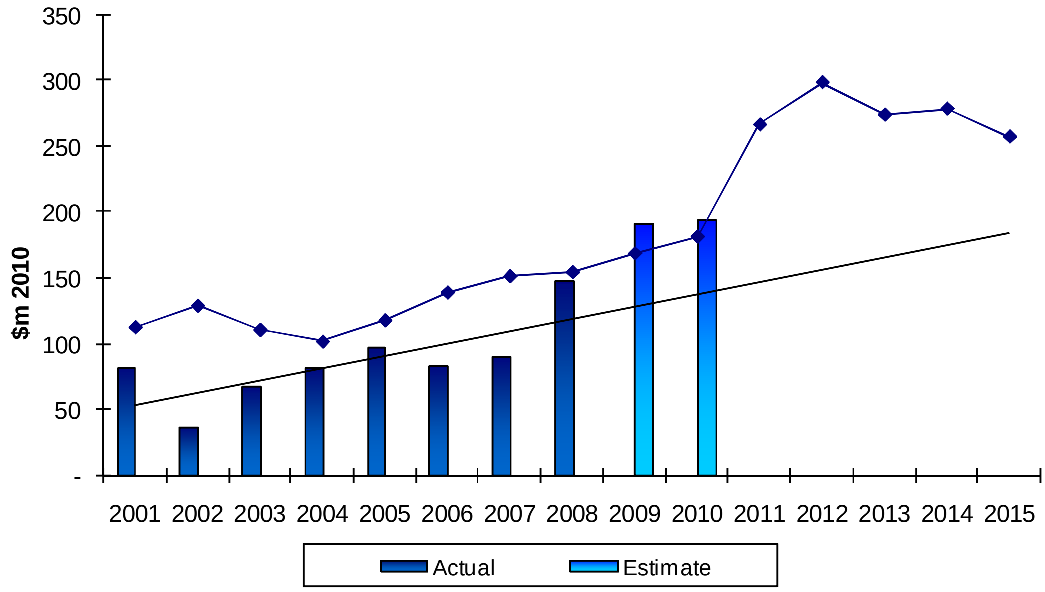
9.1.1 Overall capex

Overall capex is forecast to increase by 156% over actual expenditures in the current period. The main areas where capex is forecast to increase are reinforcement, reliability and quality maintained and new connections.

The following chart provides a summary of the overall capex figures for SP AusNet. Key aspects of this chart include:

- SP AusNet has consistently spent less than they proposed in the 2001 and 2006 EDPRs
- CitiPower is proposing a future level of capex that is significantly higher than the historical levels of expenditure and is not consistent with the historical trend in capex.

Figure 98 – SP AusNet Capex Summary

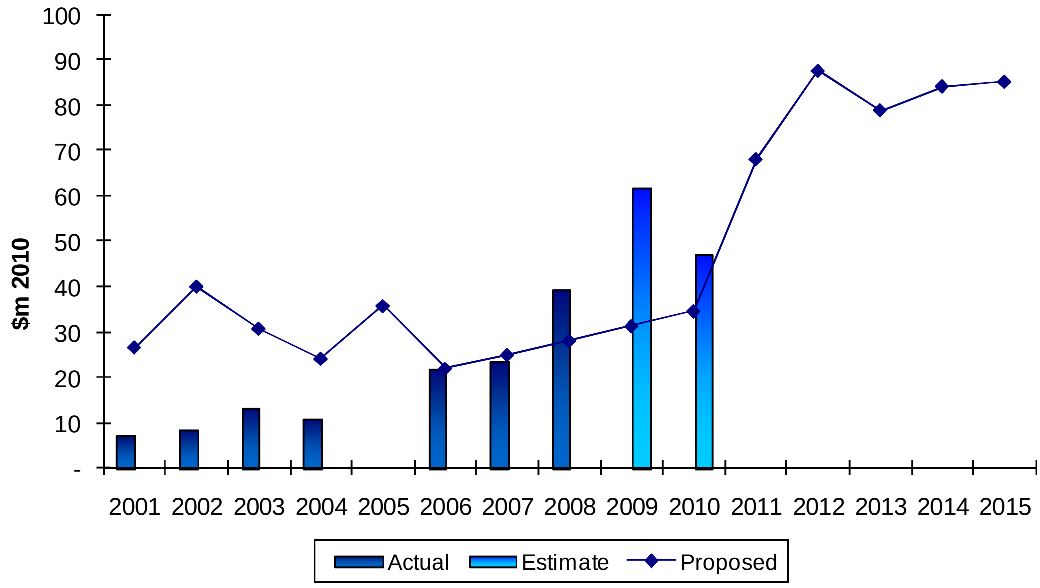


9.2 Reinforcement

SP AusNet is proposing a reinforcement program that is 186% greater than actual expenditures in the current Regulatory Control Period. SP AusNet estimates that its reinforcement capital expenditure for the 2006-10 regulatory control period will be $194 million ($2010). It is forecasting that this will increase to $404 million ($2010) in the 2011-15 regulatory control period.

The following chart provides a summary of reinforcement capex for SP AusNet.

Figure 99 - SP AusNet Reinforcement Capex Summary



This chart indicates that SP AusNet's reinforcement expenditure has been trending up, particularly over the current regulatory periods. SP AusNet has estimated that it will have a significant spike in expenditure in 2009 and then a step increase in 2011 and 2012, with expenditure remaining at a relatively high level for the remainder of the period.

The 2001 EDPR forecasts prepared by SP AusNet were significantly over the actual expenditure incurred. However, in the current period actual in the first two years were at the forecast level and are estimated to exceed the forecast level in the remaining years.

SP AusNet is the only DNSP that appears to have under-forecast its reinforcement expenditure for the current period. However, SP AusNet's proposal indicates two factors that contributed to this under-forecast[103]: higher input costs and higher demand growth than anticipated. SP AusNet's proposal states that input costs were 37.5% higher (based upon a sample of projects) and demand was nearly double the assumptions used to derive its 2006 EDPR forecast.

On this point, it is noted that SP AusNet's documentation on its planning methodology indicates that it considers that "all the expected reinforcement works will not be delivered" in the current period[104], which suggests a back-log may exist going into the next period. However, based upon our project review discussed below, we have found no significant evidence of this (i.e. projects where risks are clearly above the capital costs to reduce them). Therefore, allowing for the assumption changes noted above, we consider it reasonable to assume that SP AusNet's underlying process was over-forecasting network needs.

SP AusNet's proposal indicates that significant increases in expenditure are required across all the main network types i.e. sub-transmission lines, zone substations, HV feeders, and distribution substations (and associated LV). SP AusNet considers that this requirement is driven by the higher demand growth that is anticipated to continue

[103] Pg 101, SP AusNet proposal
[104] Pg 13, AMS 20-12.

through the next period, particularly pockets of very high growth, and the high utilisation of its assets.

9.2.1 Forecasting methodology

SP AusNet has developed its reinforcement plans largely based upon a bottom-up build of individual network needs and projects to address these needs. SP AusNet considers that these plans have been developed using the actual planning processes it applied in practice. However, due to their proposed timing, many projects will not have been through the full evaluations and justifications that would be required for approval.

A major portion of these plans is developed via the risk evaluation approach SP AusNet applies at the sub-transmission level. This approach is similar to the full probabilistic planning approach that is applied at transmission level in Victoria. This approach assigns an economic value to the expected energy that will not be served to customers (often related to the probability of network outages) and then balances this against the capital cost to reduce these risks, to ensure capital projects are economically justified.

Future predictions of the value of the expected energy not supplied are calculated using a number of key input assumptions, most notably:

- the 50% probability of exceedance maximum demand forecast
- a load profile, based upon the actual load profile for 2007/08
- a value of customer reliability (VCR) based upon the customer classes at the zone substation level, and the VCRs for these customer classes as applied by AEMO at the transmission level
- transformer outage rates based upon those used for assessing transmission connection augmentations
- line outage rates based upon historical information.

For distribution feeders, SP AusNet applies a more deterministic approach that considers the loading of feeders, their rating and the load transfer capability. The plans however are still built up from individually identified needs.

For distribution substations, SP AusNet applies a pseudo “bottom-up” approach, whereby the quantity of distribution transformers requiring upgrading is calculated at an aggregate level. This process involves estimating the future maximum demands of the transformer population, based upon customer types and metering information associated with individual substations. The number of transformers requiring upgrading is then determined based upon the quantity with a predicted maximum demand above a function of the transformer rating. The expenditure is calculated based upon the quantity at various standard sizes and a unit cost for that size.

It is important to note that the methodology associated with the distribution substation is based upon a new pre-emptive upgrade program that has been commenced in the current period. Prior to this, distribution transformers would generally be replaced in a reactive fashion.

9.2.2 Nuttall Consulting detailed review

9.2.2.1 Process

Nuttall Consulting's detailed review of SP AusNet's reinforcement expenditure has included a review of its forecasting methodology and a number of specific projects. The general process applied by Nuttall Consulting in conducting its review of SP AusNet's reinforcement expenditure is summarised in Section 4.2 of this report.

The projects reviewed included:

- Mooroolbark new zone substation
- Wollert new zone substation
- KMS-SMR 66 kV line establishment
- Zone substation transformer upgrade program
- Distribution substation upgrades

Key SP AusNet documents, in addition to SP AusNet's proposal, included in this review are:

- AMS 20-12 Capacity
- 2009 Distribution System Planning report
- Various project reports provided with SP AusNet's proposal

Other documentation specific to the projects under review are identified in the sections below.

9.2.2.2 Findings on methodology

Overall, we consider that SP AusNet's methodology is reasonable for developing capital plans for internal purposes. In this regard, the process should result in the identification of network needs, a list of projects to address these needs, and expenditure projections for the medium-term management of the network. In turn, this process results in a relatively comprehensive list of individual network needs and projects that can be monitored and developed further through the next period.

However, we do not consider that this largely "bottom-up" based process has been shown to be "fit for purpose" in terms of being a reasonable unbiased estimator for future prudent and efficient expenditure at the aggregate level. In particular, we do not consider that such a process adequately allows for the further optimisation of projects and synergies between projects that will occur as the individual projects and the overall capital plans advance through the capital governance process.

It is accepted that in some circumstances these processes will result in some projects being advanced or their scopes increased. However, in our view, the more detailed evaluation and justification associated with the project approval within the governance process will most likely result in overall expenditure being less than the simple summation of the project plans, as applied by SP AusNet to determine its reinforcement expenditure.

Related to the points above, we also have some concern that SP AusNet's use of a load profile, based upon the 2007/08 year, may tend to overestimate risks, particularly in the latter half of the next period. This is based upon our view that the “peakiness” of the load profile at a time of high demand will increase due to the fact that demand growth is expected to outstrip energy growth by a significant amount. Our analysis presented in Appendix J suggests this may be material, and may result in the deferment of some projects.

It is accepted that the use of a 50% probability of exceedance maximum demand may understate expected risks. As such, there could be some argument that these two matters trade off somewhat. However, given the sensitivity to risks of the assumed maximum demand condition is well known in the industry, we consider it reasonable to assume that the optimism in this assumption is inherently allowed for in SP AusNet’s evaluations. Therefore, we do not consider that this matter should affect our findings on the conservatism in the load profile assumed.

9.2.3 Project reviews

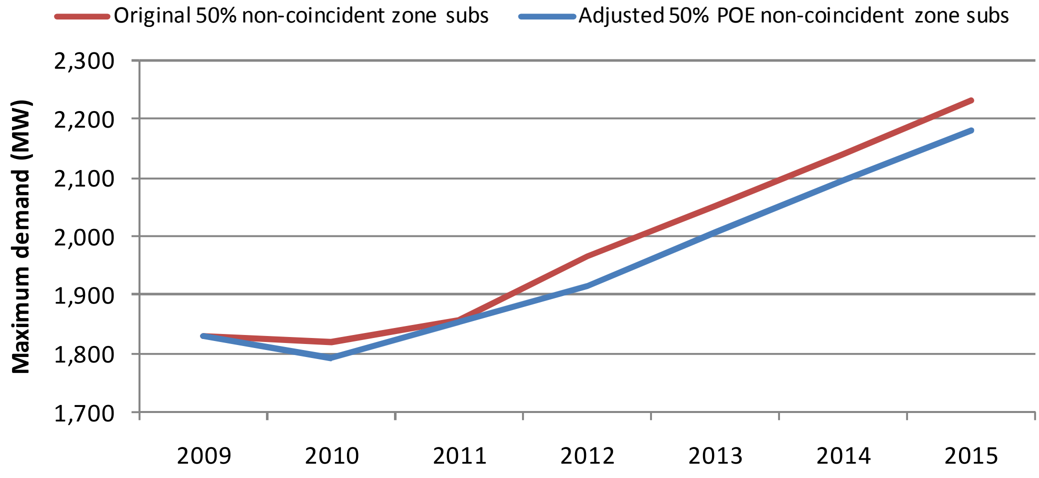
As noted in Section 4.2.4, the aim of the Nuttall Consulting review has been to determine the likelihood that the project expenditure will be required as proposed by SP AusNet. We consider that this is a reasonable approach to account for the likely consequences of the governance processes and the other specific methodological concerns discussed above.

An additional input to our review has been the findings of the AER’s review of SP AusNet’s load forecasts. Of particular relevance to our review are the maximum demand forecasts. The AER’s findings here were that SP AusNet has overstated the growth in maximum demand.

A comparison of the SP AusNet maximum demand forecast and the AER’s view is shown in the chart below. This chart indicates that the AER’s adjustments result in maximum demand levels being delayed by around 1/2 year. Given that we may expect this reduction to be most significant in the areas where high load growth is forecast, we consider that this reduction may be material in deferring some projects.

It is important to note that we have not been able to analyse the effect of these adjustments in detail. However, we have attempted to allow for these to some degree in our assessment of the likelihood of the projects. We would recommend however that the AER require SP AusNet to reassess its plans more comprehensively in light of these load forecast findings to determine their effects.

Figure 100 – SP AusNet maximum demand forecast



The following summarises the main findings for the projects reviewed.

9.2.3.1 Mooroolbark new zone substation

Cost: 18.1 million

Completion: 2014

This project involves the establishment of a new zone substation at Mooroolbark. This project is driven by a number of factors: load at risk at the existing LDL, CYN and RWN zone substations, voltage stability issues associated with the existing loop, and loss reduction benefits.

SP AusNet's energy at risk and loss reduction calculations support the timing of the proposed project. However, we consider SP AusNet's simplifications used to estimate the value of the loss reduction may well be conservative. Given that this is a significant factor justifying the project (i.e. without it, it appears that the timing would be deferred), we consider that a more complete loss study would need to be performed to better estimate the benefits of the reduction in losses.

Furthermore, given our views on the affect of the load profile assumed by SP AusNet and the AER's reduction to the demand forecast, we consider that these may result in a modest deferment of this project.

Finally, given the scale of the proposed project and range of issues being addressed, it is considered reasonable to assume that a more extensive economic analysis of the individual issues and options to address specific issues may well result in the project scope and timing being optimised further.

Based upon the above, we consider that expenditure associated with these works has a moderate probability (50%) of being required as proposed by SP AusNet.

9.2.3.2 Wollert new zone substation

Cost: .6.3 million

Completion: 2014

This project involves the establishment of a new zone substation at Wollert. This project is driven by load at risk at the exiting Epping zone substation. The project also allows the alleviation of a number of forecast feeder overloads.

SP AusNet's energy at risk calculations indicate that the project is justified and the options it has considered appear reasonable. However, based upon the information in the SP AusNet planning report for this project, there does appear to be the possibility of transferring some load to adjacent zone substations (including one which is planned in the next period) to manage some of these risks. Furthermore, given our views on the affect of the load profile assumed by SP AusNet and the AER's reduction to the demand forecast, we consider that these, in combination with the available transfers, should result in a modest deferment of this project.

Based upon the above, this project has been assigned a moderate probability (50%) of occurring as planned.

9.2.3.3 KMS-SMR 66 kV line upgrade

Cost: 16.8 million

Completion: 2014

This project involves the establishment of a 2nd line between KMS and SMR. This project is driven by energy at risk following the outage of a section of the existing 66kV loop. The energy at risk is related to thermal and voltage stability issues. The timing of the project is also related to loss reduction benefits.

SP AusNet's energy at risk and loss reduction calculations support the timing of the project. However, we have a number of concerns with SP AusNet's evaluation.

Firstly, given the scale of the proposed project, it is considered that a more extensive economic analysis of the issues and options to address specific issues may well result in the project scope and timing being optimised further. For example, we consider that other reasonable options that are not adequately discussed and evaluated include the use of reactive compensation to defer the need for a new line or alternative new line arrangements, such as from MDI to YEA. Related to this matter, it is noted that the expected energy not served is based upon a historical outage probability for the existing line that appears high (i.e. 2.3 outages per year). This outage probability requires greater justification and the options assessment should consider options to improve the probability.

Secondly, given our views on the affect of the load profile assumed by SP AusNet and the AER's reduction to the demand forecast, we consider that these may result in a modest deferment of this project.

Finally, we consider SP AusNet's simplifications used to estimate the value of the loss reduction may well be conservative. Given that this is a significant factor justifying the project (i.e. without it, it appears that the timing would be deferred), we consider that a more complete loss study would need to be performed to better estimate the benefits of the reduction in losses.

Based upon the above, this project has been assigned a moderate probability (50%) of occurring as planned.

9.2.3.4 Additional zone substation transformer upgrades

Cost: 55 million

Completion: various from 2011-2015

This project involves the upgrade of a number of existing substations by adding new transformers or replacing existing units with ones of higher capacity. This program is driven by the energy at risk at various existing zone substations.

Based upon a review of a sample of transformer upgrades within this program (FGY, KMS, MOE, CLN), SP AusNet's energy at risk calculations support the timing of the upgrades. However, given the scale of the proposed project, it is considered that a more extensive economic analysis of the issues and options to address specific issues may well result in the project scope and timing for some of these projects being optimised further.

For example, in some of the planning documents associated with the individual zone substations it appears that modest levels of load transfers were identified, but not allowed for in the analysis. Given our views on the affect of the load profile assumed by SP AusNet and the AER's reduction to the demand forecast, we consider that these, in combination with the available transfers, should result in a modest deferment for some of the project.

Additionally, given the number of proposed transformer upgrades and the relationship of outage duration assumptions on the risk levels, we consider it reasonable to assume that more extensive analysis of the management of the transformer fleet, including the use of transformer spares, may result in the deferral of some of this program.

As such, this project has been assigned a moderate probability (50%) of occurring as planned.

9.2.3.5 Distribution upgrade program

Cost: 42 million

Completion: 2011-2015

This program involves the upgrade of the distribution transformers (and associated LV works). The key driver for this project is the projected loading at the distribution transformers.

The key factor resulting in the proposed increased expenditure for this program is the move to a pro-active upgrade program. The aim here is to replace the transformers before they fail, improving the reliability of the network and reducing safety risks.

However, we do not consider that SP AusNet has adequately demonstrated that this program is economically justified, in terms of actually realising the anticipated benefits. In particular, we do not consider that the DNSPs have provided sufficient evidence to show that the program can adequately target specific transformers, such that it will reduce the transformer failure rate sufficiently. The important point here is that SP AusNet does not meter load at the distribution transformer; it has to estimate the loading at a particular transformer via customer metering data. Furthermore, determining when a distribution transformer may fail is more problematic than power transformers, as detailed condition information is not available.

It is also worth noting that we also consider that a delay until the AMI roll-out may allow information from these meters to be used to more accurately determine transformer loadings and target transformers. We also note that the STPIS provides some incentive and reward for undertaking these programs if it will be improving reliability.

Based upon the above, the distribution transformer upgrade program has been assigned a moderate probability (60%) of occurring as planned. This probability has been assigned to allow for the existing levels of upgrades, with some allowance for the escalation in volumes.

9.2.4 Overall findings

Based upon our review, we do not consider that SP AusNet has adequately demonstrated that its proposed increases in reinforcement expenditure are reasonable. Moreover, we consider that significant reductions to the proposed plans will occur as the plans pass through the governance processes and more detailed evaluations and justifications are undertaken. In our opinion, a reasonable estimate will be more in line with the historical trend.

This view is based upon a number of findings from our project reviews, which draw upon our high-level expenditure analysis and the findings of the methodology reviews.

Firstly, the timing of the projects reviewed were generally justified by SP AusNet through the benefits due to reducing EENS. In many cases, however, we consider that the project may well be optimally deferred if evaluations allow for available load transfers, a load profile more reflective of the next period, and the AER’s proposed reductions in forecast demand.

Secondly, given the number of proposed transformer upgrades, we consider that more effective use of spares may allow some of these risks associated with transformer failures to be reduced, resulting in the deferral of some projects.

Thirdly, in many cases, SP AusNet is proposing a large project to address a number of issues. However, there is limited detailed economic analysis of these projects. We consider that there is a reasonable possibility that a lower cost option may be found to be the preferred option in many cases following the more rigorous evaluation that will occur as the project flows through the governance processes.

Finally, with regard to the distribution transformer upgrade program, we do not consider that SP AusNet has adequately demonstrated that the proposed pro-active upgrade program will realise the benefits that are predicted.

Using the approach discussed in Section 4.2, we have developed a forecast of the reinforcement expenditure using:

- the weighted average probability from the project reviews to determine the reasonable estimate to total expenditure
- a constant growth rate assuming a notional 2008 base-line, derived from the average of the historical 2006-2008 expenditure.

Based upon this process, we have estimated the SP AusNet reinforcement expenditure in the next period will be 53% of the SP AusNet proposal and the expenditure growth rate from historical levels will be 10.7%.

Our estimate of SP AusNet's reinforcement capex is shown in Figure 33 and Table 24 below. It is important to note that this should be considered as an estimate only. The AER may need to make further adjustments to allow for its findings on the other matters, such as overheads and labour and material escalation, which are not accurately allowed for here.

Figure 101 – SP AusNet reinforcement capex recommendation

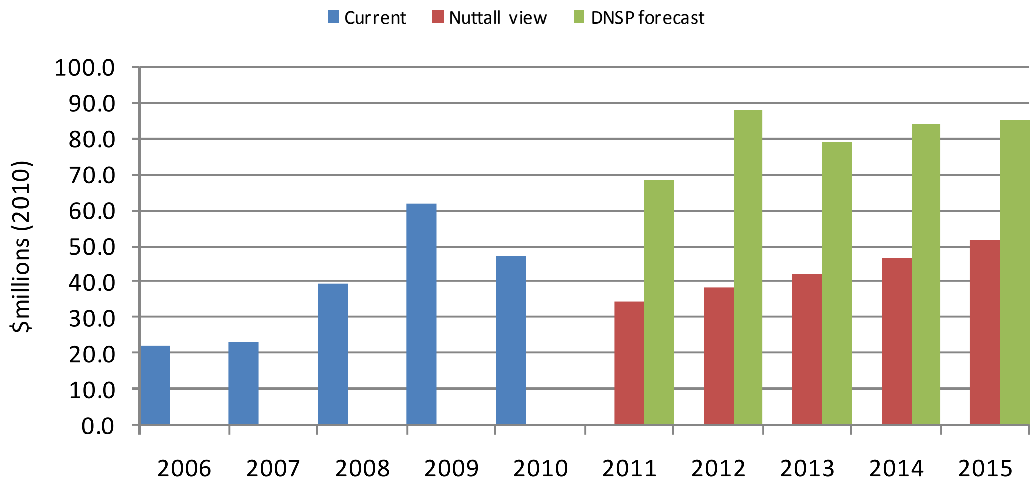


Table 85 – SP AusNet reinforcement capex recommendation

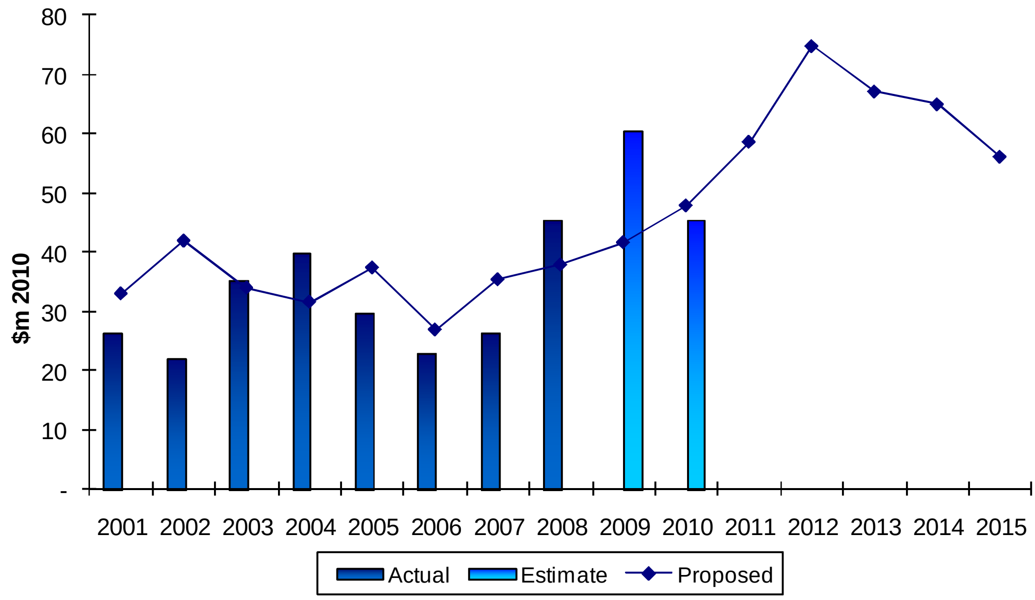
	$millions (2010)				
	2011	**2012**	**2013**	**2014**	**2015**
SP AusNet - proposed	68.2	87.6	78.9	84.2	85.3
SP AusNet - recommended	**34.6**	**38.3**	**42.4**	**46.9**	**51.9**

9.3 Reliability and quality maintained

SP AusNet is proposing an increase of 103% in reliability and quality maintained capex for the next Regulatory Control Period when compared against actual expenditure in the current Regulatory Control Period. SP AusNet estimates that its Reliability and Quality Maintained capital expenditure for the 2006-10 regulatory control period will be $201 million ($2010). It is forecasting that this will increase to $322 million ($2010) in the 2011-15 regulatory control period.

The following chart provides a summary of reliability and quality maintained capex for SP AusNet. This indicates that the trend in actual expenditure is relatively flat, with a significant increase from 2008. The profile also indicates a pattern of high expenditure at the end of the period that is followed by lower expenditure at the beginning of the next period. It also indicates that SP AusNet has historically over-forecast RQM expenditure, particularly in the early years of the regulatory period. This patterns appears to follow the regulatory incentive powers, which are higher at the beginning of the period.

Figure 102 – SP AusNet RQM capex



9.3.1 Overview of activity code review

Explanation of expenditure profile – trends and major drivers of increases

For SP AusNet, a number of asset expenditure elements have been transferred in purely for review purposes. The rationale here was that, although the driver was predominantly safety related, the forecasting methodology applied by SP AusNet was largely based upon the age/condition of the assets.

The assets and the expenditure are as follows:

- $18.7 million on HV fuses
- $14.3 million on cross arms
- $52.6 million on overhead line replacement - conductors
- $11.6 million on overhead line replacement – insulators
- $15.3 million on services.

It is important to note that these items are included in the RQM activity code breakdown prepared by SP AusNet, and then subtracted to form the ESL component. It is also worth noting that at the activity code level, there is a gap in the 2009 and 2010 estimates as it appears that SP AusNet has not allocated its estimate into these categories at the time of our analysis.

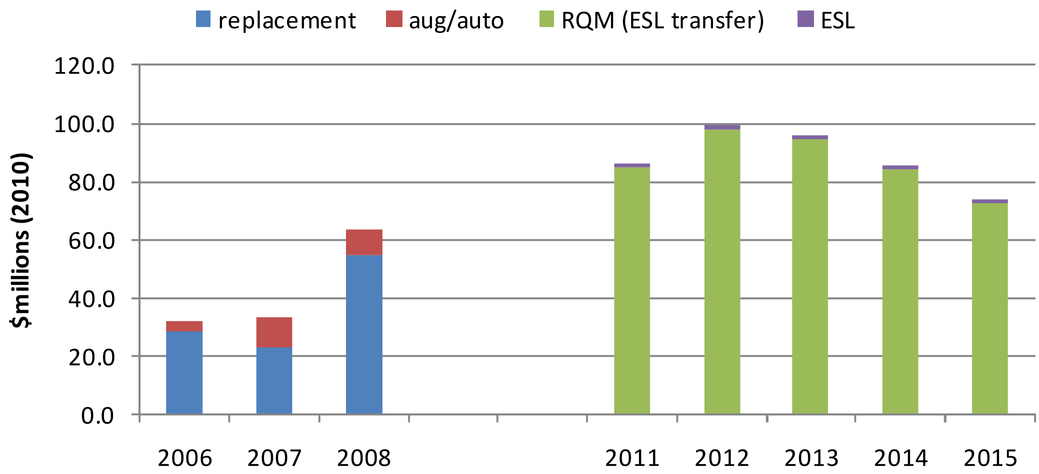
Table 86 - Summary of SP AusNet RQM and ESL expenditure

Average per annum expenditure ($2010)		% increase (from 2006-2008)
2006-2008	2011-2015	2011-2015
43.1	88.2	104%

As indicated in Table 86, SP AusNet is proposing a significant increase in RQM expenditure from 2006-2008 levels. The analysis at the activity code level also shows that some augmentation and automation activity codes, of which a portion of their expenditure has been allocated to the RQM category in the current period, is no longer allocated to RQM in the next period. However, the RQM category has a new allowance that is defined as "recoverable works residual", which is not used in the current period.

The breakdown of expenditure is shown in Figure 103. This shows a large step increase in 2011 with expenditure slowly reducing from 2012. The figure also indicates that the remaining ESL level is relatively immaterial (i.e. the amount transferred in is by far the larger portion).

Figure 103 - SP AusNet RQM expenditure profile



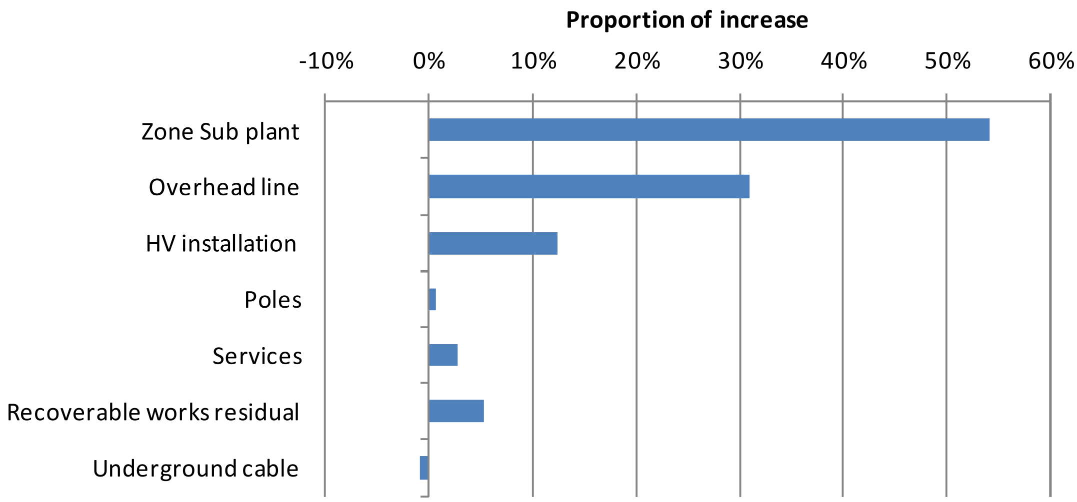
The breakdown of the 2011-2015 RQM expenditure into SP AusNet's activity codes is shown in Table 87. These activity codes are ranked in terms of significance, based upon the proportion of total RQM expenditure.

Table 87 - Activity Code summary

Activity Code	Average per annum ($m 2010)		Proportion of 2011-2015	Increase from 2006-2008
	2006-08	2011-15		11-15
Zone Sub plant	1.1	28.1	32%	2468%
Overhead line	10.8	26.2	30%	142%
HV installation	8.9	15.1	17%	70%
Poles	10.8	11.0	13%	3%
Services	2.8	4.2	5%	50%
Recoverable works residual	0.0	2.6	3%	na
Underground cable	1.3	0.9	1%	-33%
Total	**43.1**	**88.2**	**100%**	**104%**

The activity code breakdown of the proposed increase in expenditure for the next period (compared to the average of 2006-2008) is shown in Figure 104. This illustrates that the expenditure on substation plant (e.g. transformers, circuit breakers) is by far the most significant contributor to the proposed increase. The overhead line activity code is also showing a significant increase.

Figure 104 - SP AusNet activity code proportion of increase



9.3.2 Zone substation plant

Activity code and expenditure summary

The zone substation activity code broadly covers the age/condition based replacement of primary and secondary plant within the zone substations. A major portion of this expenditure in the next period is due to the proposed replacement of power transformers and circuit breakers.

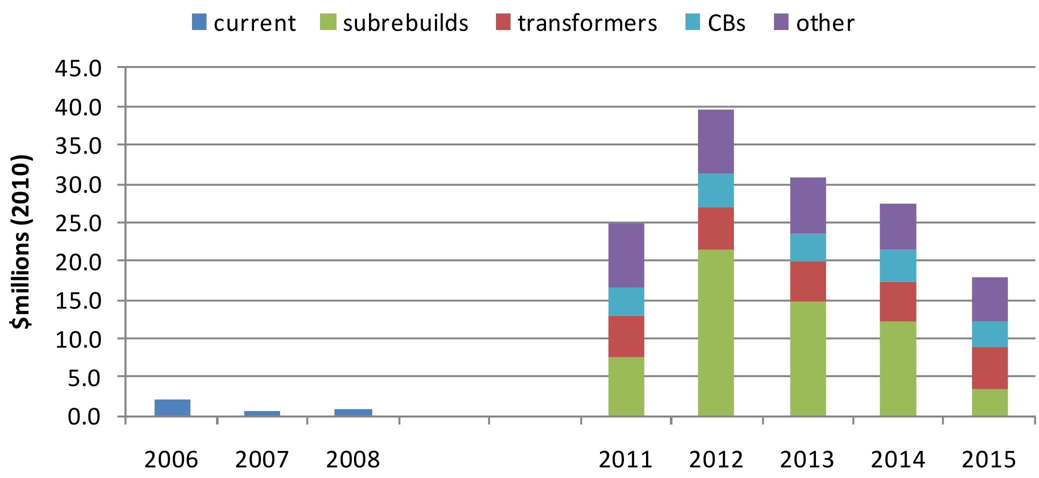
Table 88 and Figure 105 provide an overview of the expenditure in this category. Figure 61 also indicates the proportion of expenditure on the transformer and CB replacements and the substation rebuilds.

This analysis indicates that this activity code represents 32% of the total RQM expenditure in the next period, with expenditure stepping up significantly in 2011. It is noted however that expenditure in this category over the 2006-2008 period is very low.

Table 88 - Overview of expenditure for the zone substation plant replacement

Activity Code	Average per annum ($m 2010)		Proportion of 2011-2015	Increase from 2006-2008
	2006-08	2011-15		11-15
Zone Sub plant	1.1	28.1	32%	2468%

Figure 105 - Expenditure profile for the zone substation plant replacement



Forecasting methodology and rationale

The forecasts in this category are mainly based on three methodologies relating to transformers, circuit breakers, and the substation rebuilds.

The forecasts for the HV CB and transformer replacements are based upon a quantitative risk modelling of the transformer and CB fleet.

Key features of the approach are:

- the use of asset specific condition information (or assumptions if data is not available) and age information to determine probability of failure rates
- internal probabilistic models to predict the degradation of condition and probability of failure as the asset ages
- asset failure consequence assumptions (in $ terms)
- risk predictions (in $ terms) based upon the probability of failure predictions and failure consequences

- NPV analysis of the risk costs and the replacement costs of each asset item to predict the optimal timing for replacement
- the ability to input asset specific interventions, such as refurbishments, which then adjust the condition and failure probability of those assets.

The substation rebuild projects are based upon NPV analysis of various replacement and refurbishment options. This analysis allows for operational and capital costs, and estimates of the network performance based risk costs. The risk costs are a significant factor in the analysis and are based upon probability of failure and consequence calculations for individual assets. The substation rebuilds also have relatively detailed reports that discuss the options and the various issues associated with existing substations.

This modelling has resulted in 20 transformers being proposed for replacement in the next period under RQM, compared to two in the current period, with none between 2006 and 2008. With regard to circuit breakers, 103 circuit breakers of various types are planned for replacement at a number of locations through the next period, compared to 31 in the current period, of which only 11 were replaced between 2006 and 2008.

SP AusNet has provided the spreadsheet models and associated reports in support of its forecast.

Nuttall Consulting views

The Nuttall Consulting review of this category has focused on the transformer and CB replacement forecast models. The outputs from these models become major factors in then defining the need for the substation rebuild projects, and their associated economic analysis.

Nuttall Consulting has reviewed the spreadsheet models that have been used to forecast transformer and HV CB replacement needs, and the associated documents. The model is a contemporary approach to predicting replacement needs, and in principle at least, we see no reason to consider it is not appropriate for this purpose. It is similar in principle to the CBRM models used by CitiPower and Powercor for similar purposes.

As with the CBRM model, the important point is that the model appears to be primarily an asset management tool that allows assets to be targeted and prioritised over the short to long term. It is expected however that following this modelling exercise, far more detailed review and testing will occur prior to any replacements being approved.

The main issue for our review is then whether it is "fit for purpose" in terms of producing forecasts for regulatory purposes, or does it include some bias. Like any other modelling approach, this depends on the calibration and validation of the model. This is particularly important given that the model is forecasting such a significant step up in replacement qualities from recent historical levels.

As with the CBRM approach, important matters, in the context of this model, are:

- the existing probability of failure and the ageing relationship used to predict the degradation with time
- consequence assumptions which together with the probability of failure are used to determine risk profiles for each asset.

With regard to transformers, the replacement model uses a condition score (from 1 to 5) for various elements of the existing transformers. This is then used with an age model to determine the probability of failure and how this degrades with time.

To understand the significance of the probability of failure and aging model, we have reviewed the actual condition information on the transformers that is provided in the SP AusNet documentation. A critical piece of condition information concerns the winding insulation, as this is the most critical factor that defines the end of life of the transformer. As noted previously for Jemena and United Energy, this is the primary condition information that is used to determine the end of life of their transformers.

The estimated degree of polymerisation for the transformers proposed for replacement is between 200 to 500, which suggests advanced aging for many of the transformers. However, only three parameters have an estimated DP of 200-250, which would suggest they are close to their end of life in the next period. The others have a DP of 300 or greater, which suggests their end of life may be near the end of the next period or later.

It is clear from our review of the model that the various condition scores and age models result in a shorter economic life. It is appears that the use of the 1 to 5 grading for the condition scores gives a fairly course grading for critical factors such as windings, where a score of 4 or 5 is used for all transformers proposed for replacement.

Unfortunately, due to the formation of the model, how the various factors contribute to the probability of failure and resulting risk is not very transparent. This makes it very difficult from the model outputs alone to appreciate what options to mitigate specific risks may be reasonable, what deferral options should be considered, and ultimately, whether the predicted optimal timing is indeed optimal. The SP AusNet documentation does not provide a post-model evaluation of the models findings to rigorously investigate these issues.

The CB model is similar to the transformer model, but with its formulation slightly simpler. It uses one condition score (ranked 1 to 5) and an age model to determine the probability of failure and its degradation with time. It is clear from the model that the assumed life has a significant impact on the predicted probability of failure. However, the assumed lives are lower than those we have derived in our repex model, based upon recent historical replacement levels. This suggests that the model may be significantly overstating the probability of failure for the older assets.

Due to these issues and the general matter of proof of “fit for purpose”, Nuttall Consulting has requested that SP AusNet provide information indicating how it calibrated and validated its models. This requested an explanation in terms of recently retired asset test data and historical failure information[105].

SP AusNet’s response to this request provided limited additional information. It states that the age model for the transformer has been benchmarked against a number of sources, but does not explain how this has been performed and the findings against its own data.

The response also provided some analysis of historical failure levels, which indicates that the number of outages forecast by the model is less than the actual outage history for

[105] Requested in email, dated 3/310, response in email, dated 9/3/10

transformers and slightly more for CBs (i.e. SP AusNet consider the model to be conservative for transformers and only marginally optimistic for CBs). However, based upon the data provided for transformers, it appears that no coil failures have occurred. Since this is a major factor driving risks in the model, this may suggest the model is overstating risks. Furthermore, the analysis presented by SP AusNet does not demonstrate that the spread of failures is as localised to the poor condition assets, as appears to occur in the model.

For example, the modelled probability of failure for the RUBA #1 transformer windings is around 20% per annum from for last 5 years; therefore, we may have expected one failure to have occurred during this period. This does not appear to have occurred, but the estimated risks associated for this are approximately 60% of the total risks. As such, it seems reasonable to assume that the model may be overstating risk considerably.

Similarly for the RUBA 22kV CBs, within the model they have a combined probability of failure of around 100% per annum for the last 5 years i.e. this suggests that on average 1 major failure of an HV CB per year at this substation. The SP AusNet documentation on this rebuild does not indicate that this is the case. A similar issue is noticeable with the YPS circuit breakers.

