Review of ETSA Utilities regulatory proposal for the period July 2010 to June 2015

for Australian Energy Regulator

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Glossary

Previous regulatory control period	The period 1 July 2001 to 30 June 2005
Current regulatory control period	The period 1 July 2005 to 30 June 2010
Next regulatory control period	The period 1 July 2010 to 30 June 2015
Good electricity industry practice	Has the meaning given by the National Electricity Rules: The exercise of that degree of skill, diligence, prudence and foresight that reasonably would be expected from a significant proportion of operators of facilities forming part of the power system for the generation, transmission or supply of electricity under conditions comparable to those applicable to the relevant facility consistent with applicable regulatory instruments, reliability, safety and environmental protection. The determination of comparable conditions is to take into account factors such as the relative size, duty, age and technological status of the relevant facility and the applicable regulatory instruments.

List of abbreviations

AER	Australian Energy Regulator
BMS	business management system
C&I	commercial and industrial
CAM	cost allocation method
capex	capital expenditure
CBRM	condition-based risk management
CIA	corporation-initiated augmentation
CICW	customer-initiated capital works
COIN	company initiated augmentation
CPI	Consumer Price Index
CPoW	consolidated program of work
D&C	design and construct
DM	demand management
DNAP	distribution network augmentation plan
DNR	domestic and rural (sub-divisions)
DNSP	Distribution Network Service Provider
EBA	enterprise bargain agreement
GFC	global financial crisis
ICT	information and communication technology
MAMP	mains asset maintenance policy
MSS	minimum service standard
MVA	mega volt amps
NAMP	network asset management program
NER	National Electricity Rules
NMP	network management plan
NPV	net present value

NTC	Network and Technical Committee
opex	operating expenditure
PoE	probability of exceedance (in relation to forecast demand)
RAB	Regulatory Asset Base
RIN	Regulatory Information Notice
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SAMP	substation asset maintenance policy
SNAP	sub-transmission network augmentation plan
STPIS	Service Target Performance Incentive Scheme

Notes

All dollar values in this report are expressed as $m real 2009-10 unless stated otherwise.

Table N1 below provides the escalation rates (as advised by the AER) used to convert historical expenditures to the 2009-10 reference year for direct comparison with the forecasts presented by the businesses.

Table N1 Escalation rates used to convert historical expenditures to real 2009-10

	2001-02	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10
Escalation rates	1.2478	1.2063	1.1829	1.1556	1.1222	1.0955	1.0509	1.0256	1.000

Source: AER, based on consumer price inflation

Executive summary

The Australian Energy Regulator, in accordance with its responsibilities under the National Electricity Rules, is required to conduct an assessment of the appropriate revenue determination to be applied to direct control services provided by ETSA Utilities for the period 1 July 2010 to 30 June 2015 (the next regulatory control period).

ETSA Utilities proposes to invest capital expenditure of $2,309.9m in its electricity system, $363m of capital expenditure in non-system assets and spend $1,131m on operations and maintenance. Parsons Brinckerhoff (PB) has been engaged to provide an independent view on the prudence and efficiency of these proposed expenditures, and to review the service standards proposed to be delivered for these expenditures.

In undertaking this review PB has adopted a phased approach to provide broad coverage of the expenditure proposal while enabling a more detailed examination of key issues — as required. The three stages of the PB review are: a high level 'portfolio' review; a more detailed, 'focused' review of specific areas identified in the high-level review; and a reporting stage.

Overall, PB has found that:

- The proposed total capital expenditure of $2673.6m (excluding superannuation and equity raising costs) has not been found to be prudent and efficient. PB recommends a reduction of $618.4m (23%) for a range of reasons described below. PB's advice is that a prudent and efficient expenditure in the next regulatory control period would be $2055.2m.

- The proposed total operating and maintenance expenditure of $1,131.1m has not been found to be prudent and efficient. PB recommends a reduction of $45.9m (4.1%) for a range of reasons described below. PB's advice is that a prudent and efficient expenditure in the next regulatory control period would be $1085.3m.

PB's detailed findings for each expenditure category are set out below.

System capital expenditure

ETSA Utilities proposes to invest capital expenditure of $2,309.9m[1] on its electricity system over the next regulatory control period, a real increase of 126% compared with the expenditure in the current regulatory control period. PB has found $1,716.2m (74%) of the proposed expenditure to be prudent and efficient. PB's key findings are as follows:

- ETSA Utilities capital governance is consistent with good electricity industry practice.

- Risk assessment practices do not support project prioritisation.

- Planning criteria are aligned with good electricity industry practice, and the demand forecast is consistently applied.

[1] Exclusive of Superannuation costs and Equity Raising costs.