Finally, the calibration analysis presented by SP AusNet does not attempt to confirm that the modelled consequences and resulting risks for these predicted failures are equivalent to actual average consequences and risks that have occurred. For example, for CBs, the consequences appear to be based upon an s-factor calculation; however, it has not been demonstrated that the s-factor contribution and its predicted changes from 2005 to 2009 are reflective of actual s-factor contributions from CBs failure over this period. We would have expected that this type of analysis would have been undertaken to demonstrate the appropriateness of the model, both internally and for our purposes.

With regard to the substation rebuild economic analysis, we have similar concerns. We have reviewed the economic analysis provided by SP AusNet for the YPS, RUBA and SMR rebuild projects. For these projects, the risks appear to be driven largely by the probability of the failure of the transformers and the subsequent consequences. However, this appears to be based upon high failure probabilities (i.e. we may expect around one major transformer failure per year at these substations based upon the SP AusNet assumptions). Furthermore, the project reports provided by SP AusNet, do not address the make-up of the risks and the small-scale measures that may be applied to optimise the specific actions to mitigate these risks.

Nuttall Consulting has requested further information to support the analysis, including worked examples of the risk calculations, discussions on the options to address the most onerous risks, and an explanation of why these options would not maximise the net benefits.

We do not consider that SP AusNet's response to this request[106] adequately addresses our concerns. The response provides no justification as to why SP AusNet considers the probability of failure and resulting consequences to be reasonable. There is also very little additional discussion on the detail of the options available to mitigate the most onerous risks.

[106] Request dated 3/3/10, response provided 17/3/10.

Based upon the above concerns, and given the significant increase in replacement needs forecast through these models, we do not consider that SP AusNet has adequately demonstrated that its models are "fit for purpose". In our opinion, this would require a far more substantial and quantitative analysis to appropriately and transparently demonstrate their suitability. This would require network level and sample asset level analysis that shows that the number of failures, probability of failure, the aging relationship, and the consequences, derived through the model are reasonable unbiased estimates of the replacement needs. Such an evaluation would need to take into account SP AusNet's historical information, including failure statistics and reliability consequences, asset condition monitoring results and risk mitigation measures.

At this stage, we consider there is considerable discretion to further optimise and defer much of the program proposed by SP AusNet. It is impossible in a review of this form for us to undertake the type of analysis that would be required to determine an alternative detailed work plan.

We do accept however that the aging of the network is imposing greater needs on the business, above those faced in the current period. It is also noted that there has been very little expenditure allocated to this category in the current period up to and including 2008. As such, an increase based purely on these levels may not adequately allow for the replacement needs in this category.

On balance, we consider that an allowance based upon a notional amount of $8 million[107] in 2011, which is then increased to allow for the aging of the network, is reasonable. This is a significant increase on 2006-2008 levels, and should allow for a number of transformer replacements, a large increase in CB replacements and associated secondary works that may be allocated to the RQM category.

9.3.3 Overhead line replacement

Activity code and expenditure summary

The overhead line activity code covers expenditure on overhead line assets including conductors and pole top structures.

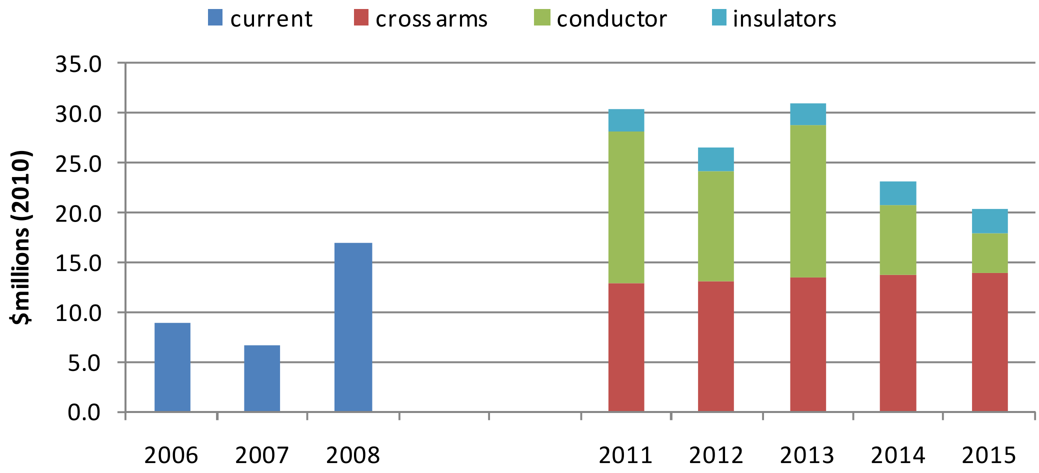
Table 89 and Figure 106 provide an overview of the expenditure in this category. Figure 106 also indicates the level of proposed expenditure in the next on cross arm replacements, conductors and insulator replacements. This analysis indicates that this activity code represents 30% of the total RQM expenditure in the next period, with expenditure anticipated to significantly increase from historical levels in 2011.

Table 89 - Overview of expenditure for overhead line replacement

Activity Code	Average per annum ($m 2010)		Proportion of 2011-2015	Increase from 2006-2008
	2006-08	2011-15		11-15
Overhead line	10.8	26.2	30%	142%

[107] This amount has been estimated based upon the Powercor expenditure in these categories, given Powercor has a similar number of power transformers and HV circuit breakers to SP AusNet.

Figure 106 - Expenditure profile for overhead line replacement



Forecasting methodology and rationale

The two main forecasting methodologies applied for this category concern cross arms and conductors.

For cross arms, SP AusNet has used a probabilistic age based model, similar in its basis to the repex model that we have applied. This assumes a Weibull distribution for the replacement life based upon the age profile of cross arms. The forecast from this model is then adjusted down to account for cross arm replacement that will occur due to other works.

The conductor replacement program is a new proactive replacement program that appears to have only recently commenced. This program is to replace aged steel and copper conductors, and appears to be related to mitigating the risk of starting bushfires through failed conductors.

SP AusNet has undertaken quantitative risk analysis to produce the forecast level of conductor replacement. This process involves:

- determining and ranking the feeder by historical failures due to failed conductors
- determining the probability of failure and consequences of failure for each feeder
- determining the quantity of steel and copper conductor that is over 50 year of age – SP AusNet considers that this is the average age when the steel and copper conductors fail
- undertaking PV analysis to determine the optimal time to replace the aged steel and copper conductor, based upon the cost of the replacement and risks due to failure.

It is also worth noting that a very similar risk analysis approach has been applied to forecast the insulator replacements.

SP AusNet has provided the spreadsheet associated with the cross arm, conductor and insulator forecasts.

Nuttall Consulting views

With regard to conductor replacement, this appears to be the main reason for the significant increase in expenditure forecast in the next period. Nuttall Consulting has reviewed the models provided by SP AusNet and it is clear that the bushfire risks are by far the most significant risks determining the scale of this program, accounting for approximately 95% of the risk. It also appears from the PV analysis presented that without these bushfire risks, the program would not be justified.

Nuttall Consulting has request further information on the program that has commenced in this period[108]. SP AusNet provided the approved business case in response to this request. This indicates that 169 km of conductor has been approved for replacement in this period. This allowed for 5km in 2008, 123km in 2009 and 41km in 2010. It is noticeable that it is significantly less than the 621 km that is proposed for 2010. It is also noticeable that the level is not trending up as may be expected if the risks are as significant as suggested by the risk analysis presented by SP AusNet in this review.

Aside from this, it is still unclear whether the scale of the program is justified. This appears to hinge on two matters. The first is whether appropriate testing can be undertaken to target the relevant conductor for replacement, in order that the risks can be materially reduced. The second is whether such testing will support SP AusNet's assumption that 50 years is the average age of the conductor requiring replacement.

Nuttall Consulting has requested information on SP AusNet's testing and the results of this testing[109]. SP AusNet's response on these matters does not indicate that it has test data to support its position at this stage. On this matter, SP AusNet has noted that it does not have test data available at this time, but it is proposing to use forensic analysis of conductor condition in the future.

As discussed previously in the Powercor section, it is understood that Energy Safe Victoria (ESV) has undertaken some testing of conductors, but at the stage of drafting this report, the findings of this testing are not known. It may well be that the findings of this testing will be very informative as to the prudent level of conductor replacement.

Given the significance of this project and its clear relationship with recommendations that may result from the Royal Commission on the 2008/9 bushfires, Nuttall Consulting considers that this program should be ring fenced and re-considered following the Royal Commission's findings. This view is also relevant for the proposed insulator replacement program, for which the risks associated with this program are primarily bushfire related also.

At this stage, given the uncertainty in how the conductor can be appropriately targeted to reduce risk, and hence the prudent criteria to develop the forecast, we consider that the expenditure allowance should be made based upon a "business as usual" view. This essentially means the business should be provided an allowance based upon its historical approach to managing risks.

If an allowance for the pre-emptive conductor replacement program were to be allowed, irrespective of the Royal Commission's findings, then SP AusNet would need to demonstrate that its proposed program is in accordance with ESV test result findings.

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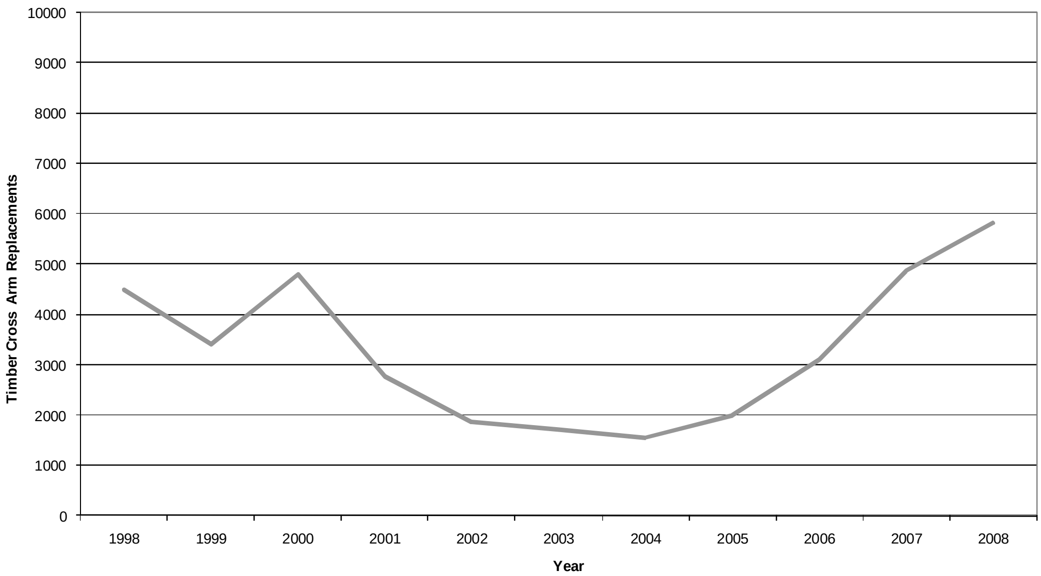
[108] Request in email dated 3/3/10, response provided in email dated 10/3/10
[109] Request in email dated 3/3/10, response provided in email dated 10/3/10

With regard to the forecast cross arm replacements, SP AusNet appears to be forecasting a step increase in replacements over historical levels. The average historical level (2006-2008) being 4800 per annum, whereas the forecast is 6551 per annum. This appears to be based upon the forecast rate being similar to the estimated rate for 2009 (see Figure 107).

Figure 107 – SP AusNet actual cross-arm replacements



However, we consider that this may be an overestimate of the cross arm replacement needs as SP AusNet changed its approach to managing cross-arms during the previous period, and this has changed again during the current period.

On this matter, the SP AusNet AMP for poles[110] indicates that in 2000 the inspection cycle for poles in fire-hazard areas was lengthened from 3 years to 5 years for timber poles and 10 years for concrete poles. This was supported by the annual vegetation inspection cycle. In 2007, SP AusNet supplemented the pole inspection cycle with a 2.5 year inspection cycle for pole top structures.

We consider that these changes may have resulted in the significant ramping of the replacement levels that appears to have occurred during the current period. However, we consider that this will most likely result in elevated levels being estimated for 2009 to 2010 as some "catch-up" has occurred. This view appears to be supported by statements made by SP AusNet, where it has stated that the changes "*reduced the volume of cross arm replacements between 2001 and 2004 but increased the volume of crossarms managed by re-inspection programs. This approach* ***deferred*** *the replacement of crossarms but could only be sustained until 2004. In 2005 replacement rates were increased to stabilize the cross arm failure rate and the volume of crossarms being re-inspected on the 18-month and 30-month cycles*"[111] (emphasis added). Therefore, we see no reason to consider that the forecast should not be around the average 2006-2008 levels with an allowance for the aging effect.

[110] AMS 20-70, page 12
[111] Email from SP AusNet to AER, dated 16/4/10

Based upon the above, for the overhead line activity code, we see no reason to allow more than the average recent historical level (2006-2008) with an allowance for an aging population. It is important to note however that this expenditure may need to be reconsidered following the findings of the Royal Commission.

9.3.4 Pole Replacement

Activity code and expenditure summary

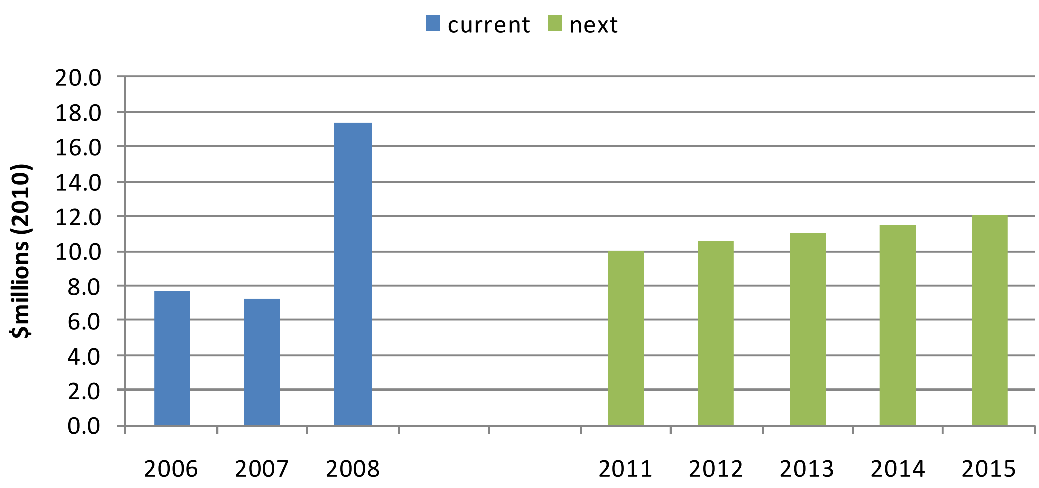
The pole replacement activity code broadly covers the age/condition based replacement of poles, including pole staking.

Table 90 and Figure 108 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents only 13% of the total RQM expenditure in the next period, with expenditure forecast to remain near the historical trend.

Table 90 - Overview of expenditure for pole replacements

Activity Code	Average per annum ($m 2010)		Proportion of 2011-2015	Increase from 2006-2008
	2006-08	2011-15		11-15
Pole	10.8	11.0	13%	3%

Figure 108 - Expenditure profile for pole replacements



Forecasting methodology and rationale

Pole replacements (including pole staking) relate to the condition based replacement of poles determined via the cyclical inspection program. SP AusNet appears to have used an age-based model to forecast pole replacement levels. However, the precise methodology adopted by SP AusNet is not clear.

Nuttall Consulting views

Expenditure on pole replacements appears to be broadly in line with the historical trend, although the reason for the peak in 2008 expenditure is not clear. Given the modest proposed increase, which is below the levels forecast by our repex model, we consider that this estimate is reasonable and have not investigated this category in any detail.

9.3.5 HV installation

Activity code and expenditure summary

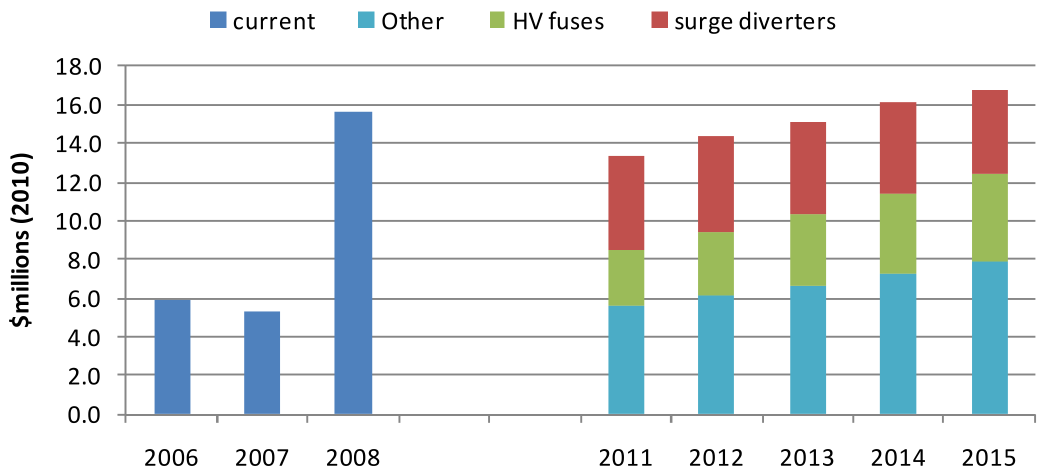
The network HV activity code broadly covers the age/condition based replacement of HV and LV network equipment covering distribution transformers and HV switchgear. A significant portion of expenditure in this activity code covers the replacement of fuses and surge diverters.

Table 91 and Figure 109 provide an overview of the expenditure in this category. Figure 109 also indicates the proportion of expenditure in the next period proposed for the fuse and surge diverter replacement programs. This analysis indicates that this activity code represents 17% of the total RQM expenditure in the next period, with expenditure anticipated to increase significantly from historical levels.

Table 91 - Overview of expenditure for the HV installation replacement

Activity Code	Average per annum ($m 2010)		Proportion of 2011-2015	Increase from 2006-2008
	2006-08	2011-15		11-15
HV installation	8.9	15.1	17%	70%

Figure 109 - Expenditure profile for the HV installation replacement



Forecasting methodology and rationale

This category covers a range of different assets. The SP AusNet documentation indicates that the forecasts in this category are generally based upon probabilistic age models, similar in nature to the repex model discussed in this report.

Nuttall Consulting views

Generally, for most of the asset categories associated with this activity code the proposed volume increases are below or in accordance with increases predicted by the calibrated repex model. As such, we have not considered these in detail.

The main asset showing a significant increase in volume is the surge diverter replacement program. SP AusNet's volume data indicates that a 60% increase in replacement volumes is proposed from 2010 to 2011 (i.e. from 1460 to 2391). The trend tails off marginally from 2011. However, this trend is not in accordance with the current period, where volumes were much lower in 2006 and 2007 and then estimated at a relatively constant level from 2008 to 2010.

All that said, the forecast increase in the overall expenditure for this category is broadly in accordance with our replacement modelling, which is showing a similar increase. As such, we have accepted the SP AusNet forecast as reasonable.

9.3.6 Services

Activity code and expenditure summary

The service activity codes cover the replacement of customer service lines and cables. A large portion of these activity codes is associated with safety related programs, which are allocated to the ESL category.

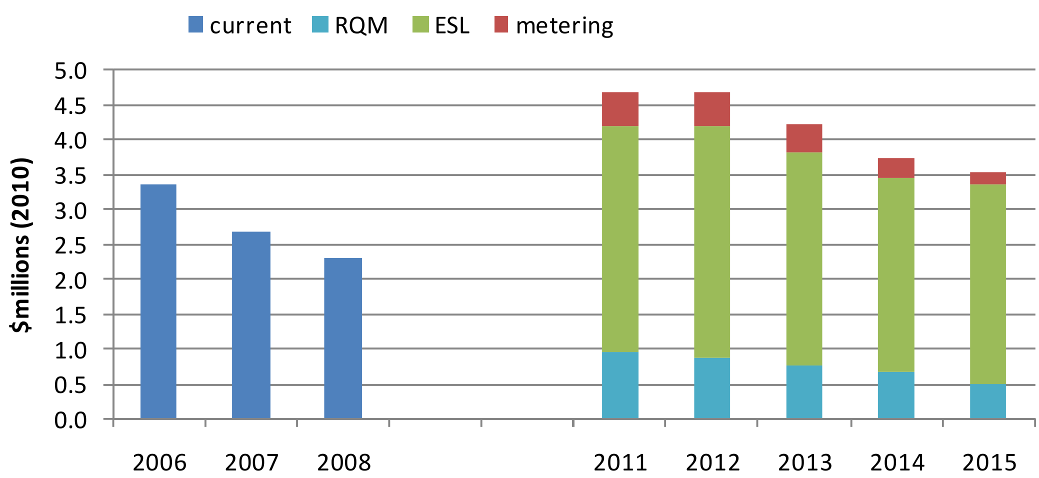
We have also included a small amount of metering expenditure in this category that is defined by SP AusNet as "metering standard control component". Due to the minor nature of this additional amount, we have not reviewed this component in any detail.

Table 92 and Figure 110 provide an overview of the expenditure in this category. Figure 110 also indicates the proportion allocated by SP AusNet to the RQM and ESL categories, and the metering component. This analysis shows that this activity code represents 5% of the total RQM expenditure in the next period, with the services component anticipated to step up from 2006-2008 levels, but then trend down over the next period.

Table 92 - Overview of expenditure for the service replacements

Activity Code	Average per annum ($m 2010)		Proportion of 2011-2015	Increase from 2006-2008
	2006-08	2011-15		11-15
Services	2.8	4.2	5%	50%

Figure 110 - Expenditure profile for the service replacements



Forecasting methodology and rationale

The SP AusNet services AMP[112] indicates that the majority of the services expenditure is driven by the replacement of neutral screen services. Historically, these services have been replaced in a reactive manner. However, the AMP indicates that SP AusNet has initiated a program over 2008 to 2010 to pro-actively replace a large number of services.

The forecasting methodology for services is based upon an age based probabilistic model, similar in nature to the repex model. This has been used to assess the economic benefits of continuing the pre-emptive replacement program for service cables. The model has been used to assess various scenarios, and has found that a program to pro-actively replace a large number of services by 2020 is optimal across these scenarios.

The forecast also appears to allow for a replacement program to cover services deemed to not comply with height regulations. However, there is little detail on the forecasting methodology applied by SP AusNet for this program, or its relationship with the methodology described above.

Nuttall Consulting views

Nuttall Consulting has reviewed the information and modelling presented by SP AusNet in support of the services forecast. We do not consider that the methodology fully supports the economic benefits of the proposed program. In this regard, the model has an inherent assumption that is not clearly supported, which defines the percentage reduction (i.e. 50%) in service failures that can be avoided by the pro-active program. Furthermore, while it is accepted that, of the scenarios modelled, the preferred is the lowest cost (in present value terms), it is not clear if other unmodelled scenarios could cost less.

All that said, the forecast increase in the overall expenditure for this category is broadly in accordance with our replacement modelling, which is showing a similar increase. As such, we have accepted the SP AusNet forecast as reasonable.

9.3.7 Underground cable

Activity code and expenditure summary

The underground cable activity code broadly covers the age/condition based replacement of underground cable and associated underground equipment (e.g. joints, terminations, link boxes etc).

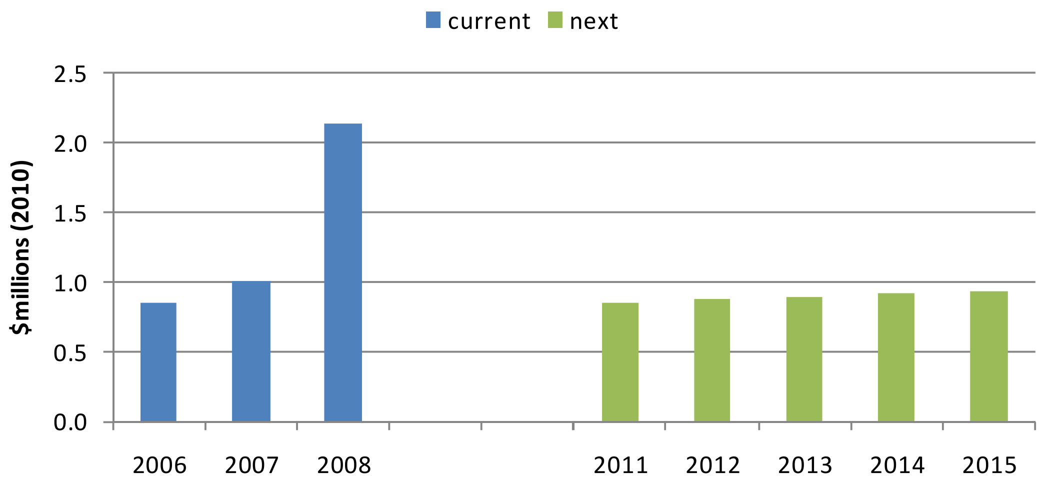
Table 93 and Figure 111 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents only 1% of the total RQM expenditure in the next period, with expenditure anticipated to trend around historical levels in 2011.

Table 93 - Overview of expenditure for underground cable replacement

Activity Code	Average per annum ($m 2010)		Proportion of 2011-2015	Increase from 2006-2008
	2006-08	2011-15		11-15
Underground cable	1.3	0.9	1%	-33%

[112] AMS 20-76

Figure 111 - Expenditure profile for underground cable replacement



Nuttall Consulting views

Given the low level of expenditure in this category, and the proposed expenditure is below the average historical level, we have not investigated this activity code in any detail, and consider that this estimate is reasonable.

9.3.8 Recoverable works residual

The "recoverable works residual" category amounts to approximately $2.6 million per annum in the next period. As noted in the introduction, this category has not been explicitly allocated by SP AusNet to the RQM category in the current period.

It is assumed that this category will cover the unplanned replacement of assets, due to third party damage when the party cannot be located to fund the replacement. However, the basis and rational for this additional component is not clear from the SP AusNet information reviewed.

It is noted that a recoverable works activity code (116 - Recoverable & Special Works) was allocated to the customer connections categories in the current period, and this no longer appears to be the case in the next. However, it is not clear what works were captured in this code and how this then relates to SP AusNet's forecast for the RQM category. For example, it is noted that the actual net capex between 2006 and 2008 allocated to "Recoverable & Special Works" was trending down, from $2.7 million in 2006 to $1.3 million in 2008, which suggests it is presently well below SP AusNet's forecast amount for the next period.

Given this uncertainty, we consider it reasonable to assume that the majority of the expenditure associated with equivalent works in the current period (2006-2008) was captured in the other activity code categories. Therefore, given our rationale of basing the forecast on historical levels, we consider that expenditure to cover these works should inherently be captured elsewhere.

9.3.9 Overall findings

The above has shown that the proposed increase in RQM expenditure in the next period is mainly due to a new program to proactively replace age conductors and significant increase in the level of replacement of assets in zone substation. A number of other assets types are also proposed to have significant increases in expenditure over historical levels.

Based upon our review, we do not consider that SP AusNet has adequately demonstrated that the increases are prudent and efficient.

The conductor replacement program is a very significant ($53 million) new program. However, we have a number of concerns with the justification for the scale of this program, particularly with respect to:

- the much lower levels replaced under this program in the current period
- the relationship of the scale of this program with conductor condition testing that has been undertaken by the ESV
- the resulting uncertainty as to what the optimum replacement amount will be.

We are not recommending any additional allowance for this program. However, as the major driver of this new program is clearly reducing bushfire risks, we are recommending that the expenditure for such a program is “ring fenced” for further review following the findings of the Royal Commission on the Victorian bushfires.

For other age/condition based replacements, SP AusNet has supplied a large number of models associated with their forecasts. These models cover combinations of age based forecasting and economic modelling.

For the zone substation transformer and circuit breaker replacement programs (and the associated substation rebuilds), SP AusNet has undertaken quantitative economic and risk analysis. However, given the substantial increases that are forecast through these models, we consider that SP AusNet has not adequately demonstrated that they have been calibrated appropriately. As such, we consider that they may be significantly overstating replacement needs.

For other assets, in the cases where the models appear to be forecasting replacement level much higher than existing levels, SP AusNet’s justification for the increase do not appear to be reasonable. It is also noted that specific issues and associated risk are discussed in the asset management plans and associated documents. However, in these cases, we do not doubt that the issues and associated risks exist, but in the justification for the increases it has not been demonstrated how SP AusNet is presently managing these matters – presumably in a prudent and efficient manner – and how the risk will change over time.

Based upon the above, we consider that the RQM allowance should be based upon the recent historical levels of RQM expenditure with some additional allowance for the aging of the network. We do however recommend a modest step increase in the expenditure level for the zone substation activity code. The historical levels (2006-2008) allocated to this code are very low. Our recommended increase is well below the level proposed by SP AusNet.

The recommended RQM expenditure is shown in Table 94. The basis for these recommendations is indicated in Table 95.

It is important to note that this recommendation must be considered in the broader context of the overall capex. We would fully expect that at the activity code level, actual expenditure may differ considerably as circumstances change and the full capital governance process is applied.

It is also important to note that this recommendation should be considered as an estimate only. The AER may need to make further adjustments to allow for its findings on the other matters, such as overhead and labour and material escalation, which are not accurately allowed for here.

Table 94 – SP AusNet RQM capex (including ESL transfers)

	$thousands (2010)				
Activity code	2011	2012	2013	2014	2015
Proposed[113]	82,654	95,094	92,087	82,108	70,635
Recommended	**49,473**	**52,361**	**54,759**	**57,533**	**60,314**

Table 95 – SP AusNet activity code based adjustments

Activity code	Nuttall Consulting view
poles	Accepted
OH line reps	Rejected - allowance based upon average 2006-2008, with increase based upon repex model findings
services	Accepted
UG cable	Accepted
HV installation	Accepted
ZS plant	Rejected - allowance based upon $8million in 2011, with increase based upon repex model findings

9.4 Environmental, Safety and Legal

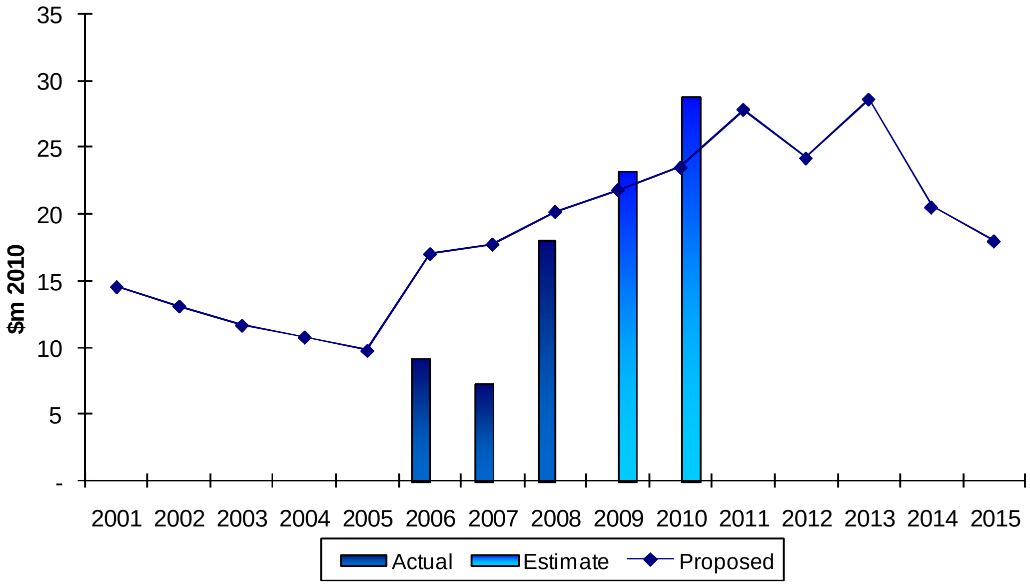
SP AusNet is proposing an increase of over 107% in Environmental, Safety and Legal capex for the next Regulatory Control Period when compared against actual expenditure in the current Regulatory Control Period. SP AusNet estimates that its' Environmental, Safety and Legal capital expenditure for the 2006-10 regulatory control period will be $86.4 million. It is forecasting that this will increase to $119.0 million in the 2011-15 regulatory control period.

[113] This amount includes RQM plus identified transfers from ESL.

For the 2006 EDPR, SP AusNet proposed Environmental, Safety and Legal expenditure of $100.1 million. The resultant actual expenditure for this period is forecast to be $86.4 million[114].

The following chart provides a summary of Environmental, Safety and Legal capex for SP AusNet.

Figure 112 - SP AusNet Environmental, Safety and Legal capex[115]



SP AusNet is proposing an enhanced network safety plan which aims to "*reduce the annual number of network related incidents reported to ESV, currently 13943 per annum, by 20% per regulatory period*"[116]. This is an ongoing program and was identified in the previous EDPR submission.

SP AusNet has also identified the need for continuing investment in security in the proposed Environmental, Safety and Legal capex.

SP AusNet states that the increase in Environmental, Safety and Legal expenditure "*is driven by increasing volumes of work to address deterioration of network assets and increased costs*". This does not appear consistent with an increase of over 100% on current expenditures as the average age of the network is only changing marginally.

The table below sets out SP AusNet's forecast Environmental, Safety and Legal capex programs.

[114] Including 2009 and 2010 estimates.

[115] SP AusNet did not report any Environmental, Safety and Legal capex as incurred during the 2001-2005 Regulatory Control Period.

[116] SP AusNet EDPR 2011-2015 - Capital Expenditure

Table 96 - SP AusNet Forecast Environmental, Safety and Legal Capex Programs

Category Direct	Costs (Real 2010 $M)
Pre emptive replacement of cables *	13.2
Cross-arms *	12.4
Pre Emptive replacement conductor - Steel *	33.7
Pre Emptive replacement conductor - Copper *	10.8
Pre Emptive replacement fog type HV insulator *	11.7
Environmental, bunding, security	2.9
HV Fuses *	16.2
OH & S - Replace CTs	0.2
OH & S - Replace disconnectors	0.6
OH & S - Replace silicon carbide gap arrestors	1.9
Total (with overheads)	**119.0**

The pre-emptive replacement categories (identified with an * above) have been considered within the reliability and quality maintained category due to their direct relationship with replacement expenditure. The expenditures are not considered further within this section.

The OH&S replacement programs identified in the Environmental, Safety and Legal category have been reviewed. These replacement programs, while being driven by health and safety requirements, are triggered through the same processes as most other replacement programs[117]. On this basis, these costs are considered to also be covered in the reliability and quality maintained assessment.

SP AusNet has indicated forecast expenditure of $2.9 million for environmental, bunding and security works.

These works are part of an ongoing program. In their 2006 submission to the ESC, SP AusNet proposed to increase capital expenditure related to environmental, safety and legal obligations over the 2006-2010 regulatory period. The proposed increase in capital expenditure was proposed to include asbestos removal, oil spill containment (bunding) and infrastructure security at critical sites.

9.4.1 Asbestos

SP AusNet state that significant asbestos materials exist in zone substations - predominantly in building construction materials and electrical boards. The replacement of these asbestos materials is difficult to justify and is typically undertaken in parallel with related CAPEX programs as the opportunity arises.

SP AusNet also not that the condition and security of asbestos clad buildings is deteriorating. In March 2008, SP AusNet developed the Asbestos Management Strategy

[117] Surge diverter replacement strategy is to "continue the prioritised replacement of all gapped silicon carbide porcelain housing surge diverters as they reach service ages of 20 years or 30 years" - AMS – Electricity Distribution Network Surge Diverters in Zone Substations, 18/11/2009.

for Electrical Transmission, Electrical Distribution and Gas Distribution Assets. This document describes the overall approach to asbestos risk assessment and management. The detailed forward program for asbestos management was not provided.

In terms of obligations for undertaking asbestos related activities, SP AusNet identified the following:

- OHS Act 2003, OHS (Asbestos) Regulations 2003
- ESMS requirement to eliminate risk or achieve ALARP risk level

Asbestos safety is a long standing issue for all DNSPs. SP AusNet has not identified any new obligations that would alter the historical approaches to the treatment of asbestos. On this basis, SP AusNet has not justified an increase in forecast capex for asbestos management.

9.4.2 Bunding

SP AusNet assets such as transformers and some circuit breakers contain significant volumes of oil. These assets are subject to leak rates and the potential for explosive failure of bushings.

SP AusNet has reported that existing bunding facilities do not comply with AS1940 or EPA Guidelines[118]. In addition, some drains are in close proximity to rapidly transport potentially burning oil off the premises and some trenches run through the bund (oil containment walls) allowing oil to drain from the bund to threaten other switchyard assets.

The regulations identified by SP AusNet as relating to bunding and oil containment are:

- Victorian Dangerous Goods Act 1985: Code of Practice for the Storage and Handling of Dangerous Goods
- ESMS requirement to eliminate risk or achieve ALARP risk level
- Spills must be contained within the premises (EPA guidelines)
- AS 1940-2004 – The storage and handling of flammable and combustible liquids

To support the proposed capex in this category, SP AusNet provided a spreadsheet[119] that calculated the risk of the "Explosive Failure of Main Tank resulting in large oil volumes thrown onto Road and escaping site". A key input into this review was the assessment of probability of the explosive failure of the transformer. Following a request for information supporting the probability assessment, SP AusNet provided an explanation of the probability calculation[120].

The probability assessment identified 262 oil related incidents over the last decade for this class of assets. However, only 3 of these incidents could possibly relate to the explosive failure of the main tank, and at least one of these was contained within the existing bunding. As the average number of zone substation transformers in the SP AusNet network over the last decade was 135.5, the actual probability of "Explosive Failure of

[118] 'Bunding Guidelines Publication 347, December 1992'
[119] Oil Management Ver 0.2.xls
[120] Oil Management Model - Event Probability Calculation Explaination (sic), 23/02/2010.

Main Tank resulting in large oil volumes thrown onto Road and escaping site" is therefore somewhat less than 0.22% (not 1.0%).

Overall, the SP AusNet risk assessment process appears robust. However the input assumptions identified above do not appear reasonable and do therefore not support the proposed additional expenditures.

As there appears to be no change in external driver or regulatory requirements for expenditure in this category, SP AusNet has not provided evidence that would support a change in the current levels of expenditure for bunding.

9.4.3 Infrastructure security

SP AusNet reported that station security facilities have essentially not changed since the initial establishment of each site and that they consider that the condition of many security facilities requires improvement.

SP AusNet considers that development of the land surrounding these sites has increased the risk profile in many cases. In addition, the increased copper price has resulted in an increase in forced entry of electricity assets.

The obligation identified by SP AusNet in relation to infrastructure security include:

- Electricity Safety Act 1998
- Electricity Safety (Management) Regulations 2009 (Draft)
- Victorian 'Terrorism (Community Protection) Act 2003'

In its 2004 submission to the ESC, SP AusNet identified "*additional capital expenditure of, on average, $3.3 million per annum to increase security measures at critical infrastructure sites and developing contingency capabilities to manage loss of key infrastructure*."[121] The proposed expenditure was a substantial increase on previous levels of expenditure.

The security of critical infrastructure is an important and ongoing requirement for all DNSPs.

In the absence of new or additional obligations, the information provided by SP AusNet supports the continuation of the existing level of expenditure.

9.4.4 Environmental, Safety and Legal Summary

Based on the above assessment, SP AusNet has provided reasonable information to substantiate the following proposed expenditures:

- Asbestos management - $188k ($2009 Direct)
- Infrastructure security - $1.44M ($2009 Direct)

The proposed capex associated with oil containment of $702k ($2009 Direct) is not sufficiently supported at this time.

[121] SPI Networks Electricity Distribution Price Review 2006 Price-Service Proposals for the Period 2006-2010, 21 October 2004.

Table 97 - Recommended SP AusNet Environmental, Safety and Legal capex

SP AusNet	Costs (2010 $M)				
Environmental, Safety and Legal	2011	2012	2013	2014	2015
Recommended Expenditure	1.124	1.138	1.153	1.166	1.179

9.5 SCADA and Network Control

SP AusNet's proposed expenditure in the "SCADA and Network Control" category represents only a small percentage (<1%) of the total net capex in the next period, and is at a level much lower than that in the current period.

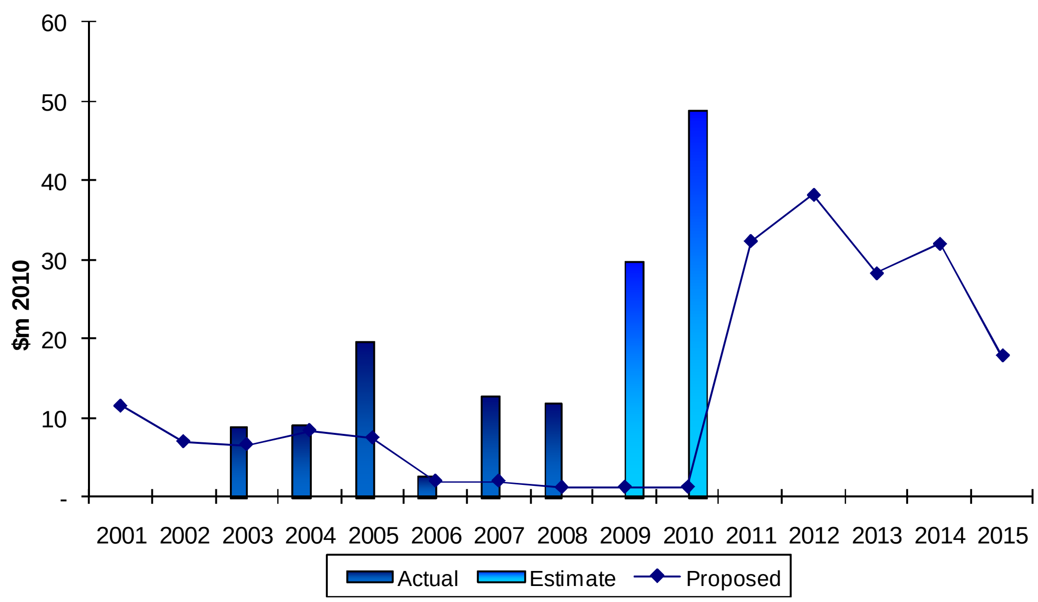
Given the low significance of this expenditure, it was agreed with the AER that Nuttall Consulting would not undertake a detailed review of this category.