- Although options analysis is not formally documented ETSA Utilities appears to consider a reasonable range of options in capacity planning decisions.
- Demand driven capex is forecast to increase by 93% in real terms and non-demand driven capex is proposed to increase by 223% in real terms.
- Non-network alternatives and demand management opportunities are considered and pursued.
- The efficiency of ETSA Utilities' revised asset management approach has not been demonstrated.
- An adjustment in expenditure is recommended in the following categories for the reasons outlined:
    - A reduction of $102.1m to the LV network capacity upgrade program as PB is of the view that the risk assessment overstates the risk, and the underlying analysis does not support the full scope of the proposed program.
    - A reduction of $31.0m to the customer connection capex to reflect the removal of a contingency allowance for 'unidentified projects' which in PB's view is unsupported and has not been demonstrated to be prudent and efficient.
    - A reduction of $228m to the asset replacement program as in PB's view the ETSA Utilities assessment of risk, and the basis of its age-based replacement proposals could not be demonstrated to be efficient.
    - A reduction of $13.5m to the security and fencing program to reflect removal of proposed high security fencing projects which exceed industry practice and are not supported by the ENA guidelines and site risk analysis.
    - A reduction of $4.7m to the CBD safety related asset replacement program due to ETSA Utilities use of a lower risk threshold, which has not been demonstrated to be economically justified, and the lack of demonstration that the timing of these projects is efficient. PB's recommendation reflects the expenditure that would be required if the risk threshold accepted in ETSA Utilities' previous annual budget process was applied.
    - A reduction of $94.5m from the Kangaroo Island security of supply project to reflect PB's view that information provided supports deferral of the undersea cable and the sub-transmission upgrade until after the next regulatory control period.
    - A reduction of $11.4m to the network security of supply program to reflect the removal of costs for operational labour and procurement of land that have been double counted, and removal of costs for the IT disaster recovery project which in PB's view is inefficient given the relocation of the network operations centre project which is also planned for completion in the next regulatory control period.
    - A total reduction of $108.8m (6.0%) to the system capital expenditure to reflect inefficiencies in the application of the real cost escalators and the errors in the adjustment of the capex forecast to a 2009-10 basis.

PB recommends that the system capex allowance for the next regulatory control period should be reduced by $593.7m (26%) from the levels proposed by ETSA Utilities. Table E1 presents the recommended system capital expenditure.

Table E1 Recommended system capital expenditure

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	406.7	512.2	482.2	465.4	443.4	2,309.9
PB adjustment	(92.4)	(127.7)	(149.5)	(121.2)	(102.9)	(593.7)
PB recommendation	314.4	384.4	332.8	344.2	340.3	1716.2

Non-system capital expenditure

ETSA Utilities proposes to invest capital expenditure of $363.7m on non-system assets in the next regulatory control period, an average increase of 99% compared with expenditure in the current regulatory control period.

PB has assessed ETSA Utilities' proposed non-system capex, including capex for information systems, plant and tools, property and fleet categories, and found the proposed expenditure to be prudent and efficient. A reduction of $24.7m (6%) to the non-system capital expenditure is recommended to reflect inefficiencies in the application of the real cost escalators and the errors in the adjustment of the capex forecast to a 2009-10 basis.

Table E2 presents PB's recommended non-system capital expenditure.

Table E2 Recommended non system capital expenditure

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	67.7	58.9	70.3	78.0	88.8	363.7[#]
PB adjustment	(4.8)	(4.2)	(4.8)	(5.2)	(5.7)	(24.7)
PB recommendation	62.9	54.7	65.5	72.8	83.1	339.0

[#] *Note: PB notes that this total of $363.7m excludes $49.5m equity raising costs. Review of equity raising costs is not within PB's scope of works.*

Operational and maintenance expenditure

ETSA Utilities proposes to spend $1,131.1m on operations and maintenance in the next regulatory control period inclusive of all allocated costs (overheads), an average increase of 54% compared with the current regulatory control period. PB has found $1,085.3m (96%) of the proposed expenditure to be prudent and efficient.

PB's key findings are as follows:

- Policies, documentation and modelling to support the asset management approach and the forecasting methodology are comprehensive, transparent and reflective of the needs of the business in the current environment.
- Asset maintenance and management practices are in a transitional stage – moving from a lagging indicator and fixed time-based inspection approach, to a future state capturing more condition based knowledge and informed through leading indicators