9.6 Non-network general - IT

SP AusNet is proposing IT capital expenditure of $148.5 million over the next regulatory control period, which represents an increase of 164% in capital expenditure from audited historical expenditure ($65.1 million). Major proposed IT capital projects include IT infrastructure asset replacements, IT application replacements and application investments with new functionality.

During 2004-2008, SP AusNet substantially **overspent** their IT capital expenditure from a proposed of $21.1 million to actual audited spending of $65.1 million.

Figure 113 - SP AusNet proposed vs actual IT capex



However, based upon the information provided and our interviews we not believe that SP AusNet has the necessary flexible and agile IT infrastructure or development approach that will permit SP AusNet to deliver these projects on time and within budget within the next regulatory period.

This is reinforced by the historical overspend, that in our opinion has been used to mitigate the lack of flexibility by building single point solutions in order to deliver individual projects which may limit and/or inhibit future project delivery.

In terms of our recommendation for allowed capital expenditure, our review is quite high-level and given the many events, factors and considerations that will occur in the future we are not able to identify specific projects which would be impacted. However, we do recommend that SP AusNet develops its IT Infrastructure and approach along a modern agile and IaaS delivery methodology as a long term investment to manage IT capital expenditures in subsequent regulatory periods as it appears that the environment is quiet static.

Given that the SP AusNet proposed expenditure is $148.5 million against a current period expenditure (estimated) of $65.1 million, and upon review of the IT strategies provided we do not consider that SP AusNet has adequately considered the internal and external factors that may impact on the proposed delivery program. We recommend that the SP AusNet proposed expenditure be reduced to historical levels of an average of $13M per annum with an additional $10M allowance over the regulatory period to provide contingency and permit investment for SP AusNet to develop a more flexible and agile project delivery.

Table 98 - Recommended SP AusNet non-network general IT capex

SP AusNet	Costs (2010 $million)				
Non-network general – IT	2011	2012	2013	2014	2015
Proposed Expenditure	32.3	38.1	28.2	31.9	17.9
Recommended Expenditure	15.0	15.0	15.0	15.0	15.0

9.7 Non-network general - other

SP AusNet's proposed expenditure in the "non-network general – other" category represents only a small percentage (3%) of the total net capex in the next period, and a negligible portion of the proposed expenditure increase.

Given the low significance of this expenditure, it was agreed with the AER that Nuttall Consulting would not undertake a detailed review of this category.

10 Appendix E - United Energy review

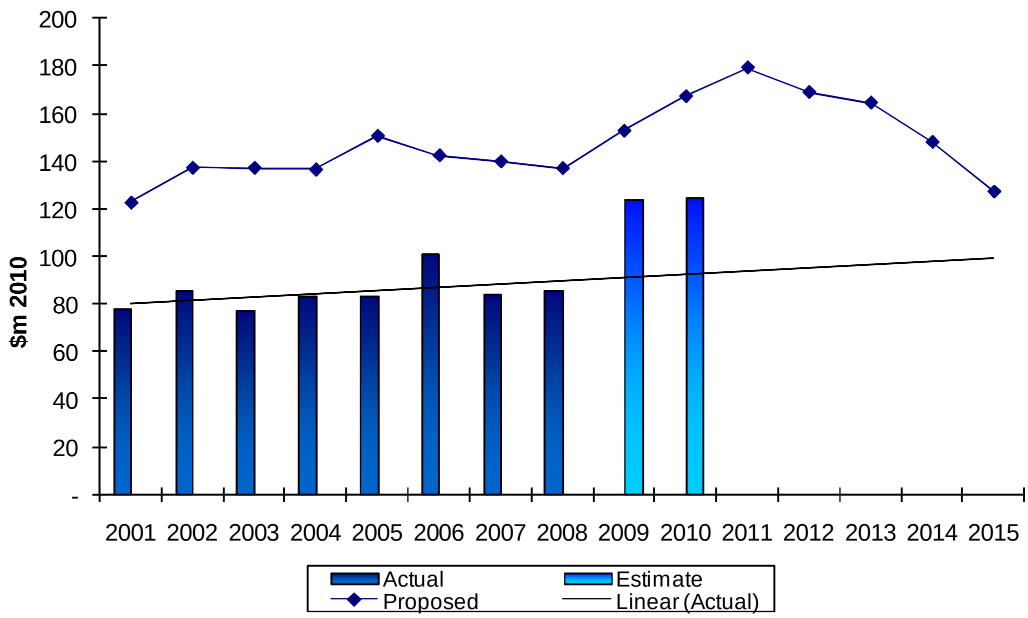
10.1 Overall capex

Overall capex is forecast to increase by 74% over actual expenditures in the current period. The main areas where capex is forecast to increase are reinforcement, reliability and quality maintained, and non-network - IT.

The following chart provides a summary of the overall capex figures for United Energy. Key aspects of this chart include:

- United Energy has consistently spent significantly less than they proposed in the 2001 and 2006 EDPRs
- Jemena is proposing a future level of capex that is significantly higher than the historical levels of expenditure and is not consistent with the historical trend in capex. It is also noted that it steps up in 2011 and reduces during the period.

Figure 114 – United Energy Capex Summary

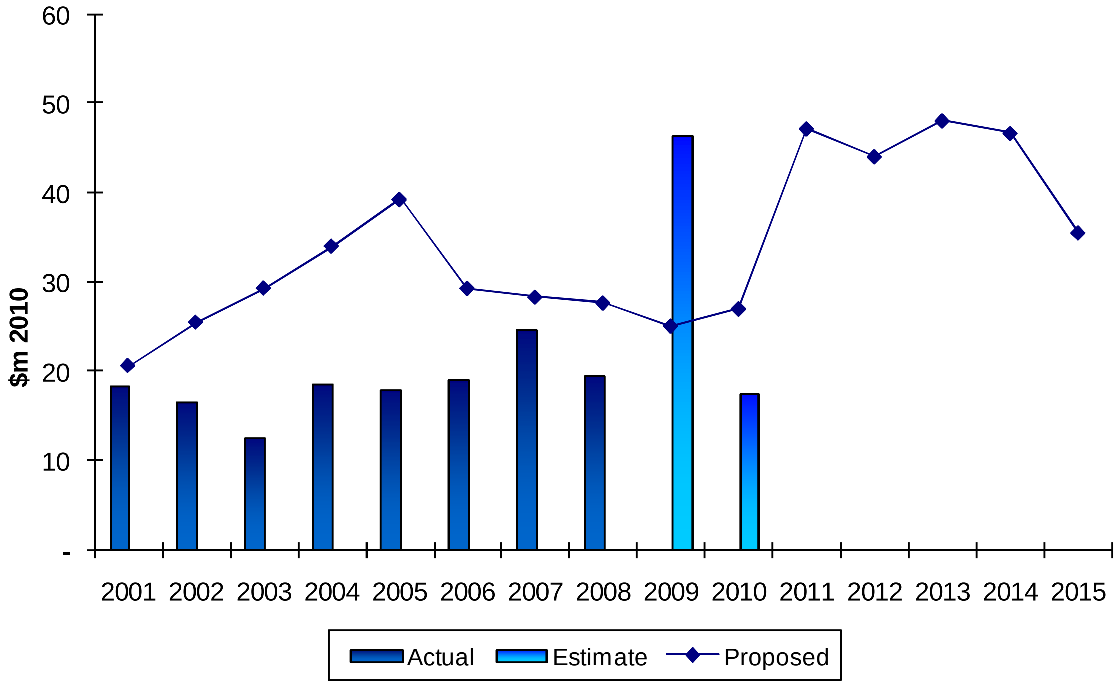


10.2 Reinforcement

United Energy is proposing a reinforcement program that is 111% greater than actual expenditures in the current Regulatory Control Period. United Energy estimates that its reinforcement capital expenditure for the 2006-10 regulatory control period will be $127 million ($2010). It is forecasting that this will increase to $222 million ($2010) in the 2011-15 regulatory control period.

The following chart provides a summary of reinforcement capex for United Energy.

Figure 115 - United Energy Reinforcement Capex Summary



This chart indicates that United Energy's reinforcement expenditure has been trending up over the previous and current regulatory periods. United Energy has estimated a significant spike in expenditure in 2009, and a significant step increase in reinforcement expenditure in 2011 with expenditure trending down slightly from that time.

The 2001 EDPR forecasts prepared by United Energy was significantly over the actual expenditure incurred. The 2006 EDPR forecast is still in excess of the actual expenditure, particularly if 2009 is excluded, but not to the level in the previous period. Interestingly, the level of over-forecast is relatively high in the early years of the forecast, which is counterintuitive to what would be expected.

United Energy's proposal indicates a number of factors driving the proposed increase reinforcement expenditure, including demand growth and the high utilisation of the sub-transmission and distribution network.

10.2.1 Forecasting methodology

United Energy has developed its reinforcement plans largely based upon a bottom-up build of individual network needs and projects to address these needs. United Energy considers that these plans have been developed using the actual planning processes it applies in practice. However, due to their proposed timing, many projects will not have been through the full evaluations and justifications that would be required for approval.

A major portion of these plans is developed via the risk evaluation approach United Energy applies at the sub-transmission level. This approach is similar to the full probabilistic planning approach that is applied at transmission level in Victoria. This approach assigns an economic value to the expected energy that will not be served to customers (often related to the probability of network outages) and then balances this against the capital cost to reduce these risks, to ensure capital projects are economically justified.

Future predictions of the value of the expected energy not supplied are calculated using a number of key input assumptions, most notably:

- the 10% probability of exceedance maximum demand forecast
- a load profile, based upon the actual load profile for 2007/08
- a value of customer reliability (VCR) based upon the Victorian average- United Energy considers that this is reasonably reflective of its customer base
- transformer outage rates based upon those used for assessing transmission connection augmentations.

It is worth noting that detailed probabilistic assessments, based upon these assumptions, do not appear to have been undertaken at this stage on all projects. In these cases, engineering judgement has been applied to determine the timing. Nonetheless, where relevant, this judgement considers the forecast level of energy at risk.

For distribution feeders, United Energy applies a more deterministic approach that considers the loading of feeders, their rating and the load transfer capability. The plans however are still built up from individually identified needs.

For distribution substations, United Energy applies a pseudo "bottom-up" approach, whereby the quantity of distribution transformers requiring upgrading are calculated at an aggregate level. This process involves estimating the future maximum demands of the transformer population, based upon customer types and metering information associated with individual substations. The number of transformers requiring upgrading is then determined based upon the quantity with a predicted maximum demand above a function of the transformer rating. The expenditure is calculated based upon the quantity at various standard sizes and a unit cost for that size.

It is important to note that the methodology associated with the distribution substation is based upon a new pre-emptive upgrade program that has been commenced in the current period. Prior to this, distribution transformers would generally be replaced in a reactive fashion.

10.2.2 Nuttall Consulting detailed review

10.2.2.1 Process

Nuttall Consulting's detailed review of United Energy's reinforcement expenditure has included a review of its forecasting methodology and a number of specific projects. The general process applied by Nuttall Consulting in conducting its review of United Energy's reinforcement expenditure is summarised in Section 4.2 of this report.

The projects reviewed included:

- Templestowe new zone substation
- Keysborough new zone substation
- Mentone transformer upgrade

- MTS-BW-MTS 66 kV line upgrade
- TBTS-DMA-RBD-STO 66 kV line
- Distribution substation upgrades

Key United Energy documents, in addition to United Energy's proposal, included in this review are:

- E-1 – Network Asset Management Plan
- E-1.29 – Planning guideline
- E-4 – PB Review of Methodology
- 2009 Distribution System Planning report

Other documentation specific to the projects under review are identified in the sections below.

10.2.2.2 Findings on methodology

Overall, we consider that United Energy's methodology is reasonable for developing capital plans for internal purposes. In this regard, the process should result in the identification of network needs, a list of projects to address these needs, and expenditure projections for the medium-term management of the network. In turn, this process results in a relatively comprehensive list of individual network needs and projects that can be monitored and developed further through the next period.

However, we do not consider that this largely "bottom-up" based process has been shown to be "fit for purpose" in terms of being a reasonable unbiased estimator for future prudent and efficient expenditure at the aggregate level. In particular, we do not consider that such a process adequately allows for the further optimisation of projects and synergies between projects that will occur as the individual projects and the overall capital plans advance through the capital governance process.

It is accepted that in some circumstances these processes will result in some projects being advanced or their scopes increased. However, in our view, the more detailed evaluation and justification associated with the project approval within the governance process will most likely result in overall expenditure being less than the simple summation of the project plans, as applied by United Energy to determine its reinforcement expenditure.

Related to the points above, we also have a significant concern that United Energy's use of a 10% PoE maximum demand forecast and a load profile based upon 2007/08, which we consider may represent 50% PoE conditions, may materially overstate the risks. On this matter, it is noted that United Energy are the only Victorian DNSP that used the 10% PoE conditions within its analysis; however, other assumptions do not appear to allow for this far more onerous forecast. We consider that this may result in some projects being advanced by up to 3 years from their optimal timing, depending on the level of load growth.

Furthermore, given the continuing trend of demand growth outstripping energy growth, we also consider that the load profile may become "peakier" during the next period. This may also result in some projects being optimally deferred from United Energy's proposed timing.

Issues associated with the distribution substation methodology will be discussed in the project reviews below.

10.2.3 Project reviews

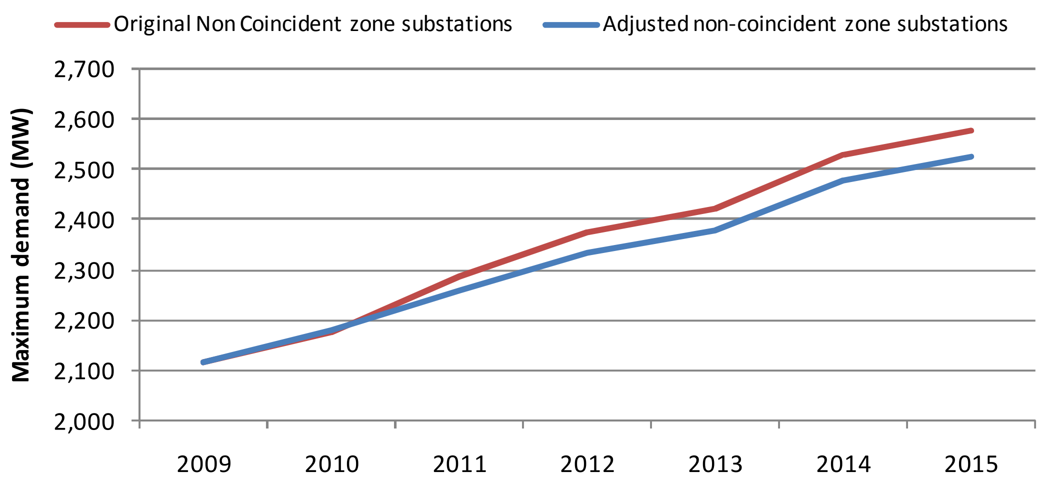
As noted in Section 4.2.4, the aim of the Nuttall Consulting review has been to determine the likelihood that the project expenditure will be required as proposed by United Energy. We consider that this is a reasonable approach to account for the likely consequences of the governance processes and the other specific methodological concerns discussed above.

An additional input to our review has been the findings of the AER's review of United Energy load forecasts. Of particular relevance to our review is the maximum demand forecasts. The AER's findings here were that United Energy has overstated the growth in maximum demand.

A comparison of the United Energy maximum demand forecast and the AER's view is shown in the chart below. This chart indicates that the AER's adjustments result in maximum demand levels being delayed by around 1/2 year.

It is important to note that we have not been able to analyse the affect of these adjustments in detail. However, we have attempted to allow for these to some degree in our assessment of the likelihood of the projects. We would recommend however that the AER require the United Energy to reassess its plans more comprehensively in light of these load forecast findings to determine their effects.

Figure 116 – United Energy maximum demand forecast



The following summarises the main findings for the projects reviewed.

10.2.3.1 Templestowe new zone substation

Cost: 10.37 million

Completion: 2014

This project involves the establishment of a new zone substation at Templestowe. This project is driven by load at risk at the exiting Doncaster zone substation.

Based upon our review of United Energy energy at risk calculations, we do not consider that United Energy has demonstrated that the project is justified in the next period. Furthermore, given the points above on the use of the 10% POE maximum demand forecast, the load profile assumed, and the AER's findings on United Energy demand forecast, we consider that there is a significant possibility that this project will be optimally deferred.

As such, this project has been assigned a low probability (33%) of occurring as planned.

10.2.3.2 Keysborough new zone substation

Cost: 12.5 million

Completion: 2013

This project involves the establishment of a new zone substation at Keysborough. This project is driven by load at risk at the exiting Dandenong South and Nobel Park zone substation.

United Energy's energy at risk calculations indicate that the project is justified. However, given the scale of this project and the point above on the 10% PoE maximum demand and load profile used in these calculations, we consider there is still some possibility that the project scope may be further optimised, resulting in the deferral of the new substation works.

As such, this project has been assigned a moderate to high probability (70%) of occurring as planned.

10.2.3.3 Mentone transformer upgrade

Cost:7.5 million

Completion: 2012

This project involves the installation of a 3rd transformer at the existing Mentone substation. This project is driven by load at risk at the exiting Mentone zone substation.

United Energy's energy at risk calculations indicate that the project is justified. Furthermore, the options appear reasonable.

However, given the point above on the 10% PoE maximum demand and load profile used in these calculations, we consider there is still some possibility that the project may be deferred. Nonetheless, given the level of energy at risk compared to the project cost, this project has been assigned a high probability (90%) of occurring as planned.

10.2.3.4 MTS-BW-MTS 66 kV line upgrade

Cost: 5.23 million

Completion: 2013

This project involves the conversion of the existing MTS-BW-MTS 22 kV loop to 66 kV. This project is related to the longer term need to upgrade the capacity of the lines. However, the timing is opportunistic, and driven by the plans to replace the three existing 22/11 kV transformers at BW with two 66/11 kV units. The BW upgrade is driven by the condition of the transformers and is included in the RQM category. Energy at risk does not appear to be sufficient to justify the 66 kV upgrade in the next period.

We have reviewed the condition information on the transformers in the life cycle plans that were provided in response to requests through the RQM review. The life cycle plans indicate that the worst BW transformers has an estimated DP of 490, which suggests that there is a good possibility that the transformers will be found to be acceptable throughout the next period.

Counter to this, United Energy's model used to predict transformer failures indicates that the worst case estimated DP value is around 200, which supports their replacement. However, as discussed in the RQM section below, we do not consider that United Energy has adequately demonstrated the accuracy of its predictive modelling.

Based upon the above, we consider that there is a reasonable possibility that the BW upgrade will be deferred resulting in the deferral of the line upgrade. As such, this project has been assigned a moderate to high probability (70%) of occurring as planned.

10.2.3.5 TBTS-DMA-RBD-STO 66 kV line

Cost: 18.6 million

Completion: 2015

The project involves the establishment of a new 66 kV line from Hastings to Rosebud. This project is driven by load at risk due to an outage of a section of the existing line. United Energy also considers that the forecast voltage drop will also result in Code compliance issues.

However, we have some concerns with the timing of this project and the alternative.

United Energy has not adequately demonstrated that the energy at risk justifies the timing of the project. Based upon our assessment we do not consider that the energy at risk due to overloading is sufficient to justify the project at the proposed time. It is noted that United Energy considers that there is also a low voltage compliance issue with this line. However, we consider that it may be possible to manage the low voltages via some form of load shedding. This option would increase the level of energy at risk, but it is not clear whether this is allowed for in United Energy's energy at risk calculations, and if not, what their affect would be.

Furthermore, given the points above on the use of the 10% maximum demand forecast and the load profile assumptions, it may be that these assumptions may be advancing the project from the optimal time.

Finally, with regard to alternatives, we consider that a lower cost alternative of a staged upgrade, involving a 22 kV initial line development, could be a reasonable alternative that has not been considered in detail at this stage.

Based upon the above, we consider that there is a reasonable possibility that the project will be deferred or work required in the next period will be reduced in scale. As such, this project has been assigned a moderate probability (70%) of occurring as planned.

10.2.3.6 Distribution upgrade program

Cost: 71 million

Completion: 2011-2015

This program involves the upgrade of the distribution transformers (and associated LV works). The key driver for this project is the projected loading at the distribution transformers.

The key factor resulting in the proposed increased expenditure for this program is the move to a pro-active upgrade program. The aim here is to replace the transformers before they fail, improving the reliability of the network and reducing safety risks.

However, we do not consider that United Energy has adequately demonstrated that this program is economically justified, in terms of actually realising the anticipated benefits. In particular, we do not consider that the United Energy has provided sufficient evidence to show that the program can adequately target specific transformers, such that it will reduce the transformer failure rate sufficiently. The important point here is that United Energy does not meter loading at the distribution transformer; it has to estimate the loading at a particular transformer via customer metering data. Furthermore, determining when a distribution transformer may fail is more problematic than power transformers, as detailed condition information is not available.

It is also worth noting that we also consider that a delay until the AMI roll-out may allow information from these meters to be used to more accurately determine transformer loadings and target transformers. We also note that the STPIS provides some incentive and reward for undertaking these programs if it will be improving reliability.

Based upon the above, the distribution transformer upgrade program has been assigned a low probability (60%) of occurring as planned. This probability has been assigned to allow for the existing levels of upgrades, with some allowance for the escalation in volumes due to demand growth.

10.2.4 Overall findings

Based upon our review, we do not consider that United Energy has adequately demonstrated that its proposed increases in reinforcement expenditure are reasonable. Moreover, we consider that significant reductions to the proposed plans will occur as the plans pass through the governance processes and more detailed evaluations and justifications are undertaken. In our opinion, a reasonable estimate will be more in line with the historical trend.

This view is based upon a number of findings from our project reviews, which draw upon our high-level expenditure analysis and the findings of the methodology reviews.

Firstly, in many cases, the timing of the projects reviewed did not appear to be economically justified or were marginal, in terms of the benefits through the reduction in EENS. Given the point made above on the use of the more onerous 10% PoE MD condition, and load profile assumed by United Energy, and the AER’s findings on United Energy demand forecast, we consider there is a reasonable possibility that many projects could be deferred.

Secondly, for one project reviewed, the main driver of the timing of the project was the age/condition of existing assets. Without this issue, it appears that the EENS and capacity issues would not require the augmentation at the proposed time. For this project, we have reviewed the condition information available in the relevant asset life cycle plans. In our opinion, based upon the information available, there did not appear to be a compelling case that the project was required at the proposed time, and there still appears to be significant discretion in the timing.

Thirdly, in a few cases, there appeared to be other lower cost options, not considered in detail by United Energy, that we considered may have a reasonable probability that they may be found to be the preferred option.

Finally, with regard to the distribution transformer upgrade program, we do not consider that United Energy has adequately demonstrated that the pro-active upgrade program will realise the benefits that are predicted for the reasons outlined above.

Using the approach discussed in Section 4.2, we have developed a forecast of the reinforcement expenditure using:

- the weighted average probability from the project reviews to determine the reasonable estimate to total expenditure
- a constant growth rate assuming a notional 2008 base-line, derived from the average of the historical 2006-2008 expenditure.

Based upon this process, we have estimated the United Energy reinforcement expenditure in the next period will be 63% of the United Energy proposal and the expenditure growth rate from historical levels will be 7.0%.

Our estimate of the United Energy's reinforcement capex is shown in Figure 33 and Table 24 below. It is important to note that this should be considered as an estimate only. The AER may need to make further adjustments to allow for its findings on the other matters, such as overheads and labour and material escalation, which are not accurately allowed for here.

Figure 117 – United Energy reinforcement capex recommendation

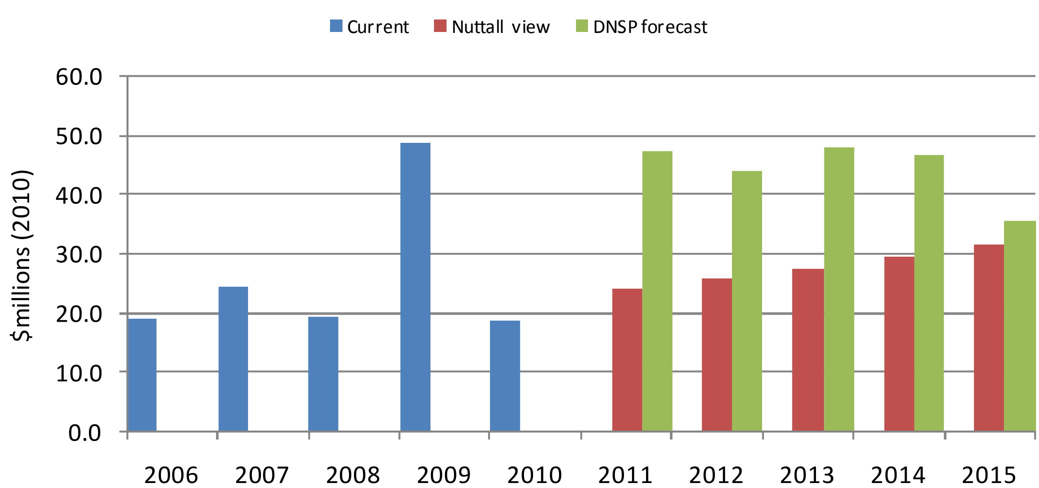


Table 99 – United Energy reinforcement capex recommendation

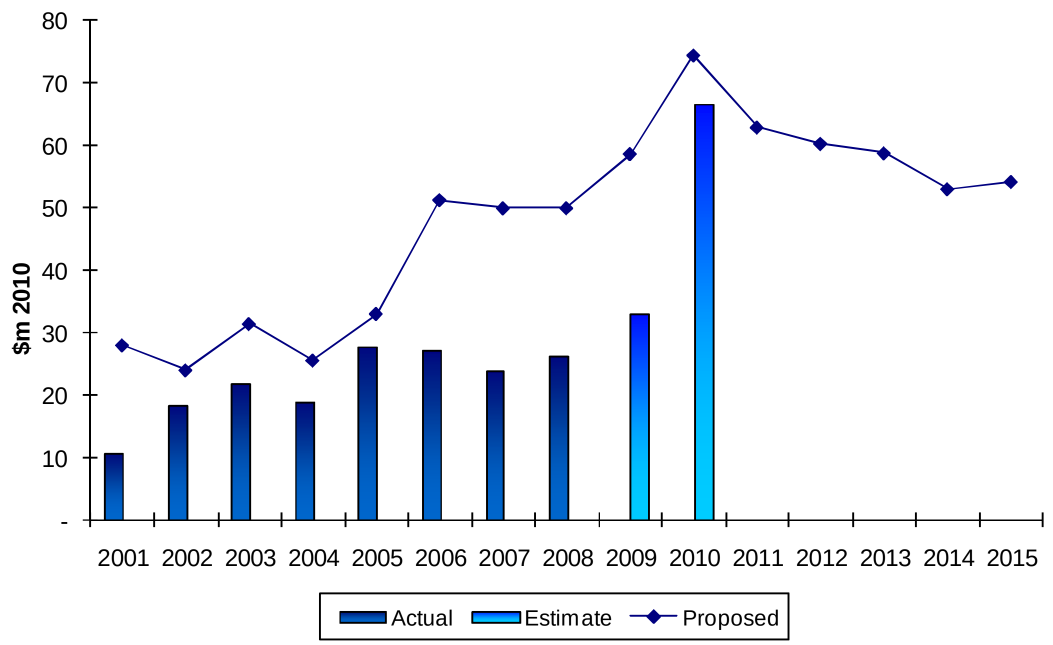
	$millions (2010)				
	2011	2012	2013	2014	2015
United Energy - proposed	47.2	44.1	48.1	46.7	35.5
United Energy - recommended	**24.1**	**25.8**	**27.6**	**29.6**	**31.6**

10.3 Reliability and quality maintained

United Energy is proposing an increase of 124% in reliability and quality maintained capex for the next Regulatory Control Period when compared against actual expenditure in the current Regulatory Control Period. United Energy estimates that its Reliability and Quality Maintained capital expenditure for the 2006-10 regulatory control period will be $177 million ($2010). It is forecasting that this will increase to $289 million ($2010) in the 2011-15 regulatory control period.

The following chart provides a summary of reliability and quality maintained capex for United Energy. This indicates that the trend in actual expenditure is relatively flat, with a significant increase estimated for 2010. It also indicates that United Energy has historically over-forecast RQM expenditure, particularly in the current period.

Figure 118 – United Energy RQM capex



10.3.1 Overview of activity code review

Explanation of expenditure profile – trends and major drivers of increases

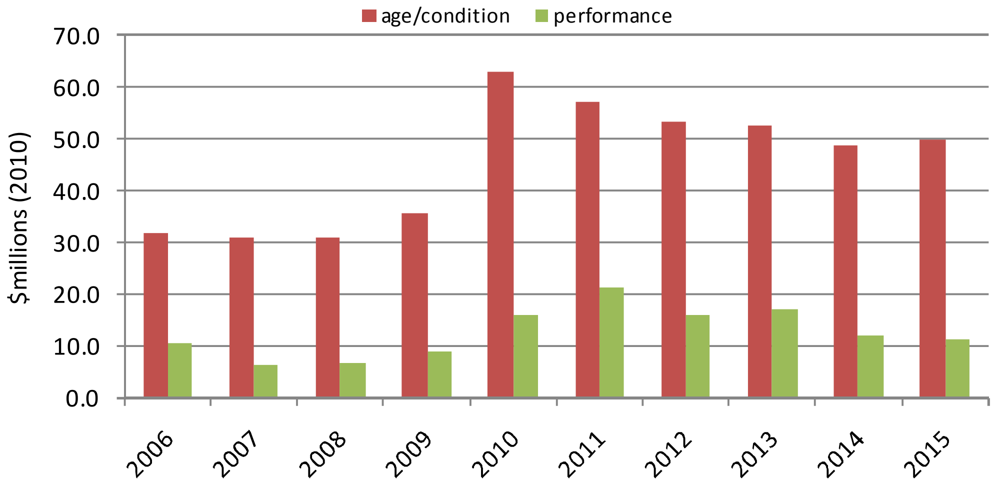
Table 100 - Summary of United Energy RQM expenditure

Average per annum expenditure ($2010)			% increase (from 2006-2008)	
2006-2008	2009-2010	2011-2012	2009-2010	2011-2015
39.0	61.5	67.8	58%	74%

As indicated in Table 100, United Energy is proposing a significant increase in RQM expenditure from 2010. The increase is mainly driven by two factors: increased age/condition related asset replacement; and the need for a number of performance related programs to maintain reliability and quality to the target levels. United Energy considers that the additional performance works are required due to two factors: the degradation expected in the next period through climate change and degradation in asset failure rates that have occurred historically.

The breakdown of expenditure into the age/condition and performance drivers is shown in Figure 119. This shows a large step increase in 2010 with expenditure slowly reducing after that date.

Figure 119 - United Energy RQM expenditure profile



The breakdown of the 2011-2015 RQM expenditure into United Energy's activity codes is shown in Table 101. These activity codes are ranked in terms of significance, based upon the proportion of total RQM expenditure.

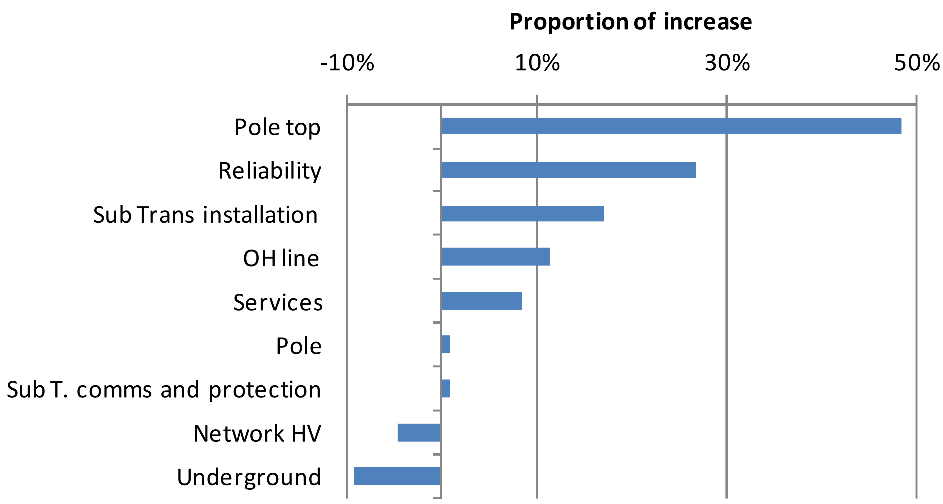
Table 101 - Activity Code summary

Activity Code	Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
	2006-08	2009-10	2011-15		90-10	11-15
Pole top	5.5	8.7	19.4	29%	58%	254%
Reliability	7.9	12.3	15.6	23%	57%	99%
Services	5.7	9.0	8.2	12%	59%	43%
Sub T installation	1.9	3.0	6.8	10%	59%	265%
Sub T. comms and protection	4.5	7.0	4.7	7%	58%	5%
Network HV	5.9	9.4	4.6	7%	58%	-22%
OH line	0.2	0.4	3.5	5%	58%	1369%
Pole	2.6	4.1	2.8	4%	58%	10%
Underground	4.9	7.7	2.2	3%	57%	-55%
Total	**39.0**	**61.5**	**67.8**	**100%**	**58%**	**74%**

It is important to note that Nuttall Consulting understands that United Energy developed the 2009 and 2010 forecasts by scaling the average of the 2006 to 2008: 2009 being approximately 114% of the average and 2010 being 200%. As such, these years may not be a reliable indicator of United Energy's expectation of the trend in the last two years of the current period for individual activity codes.

The breakdown of the proposed increase in expenditure for the next period (compared to the average of 2006-2008) into activity codes is shown in Figure 120. This illustrates that the expenditure on pole top structures is by far the most significant contributor to the proposed increase. The activity codes associated with maintaining reliability, sub transmission installations (i.e. zone substation primary plant), and overhead lines are also contributing a significant proportion to the proposed increase.

Figure 120 - United Energy activity code proportion of increase



In the review of expenditure in the individual activity codes that follows, the expenditure profiles will be considered from a "business as usual" perspective. As such, it will be assumed that climate change and the need to allow for performance degradation are no more significant than the business has faced in its recent history. This matter will be addressed further in the summarising section.

It is also worth noting that for a number of asset types, United Energy has used a proprietary age based replacement model to develop the volume forecasts. This model is similar in philosophy to the repex model discussed here. However, it uses a deterministic replacement life and condition assumptions to adjust the anticipated life of assets. The model had been developed for United Energy by PB Associates for the previous revenue review. It is also based on the model that the ESC used in its 2001 EDPR.

United Energy has updated this model with revised input data for its model exercise for this revenue proposal. In the discussions that follow, this model will be called the PB replacement model.

Finally, a number of activity codes also have an element of the Environmental, Safety and Legal expenditure (ESL) allocated to them. This will be indicated when relevant, but the ESL portion will not be discussed here.

10.3.2 Pole top structures

Activity code and expenditure summary

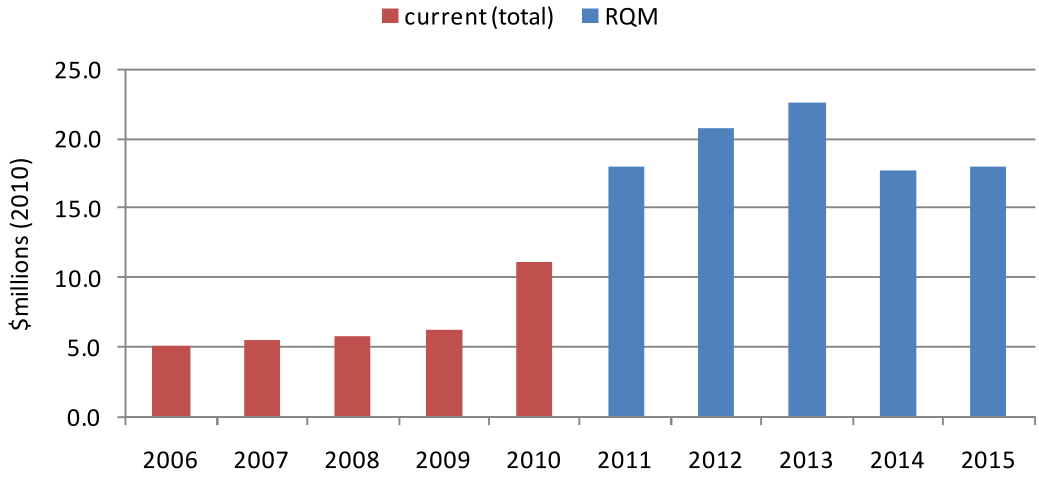
The pole top structure activity code covers the age/condition based replacement of these assets i.e. cross arms, insulators, etc.

Table 102 and Figure 121 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents 29% of the total RQM expenditure in the next period, with expenditure forecast to step up significantly in 2011 and then increase in a sawtooth pattern.

Table 102 - Overview of expenditure for pole top structure replacements

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
5.5	8.7	19.4	29%	58%	254%

Figure 121 - Expenditure profile for pole top structure replacements



Forecasting methodology and rationale

The United Energy forecast is mainly based upon two cross arm replacement programs. The first is related to the condition based replacement of cross arms determined via the cyclical inspection program. The second program relates to cross-arm replacements to mitigate pole top fires. This is an ongoing program and relates to the replacement of cross-arms in locations that are identified as having a history of pole top fires. The scale of this program is not clear from the United Energy documentation.

United Energy has used the PB replacement model to forecast the replacement quantities for cross arms. The documentation indicates that the output of the model forecast a large step increase, which was then manually smoothed by United Energy.

The other main element of this category is an insulator replacement program. This represents approximately 10% of the expenditure. The methodology to estimate this amount is not clear, but does appear to be based on an ongoing replacement program.

Nuttall Consulting views

Given these programs appear to be ongoing, or at least the risks associated with these programs should not be changing significantly from the current period to the next, then it is not clear why such a significant step increase is justified in 2011.

United Energy considers the forecast numbers are in line with recent historical notification rates and the existing backlog of replacements, which is above the annual notification rate. United Energy also considers that the life used in the PB model is equivalent to the average age of recently replaced cross arms, and has presented analysis to demonstrate this.

Nuttall Consulting is not in a position to dispute this information; however, in the absence of information to the contrary, it has to be assumed that the levels of backlog are being prudently managed, and as such, there is not a pressing need to have a step change in the cross arm replacement expenditure in 2011 due to this issue. With regard to the age of the recently replaced cross arms, United Energy's analysis may be correct; however, due to the sample size compared to the population size, this does not mean that the average age can be considered representative of the average life.

Finally, with regard to the pole fire mitigation program, the scale of this program and the approach to estimate the quantities are not clear from the United Energy documentation. It is understood that this program is relatively new. Nonetheless, the risks associated with this program are not new, and it would be expected that the highest priority areas would have been addressed in the current period. As such, in the absence of detailed information to justify the scale of this program in the next period, we do not consider that United Energy has demonstrated this program will result in a major increase in expenditure.

Based upon the above, Nuttall Consulting considers it is reasonable to assume that the pole top forecast should be based upon the historical trend with some allowance for the aging of the network.

10.3.3 Zone substation

Activity code and expenditure summary

The zone substation activity code broadly covers the age/condition based replacement of primary plant within the zone substations. A major portion of this expenditure in the next period is due to the proposed replacement of power transformers and circuit breakers.

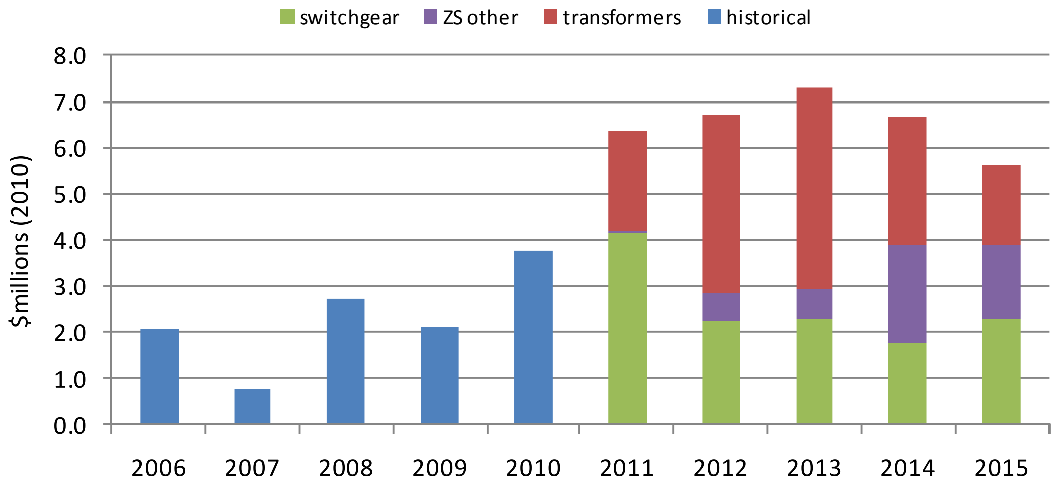
Table 103 and Figure 122 provide an overview of the expenditure in this category. Figure 61 also indicates the proportion of expenditure on the transformer and CB replacements and performance enhancements. The performance enhancements mainly include the upgrading of a transformer in 2012.

This analysis indicates that this activity code represents 19% of the total RQM expenditure in the next period, with expenditure stepping up significantly in 2011. This increase is largely due to increased transformer and HV CB replacement activity, and the performance enhancements.

Table 103 Overview of expenditure for the zone substation plant replacement

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
1.9	3.0	6.8	10%	59%	265%

Figure 122 - Expenditure profile for the zone substation plant replacement



Forecasting methodology and rationale

The forecasts in this category are mainly based on two methodologies relating to transformers and circuit breakers.

For transformers, expected replacement dates are prepared for the fleet based upon condition monitoring information and a condition degradation model. Various condition test results are used to assess the overall condition of the transformers. The primary test information for replacement timing however concerns the condition of the insulation material. The degradation of the condition through time is forecast, based upon its existing condition and loading. This calculation predicts the strength of the insulation material (i.e. in the form if its degree of polymerisation (DP)) and determines the replacement time, based upon standard industry criteria.

For the circuit breakers, a risk assessment has been performed to prioritise circuit breaker types for replacement. This assessment accounts for a number of factors, including the condition, age, performance and operational aspects of the circuit breaker type.

For both transformers and circuit breakers, engineering judgement is then used to develop the replacement program, based upon the other considerations e.g. augmentation requirements and other replacement needs. For the transformers, the issue of noise mitigation appears to be a significant factor that is affecting the proposed timing.

This process has resulted in nine transformers being proposed for replacement in the next period under RQM, compared to one in the current period and zero between 2006 and 2008. With regard to circuit breakers, 113 circuit breakers of various types are planned for replacement at a number of locations through the next period, compared to 56 in the current period and only 18 between 2006 and 2008.

Nuttall Consulting views

Nuttall Consulting has focused its review on the transformer and circuit breaker forecasts, and associated methodology.

For transformers, Nuttall Consulting has reviewed the existing condition information detailed in the asset life cycle plans. Of particular note here is the degree of polymerisation (DP) estimate, via the furan analysis, which indicates that many of the transformers proposed for replacement are at an advance stage of aging (DP estimated value of 475 to 641), but they may still have around 5-10 years remaining life.

Nuttall Consulting requested further information on the transformer model and its calibration/validation. The information provided by United Energy in response to this request[122] indicates that the DP estimate through the model is much lower than the values in the life cycle plan. This indicates DP values in 2009 of between 200 and 260, which would suggest remaining lives below 5 years.

However, these DP values are still much higher than the model DP values for the transformers that are programmed for replacement in this period, which were 60-80 – indicating that the transformers were well past their end of life (end of life being around 200).

This may suggest the model underestimates the remaining life of the transformers, via its prediction of the DP value, by some margin. In support of the model, United Energy has provided other DP estimates it has recently taken, which indicate that the model is closer to these estimates. However, even here, on average, they tend to show that the model may still underestimate the remaining life, but to a lesser degree.

Given this uncertainty as to the accuracy of the model, and the DP estimates that are provided in the life cycle plan, we consider that United Energy has not adequately demonstrated that its proposed large number of transformer replacement are reasonable.

With regard to HV circuit breakers, Nuttall Consulting considers that United Energy's risk assessment is high level, and is not to a level where risks can be readily compared from one element to another. As an example, it is not clear how well the risks deduced for the various factors can be compared against one another. Nuttall Consulting requested that United Energy explains how it has weighted the various factors to achieve comparability, but it appears from the response that this is still work in progress[123]. Furthermore, United Energy has not supplied any additional analysis that supports the scale of its program in the next period.

It is noted that the life cycle plan includes a summary of issues associated with certain switchgear, but this does not provide any real detail of these issues relevant to this review. Examples of relevant detail would include how the issues are being managed into the next period, how the risk will change from this period to the next, available options to mitigate the risk, and the evaluation that supports the proposed timing. Given this lack of justification, it is not clear why the replacement levels cannot be undertaken broadly in line with recent historical levels.

Based upon the above, Nuttall Consulting considers it is reasonable to assume that the zone substation forecast should be based upon the historical trend with some allowance for the aging of the network.

10.3.4 Pole Replacement

Activity code and expenditure summary

[122] Requested in email, dated 2/3/10, response in email, dated 11/3/10
[123] Requested in email, dated 2/3/10, response in email, dated 11/3/10

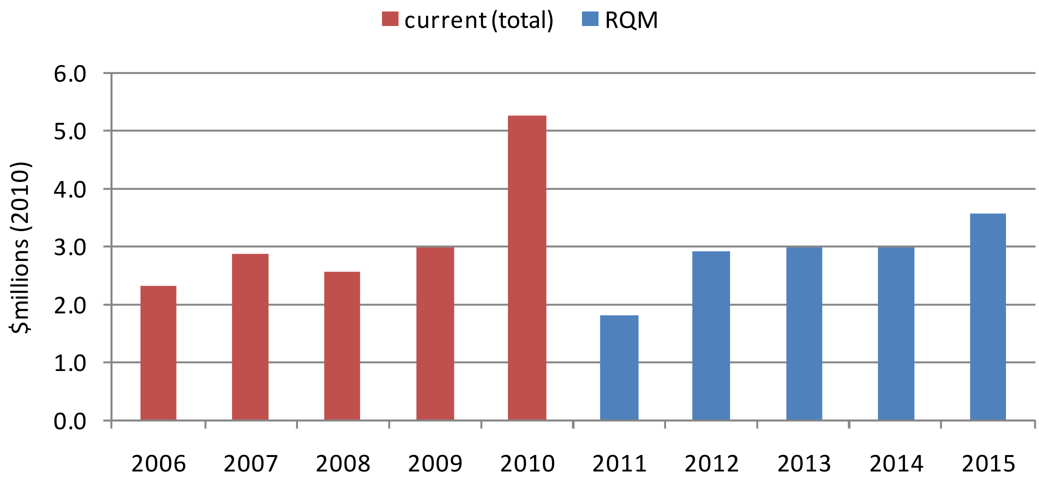
The pole replacement activity code broadly covers the age/condition based replacement of poles, including pole staking.

Table 104 and Figure 123 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents only 4% of the total RQM expenditure in the next period, with expenditure forecasts to remain near the historical trend.

Table 104 Overview of expenditure for pole replacements

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
2.6	4.1	2.8	4%	58%	10%

Figure 123 - Expenditure profile for pole replacements



Forecasting methodology and rationale

Pole replacements (including pole staking) relate to the condition based replacement of poles determined via the cyclical inspection program. United Energy has used the PB replacement model to forecast the replacement quantities for this program.

Nuttall Consulting views

Expenditure on pole replacements appears to be broadly in line with the historical trend. Given the low materiality of this activity code and the modest proposed increase, which is broadly in line with our replacement modelling, we consider that this estimate is reasonable.

10.3.5 Overhead line replacement

Activity code and expenditure summary

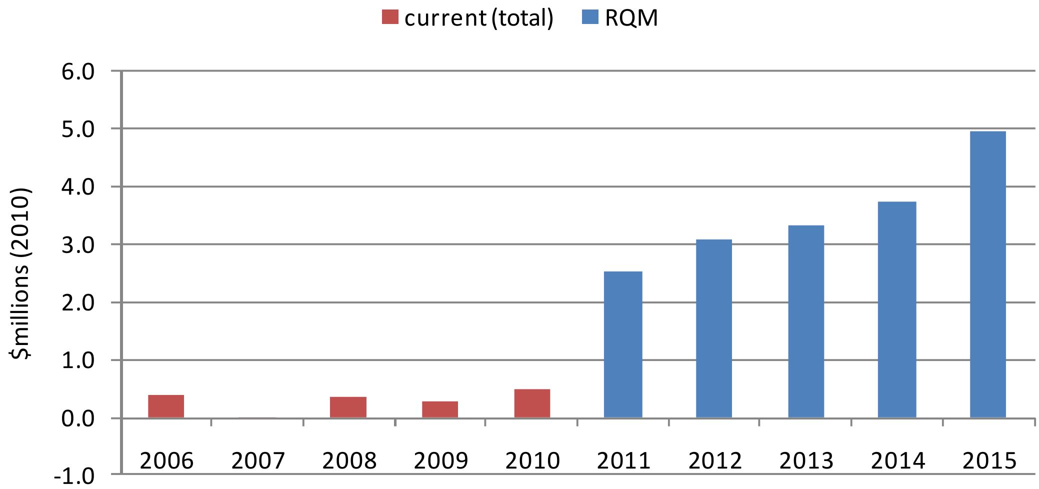
The overhead line activity code covers expenditure on overhead line conductors and associated connecting equipment. This category mainly includes the age/condition based replacement of conductors.

Table 105 and Figure 124 provide an overview of expenditure in this category. This analysis indicates that this activity code represents 5% of the total RQM expenditure in the next period, with expenditure anticipated to significantly increase from historical levels in 2011.

Table 105 - Overview of expenditure for overhead line replacement

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
0.2	0.4	3.5	5%	58%	1369%

Figure 124 - Expenditure profile for overhead line replacement



Forecasting methodology and rationale

United Energy has forecast the quantity based upon the PB replacement model. The PB model output has been manually smoothed.

The main factor associated with the increase in expenditure appears to be new aerial inspection techniques, which are anticipated to result in higher volumes of conductor replacement.

It is also noted that there is a program to replace aged copper and steel conductors, but the historical scale of this program is not clear. It does appear that the forecast volumes for this program have been produced through the PB model.

Nuttall Consulting views

Based upon the volume information provided by United Energy, it appears that United Energy is assuming that the combination of the aging of the network, its new inspection techniques, and its steel/copper replacement program, will result in a 600% increase in conductor replacement levels from the 2005 level, with the majority of this being a step in 2011. However, at this stage, it is not clear to us if this can be considered reasonable. United Energy has provided no quantitative analysis that justifies this scale of increase (i.e. that the risks out-weigh the costs of the program). Given that this program has not been introduced earlier, it seems reasonable to assume that United Energy considered the risks manageable, and as such, a significant increase in expenditure may not result.

Based upon the above, we see no reason to allow more than the average recent historical level with some allowance for an aging population.

10.3.6 Underground cable

Activity code and expenditure summary

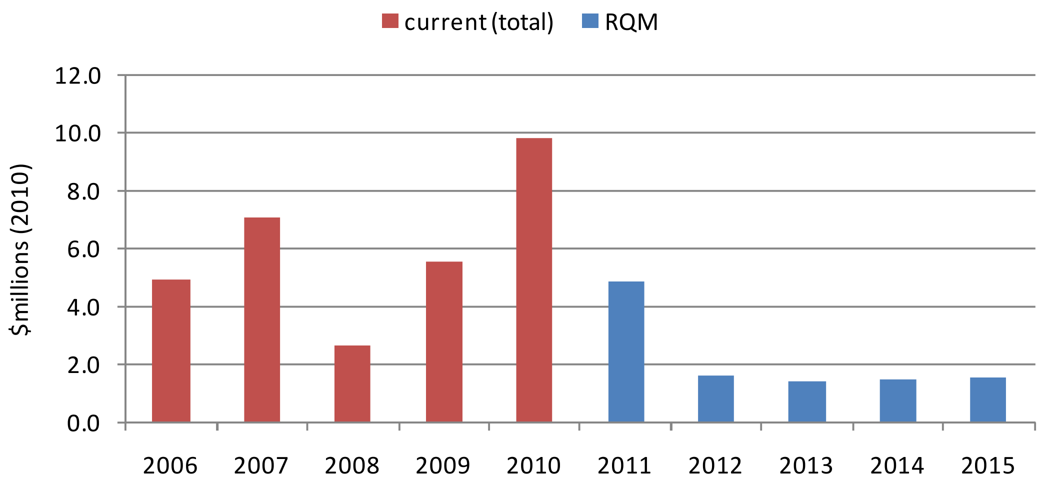
The underground cable activity code broadly covers the age/condition based replacement of underground cables and associated underground equipment (e.g. joints, terminations, link boxes etc).

Table 106 and Figure 125 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents only 3% of the total RQM expenditure in the next period, with expenditure anticipated to significantly reduce from historical levels in 2012.

Table 106 - Overview of expenditure for underground cable replacement

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
4.9	7.7	2.2	3%	57%	-55%

Figure 125 - Expenditure profile for underground cable replacement



Forecasting methodology and rationale

The United Energy information indicates that the forecasts for the cable replacements are based upon the PB replacement model, and joint and terminations are based upon historical failure rates.

Nuttall Consulting views

Given that expenditure on underground cable replacements appears to be reducing in the next period, this asset type has not been reviewed in any detail. Nuttall Consulting considers that this estimate appears reasonable.

10.3.7 Reliability

Activity code and expenditure summary

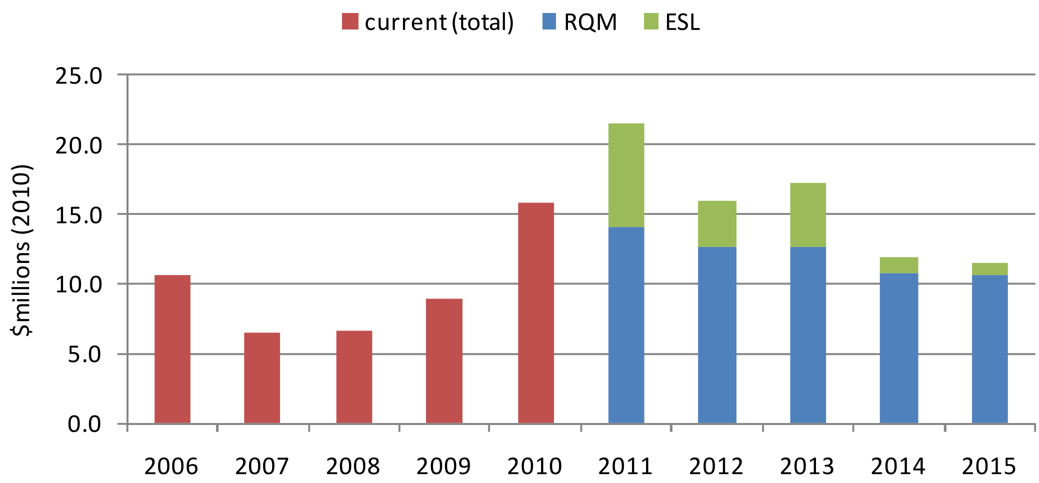
The reliability activity code broadly covers works to address reliability and quality of supply issues on the network. This activity code includes an element of work that is allocated to the ESL expenditure category.

Table 107 and Figure 126 provide an overview of the expenditure in this category, indicating the portion in the ESL category. This analysis indicates that this activity code represents only 23% of the total RQM expenditure in the next period, with forecast expenditure proposed to increase significantly in 2011 and then ramp down slightly.

Table 107 - Overview of expenditure for reliability

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
7.9	12.3	15.6	23%	57%	99%

Figure 126 - Expenditure profile for reliability



Forecasting methodology and rationale

The United Energy documentation indicates that the reliability forecasts are based upon a range of assumed projects to maintain reliability and quality of supply at the target level. A large portion of this work covers the installation of HV ABC (presumable for the replacement of bare conductors for reliability and fire mitigation reasons) and the installation of harmonic filters for power quality reasons.

Nuttall Consulting views

The detailed justification for the projects in this category is not clear from the United Energy documentation, particularly with respect to their impact on reliability in the context of the significant increases in expenditure proposed elsewhere. However, assuming that the matters affecting reliability in the current period are largely similar to those in the next (i.e. “business as usual”) and in the absence of a more detailed and quantitative justification for the expenditure increase, we consider that an allowance based upon the historical level is reasonable.

The matter of performance related expenditure to maintain reliability will be discussed further in the summarising section.

10.3.8 Network HV

Activity code and expenditure summary

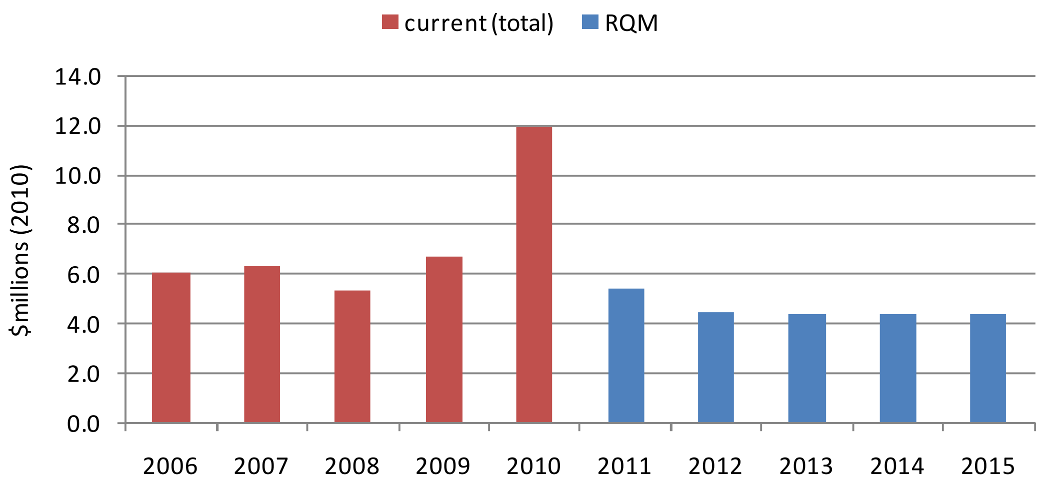
The network HV activity code broadly covers the age/condition based replacement of HV and LV network equipment covering distribution transformers and HV switchgear.

Table 108 and Figure 127 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents 7% of the total RQM expenditure in the next period, with expenditure anticipated to trend down slightly from historical levels.

Table 108 - Overview of expenditure for the network HV replacement

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
5.9	9.4	4.6	7%	58%	-22%

Figure 127 - Expenditure profile for the network HV replacement



Forecasting methodology and rationale

The United Energy documentation indicates that the forecasts in this category are based upon a number of methods including:

- assumed failure rates for overhead line switchgear (i.e. air break switches), based upon a new proposed inspection program
- the PB model for distribution transformer replacement quantities
- knowledge and engineering judgement to estimate distribution substation switchgear replacements, based upon a new proposed inspection manual.

Nuttall Consulting views

Given that forecast expenditure on the network HV category is in line with the historical trend, this asset type has not been investigated in any detail. Nuttall Consulting considers that this estimate is reasonable.

10.3.9 Protection

Activity code and expenditure summary

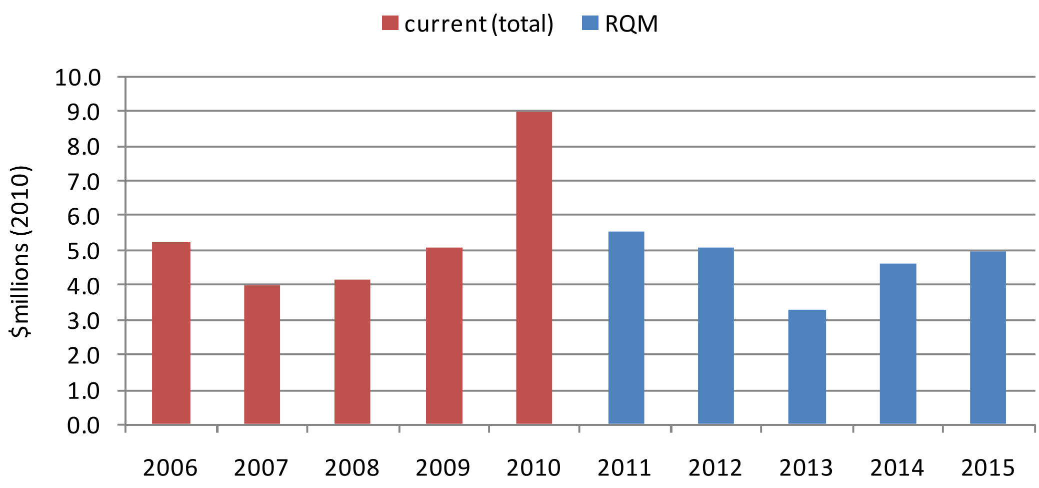
The protection activity code largely covers the age/condition based replacement of protection relays and some other secondary systems.

Table 109 and Figure 128 provide an overview of the expenditure in this category. This analysis indicates that this activity code represents 7% of the total RQM expenditure in the next period, with forecast expenditure at similar levels compared to average historical levels.

Table 109 - Overview of expenditure for protection replacements

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
4.5	7.0	4.7	7%	58%	5%

Figure 128 - Expenditure profile for protection replacements



Forecasting methodology and rationale

The United Energy documents indicate that the relay replacement programs have been forecast based upon installation age. It is also noted that DC systems are also forecast based upon installation age and communications equipment is based upon the known number of obsolete RTU's. In all cases, however the detail of this methodology is not clear.

Nuttall Consulting views

Although the methodology for producing forecasts is not clear, given that expenditure is similar to the historical trend, Nuttall Consulting does not consider the estimate is unreasonable. As such, we have not investigated this category in any detail.

10.3.10 Services

Activity code and expenditure summary

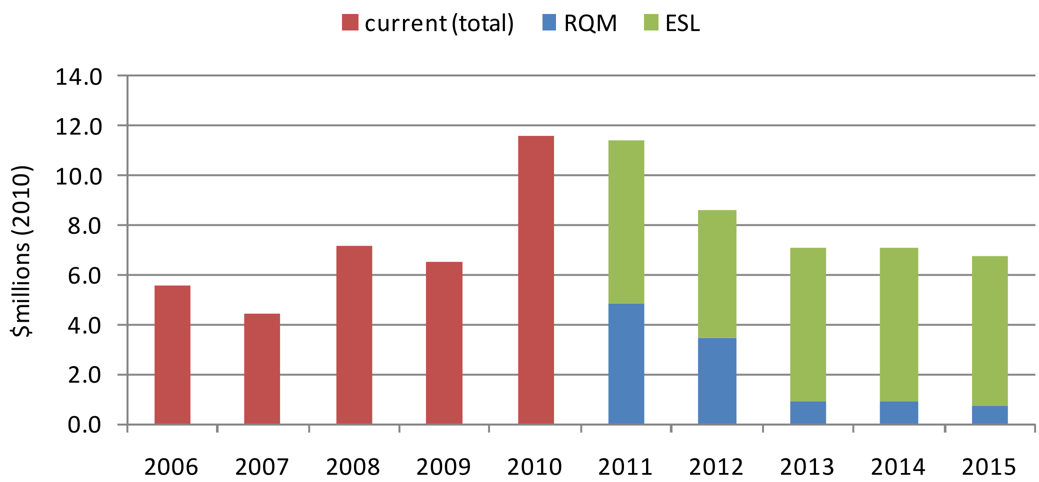
The service activity codes broadly cover the age/condition based replacement of customer service lines and cables. A large portion of this activity code is associated with a safety related ongoing program to replace neutral screen services, which is allocated to the ESL category.

Table 110 and Figure 129 provide an overview of the expenditure in this category, indicating the proportion in the ESL category. This analysis shows that this activity code represents 12% of the total RQM expenditure in the next period, with RQM expenditure anticipated to trend down in the next period.

Table 110 - Overview of expenditure for the service replacements

Average per annum ($m 2010)			Proportion of 2011-2015	% increase from 2006-08	
2006-08	2009-10	2011-15		2009-10	2011-15
5.7	9.0	8.2	12%	59%	43%

Figure 129 - Expenditure profile for the service replacements



Forecasting methodology and rationale

It is noted that the major factor associated with the forecast increase in expenditure in this category relates to the neutral screen services replacement program, which is in the ESL category.

The majority of the expenditure in the RQM category is associated with replacements due to a height rectification program. This is an ongoing program, with the majority of work being programmed between 2008 and 2012. The United Energy documentation indicates that the forecast is based upon known works that are part of its Electrical Safety management plan, with the higher risk works prioritised. This work appears to be a large portion of the expenditure in the current period.

Nuttall Consulting views

Given that the RQM portion of the services expenditure appears to be in accordance with the historical profile for these programs and is forecast to trend down significantly in the next period, Nuttall Consulting does not consider the estimate is unreasonable. As such, we have not investigated this category in any detail.

10.3.11 Overall findings

The above has shown that the proposed increase in RQM expenditure in the next period is mainly driven by two factors: increased age/condition related asset replacement and the need for a number of performance related programs to maintain reliability and quality to the target levels. United Energy considers that the additional performance works are required due to two factors: the degradation expected in the next period through climate change and degradation in asset failure rates that have occurred historically.

With regard to the increase driven by climate change, the AER has instructed Nuttall Consulting that it does not consider that United Energy's approach is appropriate, and as such, the AER intends to reject claims for expenditure increases based upon climate change, including those in the RQM category.

With regard to other performance enhancement projects, United Energy has not provided detailed evaluations of the changes to reliability due to its proposed program. Furthermore, based upon our "business as usual" approach, it is not clear why an allowance based upon increases to allow for the aging of the network plus an allowance for the historical level of reliability/quality related expenditure is not appropriate.

With regard to the age/condition based replacements, it is obvious that United Energy is proposing to undertake increased levels of replacement and introduce a number of new pre-emptive replacement programs. However, United Energy has not provided any economic analysis that demonstrates that the increases are prudent and efficient. It is also worth noting that, as the aim of some of the pre-emptive programs is to improve performance, the STPIS may be an appropriate mechanism for funding such changes.

It is noted that in some cases, a replacement model has been used to determine quantities for replacement (the PB model). However, in the cases where this appears to be forecasting replacement level much higher than existing levels, United Energy's justifications for the increase do not appear to be reasonable.

For other assets, the basis for the increase appears to be due to known issues and associated risks, which are discussed in the asset "life cycle management plans". However, in these cases, we do not doubt that the issues and associated risks exist, but it has not been demonstrated how United Energy is presently managing these matters – presumably in a prudent and efficient manner – and how the risks will change over time. As such, it is not evident that the scale of the increase is required.

Based upon our review, we do not consider that United Energy has adequately demonstrated that the increases are prudent and efficient. We consider that the RQM allowance should be based upon the recent historical levels of RQM expenditure with some additional allowance for the aging of the network.

The recommended RQM expenditure is shown in Table 111. The basis for these recommendations is indicated in Table 112.

It is important to note that this recommendation must be considered in the broader context of the overall capex. We would fully expect that at the activity code level, actual expenditure may differ considerably as circumstances change and the full capital governance process is applied.

It is also important to note that this recommendation should be considered as an estimate only. The AER may need to make further adjustments to allow for its findings on the other matters, such as overhead and labour and material escalation, which are not accurately allowed for here.

Table 111 – United Energy RQM capex recommendation

	$thousands (2010)				
Activity code	2011	2012	2013	2014	2015
Proposed	62,802	60,170	58,672	52,943	54,101
Recommended	**35,250**	**31,657**	**28,496**	**31,234**	**33,464**

Table 112 – United Energy activity code based adjustments

Activity code	Nuttall Consulting view
RQM	Rejected - allowance based upon average 2006-2008, with increase based upon repex model findings
Sub T. comms and protection replacement	Accepted
Network HV replacement	Accepted
Services replacement	Accepted
OH line replacement	Rejected - allowance based upon average 2006-2008, with increase based upon repex model findings
Pole replacement	Accepted
Sub T installation replacement	Rejected - allowance based upon average 2006-2008, with increase based upon repex model findings
UG replacement	Accepted
Pole top replacement	Rejected - allowance based upon average 2006-2008, with increase based upon repex model findings

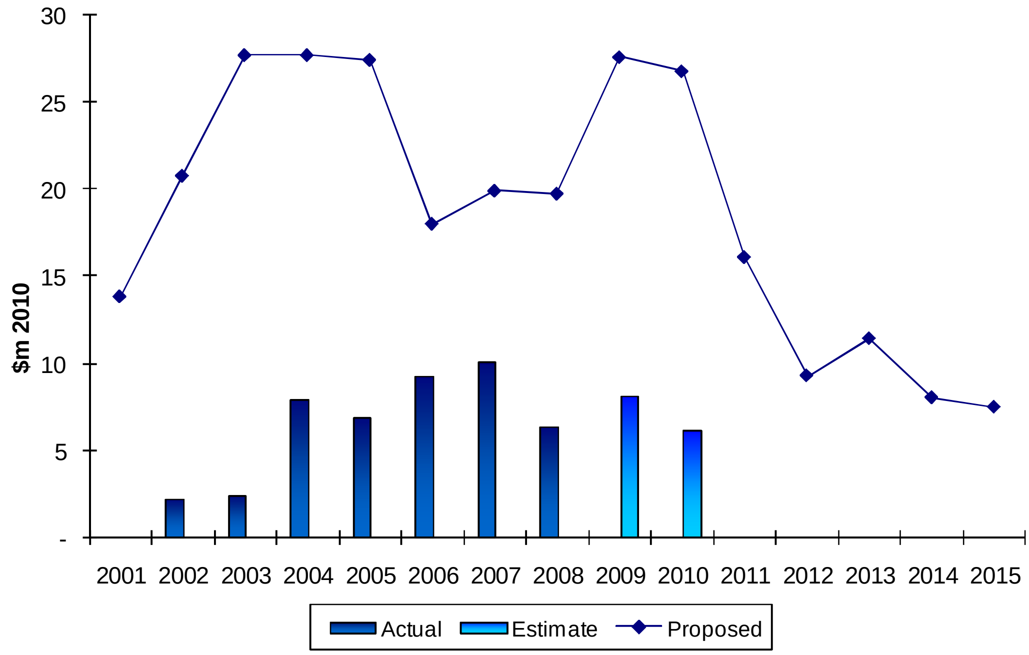
10.4 Environmental, Safety and Legal

United Energy is proposing an increase of over 22% in Environmental, Safety and Legal capex for the next Regulatory Control Period when compared against actual expenditure in the current Regulatory Control Period. United Energy estimates that its' Environmental, Safety and Legal capital expenditure for the 2006-10 regulatory control period will be $39.9 million. It is forecasting that this will increase to $52.2 million in the 2011-15 regulatory control period.

For the 2006 EDPR, United Energy proposed Environmental, Safety and Legal expenditure of $112.0 million. The resultant actual expenditure for this period is forecast to be $39.9 million[124].

The following chart provides a summary of Environmental, Safety and Legal capex for United Energy.

Figure 130 - United Energy Environmental, Safety and Legal capex



United Energy states that the increasing[125] expenditure profile forecast for the next Regulatory Control Period is largely due to two major programs:

- The replacement of neutral-screened overhead services.
- The installation of ground fault neutralisers ("GFN") in zone substations that serve high bushfire risk areas.

The review of Victorian DNSP proposed expenditures has been undertaken on the assumption that existing expenditure levels are efficient. The United Energy arguments to increase these levels to account for neutral screen services and ground fault neutralisers are each assessed below.

[124] Including 2009 and 2010 estimates.
[125] Based on current expenditure levels.

10.4.1 Neutral screen services

United Energy has a significant population of this type of service cable.

The electricity distribution industry in Victoria has been aware for many years that neutral screen services have a failure mode that can result in minor or in some rare cases major electrical shock to the public. A number of Victorian DNSPs identified the need to replace these assets as early as 2004 based on the risk of neutral failures.

In 2004, United Energy stated that "The 2001 Determination provided a fund to enable Distributors to undertake a range of compliance related programs including ... Testing of LV neutrals".[126]

In December 2001, United Energy *"initiated a project to implement an Electricity Safety Management Scheme (ESMS). As a result of the work it was identified that some network assets were non-compliant with respect to the Network Asset Regulations 1999. In co-operation with the Office of Chief Electrical Inspector (OCEI), a program was undertaken to develop and implement a set of maintenance plans to rectify the non-compliant items, or alternatively, to seek an exemption for the non-compliance in accordance with the Network Asset Regulations 1999"*[127]. This document identified the United Energy was required under regulation 27(2) to implement a testing program for the neutral conductor of service cables to approximately 460,000 overhead and 80,000 underground connections.

This document also identified that a detailed risk assessment was undertaken and that this methodology enabled United Energy to categorise the non-compliant assets into various risk levels and maintenance priorities so that resources are directed towards the highest priority item first, followed then by the next highest priority risks.

In its current proposal, United Energy states that the replacement program was originally a 10-year replacement program and that to better manage this public safety risk, a five-year program is now proposed to replace the total population of this service cable type. However, United Energy is not proposing to commence this accelerated program until 2011 suggesting that they consider it prudent to manage the existing level of risk until that time.

To satisfy the Electricity Safety (Network Assets) Regulations 1999 United Energy determined that all overhead services needed to be measured for neutral to earth resistance by the end of 2009[128]. United Energy has reportedly[129] halted this program for the duration of the AMI roll out. This deferral again suggests that United Energy consider the risks to be within an acceptable range.

The industry, and United Energy specifically, have been aware of issues relating to neutral screen services for a long time and have had dedicated testing and replacement programs in place for nearly a decade. United Energy is not proposing to commence the accelerated replacement program until 2011. United Energy has not demonstrated any changed

[126] Electricity Network Asset Management Plan 2005-2010 - Document No UE4362, 1 October 2004.

[127] Electricity Safety Maintenance Plans For Overhead Service Heights Pole Mounted Substation Clearances Neutral Testing Program And The Management of Shallow Underground Cables - DOCUMENT No. UE 4200-30, 23 April 2003.

[128] LV Overhead Services Lifecycle Management Plan, Document No.: UE 4356 – 117, 10/09/2009.

[129] Ibid

regulation or business driver that suggests the neutral screen replacement program should be materially different from current adopted practices.

10.4.2 Ground fault neutralisers

In 2009, United Energy initiated a trial of resonant earthing at the Frankston South zone substation. From the data obtained from this trial, and international trials, it was recommended to introduce a program to install resonant earthing at every distribution zone substation on the United Energy network.

Resonant earthing systems (also known as Ground Fault Neutralisers or GFNs) have the capacity to reduce an earth fault current to such a low level that transient earth faults become self clearing without the need to disconnect customers. As a result of this significant reduction in fault current, the risk of fire ignition is also substantially reduced.

A GFN has been installed in Frankston South zone substation and its in-service performance in reducing fault energy and reducing voltage quality dips has been excellent. The further installation of GFNs will serve to materially reduce the risk of fire starts in United Energy's fire risk areas.

In their GFN strategy, United Energy states that "o*ver the next 10 years, the average cost to install resonant earthing and upgrade SWER on the United Energy network is approximately $1.8M per zone substation. The project is financially beneficial with a payback in well less than 3 years. If additional benefits were quantified in this report, it is expected the benefits would increase even further*"[130].

The United Energy business case for the Frankston South zone substation[131] shows a payback period of 3.4 years and a positive NPV. This document also notes that the Frankston South location is considered to be the most difficult location site.

On this basis, it would not appear reasonable to allow additional expenditure funding for the GFN roll out as the benefits outweigh the costs and the costs can be fully recovered within the regulatory period.

United Energy has not identified the additional benefits referred to in the above documentation and has not quantified the reduction in fire ignition risk. These factors should be quantified along with any outworkings from the bushfire royal commission for any additional expenditure to be considered.

10.4.3 Environmental, Safety and Legal summary

The review of Victorian DNSP proposed expenditures has been undertaken on the assumption that existing expenditure levels are efficient. United Energy has not provided evidence to substantiate an increase in the overall level of Environmental, Safety and Legal capex. On this basis it is reasonable to recommend that the existing levels of Environmental, Safety and Legal capex are continued into the next control period.

[130] UED 2009 Strategy - Ground Fault Neutraliser (GFN) and Single Wire Earth Return (SWER), 23 November 2003.

[131] Addendum to Business Case United Energy Trial Installation of Petersen Coil at Frankston South Zone substation - UEPQ-08-902, February 2010.

Table 113 - Recommended United Energy Environmental, Safety and Legal capex

United Energy Environmental, Safety and Legal	Costs (2010 $M) 2011	2012	2013	2014	2015
Recommended Expenditure	7.219	7.219	7.219	7.219	7.219

The recommended Environmental, Safety and Legal capex for United Energy is based on the average actual expenditures incurred in the previous 5 years exclusive of indexation and escalation.

10.5 SCADA and Network Control

United Energy's proposed expenditure in the "SCADA and Network Control" category represents only a very small percentage (<1%) of the total net capex in the next period, and only a very small portion of the proposed expenditure increase (2%).

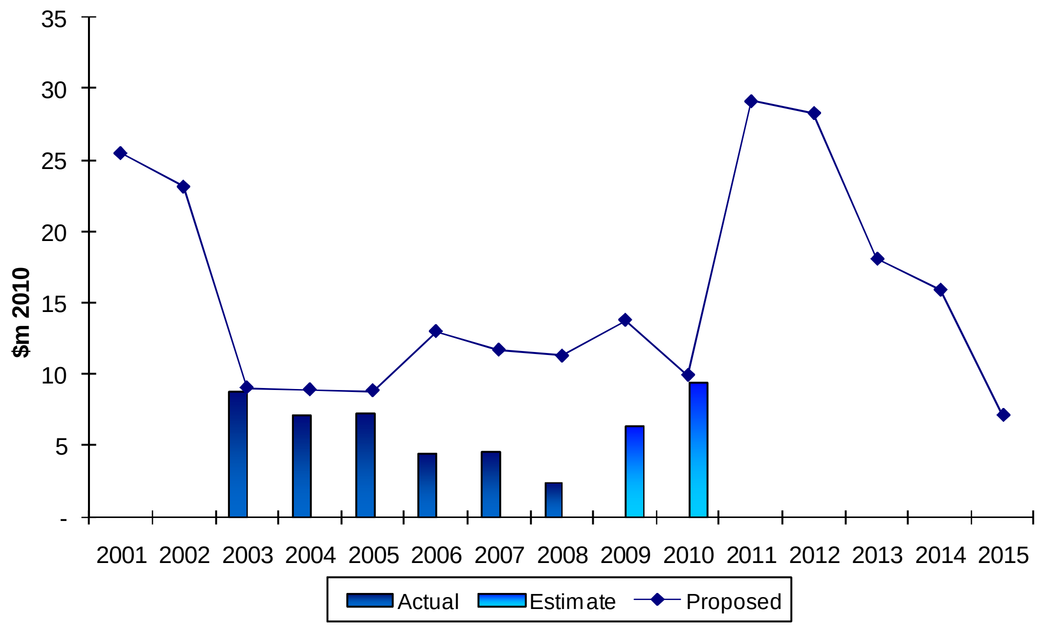
Given the low significance of this expenditure, it was agreed with the AER that Nuttall Consulting would not undertake a detailed review of this category.

10.6 Non-network general – IT

United Energy submitted IT capital expenditure of $98.5 million over the forthcoming regulatory control period, which represents an increase of 280% in capital expenditure from audited historical expenditure ($34.8 million). Major proposed IT capital projects include ERP –SAP Consolidation, CIS Migration of Legacy Meters, SCADA Replacement, DMS Upgrade, Identity and Access Management System, Market System Upgrade (CATS/B2B), System Rationalisation and Consolidation, Enterprise Content Management, Management (CMS) and the fit out of New Production & Disaster Recovery Data Centres.

During 2004-2008, United Energy underspent their IT capital expenditure from a proposed of $53.6 million to actual audited spending of $34.6 million.

Figure 131 - United Energy proposed vs actual IT capex



United Energy currently has four data centres, two which are recent additions funded under AMI. The long term plan is to consolidate into 2 data centres and United Energy have submitted capital costs to complete as part of their submission.. United Energy stated that capacity planning was a significant challenge, but made no mention of adopting a flexible architecture to deal with future requirements. In the interview, United Energy stated there significant “change fatigue” within the organisation given the amount of change that has historically occurred.

There is no IT strategy in place today, but one is currently being developed. The lack of an IT strategy was a significant issue for the review, and we were concerned as to how IT designs may have to be reworked as the strategy developed; possibly incurring delays and additional costs. Nevertheless, United Energy have chosen a new independent SAP based solution for the AMI platform, intending to leverage it moving forward, with the current SCADA, DMS and SAP systems requiring replacement and integration in the future into this single system.

United Energy are forecasting expenditure of $6 million on IT infrastructure based upon expected growth of 20% per year in the Compute and Storage platform. No details on the current utilisation levels of the current infrastructure were provided and there were no details on any plans to provide increasing efficiency by further adoption of virtualisation.

United Energy IT capital cost expenditure ramps up substantially to around $20 million for three years and then reduces to $15.9 million in 2014 and around $7 million in 2015. This reflects United Energy’s desire to deliver most projects within the first 3 years, including data centres moves and applications upgrades. In our opinion, United Energy have not fully considered the complexity of what they are proposing and the amount of change the business can absorb, given the lack of agility in the IT environment. The organisation has already identified that it is dealing with “Change Fatigue” and the lack of the IT Strategy demonstrates to us a lack of enterprise level planning, that is almost certain to generate additional delays in the future and incur additional costs. We believe it more likely that United Energy will take five years (potentially longer) to complete the projects planned for the first three years and that expenditures in 2014 and 2015 are likely to be deferred or even abandoned for other alternatives. Therefore, we recommend that first three years of capital cost be spread over five years and that the final two years of capital cost not be approved for the next control period.

Table 114 - Recommended United Energy non-network general IT capex

United Energy	Costs (2010 $M)				
Non-network general – IT	2011	2012	2013	2014	2015
Proposed Expenditure	29.1	28.3	18.0	15.9	7.1
Recommended Expenditure	19.7	19.7	19.7	19.7	19.7

10.7 Non-network general - other

United Energy's proposed expenditure in the "non-network general – other" category represents only a small percentage (2%) of the total net capex in the next period, and a negligible portion of the proposed expenditure increase (1%).

Given the low significance of this expenditure, it was agreed with the AER that Nuttall Consulting would not undertake a detailed review of this category.

11 Appendix F – DNSP Capex comparative analysis

This appendix provides a detailed listing of the comparative analysis of NEM DNSP capital expenditure, which is discussed in Section 2.

The charts are grouped as follows:

- state comparisons
- individual DNSP comparisons.

11.1 State comparisons

This section provides state-wide electricity distribution comparative analysis for Victoria, New South Wales and Queensland. These three states were selected for this analysis as they are the largest in Australia and all contain multiple DNSPs.

Figure 132 - Capex per RAB

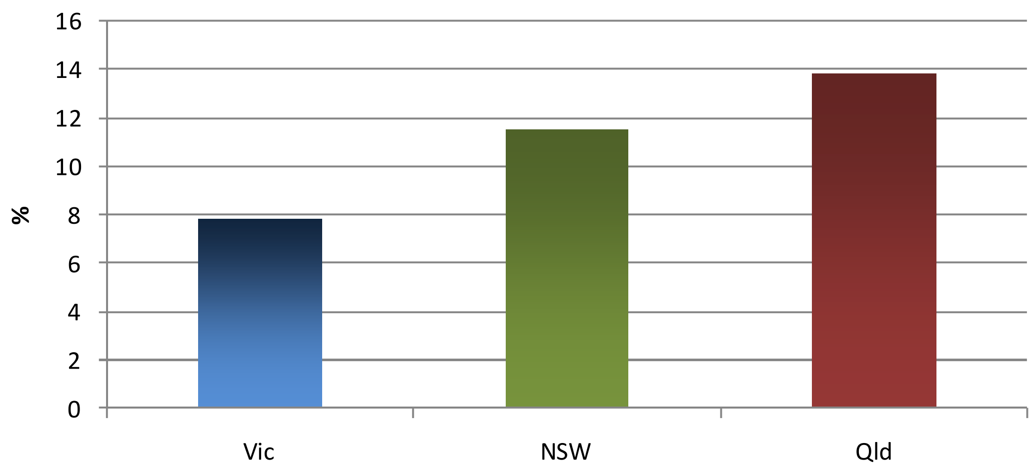


Figure 133 - Capex per Line Length

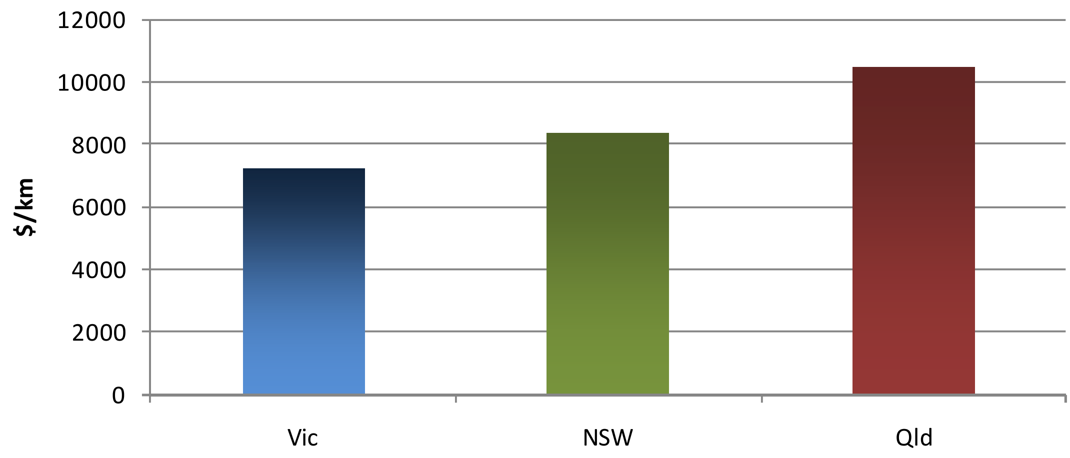


Figure 134 - Capex per Customer

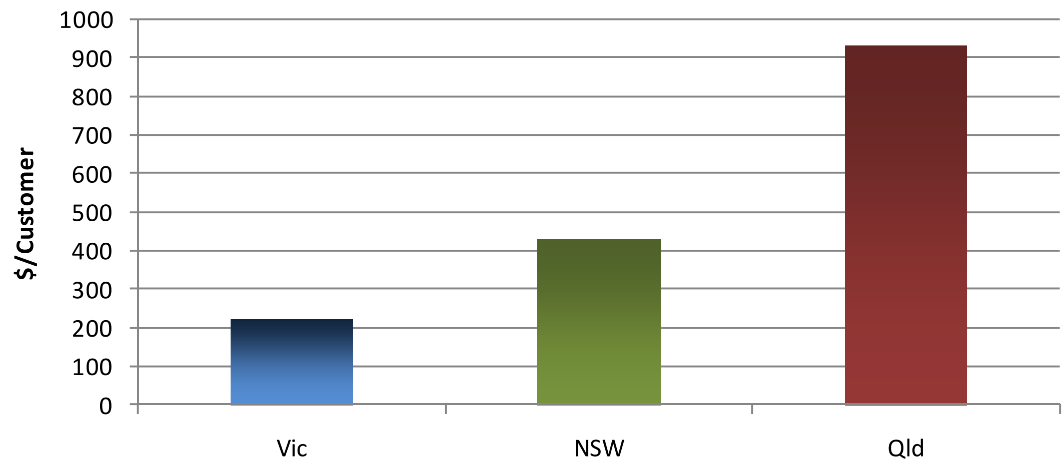


Figure 135 - Capex per Energy Distributed

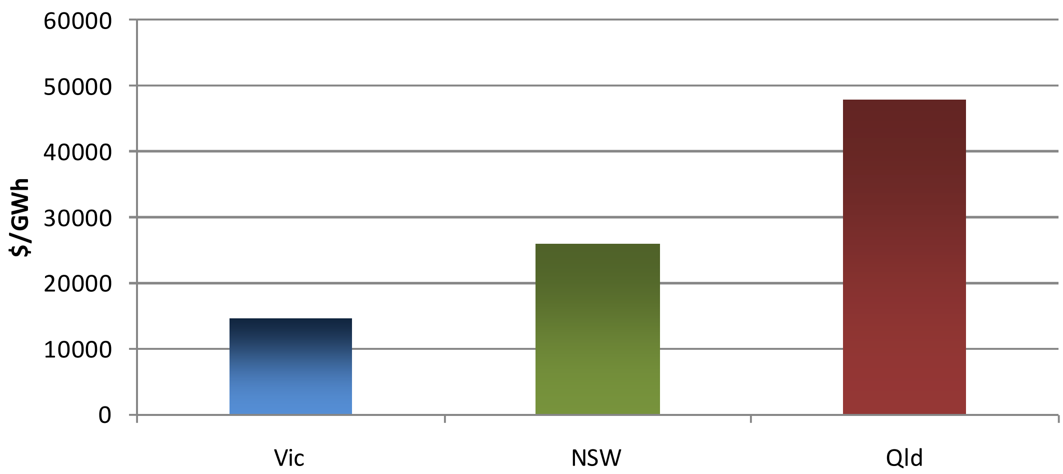
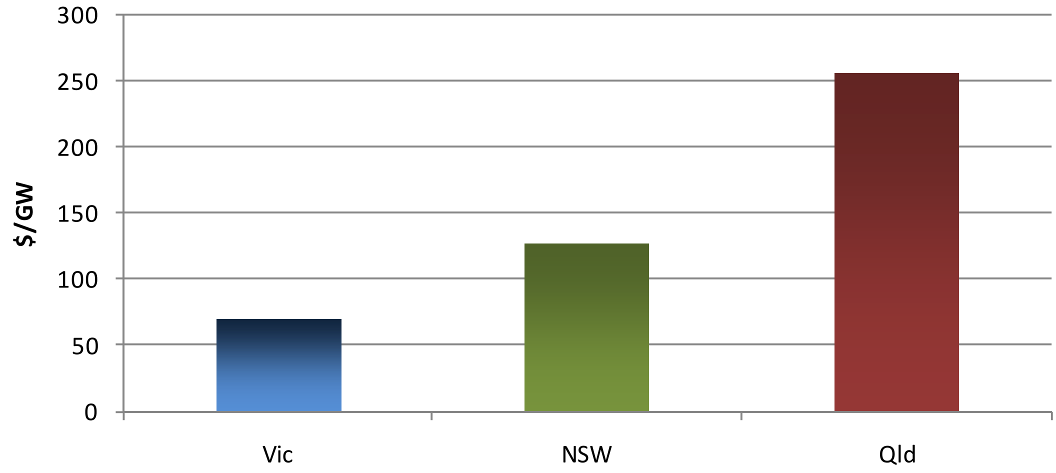


Figure 136 - Capex per Peak Demand



11.2 Individual DNSP comparisons

The charts contained in this section provide comparative analysis information for the Australian National Electricity Market DNSPs. The capex information for each DNSP is based on the average of the previous 5 years of actual capex as reported to the AER.

When comparing capex at an individual company level there are factors that significantly impact expenditure and influence the value of the benchmark. The most significant of these factors is the customer density of the areas serviced by the DNSP. One way of considering the customer density is to take account of the number of customers per km of overhead or underground distribution lines. The following charts use customer density as the X-axis to allow for a visual comparison of the results that takes this factor into account.

The company codes used on each of the charts are as follows:

- 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

Figure 137 - Capex per RAB

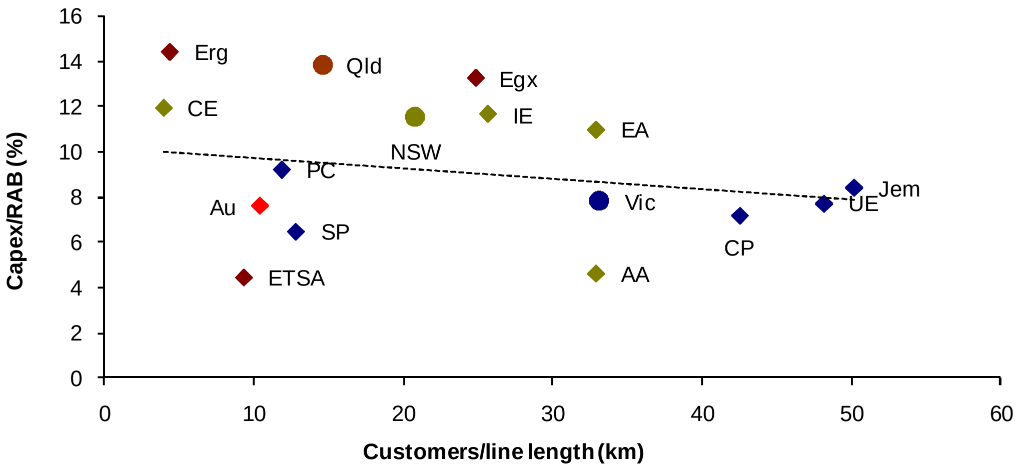


Figure 138 - Capex per Line Length

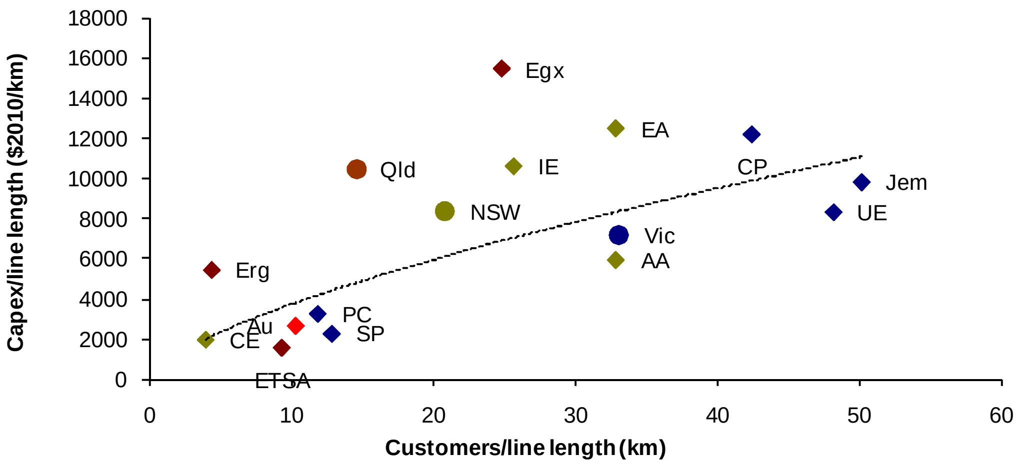


Figure 139 - Capex per Customer

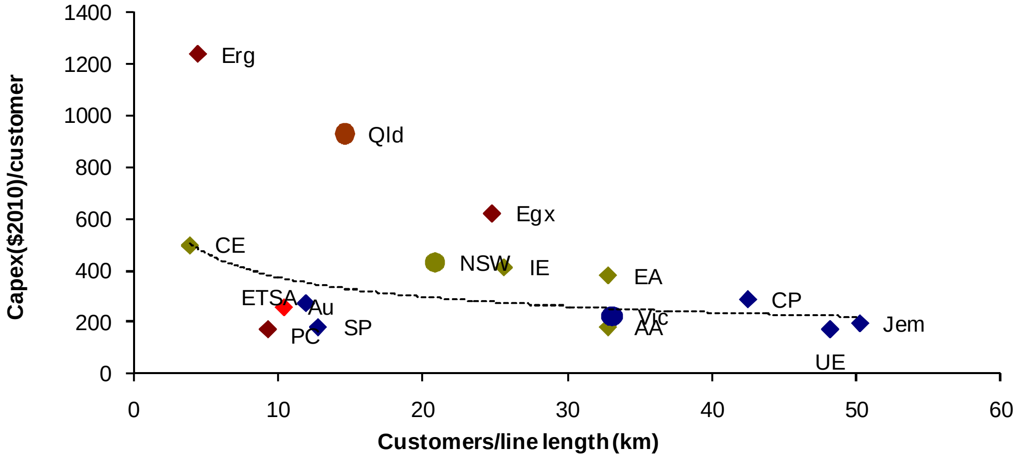


Figure 140 - Capex per Energy Delivered

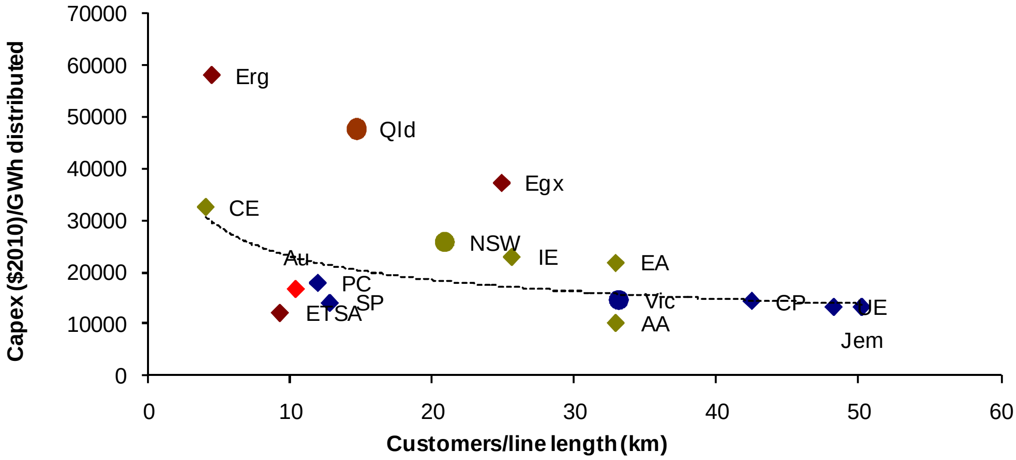
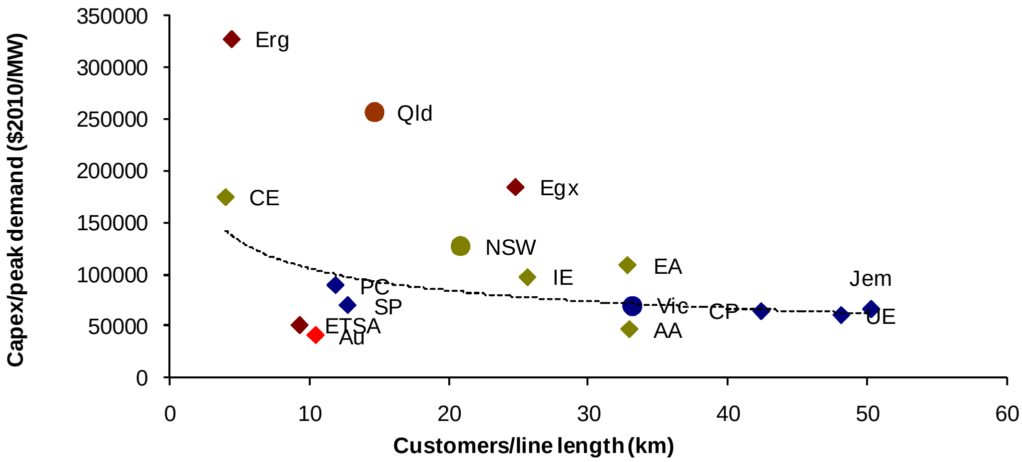


Figure 141 - Capex per Maximum Demand



12 Appendix G - Capital governance review

12.1 Approach to establishing an assessment framework

Nuttall Consulting has undertaken a desktop review of the capital governance practices of the Victorian DNSPs. This review is being carried out in conjunction with a broader review of the capital expenditure proposals submitted by the DNSPs for the next regulatory control period.

12.1.1 Regulatory and legal requirements

The requirements governing capital expenditure practices by a Distribution Network Service Providers (DNSP) can be linked to various aspects of the DNSPs roles, responsibilities and obligations, set out in various regulatory instruments. In the context of this review, this is most notable in:

1. Chapter 6 of the National Electricity Rules (NER)
2. the Victorian Electricity Distribution Code (EDC).

12.1.1.1 Chapter 6 of the National Electricity Rules

Paragraph 6.5.7(c) of Chapter 6 of the NER deals with forecast capital expenditure and requires that[132]:

The AER must accept the forecast of required capital expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast capital expenditure for the regulatory control period reasonably reflects:

1. *the efficient costs of achieving the capital expenditure objectives; and*
2. *the costs that a prudent operator in the circumstances of the relevant Distribution Network Service Provider would require to achieve the capital expenditure objectives; and*
3. *a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.*

Collectively, these requirements are referred to as the *capital expenditure criteria*. The *capital expenditure objectives* are defined at paragraph 6.5.7(a) as follows:

A *building block proposal* must include the total forecast capital expenditure for the relevant *regulatory control period* which the *Distribution Network Service Provider*

[132] Note that the text in these direct quotes from the National Electricity Rules (NER) is reverse italicised, so that NER defined terms appear as non-italicised text in this report.

considers is required in order to achieve each of the following (the capital expenditure objectives):

1. *meet or manage the expected demand for standard control services over that period;*
2. *comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;*
3. *maintain the quality, reliability and security of supply of standard control services;*
4. *maintain the reliability, safety and security of the distribution system through the supply of standard control services.*

Further, paragraph 6.5.7(e) provides:

In deciding whether or not the AER is satisfied as referred to in paragraph (c), the AER must have regard to the following ('the capital expenditure factors'):

1. *the information included in or accompanying the building block proposal;*
2. *submissions received in the course of consulting on the building block proposal;*
3. *analysis undertaken by or for the AER and published before the distribution determination is made in its final form;*
4. *benchmark capital expenditure that would be incurred by an efficient Distribution Network Service Provider over the regulatory control period;*
5. *the actual and expected capital expenditure of the Distribution Network Service Provider during any preceding regulatory control periods;*
6. *the relative prices of operating and capital inputs;*
7. *the substitution possibilities between operating and capital expenditure;*
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 target performance incentive scheme in respect of the regulatory control period;*
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;*
10. *the extent the Distribution Network Service Provider has considered, and made provision for, efficient non-network alternatives.*

Furthermore, per paragraph 6.5.7(b):

The forecast of required capital expenditure of a *Distribution Network Service Provider* that is included in a *building block proposal* must *comply with the requirements of any relevant regulatory information instrument*.

12.1.1.2 The Victorian Electricity Distribution Code

Paragraph 3.1 of the Victorian Electricity Distribution Code (EDC) deals with **good asset management** and provides:

A **distributor** must use best endeavours to:

*(a) assess and record the nature, location, condition and performance of its **distribution system** assets;*

*(b) develop and implement plans for the acquisition, creation, maintenance, operation, refurbishment, repair and disposal of its **distribution system** assets and plans for the establishment and **augmentation** of **transmission connections**:*

- *to comply with the laws and other performance obligations which apply to the provision of **distribution** services including those contained in this Code;*
- *to minimise the risks associated with the failure or reduced performance of assets; and*
- *in a way which minimises costs to **customers** taking into account **distribution losses**; and*

*(c) develop, test or simulate and implement contingency plans (including where relevant plans to strengthen the security of supply) to deal with events which have a low probability of occurring, but are realistic and would have a substantial impact on **customers**.*

12.1.2 Assessment of regulatory requirements

Taken together, these requirements imply that the DNSP should have in place and follow sound governance processes and practices with respect to capital forecasting, planning and capital project/programme execution. If they do have these processes and practices in place, and if they are followed in actual practice, there can be a good degree of confidence that the capital expenditure objectives stated at paragraph 6.54.7(c) of the NER will be met.

Accordingly, the basis of this review is to determine the extent to which each DNSP has provided evidence in its regulatory proposal that it has in place sound governance processes and practices governing capital forecasting, planning and capital project/programme execution.

12.1.3 PAS 55

PAS 55:2008[133] (PAS 55) is a Publicly Available Specification that was developed in response to demand from industry for a standard relating to asset management in infrastructure intensive industries. It was developed on the basis that asset management would best lend itself to standardisation as a specification, with the information on implementing asset management distilled into key requirements. The criterion for including such requirements has been that, without them, the asset management system would be regarded as deficient. In our view, PAS 55 provides a suitable guideline for the assessment of the regulatory requirements relating to capital governance practices within the submitting DNSPs, as outlined above.

The Victorian DNSPs are also familiar with PAS 55 most referencing the standard in one form or another in their submissions.

[133] The Publicly Available Specification PAS 55:2008 is published by BSI in two parts: (1) PAS 55-1 is *Part 1: Specification of the optimized management of physical assets* and (2) PAS 55-2 is *Part 2: Guidelines for the application of PAS 55-1.*

While PAS 55 deals broadly with all aspects of asset management, the approach we have taken to assess DNSP submissions against the capex governance requirements is to frame an appropriate subset of criteria derived from PAS 55 and then to assess each submission against this set of criteria.

The assessment criteria take the form of a set of questions structured in line with the high-level framework set out in PAS 55. That framework is based on a continual improvement cycle with the following sequence of elements:

1. policy and strategy
2. asset management information, risk assessment and planning
3. implementation and operation
4. checking and corrective action
5. management review and continual improvement.

The cycle is completed by linking the completion of step 5 to the beginning of step 1.

PAS 55-1 expands each of these elements into a set of requirements. PAS 55-2 elaborates on each of the requirements set out in PAS 55-1 and provides guidelines for their application. Our assessment framework for the capex governance aspects of the DNSP submissions is based on both parts 1 and 2 of PAS 55.

In creating a subset of assessment criteria focused on capex governance processes, it is important to note that PAS 55 provides a comprehensive framework for asset management that is significantly beyond the scope of an assessment framework we would regard as appropriate for the task in hand. The process of distillation of the key aspects of PAS 55 relevant to prudent capex governance practices and processes has accordingly been undertaken with a focus on what, in our view, are the most important high-level processes and practices that a prudent electricity network asset managing organisation would be expected to have in place.

12.2 Assessment framework

12.2.1 Summary of approach

By deriving a set of questions for the assessment of each DNSP submission, an objective framework is established which also allows contrasts and comparisons to be formed between the regulated businesses. A simple high, partial, low ranking methodology has been used to rate the individual criterion assessments.

3 – High – the submitted information demonstrates a high degree of alignment with the assessment criterion.

2 – Partial – the submitted information demonstrates a partial degree of alignment with the assessment criterion but one or more key aspects are omitted.

1 – Low – the submitted information demonstrates little or no alignment with the assessment criterion.

The initial **highlighted** question in each element group provides a summary high-level question for that entire element group and subsequent questions explore more detailed aspects of the element.

The overall assessment framework is therefore comprised of:

1 the set of assessment questions, with the **highlighted** question forming the high-level summary question for the specific element;

2 the ranking provided; and

3 a brief set of comments focused on the non-highlighted subsidiary questions that assists an understanding of the rationale for the assessed ranking.

The approach is a desktop-based assessment of current DNSP reported practice. Nuttall Consulting has not undertaken any physical review of the DNSP practices to ensure that the reported practices match actual practices, or the length of time that the current practices have been in place.

12.2.2 Assessment criteria

The following subsections work through each of the elements of the PAS 55-derived asset management framework and the development of a set of assessment criteria in the form of a series of key questions.

12.2.2.1 Policy and strategy

The primary focus in this framework element is that the organisation approaches capex governance in a formalised, top-down manner and that the key elements of capex governance are derived from the organisation's high-level business policies and strategies. The assessment criteria are accordingly framed to test the extent to which appropriate polices and strategies governing capex management within the organisation are in place.

The assessment questions are:

1 Does the submission demonstrate the appropriate policies and strategies governing capex?

2 Are the capex polices and strategies derived from, and consistent with, the organisation's strategic plan and other policies?

3 Have the capex policies and strategies been reviewed and, if appropriate, amended recently to maintain currency and consistency with the broader organisational policies and strategies?

4 Do the capex policies and strategies provide a foundation from which specific capex objectives, targets and plans are to be produced?

5 Are the capex polices and strategies appropriate to the nature and scale of the organisation's assets and operations?

6 Have the capex polices and strategies been endorsed by senior management and is there evidence that they are communicated and highly visible within the organisation, including within any contractors' organisations?

7 Does the capex strategy demonstrate a clear understanding of and linkage to:

a. the nature and scope of the services required by the organisation’s consumers;

b. the legal and regulatory obligations of the organisation; and

c. the wider needs of the organisation’s stakeholders, including consideration of matters such as health and safety, sustainability and environmental needs?

8 Does the capex strategy identify and clearly state the function, performance and condition requirements of its assets?

9 Does the capex strategy highlight and pursue goals of optimisation and attaining the best value in the longer term for capital deployed and the maintenance of appropriate levels of quality and security?

12.2.2.2 Asset management information

The primary focus in this framework element is that the organisation provides an asset information system and associated processes that support its capex assessment, decision-making and planning needs. The assessment criteria are accordingly framed to test the extent to which information systems and processes are in place that support capex management within the organisation.

The assessment questions are:

1 Does the submission demonstrate that an appropriate information system and associated processes governing capex are provided and maintained?

2 Are the capex-specific aspects of the information system and processes integrated with the organisation’s wider asset management information system?

3 Is the information accessible to all the relevant people, including any contractors employed in capex delivery functions?

12.2.2.3 Risk management – identification, assessment and control of risks

The primary focus in this framework element is that the organisation operates a comprehensive risk management framework that encompasses its capex functions. The assessment criteria are accordingly framed to test the extent to which risk management practices are in place that identify, assess and manage capex-related risks within the organisation.

The assessment questions are:

1 Does the submission demonstrate that an appropriate risk management system and associated processes governing capex functions are provided for and operated within the organisation? Capex specific risks include asset-related design, specification, procurement, construction, installation, commissioning, inspection, monitoring, refurbishment, replacement, decommissioning and disposal risks as appropriate.

2 Does the risk management system enable specific capex-related risks to be identified at all levels within the organisation and documented within the system?

3 Does the risk management system assign accountability for specific risks to the appropriate management level in the organisation for assessment and development of risk mitigations and controls, based on risk impact and likelihood?

4 Does the risk management system provide routine reviews of risks and risk treatments at all levels, including up to the executive management and board of directors levels for the most critical risks?

5 Does the risk management system ensure that relevant identified risk controls provide:

   a. specific objectives as inputs into capex plans, resource plans including staffing levels, the identification of training needs and the development of operational controls; and

   b. updated requirements governing the specifications of each of the capex-related processes listed in Q1 above?

12.2.2.4 Capex planning

The primary focus in this framework element is that the organisation drives its capex functions and processes on a comprehensively planned basis. The assessment criteria are accordingly framed to test the extent to which asset management plans incorporating specific capex objectives are in place.

The assessment questions are:

1 Does the submission include an asset management plan, developed in accordance with an appropriate plan preparation process that comprehensively governs the capex functions of the organisation?

2 Are the stated capex objectives in the asset management plan consistent with the organisation's capex strategies and policies and are they quantified, optimised and prioritised?

3 Are the key capex-related asset management drivers (asset condition monitoring, asset lifecycle management, consumer demand levels) identified and assessed?

4 Is there evidence provided that the costs and benefits (performance, risk reduction, compliance) of proposed capex are evaluated and, conversely, that the total cost/risk impact to the business of not performing the work is evaluated?

5 Are appropriate summaries of capital asset management plans made available to a wide range of external stakeholders and is their feedback sought and considered?

12.2.2.5 Implementation and operation

The primary focus in this framework element is the structure, authority and responsibility for capital asset management within the organisation. The assessment criteria are accordingly framed to test the extent to which capital asset management and delivery is controlled.

The assessment questions are:

1 Does the submission include an overview of the organisation's capex governance practices that relate to the establishment of a fit-for-purpose organisational structure governing roles, responsibilities and delegated authorities?

2 To what extent is this structure consistent with the achievement of its capital asset management policies, strategies, objectives, targets and plans?

3 Are there provisions relating to the efficient and cost-effective delivery of capex plans and is responsibility clearly assigned for specific outcomes in terms of capex programme and project delivery and timeframes?

4 Are appropriate practices, processes, emergency plans and organisational controls in place, are they documented and communicated and are the documents controlled, available and maintained? These practices, processes and controls should include provisions governing the architecture, design, purchasing, construction, commissioning, refurbishment, replacement and disposal of capital assets.

12.2.2.6 Checking and corrective action

The primary focus in this framework element is performance monitoring of both the capital asset management system and of the capital projects and programmes post-implementation. The assessment criteria are accordingly framed to test the extent to which performance monitoring of capital asset management systems and assets is carried out.

The assessment questions are:

1 Does the submission summarise the procedures by which the capital asset management system is monitored and reviewed and are these procedures appropriate? Does the submission summarise the procedures by which capital projects and programmes are monitored and reviewed post-implementation and are these procedures appropriate?

2 Are failures, incidents, emergencies and non-conformances of capital functions routinely reported and assessed on a risk management basis for possible corrective or preventive action, and is responsibility assigned for the implementation of all follow-up actions?

3 Are audits of capital asset management processes routinely scheduled and carried out by suitably independent people (whether internal or external to the organisation)?

4 Are post-implementation reviews of capital projects and programmes routinely undertaken and does the post-implementation review approach focus on continual improvement outcomes?

12.2.2.7 Management review and continual improvement

The primary focus in this framework element is that capital asset management and governance is afforded top level attention within the organisation. The assessment criteria are accordingly framed to test the extent to which board-level and executive management involvement is provided over capital asset management practices and processes.

The assessment questions are:

1 Does the submission summarise the extent of involvement of the board of directors, the CEO and executive management in the organisation’s capital asset management processes and is the extent of involvement appropriate?

2 Does this involvement relate to the adequacy of the systems and processes themselves as well as to the relevant controls, delegations and approvals in place?

3 Does the management review process address the possible need for changes to policy, strategy, objectives and other elements of the capital asset management system in the light of review audit results, changing circumstances and the organisation's commitment to continual improvement?

4 In the context of continual improvement, does the submission provide evidence of any programmes the organisation has in place for the acquisition of capital asset-related knowledge of state-of-the-art and emerging technologies, practices, trends, tools and techniques?

5 Is there evidence that such knowledge-acquisition leads to evaluations to establish their potential benefit to the organisation, consumers and wider stakeholders and, where appropriate, their adoption?

12.3 DNSP assessments

12.3.1 CitiPower

C0042 – Review of CitiPower's policies, practices, procedures and governance arrangements presents a report of a review undertaken by PB of the policies, practices, procedures and governance arrangements used to develop the forecast costs for system capital expenditure. PB observes in its review summary that:

In relation to the governance systems and processes we found that CitiPower is well organised, makes use of committees of review, and has well documented approval processes. A strength of the CitiPower approach is the senior level of the committee that approves all significant network investments and the inclusion of a technical expert on that committee.

This review of CitiPower's capital governance processes tends to support PB's findings; it finds significant evidence of capital governance approaches that are broadly developed with reference to the provisions of PAS 55.

Of note is the fact that CitiPower and Powercor have shared ownership and management structures. The submitted documents reviewed in respect of assessing capital governance processes appear to be highly congruent, particularly in respect of processes, practices and approaches. The detailed capital governance assessments for these two companies have been undertaken by reviewing in detail CitiPower's documentation. Further comment on the assessment approach in respect of Powercor is provided under the Powercor review heading below.

In our view, from a review of submitted documents, CitiPower's documentation demonstrates well-developed capital governance processes and practices that, if followed, would be expected to deliver prudent and efficient outcomes for its stakeholders.

Assessment criteria	Ranking	Comments
Policy and strategy Does the submission demonstrate that appropriate policies and strategies governing capex are in place?	3 – high	• In *C0029 Asset Management Framework* CitiPower describes its high level approach to asset management. It states that it is committed to the application of best practice asset management strategies to ensure the safe and reliable operation of its electrical network. • CitiPower's asset management framework is based on PAS 55-1, suitably adapted for its specific business purposes. This provides a significant level of confidence that the elements in the assessment framework, which are a subset of PAS 55-1 focused on capital governance processes and practices, will be observed in CitiPower's submitted documentation.

Assessment criteria	Ranking	Comments
		• Figure 7.1 provides an overview of the way in which Citipower's asset management framework maps to the specific requirements of PAS 55-1. This diagram indicates a significant degree of congruence between an adapted PAS 55-1 and CitiPower's asset management framework. • The asset management framework indicates that the capex polices and strategies derived from and consistent with the organisation's strategic plan and other policies. Figure 7.3 demonstrates these linkages in detail. • It is evident from the November 2009 publication date of C0029 and the references to specific strategies in Figure 7.3 that the capex policies and strategies have been recently reviewed to maintain currency and consistency with the broader organisational policies and strategies. • The capex policies and strategies evidently provide a sound foundation from which specific capex objectives, targets and plans can be produced. • The capex polices and strategies appear to be broadly appropriate to the nature and scale of the organisation's assets and operations. They cover a wide variety of subject categories that are highly applicable to a business engaged in the distribution of electricity. • The capex focused strategies appear to demonstrate a clear understanding of and linkage to: a. the nature and scope of the services required by the organisation's consumers; b. the legal and regulatory obligations of the organisation; and c. the wider needs of the organisation's stakeholders, including consideration of matters such as health and safety, sustainability and environmental needs. Stakeholder interests are identified and discussed at s. 7.2. • Figure 7.2 identifies how a range of capex strategies link with specific network asset management plans. With reference to a sample of these plans it is evident that they identify and clearly state the function, performance and condition requirements of CitiPower's assets. • Several of the asset management strategies cited at Figure 7.3 highlight the pursuit of

Assessment criteria	Ranking	Comments
		goals of optimisation and attaining the best value in the longer term for capital deployed and the maintenance of appropriate levels of quality and security.
Asset management information Does the submission demonstrate that an appropriate information system and associated processes governing capex are provided and maintained?	3 – high	• A comprehensive asset data management system is described in C0029 in s. 13.6. • The capex-specific aspects of the information system and processes appear to be integrated with the organisation's wider asset management information system. Figure 13.1 describes the key system linkages. • S. 13.7 Document Management discusses how key documentation is managed and made available throughout the organisation. It is evident that the managed information is widely accessible to all the relevant people, including any contractors employed in capex delivery functions.
Risk management – identification, assessment and control of risks Does the submission demonstrate that an appropriate risk management system and associated processes governing capex functions are provided for and operated within the organisation?	2 – partial	• In C0029 at s. 13.2 CitiPower's approach to risk management is described. CitiPower has in place an Enterprise Risk Management Framework that details the business's policy, guiding principles, accountabilities, roles and responsibilities and methodology regarding enterprise risk management. It includes information relating to the tools and templates necessary for a uniform, whole of business approach. • It is expected that risk management as it applies to capital governance processes and practices will fall under the whole of business approach described. However, the Enterprise Risk Management Framework document 13-10-P0001, while referenced, is not listed in the CitiPower Attachment Register. Hence, it has not been possible to assess risk management at a more detailed level.
Capex planning Does the submission include an asset management plan, developed in accordance with an appropriate plan preparation process that comprehensively governs the capex functions of the organisation?	3 – high	• CitiPower's asset management objectives are listed in s. 8 of C0029. While no detail of the linkages to the organisation's capex strategies and policies is provided, they appear to be broadly consistent. The objectives are partially quantified but some have neither target completion dates (where relevant) nor output measurements that specify completion quality – presumably the relevant timeframe is "for each year within the plan period". It is unclear whether the objectives are optimised and they are not prioritised. However, at a project level *C0013 Attachment – CitiPower's governance overview* provides guidance on how projects and programmes are optimised and

Assessment criteria	Ranking	Comments
		prioritised. This is undertaken on an appropriate risk management basis. • CitiPower's asset management planning documents are organised asset-specifically, e.g. there is a "HV Circuit Breakers" asset management plan. The structure of each of the plans is stated to be based on PAS 55-1, hence a high degree of confidence that the key asset management principles from PAS 55-1 will have been incorporated into CitiPower's asset management planning, and hence to its capex specific plans. • There is evidence that the key capex-related asset management drivers (asset condition monitoring, asset lifecycle management, consumer demand levels) are identified and assessed in the relevant network asset management plans. • There is evidence provided that the costs and benefits (performance, risk reduction, compliance) of proposed capex are evaluated. *C0007 Capital Expenditure Evaluation & Review Policy* details policy in relation to the preparation and evaluation of business case submissions. • While it is unclear to what extent appropriate summaries of capital asset management plans are made available to a wide range of external stakeholders or whether their feedback is sought and considered, there are several references to stakeholder interaction in C0029 in respect of development of asset management plans. Further elaboration on the specifics of stakeholder interaction in future submissions would enhance CitiPower's documentation.
Implementation and operation Does the submission include an overview of the organisation's capex governance practices that relate to the establishment of a fit-for-purpose organisational structure governing roles, responsibilities and delegated authorities?	3 – high	• An overview of the organisational structure relating to asset management and hence to capex management is provided in C0029 in s. 10. • CitiPower's Electricity Networks functional structure is typical of that broadly employed by many DNSPs and appears to be well consistent with the achievement of its capital asset management policies, strategies, objectives, targets and plans. • The Network Asset Strategy and Performance group is responsible for network strategic planning, system planning and embedded generation analysis, project establishment and the capital works program, budgeting, asset management of primary and secondary assets, security and reliability strategies for the Electricity Networks. This role responsibility would presumably incorporate objectives for providing for the efficient and cost-effective delivery of capex plans. • The Customer Projects group is responsible for negotiating and reaching agreement

Assessment criteria	Ranking	Comments
		with Customers for all Network extensions, upgrades and general asset related enquiries. Project delivery for major customer initiated augmentation projects is provided by Customer Projects with project delivery for the remaining projects via service level agreements. • The Network Engineering group goal is to provide engineering and technical expertise to CitiPower. It appears that this group's responsibilities include ensuring that appropriate documented practices are in place relating to all aspects of capital assets. CitiPower has a comprehensive set of design standards that are published on the corporate intranet and subject to a process of continual improvement (C0029 s. 12.10). • *C0013 Attachment - CitiPower's governance overview* provides details of CitiPower's cost control process which ensures that all capital investment is appropriately appraised, monitored and managed to ensure delivery of optimum outcomes for shareholders, customers, the community and employees.
Checking and corrective action Does the submission summarise the procedures by which the capital asset management system is monitored and reviewed and are these procedures appropriate? Does the submission summarise the procedures by which capital projects and programmes are monitored and reviewed post-implementation and are these procedures appropriate?	3 – high	• It appears (see C0013 discussion on "periodic review") that procedures are in place that report and manage failures, incidents, emergencies and non-conformances of capital functions. These appear to be assessed on a risk management basis for possible corrective or preventive action in the future. • No specific reference of CitiPower undertaking routine audits of capital asset management processes was detected in our review, although there is widespread evidence throughout the documentation of recently updated processes and practices generally and the engagement of external specialists undertaking reviews of key aspects of CitiPower's operations. • CitiPower undertakes post-implementation reviews of some capital projects and programmes and the post implementation review approach is stated to focus on continual improvement of decision making processes and on the identification of corrective actions. (see C0013 and C0009)
Management review and continual improvement	3 – high	• *C0013 Attachment – CitiPower's governance overview* describes CitiPower's governance framework. Additionally, PB's review of governance arrangements (C0042)

Assessment criteria	Ranking	Comments
Does the submission summarise the extent of involvement of the board of directors, the CEO and executive management in the organisation's capital asset management processes and is the extent of involvement appropriate?		provides an external view of the same. • Board level and senior management involvement appears to relate to the adequacy of the systems and processes themselves as well as to the relevant controls, delegations and approvals in place. • CitiPower maintains a Capital Investment Committee and a Network Planning Committee with senior management participation that formalise key capital governance roles at senior levels of the organisation. These committees hold delegated authorities for investment approval up to prescribed levels and seek to ensure that proposed expenditures are in line with key corporate drivers as well as undertaking post-implementation reviews. • The management review process appears to address the possible need for changes to policy, strategy, objectives and other elements of the capital asset management system in the light of review audit results, changing circumstances and the organisation's commitment to continual improvement. Of note is the PB review of policies, practices and procedures (C0042) commissioned in pursuit of this objective. • In the context of continual improvement, the submission provides evidence of programmes the organisation has in place for the acquisition of capital asset-related knowledge of state-of-the-art and emerging technologies, practices, trends, tools and techniques. There are several references in C0029 to the assessment and adoption of new technologies in reference to design and procurement standards. This includes a New Technology and Innovation Policy detailed at s. 13.11. • Thus, evidence is provided that such knowledge acquisition leads to evaluations to establish their potential benefits and it appears that, where appropriate, new technologies and innovative practices are adopted.

12.3.2 Powercor

P0042 – Review of Powercor's policies, practices, procedures and governance arrangements presents a report of a review undertaken by PB of the policies, practices, procedures and governance arrangements used to develop the forecast costs for system capital expenditure. PB observes in its review summary that:

In relation to the governance systems and processes we found that Powercor is well organised, makes use of committees of review, and has well documented approval processes. A strength of the Powercor approach is the senior level of the committee that approves all significant network investments and the inclusion of a technical expert on that committee.

This review of Powercor's capital governance processes tends to support PB's findings; it finds significant evidence of capital governance approaches that are broadly developed with reference to the provisions of PAS 55.

Of note is the fact that Powercor and CitiPower have shared ownership and management structures. The submitted documents reviewed in respect of assessing capital governance processes appear to be highly congruent, particularly in respect of processes, practices and approaches. Thus, this review of Powercor effectively mirrors that of CitiPower. We have undertaken sample checking of references to ensure the validity of this approach.

In our view, from a review of submitted documents, Powercor's documentation demonstrates well-developed capital governance processes and practices that, if followed, would be expected to deliver prudent and efficient outcomes for its stakeholders.

Assessment criteria	Ranking	Comments
Policy and strategy Does the submission demonstrate that appropriate policies and strategies governing capex are in place?	3 – high	• In *P0029 Asset Management Framework* Powercor describes its high level approach to asset management. It states that it is committed to the application of best practice asset management strategies to ensure the safe and reliable operation of its electrical network. • Powercor's asset management framework is based on PAS 55-1, suitably adapted for its specific business purposes. This provides a significant level of confidence that the elements in the assessment framework, which are a subset of PAS 55-1 focused on capital governance processes and practices, will be observed in Powercor's submitted documentation.

Assessment criteria	Ranking	Comments
		• Figure 7.1 provides an overview of the way in which Powercor's asset management framework maps to the specific requirements of PAS 55-1. This diagram indicates a significant degree of congruence between an adapted PAS 55-1 and Powercor's asset management framework. • The asset management framework indicates that the capex polices and strategies derived from and consistent with the organisation's strategic plan and other policies. Figure 7.3 demonstrates these linkages in detail. • It is evident from the November 2009 publication date of P0029 and the references to specific strategies in Figure 7.3 that the capex policies and strategies have been recently reviewed to maintain currency and consistency with the broader organisational policies and strategies. • The capex policies and strategies evidently provide a sound foundation from which specific capex objectives, targets and plans can be produced. • The capex polices and strategies appear to be broadly appropriate to the nature and scale of the organisation's assets and operations. They cover a wide variety of subject categories that are highly applicable to a business engaged in the distribution of electricity. • The capex focused strategies appear to demonstrate a clear understanding of and linkage to: d. the nature and scope of the services required by the organisation's consumers; e. the legal and regulatory obligations of the organisation; and f. the wider needs of the organisation's stakeholders, including consideration of matters such as health and safety, sustainability and environmental needs. Stakeholder interests are identified and discussed at s. 7.2. • Figure 7.2 identifies how a range of capex strategies link with specific network asset management plans. With reference to a sample of these plans it is evident that they identify and clearly state the function, performance and condition requirements of Powercor's assets. • Several of the asset management strategies cited at Figure 7.3 highlight the pursuit of

Assessment criteria	Ranking	Comments
		goals of optimisation and attaining the best value in the longer term for capital deployed and the maintenance of appropriate levels of quality and security.
Asset management information Does the submission demonstrate that an appropriate information system and associated processes governing capex are provided and maintained?	3 – high	• A comprehensive asset data management system is described in P0029 in s. 13.6. • The capex-specific aspects of the information system and processes appear to be integrated with the organisation's wider asset management information system. Figure 13.1 describes the key system linkages. • S. 13.7 Document Management discusses how key documentation is managed and made available throughout the organisation. It is evident that the managed information is widely accessible to all the relevant people, including any contractors employed in capex delivery functions.
Risk management – identification, assessment and control of risks Does the submission demonstrate that an appropriate risk management system and associated processes governing capex functions are provided for and operated within the organisation?	2 – partial	• In P0029 at s. 13.2 Powercor's approach to risk management is described. Powercor has in place an Enterprise Risk Management Framework that details the business's policy, guiding principles, accountabilities, roles and responsibilities and methodology regarding enterprise risk management. It includes information relating to the tools and templates necessary for a uniform, whole of business approach. • It is expected that risk management as it applies to capital governance processes and practices will fall under the whole of business approach described. However, the Enterprise Risk Management Framework document 13-10-P0001, while referenced, is not listed in the Powercor Attachment Register. Hence, it has not been possible to assess risk management at a more detailed level.
Capex planning Does the submission include an asset management plan, developed in accordance with an appropriate plan preparation process that comprehensively governs the capex functions of the organisation?	3 – high	• Powercor's asset management objectives are listed in s. 8 of P0029. While no detail of the linkages to the organisation's capex strategies and policies is provided, they appear to be broadly consistent. The objectives are partially quantified but some have neither target completion dates (where relevant) nor output measurements that specify completion quality – presumably the relevant timeframe is "for each year within the plan period". It is unclear whether the objectives are optimised and they are not prioritised. However, at a project level *P0013 Attachment – Powercor's governance overview* provides guidance on how projects and programmes are optimised and

Assessment criteria	Ranking	Comments
		prioritised. This is undertaken on an appropriate risk management basis. • Powercor's asset management planning documents are organised asset-specifically, e.g. there is a "HV Circuit Breakers" asset management plan. The structure of each of the plans is stated to be based on PAS 55-1, hence a high degree of confidence that the key asset management principles from PAS 55-1 will have been incorporated into Powercor's asset management planning, and hence to its capex specific plans. • There is evidence that the key capex-related asset management drivers (asset condition monitoring, asset lifecycle management, consumer demand levels) are identified and assessed in the relevant network asset management plans. • There is evidence provided that the costs and benefits (performance, risk reduction, compliance) of proposed capex are evaluated. *P0007 Capital Expenditure Evaluation & Review Policy* details policy in relation to the preparation and evaluation of business case submissions. • While it is unclear to what extent appropriate summaries of capital asset management plans are made available to a wide range of external stakeholders or whether their feedback is sought and considered, there are several references to stakeholder interaction in P0029 in respect of development of asset management plans. Further elaboration on the specifics of stakeholder interaction in future submissions would enhance Powercor's documentation.
Implementation and operation Does the submission include an overview of the organisation's capex governance practices that relate to the establishment of a fit-for-purpose organisational structure governing roles, responsibilities and delegated authorities?	3 – high	• An overview of the organisational structure relating to asset management and hence to capex management is provided in P0029 in s. 10. • Powercor's Electricity Networks functional structure is typical of that broadly employed by many DNSPs and appears to be well consistent with the achievement of its capital asset management policies, strategies, objectives, targets and plans. • The Network Asset Strategy and Performance group is responsible for network strategic planning, system planning and embedded generation analysis, project establishment and the capital works program, budgeting, asset management of primary and secondary assets, security and reliability strategies for the Electricity Networks. This role responsibility would presumably incorporate objectives for providing for the efficient and cost-effective delivery of capex plans. • The Customer Projects group is responsible for negotiating and reaching agreement

Assessment criteria	Ranking	Comments
		with Customers for all Network extensions, upgrades and general asset related enquiries. Project delivery for major customer initiated augmentation projects is provided by Customer Projects with project delivery for the remaining projects via service level agreements. • The Network Engineering group goal is to provide engineering and technical expertise to Powercor. It appears that this group's responsibilities include ensuring that appropriate documented practices are in place relating to all aspects of capital assets. Powercor has a comprehensive set of design standards that are published on the corporate intranet and subject to a process of continual improvement (P0029 s. 12.10). • *P0013 Attachment - Powercor's governance overview* provides details of Powercor's cost control process which ensures that all capital investment is appropriately appraised, monitored and managed to ensure delivery of optimum outcomes for shareholders, customers, the community and employees.
Checking and corrective action Does the submission summarise the procedures by which the capital asset management system is monitored and reviewed and are these procedures appropriate? Does the submission summarise the procedures by which capital projects and programmes are monitored and reviewed post-implementation and are these procedures appropriate?	3 – high	• It appears (see P0013 discussion on "periodic review") that procedures are in place that report and manage failures, incidents, emergencies and non-conformances of capital functions. These appear to be assessed on a risk management basis for possible corrective or preventive action in the future. • No specific reference of Powercor undertaking routine audits of capital asset management processes was detected in our review, although there is widespread evidence throughout the documentation of recently updated processes and practices generally and the engagement of external specialists undertaking reviews of key aspects of Powercor's operations. • Powercor undertakes post-implementation reviews of some capital projects and programmes and the post implementation review approach is stated to focus on continual improvement of decision making processes and on the identification of corrective actions. (see P0013 and P0009)
Management review and continual improvement	3 – high	• *P0013 Attachment – Powercor's governance overview* describes Powercor's governance framework. Additionally, PB's review of governance arrangements (P0042)

Assessment criteria	Ranking	Comments
Does the submission summarise the extent of involvement of the board of directors, the CEO and executive management in the organisation's capital asset management processes and is the extent of involvement appropriate?		provides an external view of the same. • Board level and senior management involvement appears to relate to the adequacy of the systems and processes themselves as well as to the relevant controls, delegations and approvals in place. • Powercor maintains a Capital Investment Committee and a Network Planning Committee with senior management participation that formalise key capital governance roles at senior levels of the organisation. These committees hold delegated authorities for investment approval up to prescribed levels and seek to ensure that proposed expenditures are in line with key corporate drivers as well as undertaking post-implementation reviews. • The management review process appears to address the possible need for changes to policy, strategy, objectives and other elements of the capital asset management system in the light of review audit results, changing circumstances and the organisation's commitment to continual improvement. Of note is the PB review of policies, practices and procedures (P0042) commissioned in pursuit of this objective. • In the context of continual improvement, the submission provides evidence of programmes the organisation has in place for the acquisition of capital asset-related knowledge of state-of-the-art and emerging technologies, practices, trends, tools and techniques. There are several references in P0029 to the assessment and adoption of new technologies in reference to design and procurement standards. This includes a New Technology and Innovation Policy detailed at s. 13.11. • Thus, evidence is provided that such knowledge acquisition leads to evaluations to establish their potential benefits and it appears that, where appropriate, new technologies and innovative practices are adopted.

12.3.3 SP AusNet

SP AusNet’s submitted documents have been reviewed in terms of the capital governance assessment framework developed for this review. The material is set out across a wide range of different documents throughout the submitted document library and not comprehensively covered in any one place. It is thus possible in the context of this review that some relevant references have been overlooked.

While one reference to PAS 55 was detected, it does not appear that SP AusNet has adopted a specific objective to develop its approaches to asset management in accordance with the framework set out in PAS 55. Had this been the case, reference to such an objective would have been expected to be found in the Asset Management Strategy document or in the Regulatory Proposal. Nevertheless, widespread evidence of broadly sound processes and practices in respect of capital asset management governance is evident in the submitted documents.

In our view, from a review of submitted documents, SP AusNet’s documentation demonstrates generally well-developed capital governance processes and practices that, if followed, would be expected to deliver prudent and efficient outcomes for its stakeholders.

Assessment criteria	Ranking	Comments
Policy and strategy Does the submission demonstrate that appropriate policies and strategies governing capex are in place?	3 – high	• The capex polices and strategies are integrated into SP AusNet’s asset management policies and strategies. These are covered in the document *Appendix C – SPA – Asset Management Strategy* (the AMS). They appear to be derived from the organisation’s strategic plan and other policies and consistent with these, for example the 30 year Network Development Strategy is referenced as a key informing document for the AMS. • The current version of the AMS document was published in November 2009 and appears to have been refreshed to reflect current conditions and is up to date. • The capex-specific asset management policies and strategies appear to provide a foundation from which specific capex objectives, targets and plans have been produced and are appropriate to the nature and scale of the organisation’s assets and operations. • The AMS is signed off by the Manager, Asset Strategy and Planning and the Director, Regulatory and Network Strategy. It appears to be a key business document within the organisation (see AMS s 2.1) but it is unclear as to the extent of its circulation either internally or within relevant contractor organisations. The Asset Management Policy

		statement, copied at AMS s 2.1, is in a 1-page format and in a style that would be expected to be prominently displayed in both company and contractors' workplaces. • The AMS discusses and demonstrates a clear understanding of the nature and scope of the services required by the organisation's consumers, the legal and regulatory obligations of the organisation and the wider needs of the organisation's stakeholders. These drivers are well summarised in the Asset Management Policy statement (AMS s 2.1) • The AMS identifies and clearly states the function, performance and condition requirements of its assets in the Plant Strategies sections (AMS s. 8). • The AMS highlights the goals of optimisation and attaining the best value in the longer term for capital deployed and the maintenance of appropriate levels of quality and security. • One reference to an asset management approach based on PAS 55 was found in the Asset Management Governance Committee Charter but it is not clear to what extent PAS 55 has been adopted throughout the organisation's asset management processes and practices as no further mention is made of it in the Regulatory Proposal or the AMS.
Asset management information Does the submission demonstrate that an appropriate information system and associated processes governing capex are provided and maintained?	3 – high	• The AMS highlights an information system strategy (AMS s. 8.1) and references a specific information system strategy document (AMS 20-83 Asset Data Gathering Networks). The strategy appears to incorporate a standardised system architecture that is being progressively rolled out over time. • AMD s. 7.8 also provides a brief overview of SP AusNet's asset management information systems. It appears that the capex-specific aspects of the information system and associated processes are integrated with the organisation's wider asset management information system. It is not specifically clear whether information is accessible to all the relevant people, including any contractors employed in capex delivery functions.
Risk management – identification, assessment and control of risks Does the submission demonstrate that an appropriate risk management system and associated processes governing capex functions are provides for and operated	3 – high	• The Risk Management Policy and the Risk Management Framework documents appear to provide a comprehensive business-wide framework for risk management within SP AusNet that should serve the purposes of capex-related risk management. • The risk management system appears to enable specific capex-related risks to be identified at all levels within the organisation and documented within the system. • The risk management system assigns accountability for specific risks to the appropriate management level in the organisation for assessment and development of risk

within the organisation?		mitigations and controls, based on risk impact and likelihood. • The risk management system provides routine review of risks and risk treatments at all levels, including up to the executive management and board of directors levels for the most critical risks. • Capex-specific risk management provisions in respect of project engineering and estimating are detailed in the document Project Engineering and Estimating Risk Management Framework.
Capex planning Does the submission include an asset management plan, developed in accordance with an appropriate plan preparation process that comprehensively governs the capex functions of the organisation?	3 – high	• Comprehensive details of capex planning for SP AusNet are provided within the Asset Management Strategy (AMS) document and in a wide range of subsidiary submitted documents that provide specific detail on planning policies for individual asset types. • The stated capex objectives in the asset management plan appear to be consistent with the organisation's capex strategies and policies and are quantified, optimised and prioritised. Figure 5 provides an overview of the asset management planning process that highlights • A range of key capex-related asset management drivers are identified and assessed (AMS s. 4) • Costs and benefits (performance, risk reduction, compliance) of proposed capex are evaluated (e.g. s. 7.11) • AMS s. 3.1 provides a brief discussion of community engagement in SP AusNet's asset management planning. • The AMS appears to be an internally accessible document. SP AusNet does publish a Distribution System Planning Report, as required by the ESC, that provides a range of asset management planning information in a publicly accessible format.
Implementation and operation Does the submission include an overview of the organisation's capex governance practices that relate to the establishment of a fit-for-purpose organisational structure governing roles, responsibilities	2 – partial	• No details of SP AusNet's organisational structure could be found in either the Regulatory Proposal or the AMS. • A range of documents provide detail of provisions relating to the efficient and cost-effective delivery of capex plans (see e.g. Capital Project Approvals Policy, Delegation of Authority). There appear to be well controlled processes and practices around capex delivery, with responsibility being assigned for specific capex programme outcomes. • A range of charter and policy documents indicates broadly appropriate practices, processes, emergency plans and organisational controls are in place at SP AusNet.

and delegated authorities?		
Checking and corrective action Does the submission summarise the procedures by which the capital asset management system is monitored and reviewed and are these procedures appropriate? Does the submission summarise the procedures by which capital projects and programmes are monitored and reviewed post-implementation and are these procedures appropriate?	3 – high	• The role of the Asset Management Governance Committee includes a role to “ensure processes are in place to review practices, standards and processes employed in managing the energy network”. • The document AMS 10-21 Program Delivery provides details of a range of project implementation controls and quality systems. It appears from this that that failures, incidents, emergencies and non-conformances of capital functions are routinely reported and assessed on a risk management basis for possible corrective or preventive action and that responsibility is assigned for the implementation of follow-up actions. • Detail provided in the Asset Management Governance Committee Charter indicates that audits of capital asset management processes are routinely scheduled and carried out. • From AMS 10-21 it is clear that post-implementation reviews of capital projects and programmes are routinely undertaken that the post-implementation review approach focuses on continual improvement outcomes (see s. 5). A further reference to post implementation reviews is provided in policy statement 7 of the Capital Project Approval Policy.
Management review and continual improvement Does the submission summarise the extent of involvement of the board of directors, the CEO and executive management in the organisation’s capital asset management processes and is the extent of involvement appropriate?	2 – partial	• No comprehensive reference to the roles of executive management in capital asset management processes could be detected in any one place. • The SP AusNet Board Charter provides mention only of the board’s role in approving major capital projects. • Charters for various governance committees are provided and the roles of these committees provide for management review of various aspects of capital asset management processes and practices. • A more comprehensive discussion of management involvement in reviewing asset management processes and practices and continual improvement in general could usefully be provided in the AMS document.

12.3.4 United Energy

United Energy has recently revised its Asset Management Plan (AMP) to incorporate the principles and approaches of PAS 55. Thus, the AMP structure closely follows the assessment criteria adopted for this review. The primary reference for this review is s. 2 of the AMP, which sets out United Energy's approaches to asset management.

In our view, from a review of submitted documents, United Energy's documentation demonstrates well-developed capital governance processes and practices that, if followed, would be expected to deliver prudent and efficient outcomes for its stakeholders.

Assessment criteria	Ranking	Comments
Policy and strategy Does the submission demonstrate that appropriate policies and strategies governing capex are in place?	3 – high	• United Energy's capex-specific polices and strategies are identified under the following headings: o Future demand o Life cycle management o AMI o Smart networks o Climate change o Environmental o Network safety and risk o Other network o Bushfire mitigation o Power quality o Monitoring and improvement • It is stated (s. 2.2) that these strategies and plans have been developed in line with long-term asset management objectives that link with a broad range of other business plans. From the information provided, it is not possible to assess the degree of consistency with these other plans. • It is apparent that the AMP has been recently revised and that current business trends and needs have been incorporated (e.g. those around AMI, smart networks and climate

		change). • The capex policies and strategies under the headings identified above appear to provide a sound foundation from which specific capex objectives, targets and plans have been produced. • The capex polices and strategies appear to be highly appropriate to the nature and scale of the organisation's assets and operations. • The capex polices and strategies discussed within the AMP have been signed off by asset owner representatives from United Energy. While it is not explicitly clear to what extent the AMP is communicated and highly visible within the organisation, including within any contractors' organisations, the document is in a form of a high quality publication of a type which would be volume printed for this purpose. • The strategies discussed in the AMP demonstrate a clear understandings of and linkages to: o the nature and scope of the services required by the organisation's consumers; o the legal and regulatory obligations of the organisation; and o the wider needs of the organisation's stakeholders, including consideration of matters such as health and safety, sustainability and environmental needs. • The capex strategies highlight and pursue goals of optimisation and attaining the best value in the longer term for capital deployed and the maintenance of appropriate levels of quality and security.
Asset management information Does the submission demonstrate that an appropriate information system and associated processes governing capex are provided and maintained?	2 – partial	• S. 2.7.12 provides a brief outline of United Energy's asset management information system, which is based around a GIS and SAP. Systems improvements are noted. • From the information provided, it is difficult assess whether and to what extent the capex-specific aspects of the information system and processes are integrated with the organisation's wider asset management information systems. A business systems infrastructure diagram would assist a more comprehensive understanding. • It is also difficult to assess from the documentation provided whether the information is accessible to all the relevant people, including any contractors employed in capex delivery functions.
Risk management – identification, assessment and control of risks	3 – high	• United Energy recognises risk management as an integral part of its business operation and strategic planning. Risk management, including risk evaluation, treatment and documentation, is undertaken in a systematic manner in conformance with AS/NZS 4360.

Does the submission demonstrate that an appropriate risk management system and associated processes governing capex functions are provides for and operated within the organisation?		AMP s. 11.6.9 provides specific detail of United Energy's risk management framework. It is noted that this framework was revised in February 2009. • The risk management system appears to provide that specific capex-related risks are able to be identified at all levels within the organisation and documented within the system. • The risk management system assigns accountability for specific risks to the appropriate management level in the organisation for assessment and development of risk mitigations and controls, based on risk impact and likelihood. • The risk management system appears to provide routine review of risks and risk treatments at all levels. However, no specific commentary is provided in the AMP on the extent to which executive management and board level involvement occurs. It is possible that this detail is provided in the referenced United Energy Risk Management Policy and Framework document (February, 2009), however this document was not included with the submission.
Capex planning Does the submission include an asset management plan, developed in accordance with an appropriate plan preparation process that comprehensively governs the capex functions of the organisation?	3 – high	• The capex functions at United Energy appear to be subject to a comprehensive planning framework centred around the AMP. • The stated capex objectives in the asset management plan appear to be consistent with the organisation's capex strategies and policies. The process provides for quantification, optimisation and prioritisation. • The key capex-related asset management drivers (asset condition monitoring, asset lifecycle management, consumer demand levels and others) are identified and assessed in the various plans that link to the AMP. • There is evidence provided of sound cost/benefit approaches to all aspects of asset management planning (see s. 2.14). • The AMP appears to be an internally accessible document. United Energy does publish a Distribution System Planning Report, as required by the ESC, that provides a range of asset management planning information in a publicly accessible format.
Implementation and operation Does the submission include an overview of the organisation's capex governance practices that relate to the establishment	3 – high	• The AMP highlights the relevant role accountabilities for capital asset management (s. 2.12). These include: o The Asset Strategy group, which is responsible for optimising physical asset life cycles against the return and capital appreciation of the assets; and o The Infrastructure Services group, which is responsible for the safe, hands-on

of a fit-for-purpose organisational structure governing roles, responsibilities and delegated authorities?		delivery of all maintenance and capital expenditure works programs that underpin the performance of the network. This includes the delivery of work, to defined plans and standards. • This structure appears to be consistent with the achievement of United Energy's capital asset management policies, strategies, objectives, targets and plans. It is typical of many infrastructure businesses that separate their plan development function from their plan delivery function. • Role accountabilities include provisions relating to the efficient and cost-effective delivery of capex plans and responsibility appears to be clearly assigned for specific outcomes in terms of capex programme and project delivery and timeframes.
Checking and corrective action Does the submission summarise the procedures by which the capital asset management system is monitored and reviewed and are these procedures appropriate? Does the submission summarise the procedures by which capital projects and programmes are monitored and reviewed post-implementation and are these procedures appropriate?	3 – high	• From the high-level description of management control principles at s. 2.13, it is likely that failures, incidents, emergencies and non-conformances of capital functions are routinely reported and assessed on a risk management basis for possible corrective or preventive action. • It appears that internal and external audits of capital asset management processes are routinely carried out (s 2.14). • Post-implementation reviews are incorporated within United Energy's project management methodology (s. 2.16), although it is not made clear to what extent these are undertaken or whether the review approach focuses on continual improvement outcomes.
Management review and continual improvement Does the submission summarise the extent of involvement of the board of directors, the CEO and executive management in the organisation's capital asset management processes and is the	3 – high	• Management review and governance is discussed at AMP s. 2.13. • Board and management involvement appears to relate to the adequacy of the systems and processes themselves as well as to the relevant controls, delegations and approvals in place. • AMP s. 2.7.11 discusses measures undertaken by United Energy to address potential needs for changes to policy, strategy, objectives and other elements of the capital asset management system in the light of review audit results, changing circumstances and the organisation's commitment to continual improvement. A number of specific examples of recent process improvements are listed.

extent of involvement appropriate?	• In the context of continual improvement, the submission provides evidence of programmes the organisation has in place for the acquisition of capital asset-related knowledge of state-of-the-art and emerging technologies, practices, trends, tools and techniques. Examples include the strategies and plans in place in the areas of AMI, smart networks, the emergence of distributed generation technologies and climate change. It is apparent that such knowledge acquisition leads to evaluations to establish their potential benefit to the organisation, consumers and wider stakeholders and, where appropriate, their adoption is pursued.

12.3.5 Jemena

The Jemena Network Asset Management Plan (NAMP) states that it is "designed around the principles outlined in the Publicly Available Specification (PAS) 55-1:2008 asset management standard". The review has confirmed that the approach taken by Jemena aligns with the principles of PAS 55.

An independent review conducted by GHD Australia Pty Ltd concluded that, in GHD's opinion, the capex forecasts and explanations provided in the reviewed information would meet NER 6.5.7 (a) and satisfy 6.5.7 (c) with some noted exceptions and qualifications.

This review of the documentation provided has revealed a generally high level of compliance with the specific NER requirements and with the principles of good asset management practice set out in PAS 55. It was also noted that the documentation, and in particular the NAMP, provides a clearly structured description of asset related policies, strategies and procedures.

In our view, from a review of submitted documents, Jemena's documentation demonstrates well-developed capital governance processes and practices that, if followed, would be expected to deliver prudent and efficient outcomes for its stakeholders.

Assessment criteria	Ranking	Comments
Policy and strategy Does the submission demonstrate that appropriate policies and strategies governing capex are in place?	3 – high	• Jemena has well developed strategic (medium to long-term) objectives for the operation, maintenance and development of their network (see Appendix 9.4 JEN Strategic Objectives). The strategic objectives are contained in a stand-alone document that is well structured and provides guidance and direction for the development of the company's asset management plan. • Jemena has set seven strategic objectives relating to infrastructure investments. Included in the strategic objectives is the requirement to make prudent and efficient investments including the regulatory requirement to achieve the asset objectives at least life cycle cost. • The strategic objectives for asset management are linked to the overarching corporate vision and goals. • The NAMP (see Appendix 9.1 JEN Asset Management Plan 2010-15) contains a description of Jemena's policies and strategies on which the planning and management of capex are based. For IT asset management the policies, strategies and processes followed to establish the IT asset management plans are clearly set out in the IT Strategy and

Assessment criteria	Ranking	Comments
		Management Plan 2011 (see Appendix 9.2 JEN IT Strategy and Asset Management Plan 2011). • Jemena has a Capital Governance System which clearly sets out the roles and responsibilities including delegated financial authorities for capital expenditure. The inclusion of the Capital Governance System is considered to be an important contributor to the achievement of overall least cost outcomes. • From the information reviewed it is considered that Jemena has developed procedures for asset management that are aligned to the company's corporate strategy, policies and strategic objectives.
Asset management information Does the submission demonstrate that an appropriate information system and associated processes governing capex are provided and maintained?	3 – high	• Jemena document an integrated suite of asset management business systems that "contain and manage asset knowledge and inform the investment decision making process" (see Appendix 9.1 page 29). The systems contain knowledge of the location, type, number, condition and performance of the physical network assets that are considered to be appropriate for the development and management of good practice asset management. • Jemena's approach to asset information management includes consideration of how business system and maintenance upgrade is undertaken. Whilst the level of detail provided is relatively low in this area, its inclusion in the NAMP demonstrates that the company gives consideration information management maintenance in its asset management planning cycle. • The approach taken by Jemena to information management provides for the integration of several information systems within a single framework. We consider that the documentation provided demonstrates that the asset information management approach adopted by Jemena for capex management is appropriate.
Risk management – identification, assessment and control of risks Does the submission demonstrate that an appropriate risk management system and	3 – High	• Jemena considers that the company "recognises risk management as an integral part of its business operation and strategic planning". To achieve this it undertakes "risk management, including risk evaluation, treatment and documentation" (see Appendix 9.1 page 37).

Assessment criteria	Ranking	Comments
associated processes governing capex functions are provided for and operated within the organisation?		• In support of this approach Jemena has provided details of its enterprise level risk management policy. The policy follows the risk management processes set out in AS/NZS 4360. This approach provides for a comprehensive risk management framework to be developed an implemented. • Within the enterprise level risk management policy, Jemena has a Capital Program Risk Management procedure. This procedure considers individual project risks and risks across the project portfolio. • We consider that the standards-based approach to risk management provides Jemena with an appropriate framework for the identification and control of risks. The Capital Program Risk Management adopted by Jemena includes the key components that are considered to be appropriate for a good industry practice approach to asset investment risk management.
Capex planning Does the submission include an asset management plan, developed in accordance with an appropriate plan preparation process that comprehensively governs the capex functions of the organisation?	3 – high	• Jemena has provided a comprehensive NAMP that sets out the basis on which the plan is developed and describes how it will guide the network capital investment projects and programs. • The NAMP states that it is compliant with the Jemena strategic objectives that have been set at the governance level. The NAMP sets out 11 asset management objectives on which the NAMP is based and has been based on the principles outlined in PAS 55. • The NAMP sets out the process through which it has been developed and provides clear links between the overarching strategic objectives and the development of capital investment plans. • We considered that Jemena has provided an asset management plan that has been developed in accordance with an appropriate plan preparation process that comprehensively governs the capex functions of the organisation.
Implementation and operation Does the submission include an overview of the organisation’s capex governance	3 – high	• The delivery of Jemena’s NAMP is undertaken by Jemena Asset Management (Pty) Ltd (JAN) through an agreement with Jemena Electricity Networks (Vic) Ltd (JEN). The documents provided demonstrate that an appropriate governance system has been

Assessment criteria	Ranking	Comments
practices that relate to the establishment of a fit-for-purpose organisational structure governing roles, responsibilities and delegated authorities?		developed for this organisational structure. • A gating methodology has been adopted as a component of project management. The company considers that this enables the achievement of investment efficiency across all projects and programmes. The gating methodology includes the stages (gates) that would be expected to be included in a standard project management process. • The documentation provided also includes a description of Jemena's approach to managing an efficient works programme. The drivers identified by Jemena for works programming include the timely construction of performance improvement projects to achieve maximum customer value for the initiatives (see Appendix 9.1 page 46). • We consider that the separated organisational structure has provided the opportunity for role clarity and a clear delegation of authorities. This has enabled the responsibilities for development and delivery of capital investment projects to be clearly established and monitored. The adoption of a standard gate-based procedure for project and programme management provides a sound basis for developing efficient works programmes.
Checking and corrective action Does the submission summarise the procedures by which the capital asset management system is monitored and reviewed and are these procedures appropriate? Does the submission summarise the procedures by which capital projects and programmes are monitored and reviewed post-implementation and are these procedures appropriate?	3 – high	• Under the organisational structure JAN is responsible for providing an annual revision of the NAMP to JEN. This revision sets out any variations from the current NAMP. The approval of the NAMP is the responsibility of JEN. • As the NAMP sets out the capital asset management system it is assumed that the annual review of the NAMP by JEN includes a review of those systems. However, this is not made explicitly clear in the documentation provided. • A component of the gate methodology is the requirement for a number of key tasks to be undertaken during the closing phase of a project. These tasks include the financial settlement of the project and a post-implementation review. • Jemena has acknowledged that continuous improvement is a discipline that is promoted by PAS 55. The asset management-related performance assessment and improvement systems include the following components: o condition monitoring o investigation of asset-related failures and incidents o evaluation of compliance o auditing processes

Assessment criteria	Ranking	Comments
		o clear improvement actions o records o regular management/executive review • Whilst these components are claimed to exist within the organisation, it was found that the term "continuous improvement" was only used in two areas of the NAMP, these were in the procurement and emergency/contingency planning sections.
Management review and continual improvement Does the submission summarise the extent of involvement of the board of directors, the CEO and executive management in the organisation's capital asset management processes and is the extent of involvement appropriate?	2 – partial	• The linkage between enterprise-wide strategy and policy and asset management processes was clearly documented throughout the NAMP. Conclusions can be drawn from this that the board, CEO and executive management have governance oversight through the setting of strategies and policies. • In terms of continual improvement, the impression gained from the documents provided is that, whilst monitoring is undertaken, full confidence that the organisation is using the information for developing improvements is not provided. The information could be improved by making it clear how the organisation uses the information gathered to drive continuous improvement. In particular, the involvement of the board and executive in setting, monitoring and driving key improvement targets could be provided. • Accordingly, a 2 – partial rating has been assessed element.

12.4 Summary of review findings

12.4.1 Comparison of DNSPs

The submitted documents provided by each of the five Victorian DNSPs incorporate well-evolved, fit-for-purpose capital governance processes and practices. They are based on asset management frameworks that have been developed with varying degrees of reference to the PAS 55:2008 standard.

Nuttall Consulting view PAS 55 as having a high degree of relevance to the asset management processes and practices of electricity network infrastructure businesses, such as the five Victorian DNSPs. We have accordingly developed our assessment framework based on this publicly available standard and structured our analysis upon the PAS 55 framework elements.

The following table shows the assessed ratings for each DNSP for each assessment element.

Table 115 - Governance review summary

DNSP	Policy and strategy	Asset manage-ment information	Risk manage-ment	Capex plannin g	Implement-ation and operation	Management review and continual improvement
CitiPower	3 - high	3 - high	2 - partial	3 - high	3 - high	3 - high
Powercor	3 - high	3 - high	2 - partial	3 - high	3 - high	3 - high
SP AusNet	3 - high	3 - high	3 - high	3 - high	2 - partial	2 - partial
United Energy	3 - high	2 - partial	3 - high	3 - high	3 - high	3 - high
Jemena	3 - high	3 - high	3 - high	3 - high	3 - high	2 - partial

Assessments against each framework element are uniformly acceptable for each DNSP. Thus, it would be expected that a DNSP that applies its documented capital governance processes and practices would be expected to deliver prudent and efficient outcomes for its stakeholders[134].

[134] Note: Nuttall Consulting has not undertaken an audit or assessment of whether these practices and processes are currently applied or have been applied in the past.

Where "2 – partial" ratings have been assessed, we feel any shortfall may be a simple matter of documentation rigour within the submitted material with respect to the identified element, as opposed to any material gap in the DNSP's processes or practices.

In some cases, the relevant material has been found to be distributed across a wide range of documents – this was found to be the case for SP AusNet in particular. While we have no significant concerns over their processes and practices, SP AusNet may benefit from adopting the generally well-structured, PAS 55-based capital asset management frameworks similar to those in use by the other DNSPs.

13 Appendix H – Asset level repex model tables

13.1 DNSP input data

Table 116 - Asset group breakdown – weighted average age

	CitiPower	Powercor	SP AusNet	Jemena	United Energy
Poles	34	31	29	27	31
Pole top structures	33	26	29	28	28
Overhead conductors	42	37	31	27	35
Underground cables	39	11	13	14	19
Zone substation switchgear	41	33	27	32	34
Distribution transformers	23	20	22	19	26
Power transformers	40	37	42	40	37
SCADA, network control, protection, secondary	32	27	0	20	19
Service lines	43	17	17	24	23
Zone substation - other	40	34	14	32	31
Distribution SWGR	25	19	19	18	15

Table 117 - Asset group breakdown – weighted average life

	CitiPower	Powercor	SP AusNet	Jemena	United Energy
Poles	58	58	44	56	56
Pole top structures	45	45	48	52	52
Overhead conductors	60	60	46	58	59
Underground cables	70	70	55	43	47
Zone substation switchgear	56	56	51	50	50
Distribution transformers	55	48	62	48	49

	CitiPower	Powercor	SP AusNet	Jemena	United Energy
Power transformers	55	55	65	55	55
SCADA, network control, protection, secondary	49	41	0	31	33
Service lines	60	67	48	40	40
Zone substation - other	53	53	51	49	48
Distribution SWGR	50	42	43	34	31

13.2 Calibration model

Table 118 - Asset group breakdown – weighted average life

	CitiPower	Powercor	SP AusNet	Jemena	United Energy
Poles	78	66	56	55	65
Pole top structures	68	49	55	56	55
Overhead conductors	86	79	87	68	85
Underground cables	87	43	42	60	60
Zone substation switchgear	65	60	64	63	63
Distribution transformers	56	47	53	48	54
Power transformers	65	68	83	67	71
SCADA, network control, protection, secondary	55	57	0	38	32
Service lines	92	69	45	57	42
Zone substation - other	65	59	45	60	61
Distribution SWGR	63	42	39	42	34

Table 119 - Asset group breakdown – weighted average life extension

	CitiPower	Powercor	SP AusNet	Jemena	United Energy
Poles	20	8	11	0	9
Pole top structures	23	4	6	4	3
Overhead conductors	26	19	42	10	26
Underground cables	17	-26	-13	18	13
Zone substation switchgear	10	4	13	13	13
Distribution transformers	1	-1	-9	0	5
Power transformers	10	13	18	12	16
SCADA, network control, protection, secondary	6	16	0	6	-1
Service lines	32	2	-2	17	2
Zone substation - other	12	6	-6	10	13
Distribution SWGR	13	1	-4	8	3

Table 120 - Asset group breakdown – average percentage growth 2009-2015

	CitiPower	Powercor	SP AusNet	Jemena	United Energy
Poles	5.8%	6.5%	8.7%	7.0%	4.5%
Pole top structures	-2.9%	11.8%	7.2%	1.6%	10.0%
Overhead conductors	14.5%	8.9%	19.0%	6.1%	14.5%
Underground cables	16.4%	9.0%	20.6%	9.2%	8.6%
Zone substation switchgear	15.5%	9.5%	4.1%	8.5%	11.5%
Distribution transformers	17.5%	7.3%	12.0%	13.1%	5.5%
Power transformers	14.5%	6.8%	7.1%	-4.5%	17.1%
SCADA, network control, protection, secondary	-0.5%	1.6%	n/a	-0.6%	4.7%
Service lines	16.4%	2.2%	20.8%	2.7%	3.7%
Zone substation - other	12.8%	5.1%	2.7%	8.0%	10.8%
Distribution SWGR	8.1%	1.8%	11.6%	5.1%	12.3%

14 Appendix I - Targeted opex review

14.1 Background

Nuttall Consulting has been requested by the AER to provide a technical review of specific areas of "step-change" in the operating expenditures proposed by the Victorian DNSPs. The following assessments have been undertaken at the direct request of the AER.

The Nuttall Consulting assessments of these opex step-change issues do not consider the issues of indexation (labour and materials).

The following summarises the review and findings for each of the matters in turn, as identified by the AER.

14.2 Vegetation management and bushfire mitigation

Powercor - Electrical Safety (Electric Line Clearance) Regulations ($8.3m)

Powercor is proposing an additional $8.3 million in operating expenditure associated with Electricity Safety (Electric Line) Clearance Regulations 2005.

The ESV has confirmed in writing that it expected the exemption would not be remade following the making of the new regulations in June 2010.

With respect to compliance with the Electricity Safety (Electric Line Clearance) Regulations (2005), all of the 5 large electrical distribution businesses received an exemption in December 2005 (or early 2006). The nature of these exemptions varied slightly with the different business processes in each business.

The exemption granted to Powercor was typical of those granted and required:

- in the High Bushfire Risk areas Powercor were required to achieve and maintained compliance during the fire danger period
- in Low Bushfire Risk areas with HV lines Powercor were required to have a plan that outlined not more than a biennial inspection and/or clearing/pruning cycle which was designed to achieve, under normal growth conditions, the minimum clearance space requirements in the Code,
- in Low Bushfire Risk areas with LV lines Powercor were required to have a plan that outlined an inspection and/or clearing/pruning cycle which was designed to achieve, under normal growth conditions, the minimum clearance space requirements in the Code.

According to Energy Safe Victoria[135] the exemption did not substantially alter the Code clearance requirements.

For the High Bushfire Risk areas, with Powercor having a 3 year clearing/pruning cycle, it is only at the beginning and end of that cycle that there could be a permitted intrusion into the clearance space and then only if it is outside the fire danger period.

In the Low Bushfire Risk areas, there is a need to have a plan to comply under normal conditions. This would not appear to alter materially the clearing/pruning work required.

Based on this, the monetary saving that the current exemption grants to Powercor is not clear.

In regard to their current plan, ESV became aware of the quantum of the non-compliance in the Low Bushfire Risk areas and did not see it was in a position to approve a plan whose stated objective was not to comply for the period of the next whole cycle during which they would cut more extensively to achieve Code clearance compliance. The granting of approval to this plan would also have had a consequential impact on the granted exemption, as the exemption requires a plan intended to achieve compliance.

Similarly, it was not clear to ESV what, if any, would be the monetary impact associated with their current plan, as it was Powercor's intent to visit on their current cycle and cut a little more than they had in the past.

As Powercor have had this plan for their Low Bushfire Risk areas in operation for more than 6 months, Powercor should be able to quantify this cost impact, if there are any. Indeed, as they have a 2-year cycle for Low Bushfire Risk areas by the time of the commencement of the next rate period, they will be 1 ½ years into that program and a large part of the costs will have been already met.

Powercor has not identified any benefits associated with the proposed opex step change. The proposed changes clearly identify increased activity in vegetation management, but do not provide any assessment of the impact that this will have on network reliability (e.g. through less vegetation contact with overhead wires) or the associated reduction in fault and emergency expenditure. This is not consistent with the operating expenditure objectives of the NER.

On this basis, Powercor has not demonstrated the prudency and efficiency of the additional $8.3 million in operating expenditure associated with Electricity Safety (Electric Line) Clearance Regulations (2005).

Nuttall Consulting notes that the results from the Victorian Royal Commission into the bushfires of 2009 is likely to have a significant impact upon the management of vegetation in Victoria and the roles of the DNSPs. It is considered likely that any recommendations from the Royal Commission will have cost impacts upon the Victorian DNSPs.

[135] Based on meetings and correspondence with representatives of ESV between 1 February and 28 February 2010.

Jemena - Vegetation management

Jemena is requesting an additional $14.9 million in operating expenditure associated with proposed changes to the Electricity Safety (Electric Line Clearance) Regulations.

The Electricity Safety (Electric Line Clearance) Regulations 2005 will “sunset” on 30 June 2010. It is proposed that these regulations will be replaced with the Electricity Safety (Electric Line Clearance) Regulations 2010 (the "draft 2010 regulations"). The draft 2010 regulations are currently under development and consultation. The current draft proposes a number of changes that may impose additional costs to the DNSPs, particularly in the area of vegetation management.

Jemena has identified the changes that it considers will impose additional vegetation management costs as:

- Changes to the Notice and Consultation requirements
- Removal of clauses that allow for leaves and small branches to remain in contact with ABC or insulated cables provided they are not likely to abrade the cable
- Removal of clauses that allow for certain vegetation to remain overhang powerlines if annually risk assessed by an arborist
- The expiration of the current exemption from certain requirements maintenance of clearance space requirements
- The strengthening of regulations with respect to the hazard space.

The breakdown of the proposed Jemena step changes are provided in the following table.

Table 121 - Jemena opex step changes - proposed vegetation management

	2011	2012	2013	2014	2015	Total
Consultation requirement	$744.30	$744.30	$744.30	$744.30	$744.30	$3.72
Inefficiencies, Consultation	$588.70	$588.70	$588.70	$588.70	$588.70	$2.94
Insulated cables	$1,077	$1,077	$392	$392	$392	$3.35
Overhanging vegetation	$120	$0	$0	$0	$0	$0.12
Exemption – cessation	$884.80	$884.80	$884.80	$884.80	$884.80	$4.42
Hazard space	$75	$75	$75	$75	$75	$0.38
Total ($M)	$3.49	$3.37	$2.69	$2.69	$2.69	$14.92

These cost impacts are considered in the following sections.

Jemena has not identified any benefits associated with the proposed opex step changes identified above. The proposed changes clearly identify increased activity in vegetation management, but do not provide any assessment of the impact that this will have on network reliability (e.g. through less vegetation contact with overhead wires) or the associated reduction in fault and emergency expenditure. This is not consistent with the operating expenditure objectives of the NER.

Notice and Consultation

The draft 2010 regulations propose the removal of clause 3(b) which requires 'notification' only to land occupiers where established vegetation management practices are being maintained. Clause 5 of the proposed Code requires the distributor to "consult" with the occupier of the property, which will impose a significant increase in administrative resource required to maintain compliance.

Current practice for notification involves the vegetation assessor, whilst undertaking cyclic inspection, to provide notification of required trimming via a pro-forma letter of advice being left in the property occupier/owner's letterbox at the same time of assessment. The occupier/owner is invited to contact the vegetation management group if they have any queries.

Jemena considers that the proposed change to "consult" will require the assessor to contact the occupier/owner to discuss their opinions over proposed tree trimming works. Jemena considers that until a dialogue has been entered into with each occupier/owner, compliance with the proposed regulation will not have been satisfied before trimming can be undertaken.

This position is at odds with that of Energy Safe Victoria (ESV). ESV considers that "notification and consultation under the proposed regulations can be by written notice or newspaper advertisement"[136]. The ESV Regulatory Impact Statement (RIS) also goes on to note that "under the existing regulations, consultation by newspaper advertisement is permitted only after taking reasonable steps and being unable to give written notice". The ESV clearly considers that the cost of consultation will be reduced under the new regulations.

The draft 2010 regulations appear to provide the option for consultation via newspaper advertisements. Clause 5 (4): "*Notice under this clause must be given—"... "(b) in writing <u>or by publication in a newspaper</u> circulating generally in the locality of the land in which the tree is to be cut or removed*". Nuttall Consulting considers that the clause is not completely clear in the interaction between the provision of a notice and consultation. In the absence of any further clarification, it would appear reasonable to rely on the interpretation of the ESV as provided in the RIS.

The ESV estimated that the current annual costs to Jemena of "notification or seeking permission" to be $349,138[137]. However, the ESV estimated the future costs of notification via newspaper as being $9,328 per annum for Jemena.

As part of the permission seeking process under the current regulations, the ESV assumes that there are some negotiations between the DNSPs and occupiers/owners of private land/affected persons. These negotiations could relate to a variety of issues including:

- the nature of the cutting or removal

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[136] Proposed Electricity Safety (Electric Line Clearance) Regulations 2010 - Regulatory Impact Statement, Final. Energy Save Victoria, 15/02/10.

[137] Ibid - Table A3.0, P137.

- when it will occur
- special trees
- access to property etc.

The ESV considers that negotiation is a natural consequence of many situations where permission is required by one party from another.

The Jemena proposed opex step change costs of $3.72 and $2.94 million for changes to consultation practices are not supported by the ESV RIS. Based on the RIS, the likely impact on Jemena of the draft 2010 regulations is an annual reduction of $339,810 per annum in opex.

Insulated cables

Clauses 9.2.1 and 9.2.2 of the 2005 regulations allow for leaves and small branches to remain in contact with ABC or insulated cables provided they are not likely to abrade the cable. Removal of these clauses is proposed under the draft 2010 regulations. Jemena consider that this will force them to alter the way in which these assets are pruned or cleared of vegetation.

The predominant area of impact according to Jemena relates to ABC mains and service cables for which Jemena are responsible for clearing (i.e. those crossing neighbouring properties and those in road reserves in non-declared areas). Jemena reports that it does not capture information on these assets to this level of detail in the vegetation management system to determine respective numbers.

The calculation by Jemena for this step change considers only the service cable category.

The RIS and Jemena concur that an additional 16,632 services will need to be cut to meet the changed regulatory requirements. The RIS and Jemena do not concur on the costing of the trimming for these services. The Jemena cost methodology considers an initial establishment of clearance space (annualised over two years) and annual trimming including re-visits. The ESV methodology only considers the establishment cost (the initial cost of meeting the requirements of the proposed code) as the proposed code does not force a change in annual maintenance cutting costs.

Jemena contend that a change to the annual maintenance cutting costs is required to balance the potential impact on customer vegetation ("given total clearance diameters exceeding 2,000mm may be required to maintain clearance between cyclic inspections"). Jemena considers that increased frequency of cutting is expected to have a lower cost than negotiating and undertaking clearing of customer vegetation - based on vegetation health and aesthetic considerations.

The Jemena forecasts appear to double count the initial cut costs and the ongoing incremental expenditures. Nuttall Consulting considers that the initial establishment of the clearance space would not require a second visit to trim the site. On this basis, Nuttall Consulting recommends that the annual trimming costs of $392k are not allowed for in first 2 years, which covers the period that the initial trim will be undertaken.

The position put forward by Jemena appears soundly based and may be more representative of Jemena's real costs than the RIS assessment, which was based on state-wide assumptions.

Nuttall Consulting considers that the Jemena proposed step change expenditures in this area are reasonable.

Clearance Space Overhang

The draft 2010 regulations propose the removal of clause 10(c) and 11.2 from the existing regulations, which currently allows vegetation to overhang 66kV powerlines in areas designated as low bushfire risk areas (LBRA) and bare overhead powerlines in areas designated as hazardous bushfire risk areas (HBRA)[138].

Jemena have approximately 100 spans overhanging the 66kV in LBRA as covered by clause 10(c) and no spans registered as overhanging the clearance space in HBRA.

Nuttall Consulting has confirmed the draft 2010 regulations do not contain the provision for overhanging vegetation. The current regulations do allow overhanging vegetation if the DNSP "*ensures that an arborist, who has the qualification of National Certificate Level IV in Horticulture and Arboriculture including the "Assess Trees" module, or the equivalent of that certificate, and at least 3 years of field experience in assessing trees carries out an annual risk assessment on the tree*"[139].

Jemena states that they "have approximately 100 spans overhanging the 66kV in LBRA". Given the current requirements of clause 12(b), it is reasonable to assume that Jemena should know exactly the number of trees impacting 66kV spans.

Jemena have also not provided a cost reduction for the removal of the arborist annual assessment of overhanging trees. Given that this is an annual requirement for a highly trained individual to assess each overhanging tree, it is reasonable to expect that this could represent a significant saving to the DNSP.

It is not clear why the removal of this clause has not been considered by the ESV in the RIS.

As this cost is not considered by the ESV, and on the basis that cost savings have not been factored into the Jemena assessment, Nuttall Consulting is unable to recommend that this step change cost should be allowed for.

Removal of exemption

Jemena is proposing an additional $4.424 million in operating expenditure associated with the cessation of the current exemptions dated 23 February 2006.

The ESV has confirmed in writing that it expected the exemptions would not be remade following the making of the new regulations in June 2010.

The exemption granted to Jemena required;

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[138] subject to the conditions outlined in Clause 12 (existing clause 10(c)) and Clause 11.2 of the 2005 regulations respectively.

[139] Electricity Safety (Electric Line Clearance) Regulations 2005, clause 12(b).

- in the High Bushfire Risk areas Jemena were required to achieve and maintained compliance during the fire danger period,
- in Low Bushfire Risk areas with HV lines Jemena were required to have a plan that outlined not more than a biennial inspection and/or clearing/pruning cycle which was designed to achieve, under normal growth conditions, the minimum clearance space requirements in the Code, and
- in Low Bushfire Risk areas with LV lines Jemena were required to have a plan that outlined an inspection and/or clearing/pruning cycle which was designed to achieve, under normal growth conditions, the minimum clearance space requirements in the Code.

According to Energy Safe Victoria[140] the exemption did not substantially alter the Code clearance requirements.

For the High Bushfire Risk areas, with Jemena having a 3 year clearing/pruning cycle, it is only at the beginning and end of that cycle that there could be a permitted intrusion into the clearance space and then only if it is outside the fire danger period.

In the Low Bushfire Risk areas there is a need to have a plan to comply under normal conditions. This would not appear to alter materially the clearing/pruning work required.

Based on this, it is not clear the monetary saving, if any, the current exemption grants to Jemena.

On this basis, Jemena has not demonstrated the prudency and efficiency of the proposed opex step change.

Hazard Space

The current 2005 regulations[141] require Jemena to monitor the condition of vegetation that could be classified as a hazard. Under the 2005 regulations, the Jemena management plan must specify the management procedures to be adopted to ensure compliance with the Code of Practice. This must include details of the methods to be used to monitor conditions in the area beyond the regrowth space to identify any vegetation that could become a hazard to the safety of the electric lines under the range of weather conditions that can reasonably be expected to prevail in that area.

The draft 2010 regulations give Jemena the authority to minimise hazards by pruning or removing trees that are likely to fall onto or otherwise come into contact with an electric line.

Jemena state that they currently have 46 hazard trees on a register. These hazard trees are being monitored at each inspection cycle. Jemena have calculated the costs of managing the hazard trees at $1,500 per tree. This cost is higher than the $1,200 estimate

[140] Based on meetings and correspondence with representatives of ESV between 1 February and 28 February 2010.
[141] Clause 9(4)(o)(iii)

to remove overhanging trees from a whole span of 66kV line. Jemena has not described the proposed action for hazard trees and how the costs build up to $1,500 per tree.

Benchmark tree removal costs from information provided during the EDPR process suggest a figure of between $1,000 and $1,200 for tree removal.

In addition, Jemena has assumed in its calculations that 50 hazard trees will require action each year. This does not appear to reconcile with the fact that Jemena currently has only 46 hazard trees on its register at present, and has not previously had the rights to remove the hazard provided under the draft 2010 regulations (i.e. this figure should represent the total number of hazard trees that have emerged since the introduction of the regulations, if not earlier).

Based on an estimated tree removal cost of $1,200 per tree, Nuttall Consulting considers that a total of $55,200 is reasonable to address the 46 identified hazard trees. This cost would be incurred on a once-off basis. Future removal of hazard trees could be undertaken as individual hazard trees are identified through the standards inspection and vegetation maintenance cycle.

Jemena vegetation management summary

The following table summarises the Nuttall Consulting recommendations in relation to the proposed Jemena vegetation management step changes.

Table 122 - Recommended Jemena vegetation management opex step changes ($000)

	2011	2012	2013	2014	2015	Total
Consultation requirement	-	-	-	-	-	-
Inefficiencies, Consultation	-	-	-	-	-	-
Insulated cables	$686	$686	$392	$392	$392	$3,330
Overhanging vegetation	-	-	-	-	-	-
Exemption – cessation	-	-	-	-	-	-
Hazard space	$55.2	-	-	-	-	$55.2
Total ($M)	$741	$686	$392	$392	$392	$3,285.2

Nuttall Consulting notes that the results from the Victorian Royal Commission into the bushfires of 2009 is likely to have a significant impact upon the management of vegetation in Victoria and the roles of the DNSPs. It is considered likely that any recommendations from the Royal Commission will have cost impacts upon the Victorian DNSPs.

SP AusNet - Hazardous trees

SP AusNet has identified additional operating expenditure associated with hazardous trees. The proposed additional expenditure required is provided in the following table. The proposed program is not based on a direct regulatory obligation, but on a cost and benefit analysis.

Table 123 - Proposed SP AusNet hazardous trees opex step changes ($million)

	2011	2012	2013	2014	2015	Total
Hazardous trees	$3.94	$3.94	$3.94	$3.94	$3.94	$19.7

SP AusNet has identified that vegetation is responsible for approximately 22% of fire reports and that much of these fire reports and due to vegetation outside of the clearance space.

SP AusNet also claim that the risk associated with vegetation management is increasing due to climate change. Nuttall Consulting has been advised by the AER that the climate change models provided by SP AusNet and the other DNSPs have not been accepted as “fit for purpose”.

The SP AusNet proposal is to target the removal of an additional 5,000 "hazard" trees per annum. The intention of this program is to reduce network fire related incidents due to trees from 17 to 10 per annum.

The estimated cost for addressing 5,000 hazard trees per annum as part of the enhanced safety program is $3.94 million. SP AusNet has estimated a societal risk of $810,000 per tree related fire incident. This assessment delivers an annual benefit for the program of an estimated at $5.67 million assuming a reduction of7 incidents per annum.

SP AusNet considers that the overall societal benefit satisfy the National Electricity Objective in promoting efficient investment in the electricity system.

Nuttall Consulting is a technical consulting business and the assessment of societal benefits is beyond the core competency of this firm. It appears self-evident to Nuttall Consulting that the costs of the bushfires of 2009 were enormous and that there is clearly a significant benefit in reducing the potential for these to recur.

Further complicating the assessment of this proposal is the impending findings and recommendations from the Royal Commission. These recommendations have a significant potential to overlap or impact on the proposed hazardous tree removal program.

Given that SP AusNet is not proposing to commence this program until 2011, the uncertain impact of the Royal Commission and the significant scale of the program (and therefore impact on customers) Nuttall Consulting recommends that this program is not added to the allowed opex, but is considered in conjunction with the findings from the Royal Commission.

SP AusNet - Electrical safety (Bushfire mitigation)

SP AusNet are proposing an additional operating expenditure requirement of $1.8 million to respond to changes in the draft 2010 regulations.

Table 124 - Proposed SP AusNet hazardous trees opex step changes ($million)

	2011	2012	2013	2014	2015	Total
Hazardous trees	$0.36	$0.36	$0.36	$0.36	$0.36	$1.80

Nuttall Consulting understands that the draft 2010 regulations require SP AusNet to either:

- provide a detailed risk assessment for maintaining a five year inspection cycle for Private Overhead Electric Lines (POELs), or
- adopt a three year cycle in accordance with regulation 7(a) of the Electricity Safety (Bushfire Mitigation) Regulations.

SP AusNet state that they do not have sufficient asset details of customer POELs to undertake the required risk assessment, and are therefore required to implement a three year inspection cycle for POELs.

SP AusNet state that no costs associated with this enhanced inspection program are currently included in SP AusNet's Base Year (2009) operating and maintenance costs.

The SP AusNet costing for an independent inspection cycle for POELs is based on the unit rate for re-inspection of SP AusNet assets ($70/pole). SP AusNet considers that, due to the volume of POEL poles (26,000), that they expect a rate closer to $60/pole for POEL poles when undertaken on a three year cycle.

Based on these inputs, SP AusNet estimates that the incremental annual cost for POEL inspections to be $364k per annum or $1.82 million over the next control period.

Nuttall Consulting has been advised by the ESV that the adoption of a five-year POEL inspection cycle is not provided for in the historical regulatory framework. However, it appears to be standard industry practice that a five-year cycle has been adopted.

On this basis, the incremental costs for moving to a three-year cycle appear reasonable.

14.3 Climate change

Nuttall Consulting has been advised that this matter will be dealt with by the AER.

14.4 IT

The Jemena IT opex plan for 2011 - 2015 is forecast as direct opex of $70.03 million. The average annual growth rate forecast by Jemena is 3.4% from 2010 to 2015. In addition to these forecast increases in opex are a number of forecast opex step changes. Jemena states that the opex step changes are due to a combination of changes in business circumstances, risk management needs and the IT systems required in response as well as external impacts on IT operations and costs. A 1% efficiency assumption has been applied to these expenditures.

Nuttall Consulting has been requested by the AER to review four specific step change areas:

- Increased support of current systems ($0.69m)
- Introduction of new systems ($2.8m)
- SAP replacement (–$0.80m)
- New data centre facilities ($7.1m)

These step change areas are assessed in the following sections.

In general, Nuttall Consulting considers that there is a lack of information provided to identify and quantify the net benefit of many of the systems proposed.

Increased support of current systems

Jemena is proposing a step change in opex costs associated with the following IT projects:

- SAS Replacement
- BRIO Query Replacement
- Asset Defects Database
- Program & Portfolio Management

Nuttall Consulting has the information provided by Jemena in relation to each of the above projects. The level of information provided by Jemena was quite detailed and supported the majority of the proposed expenditure step changes.

The four new or expanded systems are a replacement and/or upgrade of an existing system. From the information provided it is not clear why the costs of the new system are greater than the existing unsupported and obsolete system. It is generally recognised that the costs associated with maintaining an older system, especially one that is out of vendor support, will increase over time. The cost calculation used by Jemena is generally based on 25% of the tools licence costs. This methodology does not appear to consider the costs of maintaining the existing obsolete and unsupported systems that are already included in the opex base year.

The benefits of the new system also do not appear to be quantified. The documentation identifies a number of efficiencies that will be achieved through the implementation of the new tools, however the benefits of these do not appear to be considered in the step change calculations.

Based on the absence of recognition of the existing system costs and the proposed benefits, Jemena has not provided substantiation for the step change costs in this area.

Introduction of new systems

Jemena is proposing a step change in opex costs associated with introduction of new systems:

- Emergency, Risk and Safety Management
- Real Time Security Implementation
- Spatial intelligence Tool
- Distribution Management System
- RESIS - Relay equipment setting information system
- Equipment Testing Recording & Verification
- Services Delivery and Field Mobile Computing

The programs in this area were generally well documented and supported. The step change expenditures are generally recommended for consideration by the AER with the exception of the following.

- The emergency risk and safety management system introduces a range of in-house developed information and support facilities for the emergency response teams including field workers and the end customers. Jemena state that the " level of step change is consistent with the increase in the number of extreme events that JEN is likely to experience in the forthcoming regulatory control period, as explained in the AECOM expert report"142. The AER has advised Nuttall Consulting that the climate change modelling has not been accepted at this time. On this basis, Nuttall Consulting is unable to recommend the addition of this step change expenditure to the allowed opex base for the next regulatory period.
- Jemena has identified that it is one of the few DNSPs in Australian that has not already implemented a DMS. The supporting documentation also identifies that the DMS will replace a number of existing manual systems. The information provided identifies that these benefits will be assessed closer to the project commencement in 2011. Nuttall Consulting considers that the costs proposed by Jemena are not efficient as they do not recognise the project benefits. Nuttall Consulting recommends that the opex step change component of the DMS costs is not allowed as the overall benefits of the DMS could outweigh the step change operating expenditure.
- Jemena has not provided sufficient information to support the Equipment Testing Recording and Verification. It is assumed that this cost is for the input of information to the RESIS system. If this is the case, these costs would simply be replacing the existing testing, recording and verification systems - whether they are manual or electronic. Nuttall Consulting recommends that the opex step change component of the Equipment Testing Recording and Verification costs is not allowed as one system is simply being replaced by another.

[142] JEN EDPR response to AER IT opex step changes 22 Jan 10 - 12 Feb 10.pdf

SAP replacement

Jemena's corporate functions are supported by SAP 4.6c. Jemena reports that the SAP capabilities include finance, HR, payroll, asset maintenance, procurement and logistics. The SAP system is shared with other customers of Jemena Asset Management. The system is over 12 years old and is on extended support that is costly – there are approximately 200 patches that have not been implemented.

Jemena notes that the current SAP 4.6c system is not aligned with the business and many workarounds are executed by staff. In addition, there are business initiatives and operational changes that are impeded by the current system.

Nuttall Consulting has reviewed the SAP project - refer to the Nuttall Consulting capex report on non-network general - IT. The results of the Nuttall Consulting capex review support the savings proposed by Jemena commencing in 2013.

New data centre facilities

Jemena is proposing the replacement of the current data centres due to the existing facilities reaching capacity, with no scope to further expand that capacity. Jemena considers that it must find new facilities. In addition, Jemena has been given notice to do so by the owner of the production data centre facility. An interim extension to the contract has recently been agreed with the data centre owner Hewlett Packard.

Jemena must therefore enter into agreements for new data centre facilities based on a build or service provision. Jemena has ruled out the buy option based on the lack of market availability.

Proposed data centre facility projects include:

- Production DC - Facility Costs
- Production DC - Racks Costs
- Disaster Recover DC
- Disaster Recovery DC - Racks Costs

Jemena has identified the additional long-term benefits of the proposed works as including the enablement of improved infrastructure architecture within a modern technology facility. Jemena has not provided any allowance or quantified this benefit in the forecast costs.

Jemena state that market rates have been tested by competitive tender.

The main component of the forecast costs relates to purchasing data centre facilities on a "per rack" basis. The growth in racks is forecast using a Jemena model that shows an annual increment of 10%, which "reflects new system applications and their data plus new data available from the Advanced Metering Initiative".

Nuttall Consulting considers that the allocation of additional growth for AMI data should be excluded from the allowed expenditure as this should be covered through the AMI cost recovery process. Jemena has not provided an allocation for the AMI data costs, on this basis, Nuttall Consulting has assumed that this data represents 5% of the annual increment.

Jemena state that their existing rack costs are $600 per rack and that the new costs are $2,500 per rack. Nuttall Consulting considers that the new cost is in line with industry standard rates.

Jemena has provided for an incremental step change for the production and disaster recovery centre racks ($2,500 less $600 = $1,900 per rack per year).

Jemena has allocated $65k and $35k per annum for the production and disaster recovery facilities respectively. Nuttall Consulting considers that the new data centres will require additional IT resources to operate and support the facilities. These costs represent less than 10% of the overall rack costs and are considered reasonable and consistent with expected industry rates.

Table 125 - Recommended Jemena IT opex step changes ($million)

	2011	2012	2013	2014	2015	Total
IT opex step changes	$1.05	$1.10	$ 1.15	$1.21	$1.27	$5.78

14.5 ESMS

SP AusNet - Condition monitoring

SP AusNet are proposing additional operating expenditure requirements of $5.3 million to provide additional condition monitoring of high value assets.

Table 126 - Proposed SP AusNet hazardous trees opex step changes ($million)

	2011	2012	2013	2014	2015	Total
Condition monitoring	$1.04	$1.04	$1.04	$1.04	$1.04	$5.30

The additional expenditures proposed by SP AusNet appear to cover a wide number of condition assessment types and asset types. The program is stated as being to increase the existing condition management program to more effectively manage the specific network assets. The proposed program includes:

- Research and development of new CM technologies, techniques and devices
- Further development of asset health dashboards
- Increased substation inspections and asset condition scans
- Off line electrical test program for all power transformers
- Annual performance profile test for CBs that have not operated for more than 12 months
- Electrical test program for bushings of 22kV and 66kV bulk oil CBs

- Oil sampling and electrical testing of instrument transformers

As indicated by SP AusNet, condition monitoring is an important and ongoing component of asset management. There is a trade-off in the value of more and better information compared to the costs of obtaining that information.

The current regulatory regime is designed to provide incentives to the DNSPs to improve their efficiency and "outperform" the benchmark allowances. The resultant efficiencies are then retained by the business for a period of time. Businesses that invest in developing efficiencies are thereby rewarded.

The funding of research and development activities is contrary to this approach as it would provide funding to the businesses to achieve efficiencies - essentially allowing a double recovery.

The SP AusNet proposed condition monitoring expenditures will, according to SP AusNet, provide the following benefits:

- Minimise occupational health and safety (OH&S) risk to employees and contractors
- Minimise risk to public due to asset failure
- Optimised decision making for asset maintenance, operation and replacement based upon condition and risk
- Civil actions resulting from personal injury/compromised health
- ‘promote efficient investment in’ the electricity system.

SP AusNet has not provided quantification of these benefits.

One of the key outcomes of the condition monitoring is better knowledge of the real condition of the asset. This should result in better decisions being made in relation to optimal maintenance and replacement strategies. The outworking of these strategies would therefore be likely to include reduced asset failures and/or life extension, reduced outages and associated fault and maintenance expenditures. The lack of any quantitative benefits associated with this step change does not appear reasonable.

Nuttall Consulting recognises that the average asset age of the network is incrementally increasing. This may naturally result in additional expenditures associated with this aging. However, the aging of the network is quite slow as the number of new and replaced assets is offsetting the annual age increase of the network population. On this basis, it may be expected that a small number of additional condition monitoring changes would be expected over time rather than a significant step change in any single period of time.

Nuttall Consulting does not consider that the proposed opex step change for condition monitoring has been proven as prudent and efficient by SP AusNet. Nuttall Consulting does consider that a small increment in condition monitoring may be prudent, but that supporting evidence of the benefits would be necessary to justify the expenditure.

SP AusNet - Power transformer refurbishment

SP AusNet are proposing additional operating expenditure requirements of $3.8 million to provide for the refurbishment of power transformers.

Table 127 - Proposed SP AusNet transformer refurbishment opex step changes ($million)

	2011	2012	2013	2014	2015	Total
Power Transformer Refurb	$1.14	$0.77	$0.70	$0.6	$0.58	$3.8

SP AusNet notes that the five key components of transformers are oil, core & windings, bushings, on-load-tap-changers and auxiliaries (oil cooling pumps fans controls & circuitry). On site refurbishment currently addresses oil, bushings, OLTCs and auxiliaries that are assessed as being in "poor" or "very poor" condition. This on site refurbishment does not include the core & windings of the transformers.

The SP AusNet asset management documentation for power transformers[143] identifies a large percentage of the population that is older than 49 years. This is not uncommon for Australian DNSPs.

The power transformer asset management documentation describes a condition assessment and weighting process that appears to consider a number of factors including:

- Dielectric and Thermal Condition
- Physical & Operating Condition
- Historic Information
- Design Suitability & Limitations

The weighting of these conditions includes consideration of

- The type of components (e.g. core and coils) of concern
- The system planning requirements
- The most cost effective solution - replace or refurbish

The documentation provided does not describe why a step-change is required. There does not appear to be any external or internal driver that requires anything other than an incremental change to current practice. In addition, the information provided by SP AusNet indicates that it does not intend to commence the adoption of power transformer refurbishment until 2011.

In addition, the proposed refurbishment program would be likely to result in reduced power transformer failures and/or life extension, reduced outages and associated fault and maintenance expenditures. The lack of any quantitative benefits associated with this step change does not appear reasonable.

If SP AusNet is currently hindered from adopting the power transformer refurbishment program due to the benefits being incurred in a subsequent control period, then this may

[143] AMS 20-71 "Power Transformers and Station Voltage Regulators"

be a reason for the program to be considered for a step change. However, this requirement is not evident or quantified in the information provided.

Based on the lack of quantified benefits and supporting information Nuttall Consulting is unable to recommend the addition of this opex step change to the allowed expenditure.

SP AusNet - Substation earthing systems

SP AusNet are proposing additional operating expenditure requirements of $1.0 million associated with substation earthing system.

Table 128 - Proposed SP AusNet substation earthing opex step changes ($million)

	2011	2012	2013	2014	2015	Total
Substation earthing	$0.28	$0.18	$0.18	$0.18	$0.18	$1.0

SP AusNet has identified that zone substation switchyard resurfacing and earth grid testing is required to ensure that the electrical safety and surface stability integrity of the substations is maintained.

The SP AusNet step change assessment is based on the resurfacing of switchyards in six zone substations and earth grid current injection testing that is to be completed in all zone substations by 2015.

Information provided by SP AusNet notes that the resurfacing costs are based on an average estimate of $100k per substation. Current injection tests costs based on testing eight zone substations per year at an average cost of approximately $10k per substation.

SP AusNet considers that these works are required to ensure the electrical safety and surface stability integrity is maintained.

Nuttall Consulting has reviewed the proposed step change works and considers that they are reasonably required under the existing regulations. Discussions with ESV indicate that there is no material change to the regulations in the areas of substation earthing. On this basis, substation earthing and resurfacing is an existing obligation and can reasonably be considered as part of the existing cost base for SP AusNet.

Nuttall Consulting is unable to recommend that addition of this step change expenditure to the allowed expenditure for the next control period.

14.6 At risk townships (bushfire mitigation)

Powercor is proposing additional opex expenditure of $22 million for "at risk township" protection plans ($22.0m).

On 18 August 2009, the Victorian Government, as part of its response to the events of 7 February 2009, announced its intention to establish individual township protection plans for 52 towns and communities over and above standard municipal fire prevention plans. Thirty-eight of these towns are located in Powercor's service territory. The Government announcement remains an indication only at this stage as no formal requirements have yet been put in place.

Of the 38 towns within Powercor's service territory, six are already captured within the areas treated under the existing enhanced bushfire mitigation program.

The activities identified by Powercor as additional to the existing bushfire mitigation and other business obligation include:

- Line Construction Survey
- LIDAR Aerial Imaging
- Independent Asset Audit
- Ground Fuel Reduction
- Broader review of hazardous trees outside clearance space
- Research into new technologies

Of the above activities, Powercor has identified in discussions[144]that only 2 activities are currently provided for the 6 at-risk townships and that the other 4 are new initiatives that are proposed by Powercor.

Powercor was requested to "provide analysis (e.g. spreadsheet) that shows how the expenditure increases have been calculated and the proposed benefits/outcomes." The information provided by Powercor[145] was very high-level and did not provide sufficient detail to reasonably determine how the expenditure increases had been calculated.

Powercor was requested to "describe the anticipated benefits of the program (e.g. reduced asset losses, reduced outages, reduced fault and emergency works, reduced line patrols, etc). The Powercor response[146] stated that the "anticipated benefits of the program are to reduce as far as practicable the risk of fires caused by asset failure or vegetation impacting on power lines". This response does not address the information requested even thought specific benefits were identified. These benefits would almost certainly accrue from the deployment of the programs proposed by Powercor. It is not clear why Powercor has chosen not to respond to the specifics of this request for information.

Powercor has identified that the proposed works will reduce the risk of fires caused by asset failure and vegetation contact. A reduction in these events will result in:

- fewer asset losses from fires - requiring fewer capex replacements
- reduced outages from vegetation contact - resulting in improved reliability outcomes (STPIS impact) and reduced opex associated with fault restoration
- reduced outages from asset failure - resulting in improved reliability outcomes (STPIS impact) and reduced opex associated with fault restoration.

[144] 23/2/2010
[145] CitiPower Powercor Opex Step Changes v0 3.pdf
[146] Ibid

In discussions, Powercor stated that they have not considered the impact that these vegetation management activities will have upon the incidence of fire starts or outage rates.

The value of the above benefits are likely to be material and do not appear to have been accounted for in the Powercor proposed expenditures. Nuttall Consulting is unable to determine a potential value for the opex, capex and reliability benefits identified above due to the lack of supporting information provided by Powercor.

Nuttall Consulting considers that the research and development expenditure proposed by Powercor for township protection plans is not consistent with the operating expenditure objectives defined in the NER. These objectives use terms such as "maintain", "comply", and "meet or manage".

Powercor has not identified any defined benefit from the research and development projects. It is not clear how these expenditures reflect the efficient cost of achieving the operating expenditure objectives when they are additional to the current base expenditure and provide no defined benefit. On this basis, Nuttall Consulting considers that it is not consistent with the NER to accept these additional proposed expenditures.

As discussed previously, electricity regulation in the NER relies on the revealed cost approach to identify the efficient cost of service. DNSPs that are able to reduce their costs below that of the regulatory allowances are able to improve returns to their shareholders. This increased profitability acts as an incentive to reduce costs.

Research and development is one means whereby a DNSP could identify and subsequently implement business efficiencies and reduce ongoing costs. It would be inconsistent with the NER for the costs of research and development to be included in the expenditure allowances without any recognition of the potential benefits of this investment.

In its 2005 Final Determination, the ESC was of the view that research and development expenditure should not be included in allowed expenditure[147]. The ESC considered that where a distributor can identify benefits in pursuit of efficiencies, the power of the incentive-based framework would promote the distributors' development of such programs without any additional funding. In relation to reliability benefits, where projects can provide a measurable impact on reliability, the distributor benefits through the S factor scheme and the avoided payment of GSL payments.

In summary, the events of Black Saturday and the Victorian Government's announcement of the "At Risk Township" protection plans provide a compelling case for expenditure in this area. However, the lack of a claim from SP AusNet for expenditure in this area suggests that the required response may not be as material as suggested by Powercor.

The lack of supporting evidence provided by Powercor has made the assessment of the expenditures and associated benefits problematic. Nuttall Consulting recommends that the expenditures associated with line survey, LIDAR, independent asset audits and R&D should be removed and that adjustments should also be made for identified benefits and

[147] Electricity Distribution Price Review 2006-10 Final Decision Volume 1- Statement of Purpose and Reasons. October 2005, page 312.

the 2009 ground photography expenditures. The later recommendations have not been able to be quantified.

14.7 Opex/Capex balance

Jemena is proposing an increase in opex to "achieve capex/opex balance". The proposed additional expenditure over the next control period is $893,000.

- ZS TEV testing ($0.05m)
- ZS pot VT/CT testing (0.024m)
- ZA transformer dryouts (Trojan) ($0.055m)
- DP testing ($0.25m)
- ZS transformer condition testing ($0.21m)
- ZS power quality metering maintenance ($0.055m)
- ZS secondary spares maintenance ($0.002m)
- Cable testing ($0.29m)

The AER has sought information from Jemena in relation to the drivers, business cases and benefits associated with each of the expenditures described above. The following section discusses the proposed expenditures.

ZS TEV testing

Transient Earth Voltage (TEV) detection is proposed to be applied primarily to metal clad switchgear. This is a non-invasive condition monitoring procedure that can be conducted on live and in-service plant. Jemena states that this process will supplement invasive condition monitoring electrical testing of this type of plant but does not replace it. It can be described as a screening process that can provide an alert to a deteriorating plant condition associated with partial discharge.

The Jemena Zone Substation circuit breaker management plan[148] identifies that TEV testing is an "alternative" to more comprehensive and detailed condition monitoring tests. The TEV test is done more regularly, but is less invasive and does not require shut-down of the inspected assets.

The TEV testing approach as described by Jemena would appear to be a prudent approach to condition monitoring of metalclad switchgear. Jemena was asked to identify the benefits of this proposed opex increase, but did not provide any assessment of the associated reduction in intrusive testing costs, the potential for life extension or reduced failures.

ZS pot CT/VT testing

[148] Appendix 11.21- JEN 4356-151 ZSS Circuit Breakers - CONFIDENTIAL.doc

Jemena state that the increasing risk of age related failure in an ageing asset class population means that additional condition monitoring programs are required where they have not been applied in the past.

The zone substation CT/VT testing program is for the implementation of additional condition monitoring tests so that the ageing condition of oil-filled current and voltage transformers can be better assessed and consequently their refurbishment and retirement can be better planned and the risk of failure better managed.

Jemena state that without these additional condition monitoring tests it is likely that Jemena would require increased capex expenditure for retirement of aged current and voltage transformers.

The increased level of condition monitoring as described by Jemena could be considered a prudent requirement to manage an aging CT and VT asset population. Jemena however has not provided any economic analysis that demonstrates the prudency and efficiency of this proposed increase.

ZS transformer dry-outs

The dry out program for zone substation transformers was established in 2008 with the deployment of one online oil dry-out plant. Jemena is planning to deploy a second unit to more effectively cover the number on transformers in the fleet that have elevated moisture levels and thereby extend the life of these transformers.

Jemena predict that the cost of this program will double when the second unit is deployed. Jemena state[149] that without these additional life extension programs it is likely that they would require increased capex expenditure for retirement of aged transformers.

The increase in the dry-out program as described by Jemena could be considered a prudent requirement to manage an aging transformer fleet. Jemena however has not provided any economic analysis that demonstrates the prudency and efficiency of this proposed increase.

ZS DP testing

The increased focus on the assessment of the condition reflects the ageing population of the critical plant. This program is for the implementation of additional condition monitoring tests so that the ageing condition of power transformers can be better assessed and consequently their refurbishment and retirement can be better planned and the risk of failure better managed.

Jemena state[150] that without these additional condition-monitoring tests it is likely that they would require increased capex expenditure for retirement of aged transformers.

The additional transformer testing as described by Jemena could be considered a prudent requirement to manage an aging transformer fleet. Jemena however has not provided

[149] JEN response - step change opex questions 22 Jan_additional maintenance expenditure.pdf
[150] JEN part response to AER step change opex questions 22 Jan_prot review, PQ mtce and spares mgt.pdf

any economic analysis that demonstrates the prudency and efficiency of this proposed increase.

ZS transformer condition testing

Routine condition assessments via diagnostic electrical tests are not currently performed on power transformers by Jemena. Currently they are only conducted reactively as a result of problems or faults on power transformers. This program is for the implementation of routine condition monitoring tests so that the ageing condition of power transformers can be better assessed and consequently their refurbishment and retirement can be better planned and the risk of failure better managed. Jemena state that without these additional condition monitoring tests it is likely that JEN would require increased capex expenditure for retirement of aged transformers.

The use of routine electrical testing of power transformers as described by Jemena could be considered a prudent requirement to manage an aging transformer fleet. Jemena however has not provided any economic analysis that demonstrates the prudency and efficiency of this new program.

ZS PQ meter maintenance

Zone substation and end of feeder power quality (PQ) meters are relatively new assets having been installed in the early to mid 2000s. Jemena state the meters are only now due for maintenance.

Depending upon the type of hardware, the maintenance frequency for these meters varies between 5 and 8 years. Jemena originally identified 24 meters for maintenance and later amended that number to 18 units due to planned retirement of some of the meter stock.

Asset information data provided by AGLE[151] for the 2006 EDPR listed 21 PQ meters installed in 2000. The age profiles for the 1999 ESC replacement model indicated 4 units installed in 1998 and 6 units in 1995. These units must have been replaced or retired as they did not appear in the 2006 submission.

Given the 2000 installation date all of the 21 meters should have been subject to maintenance in or prior to the current control period according to Jemena's processes.

Jemena was asked whether the "existing meters (were) already due for maintenance" and why this had not been undertaken. In its response[152], Jemena did not directly answer this question.

Based on the evidence of some PQ meter installation dates as early as 2000 and the lack of a response as to whether maintenance had already been undertaken on these meters, the case for additional maintenance expenditure is not sufficiently supported.

Spares maintenance

[151] AGLE - Replacement model asset age profile - excel spreadsheet.

[152] JEN part response to AER step change opex questions 22 Jan_prot review, PQ mtce and spares mgt.pdf

Secondary spares are typically stored in a secure and stable environment (dry, corrosive free and not in direct sunlight) so as not to degrade the health and condition of the spare equipment.

Jemena state that a periodic maintenance regime is recommended for electronic based secondary spare equipment (including protection & control relays, power quality meters, battery chargers etc.) so as to ensure that the spare equipment is serviceable at all times and ready for use when required.

Jemena identified two manufacturers who recommend[153] that their equipment be powered up once every year, for one hour continuously, to avoid deterioration of electrolytic capacitors and subsequent relay failure. Jemena is proposing a more conservative maintenance interval of four years for the secondary equipment population.

The cost for this step change in expenditure is estimated based on internal labour rates and an allowance of 2 hours per device under test.

Jemena was asked to identify the benefits of this proposed additional expenditure. The Jemena response identified that "failure to implement this practice increases the risk that the spare equipment will not be serviceable when called upon, that is, during times of emergency"[154].

From the Jemena response it is not clear whether there is any benefit from the proposed expenditure:

- The risk that a spare unit may not be available has not changed as current practice is not to energise the spare units.
- It is not clear how long the manufacturer recommendations have been in place and whether there have been historical failures of spare equipment that have impacted Jemena's performance.
- If a spare unit were to fail, whether there is more than one spare or alternate options for interim operations.
- As a replacement unit is reported to cost $10k, it is not clear whether it is economically justified to spend $10k every fours years to prevent a possible failure.

Typical stores procedures are to utilise older stock as new stock is purchased. This is referred to as FIFO (first in - first out). It is not clear from the information provided by Jemena as to whether the identified protection relays are the current standard for new and replacement installations. If they are the current standard, Jemena does not appear to have considered the impact of new stock moving through the inventory and thereby deferring the need to power up the spares in question.

Based on the above, Jemena has not demonstrated that the proposed expenditure is prudent and meets the requirements of the NER. Nuttall Consulting is therefore unable to recommend the addition of this expenditure to the opex allowance.

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[153] General Electric (GE) and Schweitzer Engineering (SEL)

[154] JEN part response to AER step change opex questions 22 Jan_prot review, PQ mtce and spares mgt.pdf

In terms of efficiency, Jemena identified a two-hour unit of time to cycle "the auxiliary power supplies of all major digital microprocessor protection relays for one hour every 4 years". If this were a single unit that was being powered up, it may be reasonable to assume a two-hour labour requirement. The Jemena information did not identify the exact number of units being energised, although the $10k expenditure suggests that it is a volume of units sufficient to allow for significant synergies in the process.

Cable testing

Jemena Asset Management (JAM) has developed and is implementing an “Underground Cable Management through Condition Based Assessment” program on the United Energy network. It is intended that JAM will leverage off the learnings in the United Energy program to implement the same program on the Jemena network to manage Jemena’s underground cable population.

This will allow the condition of cables to be monitored over their life by the establishment of condition benchmarks and will assist with replacement decisions. Without these additional condition monitoring tests it is likely that JEN would require increased capex expenditure for retirement of aged cables.

Jemena staff described the tests as "partial discharge" type tests, although no information about them was provided in the referenced literature[155].

The additional testing of cables as described by Jemena could be considered a prudent requirement to manage an aging cable population. Jemena however has not provided any economic analysis that demonstrates the prudency and efficiency of this proposed increase.

Summary

As discussed above, we do not consider that Jemena has provided adequate information to support the proposed increases associated with the PQ meter maintenance and spares maintenance programs.

With regard to the other programs, we consider that the maintenance practices are reasonably well defined. In this regard, it may well be prudent to implement these practices in the next period. However, it is important to note that Jemena’s views on the need for these practices are not driven from changes to regulatory obligations, but from its views on the economic benefits. That is, in Jemena’s view, the proposed additional opex should realise net benefits through avoided capex and reduced risks. Jemena however has not provided economic analysis that clearly justifies the scale and timing of the proposed increases.

To a large extent, we consider that the incentive mechanisms in the existing regulatory regime should inherently allow for these types of changes to routine maintenance practices. This is particularly the case for the benefits due to avoided capex and reliability improvements that should result from these programs. As such, there is not a clear case

[155] Appendix 11.17 - JEN 4356-116 Underground Cables Systems - CONFIDENTIAL.pdf

that the step increases proposed by Jemena are required, even if it is prudent to undertake the programs.

It is accepted that the incentive mechanisms do not inherently allow for reductions in certain risks, such as those associated with safety and environmental matters. It is also accepted that we would expect that the proposed practices may reduce these types of risk. However, we would also expect that the benefits captured through the existing incentive mechanisms (i.e. avoided costs and reliability improvement) should form the majority of benefits realised through these programs.

Therefore, given the absence of economic analysis that clearly demonstrates the need for these step increases in the context of its existing incentive mechanisms, we do not consider they are justified.

It is worth noting that Jemena has proposed a significant increase in capex from historical levels. A significant portion of this increase is driven by Jemena's views of its aging asset base, and this in turn, is related to the proposed opex programs discussed here. We have recommended a significant reduction to Jemena's proposed capex, but our recommendation still allows for increasing levels of capex during the next period. In our view, our recommendation on capex should not invalidate our findings discussed here.

14.8 Demand management

West Melbourne Terminal Station (WMTS) is facing the likelihood of peak demand exceeding the available capacity of the station[156]. WMTS supplies Port of Melbourne, North Melbourne, Docklands and the western half of Melbourne's central business district.

Following the completion of the Metro 2012 project, the energy at risk at West Melbourne will decline through the transfer of load to Brunswick Terminal Station. CitiPower state that the necessary works will not be completed until late 2013. Consequently, in the interim period 2011-13, it will be necessary for CitiPower to seek alternate arrangements to ensure the security of the network in the areas supplied by WMTS.

CitiPower has commenced preliminary discussions with a number of parties offering demand side management services. CitiPower states that they intend to enter into agreements with one or more demand side management proponents on the basis they will be able to co-ordinate the curtailment of load in the area supplied by WMTS should the security of the network in that area be at risk.

In return for offering this service, it is anticipated that demand side management service providers will charge CitiPower an annual fee.

CitiPower was requested to provide details of the offers from the demand side service providers identified in their proposal. CitiPower provided details on only one provider - Energy Response. In discussions with CitiPower staff[157] it was confirmed that no contract

[156] Forecasts suggest that WMTS will exceed it "N" rating in 2011.
[157] 23 February 2010 - AER offices.

for these services was in place for the 2009/10 summer period and that the risk was managed through the use of voltage reduction.

The cost for demand management identified in the final report was $170,000 per MVA.

CitiPower provided a spreadsheet supporting the forecast of demand management expenditure. This spreadsheet detailed WMTS station demand in 2009 through until 2013. The spreadsheet identified a cost of $1,700,000 in 2009/10. As discussed previously, CitiPower have indicated that the contract was not in place for 2009/2010. As such, the costs indicated in the spreadsheet have not been incurred suggesting that CitiPower has found a more effective alternative.

The demand reductions identified by CitiPower as being required for WMTS were as follows:

- 2009-10 10MVA
- 2010-11 15MVA
- 2011-12 20MVA
- 2012-13 25MAV

CitiPower was requested to provide an explanation for how the demand reductions values were derived. CitiPower did not provide information that supported the development of these figures. The demand reductions proposed do not correlate with other information published by CitiPower in relation to WMTS[158]. CitiPower was requested to describe how these two documents can be reconciled. No response was provided to this request with the exception of a statement that "the figures in the spreadsheet of 10, 15, 20 & 25 MVA for 2010, 2011, 2012, & 2013 respectively are the expected guaranteed demand reduction although more is possible but cannot be guaranteed without further analysis"[159].

The 2009 Transmission Connection Planning Report (TCPR) identifies 4 options for managing the contingent risks at WMTS until the Metro 2012 project is complete. These options include:

- a contingency plan for the transfer of load to adjacent substations
- a contingency plan to utilise the capacity of the “Normal Open" 220/66 kV transformer
- demand reduction "is an opportunity to develop a number of innovative customer schemes to encourage voluntary demand reduction during times of network constraint"
- embedded generation in the order of about 150 MVA, will help to defer the need for augmentation.

[158] Transmission Connection Planning Report, Produced jointly by the Victorian Electricity Distribution Businesses, 2009 - Transmission Connection Planning Report Risk Assessment: WMTS 66 kV

[159] Email from CitiPower dated Fri 5/03/2010 5:20 PM.

The information provided by CitiPower to support the proposed demand management expenditure does not appear to consider that any of the other four options will be used. Given that the total proposed expenditure for the demand management option is $10 million, it would be prudent that the costs and benefits of the other projects are considered.

In summary, the load forecasts for WMTS clearly identify an emerging network constraint and that a response will be required to avoid the loss of supply and minimise the load at risk. Demand management is a potentially viable option for addressing these risks. The information provided by CitiPower does not support the proposed expenditures. Key areas of concern include:

- the discrepancy between proposed demand reductions and the forecast load at risk
- the lack of analysis on alternate options (as identified by the TCPR)
- demand management costs only provided by one demand management supplier
- the expected reduction in demand by demand management of 10MVA for 2009/10 was not contracted for.

Demand management may be a viable solution, or part of the solution, for addressing the contingent risks at WMTS. CitiPower has not provided information that would suggest that demand management is the only prudent alternative or the most efficient alternative. The proposed expenditure of $10 million is not supported on the information provided.

15 Appendix J – Load profiles associated with reinforcement expenditure forecasting

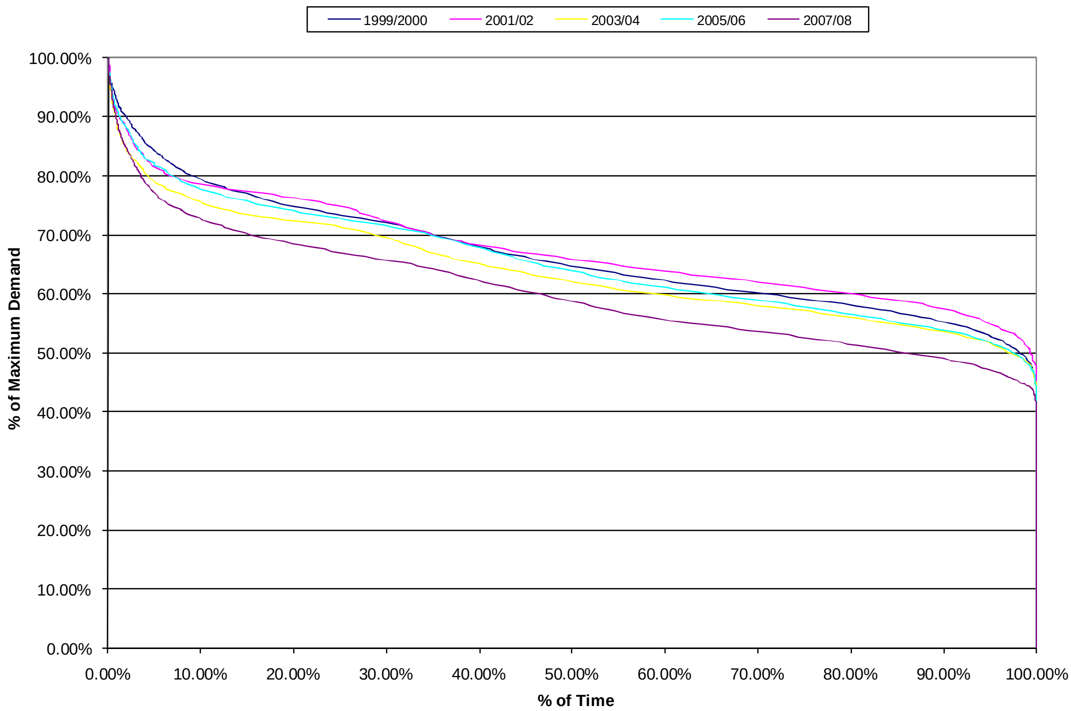
The DNSPs' methodology, used to identify network need in the reinforcement expenditure categories, estimates energy at risk based upon a number of assumptions. One of these is an assumed load profile.

Generally, all the DNSPs use a load profile based upon a historical year – generally between 1999/2000 and 2008/09. Given that demand growth has significantly outstripped energy growth during this period, and is predicted to do so through the next period, we have concerns that the DNSPs' assumptions may be overstating risks.

This appendix presents our analysis of historical load profiles in order to gauge the significance of this matter.

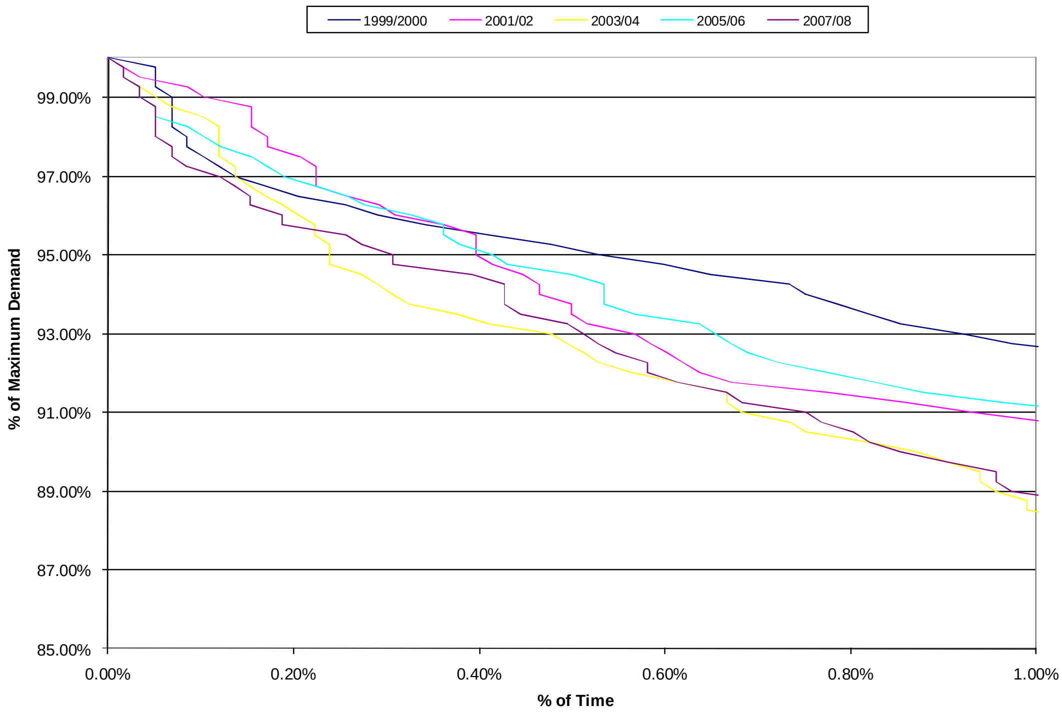
Figure 142 shows the Victorian load duration curves for the 5 years 1999/2000, 2001/02, 2003/04, 2005/06 and 2007/08.

Figure 142 – historical load duration curves



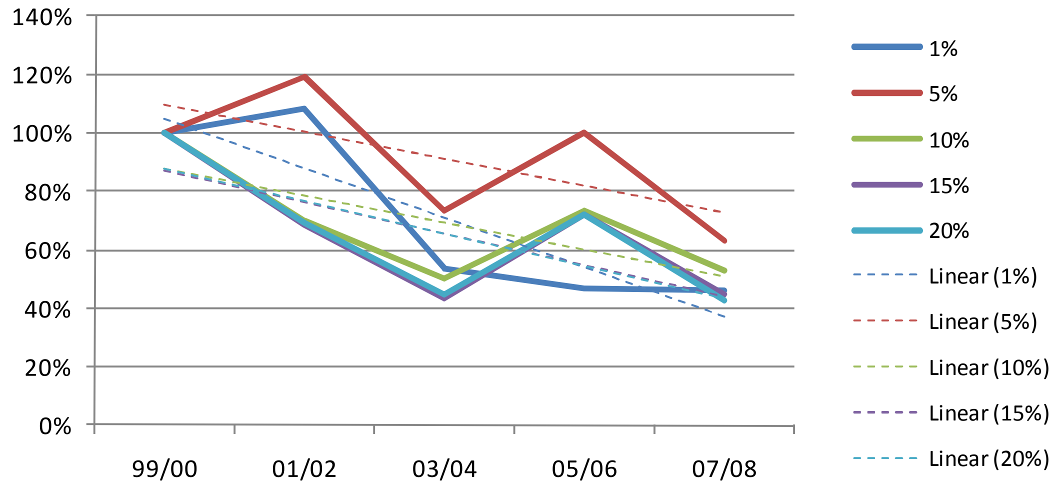
Energy is represented by the areas under the load duration curve. For calculating energy at risk, we are most interested in the curve around the peak demand regions (i.e. the top left of the load duration curve), therefore Figure 143 shows this region in more detail. This indicates that, in general, the area below the curve has been reducing since 1999/2000.

Figure 143 – historical load duration curve – near peak



To demonstrate the significance of this, Figure 144 shows the area under the curve for specific percentages from the maximum demand (i.e. the 10% curve indicates a notional network limitation that is 10% down from the maximum demand level). The percentage indicated on the y-axis has normalised the areas calculated for each load profile to the area determined by the 1999/2000 profile. This chart also shows the linear trend.

Figure 144 – percentage change in energy at risk



The chart above clearly shows that the energy at risk for a set demand level has been materially reducing since 1999/2000. More importantly, this chart suggests that load profiles, such as Jemena and CitiPower, which are based upon pre 2005/06 profiles may be overstating energy at risk by as much as 100%.

Furthermore, although it is reasonable to assume that a linear trend will not continue, it does appear reasonable to consider that an assumed load profile, based upon historical data, may be overstating energy at risk in the next period to some degree.

The significance of these results are discussed further in the respective DNSP sections that discuss reinforcement expenditure.

16 Appendix K – AMI investigations

16.1 Overview

The Victorian Government decided in 2006 for a rollout of advanced interval meters (AMI) to all Victorian electricity customers. The regulatory framework for the rollout was described in an Order in Council (OIC) made by the Victorian Governor in August 2007[160]. The OIC sets out the regulatory framework and the AER's role[161]. The OIC requires the DNSPs to install remotely read interval meters for all households and businesses consuming less than 160 MWh per annum by 31 December 2013.

The OIC provides for a pass through arrangement for AMI costs incurred by DNSPs through a building block recovery mechanism.

Under the OIC the AER was required to apply a series of tests in assessing and approving capex and opex forecasts to ensure they were within the scope of activities and specifications as set out in the OIC and otherwise prudent. In January 2009 the AER published a framework and approach paper describing "*how it would discharge its functions under the revised Order with respect to determining budgets and metering charges*"[162].

In October 2009, the AER released its final determination on the DNSPs' AMI budget and charges applications. The AER had engaged a technical consultant to assist in its review of the DNSPs' proposed budgets, and the consultant's report provided input to the draft and final determinations.

The final determination identified the allowed expenditures and charges for each of the DNSPs relating to their AMI obligations.

The AER's final determination considered the potential for double recovery of expenditures between the allowances made in the 2005 EDPR by the Essential Service Commission of Victoria and the AMI process. Nuttall Consulting has been requested by the AER to expand this investigation to cover the following:

1. consider the potential for double recovery between the expenditure proposed by the Victorian DNSPs for the 2010 EDPR and the AMI allowances
2. the identification of capex and opex proposed by the DNSPs that relates to the use of AMI data or the investigation of such.

[160] An amending Order in Council was made on 25 November 2008 - these orders are collectively referred to here as the OIC.
[161] This includes the determination of budgets, revenues and charges relating to the expenditure budgets and forecast revenues for 2009 to 2011 and associated metering charges for 2010 and 2011.
[162] Final determination - Victorian advanced metering infrastructure review 2009–11 AMI budget and charges applications, October 2009.

The potential for double counting only exists for the 2011 calendar year as this is the only period of overlap between the two price review processes.

The Nuttall Consulting approach and investigation are described in detail in the following chapters. In summary, Nuttall Consulting has seen no evidence of double counting or overlap between the EDPR proposals and the AMI allowances.

Four DNSPs (Jemena, United Energy, CitiPower and Powercor) have identified expenditures to leverage the information from the new meters. Jemena and United Energy have proposed opex of $200k each for these activities, while CitiPower and Powercor are proposing $8.1m and $18.9m in capex respectively. Whist we agree that there should be benefits through these “AMI leveraging projects”, and these benefits may well outweigh the additional costs, we do not consider that the DNSPs have:

- adequately quantified all of the costs and benefits that may accrue through the use of the AMI data, and defined these in terms of those provided for through existing incentive mechanisms (e.g. STPIS, EBSS) and those external to these schemes
- adequately demonstrated that their proposed expenditure represents only the incremental level above that available through the existing incentive mechanisms.

Therefore, in the absence of the above items, we do not consider that the DNSPs should be allowed the proposed expenditure.

16.2 Approach

Nuttall Consulting has been requested by the AER to identify and assess the potential for overlap or double-counting in the AMI and EDPR processes - specifically relating to IT opex and capex[163]. Based on this assessment Nuttall Consulting will provide a recommendation to the AER in relation to any revisions required to the EDPR proposed expenditures.

The Nuttall Consulting team has specific experience in assessing DNSP proposed IT expenditures. This experience includes extensive IT industry expertise and more than a decade of experience in investigating DNSP proposed IT expenditures for economic regulators across Australia.

The approach adopted by Nuttall Consulting for this phase of the investigation is as follows:

- identification of areas of potential overlap or double-counting between the proposed expenditures
- development of a set of questions for the DNSPs
- review and assessment of the DNSP responses
- development of a draft and final report for the AER.

[163] noting that any "missed" expenditures will also be identified where appropriate.

This investigation has relied upon the information provided by the DNSPs. Nuttall Consulting has reviewed this information for consistency and reasonableness. The information from the DNSPs has not been subject to audit by Nuttall Consulting.

The AER provided Nuttall Consulting with the reports and analysis from the initial AMI expenditure review undertaken in 2009. Following the Nuttall Consulting review of the AER AMI information, Nuttall Consulting prepared a short questionnaire regarding the DNSPs' IT systems and infrastructure. The focus of the questionnaire was to determine the level of integration/separation of the systems for AMI and the existing IT requirements of the DNSPs.

Nuttall Consulting met with each of the DNSPs and discussed the questionnaire and the scope of this review. Each of the DNSPs subsequently completed the questionnaire and returned the information to Nuttall Consulting and the AER.

The Nuttall Consulting investigation considered the IT systems and infrastructure in three categories. These categories were selected to provide a logical separation of the proposed asset types associated with the AMI project and DNSP IT activities. The IT categories identified by Nuttall Consulting were:

a) Compute Platform - the actual hardware and operating system on which the application or database operates

b) Storage Platform – the media that offers transitional or permanent storage of data

c) Network (or Connectivity) – the infrastructure that connects the Compute and Storage platforms together.

These categories are consistent with those defined in the main body of this report (section 4.6.1). The capture of AMI and non-AMI asset information in the same categories allowed Nuttall Consulting to identify assets that were potentially being utilised for both purposes or have capacity to service both purposes. This allowed Nuttall Consulting to review these identified areas for potential double-counting or overlap in proposed expenditures.

Nuttall Consulting has also reviewed the major IT systems of each of the DNSPs. This review considered the major systems for both AMI and non-AMI related activities as well as the integration and interfaces between the systems. Where the two systems were on shared platforms and infrastructure, Nuttall Consulting has reviewed the proposed assets and systems. Nuttall Consulting was not tasked to undertake an accounting reconciliation of the cost allocation processes proposed by the DNSPs.

In addition to the assessment of potential overlap or double-counting, Nuttall Consulting has also assessed four proposals to leverage the AMI data. These proposed expenditures were aimed at utilising the information provided by the AMI roll-out to provide better outcomes for customers and efficiencies for the DNSPs.

This investigation considered the expenditures proposed by the four DNSPs as well as the benefits that were suggested to eventuate. The investigation also considered the mechanism by which the benefits would accrue and how this would operate within the incentive based regulatory system.

The Nuttall Consulting investigation of each DNSP is provided below.

16.3 CitiPower/Powercor

CitiPower/Powercor have elected to host all of the AMI infrastructure in the same data centre as their existing infrastructure. Powercor and CitiPower shared the same identical backend infrastructure and the same fundamental systems. These systems are operated by CHED Services which is jointly owned by both companies.

Nuttall Consulting has not assessed the related party margins paid to CHED Services and notes that they are outside of scope as defined by the OIC.

The following table provides a summary of the major DNSP systems, the uses of those systems and notes how the expenditure is allocated. The platforms, storage and network connectivity assets are discussed following this table.

Figure 145 - CitiPower/Powercor AMI and non-AMI IT systems

System Name	Used by Standard Control Services?	Used by AMI?	New system, funded by AMI?
OMS / GIS Smallworld	Yes	Minimal	No
SAP ERP	Yes	Yes	Increment
Globalscape FTP	Yes	No	No
SAP FE Portal Internal	Yes	Yes	No
SAP FE Portal External AMI systems	No	Yes	Yes
SAP FE Portal External	Yes- Future Incremental	No	No
Citrix	Yes	Yes	Increment
Control Room Systems	Yes	No	No
SCADA	**Yes**	No	No
Call Centre Systems	Yes	**Yes**	Minimal Increment
Service Suite	Yes - future Incremental	Yes	Yes
Infra Service Desk System	Yes	No	No
Quantum	Yes	No	No
Field Mobile Computing	Yes	No	No
Utility IQ	No	Yes	Yes
Itron IEE / MTS	No	Yes	Yes
USB	**No**	Yes	Yes
CISOV	Yes	Yes	Increment

System Name	Used by Standard Control Services?	Used by AMI?	New system, funded by AMI?
Sharepoint	Yes	Minimal	No
Exchange	Yes	Minimal	No
PABX	Yes	Yes	No
SAP BI	Yes	Yes	Increment

The CitiPower/Powercor compute platform is Sun Sparc - Sun Solaris and HP AMD Blade systems running the Windows operating systems, and HP AMD Blade systems running RedHat Linux.

The storage platforms are SUN (HDS) USP 9990V with differing levels of storage capacity and different storage configurations for the AMI and non-AMI systems.

Network connectivity is via the Silver Springs meshed radio network.

All AMI and Non-AMI infrastructure is hosted in the same physical data centre. The same storage and compute platform has been used for both AMI and non-AMI.

In summary, Powercor and CitiPower share the same identical backend infrastructure and the same fundamental systems. These systems are operated by CHED Services which is jointly owned by both companies. Cost allocation between both DNSPs is relatively complex as there is no physical and little logical separation.

Nuttall Consulting has seen no evidence of double counting or overlap between the CitiPower and Powercor EDPR proposals and the AMI allowances. Based on the information provided to Nuttall Consulting there is no evidence of duplicated expenditures between the AMI and non-AMI activities. As the physical systems are shared between the AMI and non-AMI activities there is a requirement for cost allocation. Nuttall Consulting has not assessed the appropriateness of the cost allocation methodologies.

CitiPower and Powercor each provided a report by PricewaterhouseCoopers (PWC) assessing the need for investment in additional AMI capabilities. CitiPower and Powercor are proposing $8.1m and $18.9m in capex respectively as the required investments to achieve this additional capability. The reports identify a number of capabilities that were considered to provide an overall net benefit including:

- Automatic outage notification - Utilising the AMI meters' loss of supply/outage detection functionality to provide automatic outage notification and reporting.
- Enhanced load shedding capability - Using the AMI meters' functionality to enable more granular emergency load shedding by allowing a 'bottom-up' choice of customer load shed, in order to reduce the cost of unserved energy from necessary load sheds.
- Enhanced powerflow analysis and near real time network data - Leveraging data collected by the AMI meters to provide forecasting and scheduling information and simulation capability to improve network management and asset optimisation. This

functionality will be particularly important in the context of increasing embedded or distributed generation sources.

- Quality of Supply event recording/proactive voltage compliant analysis - Utilising the AMI meters' Quality of Supply (QoS) recording to allow improved analysis, network management and customer service. This will allow the businesses to adequately monitor QoS compliance.
- Customer load controls - Enabling implementation of agreed load limits, including emergency supply constraints.
- Consumption profiling - An analytical capability, whereby supply data may be quickly and easily analysed to establish consumer profiles for network planning and forecasting. This ability to understand consumer profiles will enhance the load shedding capability.

The above capabilities may be considered to deliver a range of potential benefits, including expenditure efficiencies, reliability improvements, customer service and quality improvements. Whist we agree that there should be benefits through these "AMI leveraging projects", and these benefits may well outweigh the additional costs, we do not consider that CitiPower and Powercor have:

- adequately quantified all of the costs and benefits that may accrue through the use of the AMI data, and defined these in terms of those provided for through existing incentive mechanisms (e.g. STPIS, EBSS) and those external to these schemes
- adequately demonstrated that their proposed expenditure represents only the incremental level above that available through the existing incentive mechanisms.

Therefore, in the absence of the above items, we do not consider that CitiPower or Powercor should be allowed the proposed expenditure.

16.4 SP AusNet

SP AusNet have elected to host all of the AMI infrastructure in the same data centre as their existing infrastructure.

The following table provides a summary of the major DNSP systems, the uses of those systems and notes how the expenditure is allocated. The platforms, storage and network connectivity assets are discussed following this table.

Figure 146 - SP AusNet AMI and non-AMI IT systems

System Name	Used by Standard Control Services?	Used by AMI?	New system, funded by AMI?
Network CIS	Yes	Yes	Yes (15%)
MDM	No	Yes	Yes
MMS	No	Yes	Yes
EDW	Yes	Yes	Yes (78%)

System Name	Used by Standard Control Services?	Used by AMI?	New system, funded by AMI?
PowerOn Elec	Yes	Yes	Yes (50%)
EAI (JCAPS)	Yes	Yes	No
Billing (Kinetiq)	Yes	Yes	No

SP AusNet uses two main server hardware platforms for its AMI solution:

- SUN Microsystems M9000 Production and Disaster Recovery Servers / Solaris
- SUN 6270 Blade Servers / Windows/Oracle Linux/Solaris.

SP AusNet uses three main server hardware platforms for its Enterprise solution:

- SUN Microsystems M9000 Production and Disaster Recovery Servers / Solaris
- SUN 6270 Blade Servers / Windows/Solaris
- IBM x64 Wintel Servers / Windows.

SP AusNet uses SUN 9990 Storage Area Network as the primary storage platform for AMI and as the primary enterprise storage platform.

SP AusNet's AMI solution leverages the extensive transmission backhaul network for connectivity between its Data Centres and the WiMAX base-stations. In terms of network connectivity, AMI meters have a WiMAX communication capability which enable connectivity back to the base-station.

The same storage and compute platform has been used for both AMI and non-AMI and SP AusNet has undertaken a cost allocation between new systems funded under AMI and Non-AMI. Nuttall Consulting has reviewed the assets associated with proposed AMI and non-AMI expenditure, but has not assessed the cost allocation methodology. Nuttall Consulting understands that the AER is assessing the cost allocation methodologies on the DNSPs separate to this report.

Nuttall Consulting has seen no evidence of double counting or overlap between the SP AusNet EDPR proposal and the AMI allowances. Based on the information provided to Nuttall Consulting there is no evidence of duplicated expenditures between the AMI and non-AMI activities.

SP AusNet did not propose any EDPR expenditure associated with leveraging the AMI systems or information.

16.5 Jemena

Jemena have elected to physically separate their existing data centre and disaster recovery centre from the new AMI data centre and disaster recovery centre. Jemena states that this duplication was required as the existing data centre and disaster recovery centre were unable to cater for the new AMI systems due to power and space capacity.

The following table provides a summary of the major DNSP systems, the uses of those systems and notes how the expenditure is allocated. The platforms, storage and network connectivity assets are discussed following this table.

Figure 147 - Jemena AMI and non-AMI IT systems

System Name	Used by Standard Control Services?	Used by AMI?	New system, funded by AMI?
SAP R/3 4.6c	Yes	Interfaces to	Interfaces only
SAP IS]U	No	Yes	Yes
CIS+	Yes	Interfaces to	Interfaces only
SCADA	Yes	No	No
Silverspring UIQ	No	Yes	Yes
Itron IEE	No	Yes	Yes
Cognos Ver. 8	No	Yes	Yes
Cognos Ver. 7	Yes	No	No
WebMethods Ver. 7	No	Yes	Yes
WebMethods Ver. 6.5	Yes	Interfaces to	Interfaces only
Oracle OMS	Yes	Interfaces to	Yes
Geospatial Information System (GIS)	Yes	Interfaces to	Yes

Jemena uses a number of server hardware platforms depending on the application:

- Sparc/Solaris
- Intel/Linux
- Intel/Windows
- Intel/ESX/Windows.

Jemena uses a number of main server hardware platforms for its non-AMI systems based on the needs of the respective applications:

- Sparc/Solaris IBM AIX
- Intel/Windows
- Intel/ESX/Windows.

Jemena uses SUN 9990 Storage Area Network (150TB upon completion) as the primary storage platform for AMI and EMC CLARiiON CX3-80 (200TB) as the primary enterprise storage platform. Jemena states that the primary reason for increased capacity of the AMI storage platform is to support the exponential increase in data volumes as a result of moving to the provision of data in 15 minute intervals by 6am on a daily basis.

Each AMI meter in the Jemena network forms a node within the SilverSpring Radio Frequency mesh network that connects to a backhaul network provided by Telstra. The backhaul network terminates at the data centres at EDC Mitcham and Primus. Jemena note that this system is a new IT system that supports remotely read (AMI Meter) Type 5 meter data metrology rules and obligations. Given these rules are different from Type 6 (basic meters), Type 1-4 (160mwh and above), and Unmetered Supplies. This system is not used for any other meter data provision in Jemena.

The physical separation of the data centres provides relatively simple cost allocation between the EDPR allowances and AMI. The adoption of new storage infrastructure with AMI (EMC replacing StorageTek) should provide a clear separation in terms of costs as this is completely new infrastructure that will need to be supported and maintained. Nuttall Consulting also considers that the migration from AIX to Sun (now Oracle) Solaris should provide a clear separation in terms of costs, since Solaris is now being used exclusively for AMI projects.

Nuttall Consulting has seen no evidence of double counting or overlap between the Jemena EDPR proposal and the AMI allowances. Based on the information provided to Nuttall Consulting, the physical systems described for both activities are separately identified and allocated.

Jemena has included opex step changes of $200k per annum in each of 2012 to 2015 in its regulatory proposal. This proposed expenditure is to allow Jemena to retrieve and conduct proactive analysis of data captured by the AMI meters (energy as well as power quality data) for its application to network management decision making, and to conduct trials of other AMI functions not included in the AMI scope. Jemena has confirmed that these AMI leverage expenditures have not been included in either the AMI Budget or the AMI Charges Applications.

The AMI leverage expenditure proposed by Jemena may result in a range of potential benefits, including expenditure efficiencies, reliability improvements, customer service and quality improvements. Whist we agree that there should be benefits through these “AMI leveraging projects”, and these benefits may well outweigh the additional costs, we do not consider that Jemena have:

- adequately quantified all of the costs and benefits that may accrue through the use of the AMI data, and defined these in terms of those provided for through existing incentive mechanisms (e.g. STPIS, EBSS) and those external to these schemes
- adequately demonstrated that their proposed expenditure represents only the incremental level above that available through the existing incentive mechanisms.

Therefore, in the absence of the above items, we do not consider that Jemena should be allowed the proposed expenditure.

16.6 United Energy

United Energy source their IT services from Jemena Asset Management (JAM). On this basis, IT infrastructure is shared with Jemena and therefore has the same configurations and structures as previously described in the Jemena AMI integration investigation (above). Nuttall Consulting has been advised that physical separation of the Jemena and United Energy assets is achieved through the use of separate enclosures and racks within the centres.

United Energy has elected to physically separate their existing data centre and disaster recovery centre from the new AMI data centre and disaster recovery centre. United Energy state that the current data centres at Tally Ho and Burwood had a number of issues including power and space capacity that made it impossible for United Energy to implement AMI infrastructure at the existing sites. On this basis, United Energy took the decision to implement all AMI infrastructure into the EDC Mitcham and Primus data centres.

During 2010 and 2011 United Energy intend to move non-AMI systems from Tally Ho to the EDC Mitcham data centre as part of a current project. This project will consolidate United Energy's non-AMI and AMI infrastructure in a single production data centre. Any changes to existing disaster recovery configurations may also require relevant disaster recovery equipment to move from Burwood to Primus.

The following table provides a summary of the major DNSP systems, the uses of those systems and notes how the expenditure is allocated. The platforms, storage and network connectivity assets are discussed following this table.

Figure 148 - United Energy AMI and non-AMI IT systems

System Name	Used by Standard Control Services?	Used by AMI?	New system, funded by AMI?
SAP IS-U	No	Yes	Yes
Silverspring UIQ	No	Yes	Yes
Itron IEE	No	Yes	Yes
Cognos Ver. 8	No	Yes	Yes
WebMethods Ver. 7	No	Yes	Yes
SAP R/3 4.6c	Yes	Interfaces to	No
CISPlus+	Yes	Interfaces to	No
Oracle NMS (DMS/OMS)	Yes	Interfaces to	Yes
Cognos Ver. 7	Yes	Interfaces to	No
WebMethods Ver. 6.5	Yes	Interfaces to	No
GE Smallworld	Yes	Interfaces to	Yes
Siemens Telegyr	Yes	No	No

United Energy uses a number of server hardware platforms depending on the application:

- Sparc/Solaris
- Intel/Linux
- Intel/Windows
- Intel/ESX/Windows.

United Energy uses a number of main server hardware platforms for its non-AMI systems based on the needs of the respective applications:

- Sparc/Solaris IBM AIX
- Intel/Windows
- Intel/ESX/Windows.

United Energy states that there are a number of reasons why the AMI program took the decision to change from IBM AIX to Sun Solaris as the core UNIX platform. These include:

- the change in location (new data centres)
- the capacity and age of the existing AIX infrastructure
- alignment with enterprise standards
- the increased processing power per CPU
- decreased Oracle licensing costs.

The other CPU Architecture / Operating Systems are similar with a mix of Intel and legacy RISC based servers and a large amount of virtualisation. The AMI program has implemented these platforms into new data centres so the infrastructure is separate from the Standard Control Services.

United Energy uses SUN 9990 Storage Area Network (150TB upon completion) as the primary storage platform for AMI and EMC CLARiiON CX3-80 (200TB) as the primary enterprise storage platform. United Energy states that are a number of reasons why the AMI program took the decision to change from EMC CX storage array to the Sun StorageTek platform. These include:

- the change in location (new data centres)
- the capacity and age of the existing EMC CX3-80 storage arrays
- AMI service level agreements
- increased buying power as a result of a large investment in Sun hardware.

Each AMI meter in the United Energy network forms a node within the SilverSpring Radio Frequency mesh network that connects to a backhaul network provided by Telstra. The backhaul network terminates at the data centres at EDC Mitcham and Primus. United Energy note that this system is a new IT system that supports remotely read (AMI Meter) Type 5 meter data metrology rules and obligations. Given these rules are different from Type 6 (basic meters), Type 1-4 (160mwh and above), and Unmetered Supplies. This system is not used for any other meter data provision in United Energy.

The physical separation of the data centres provides relatively simple cost allocation between the EDPR allowances and AMI. The adoption of new storage infrastructure with AMI (EMC replacing StorageTek) should provide a clear separation in terms of costs as this is completely new infrastructure that will need to be supported and maintained. Nuttall Consulting also considers that the migration from AIX to Sun (now Oracle) Solaris should provide a clear separation in terms of costs, since Solaris is now being used exclusively for AMI projects.

Nuttall Consulting has seen no evidence of double counting or overlap between the United Energy EDPR proposal and the AMI allowances. Based on the information provided to Nuttall Consulting, the physical systems described for both activities are separately identified and allocated.

United Energy has included opex step changes of $200k per annum in each of 2012 to 2015 in its regulatory proposal. This proposed expenditure is to allow United Energy to retrieve and conduct proactive analysis of data captured by the AMI meters (energy as well as power quality data) for its application to network management decision making, and to conduct trials of other AMI functions not included in the AMI scope. United Energy has confirmed that these AMI leverage expenditures have not been included in either the AMI Budget or the AMI Charges Applications.

The AMI leverage expenditure proposed by United Energy may result in a range of potential benefits, including expenditure efficiencies, reliability improvements, customer service and quality improvements. Whist we agree that there should be benefits through these “AMI leveraging projects”, and these benefits may well outweigh the additional costs, we do not consider that United Energy have:

- adequately quantified all of the costs and benefits that may accrue through the use of the AMI data, and defined these in terms of those provided for through existing incentive mechanisms (e.g. STPIS, EBSS) and those external to these schemes
- adequately demonstrated that their proposed expenditure represents only the incremental level above that available through the existing incentive mechanisms.

Therefore, in the absence of the above items, we do not consider that United Energy should be allowed the proposed expenditure.