- The base year opex of $155m for 2008/09 is prudent and efficient for the purposes of informing the forecasts.
- ETSA Utilities has provided a clear description of how and why it had established and applied scale escalators, and PB is generally satisfied that network size, work volume, workforce size and customer growth are each factors that will influence opex requirements and has used a reasonable level of discretion in selecting the activities to which each of the factors apply.
- Adjustments to the proposed expenditure are recommended for the reasons outlined:
  - A reduction of $9.9m to account for a network growth factor more reflective of the actual assets that will be installed from a bottom-up perspective.
  - A reduction in the total network access, monitoring and control opex activity of $2.66m based on a bottom-up forecast of staff required to undertake this activity.
  - A reduction in the total emergency response opex activity of $8.7m to reduce the growth escalation, on the basis that new assets are not likely to fail consistently and repeatedly in an unplanned manner.
  - A reduction of $0.3m to account for the asset replacement capex / opex trade-off.
  - A reduction of $19.5m is made to remove the escalation in network maintenance opex due to increasing asset age. This change has not been substantiated primarily due to the lack of calibration of the SKM age versus opex characteristics to ETSA Utilities existing asset base and classes.
  - A reduction of $4.8m is made to remove the 5% contingency allowance included in the proposed vegetation management.

PB recommends that the opex allowance for the next regulatory control period should be reduced by $45.8m (4.1%) from the levels proposed by ETSA Utilities. Table E3 presents PB's recommended operations and maintenance expenditure.

Table E3 Recommended operations and maintenance expenditure

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA proposal	203.3	214.7	225.7	239.0	248.4	1,131.1
PB adjustment	(4.3)	(6.8)	(9.0)	(11.5)	(14.2)	(45.9)
PB recommendation	199.0	207.9	216.7	227.5	234.3	1,085.3

Service standards

ETSA Utilities proposes a small expenditure ($25.3m) to maintain its level of reliability of supply service performance to meet the standards set by ESCoSA in its Final Decision on the South Australian Electricity Distribution Service Standards 2010-2015.

The values proposed by ETSA Utilities for the service target performance incentive scheme are generally found to be appropriate. PB's findings in relation to ETSA Utilities' reliability of supply parameters are as follows:

- The quality of ETSA Utilities' data is suitable for target setting.

- The four years of performance data available is sufficient to inform the setting of targets, which should be set at the average of the four years to June 2009.
- The Box-Cox transformation provides a more accurate normalisation of the available OMS data and should be adopted when calculating the major event day boundary for ETSA Utilities.

PB's findings in relation to ETSA Utilities' customer service parameter are as follows:

- The revised definition based on a different treatment of abandoned calls should not be accepted.
- The quality of ETSA Utilities' data is suitable for target setting.
- The targets should be set at the average of the four-year performance to 2008-09, 88.7%

PB also recommends that the proposed modified s-bank operation should not be applied as this would weaken the incentive properties of the scheme and hence is not consistent with the objectives for the scheme.

In summary, PB recommends the values for the service performance parameters shown in Table E5 be included in ETSA Utilities' STPIS.

Table E4 Recommended values for the service performance parameters

Parameter	Unit	Rate %	Targets				
			2010-11	2011-12	2012-13	2013-14	2014-15
SAIDI							
CBD	minute	0.0087	27.1	27.1	27.1	27.1	27.1
Urban	minute	0.0486	104.4	104.4	104.4	104.4	104.4
Short rural	minute	0.0089	184.0	184.0	184.0	184.0	184.0
Long rural	minute	0.0109	270.2	270.2	270.2	270.2	270.2
SAIFI							
CBD	per interruption	0.7962#	0.263	0.263	0.263	0.263	0.263
Urban	per interruption	4.0465#	1.292	1.292	1.292	1.292	1.292
Short rural	per interruption	1.0228#	1.736	1.736	1.736	1.736	1.736
Long rural	per interruption	1.5151#	2.111	2.111	2.111	2.111	2.111
Customer service							
Telephone answering	%	-0.0400	88.7	88.7	88.7	88.7	88.7

Note: # per 0.01 interruptions

Incentive rates for SAIDI and SAFI parameters are calculated using ETSA's proposed average energy consumption.

Source: PB Analysis

1. Introduction

In this section we describe the background to the review and provide details of the terms of reference. We also set out the structure of this report.

1.1 Background to the review

The Australian Energy Regulator (AER), in accordance with its responsibilities under the National Electricity Rules (NER), is required to conduct an assessment of the appropriate revenue determination to be applied to direct control services provided by Distribution Network Service Providers (DNSPs) in South Australia and Queensland for the period 1 July 2010 to 30 June 2015 (the next regulatory control period).

As part of its assessment the AER has engaged the services of Parsons Brinckerhoff (PB)[2] to provide an independent view on the prudence and efficiency of the expenditure proposals from each of the three DNSPs — Ergon Energy and ENERGEX in Queensland, and ETSA Utilities in South Australia. The advice from PB will assist the AER in making its determination in respect of the expenditure proposals from each of the businesses.

This report concerns the review of the expenditure proposal from ETSA Utilities only. The two Queensland DNSPs are the subject of separate reports by PB.

The ETSA Utilities Regulatory Proposal[3] was submitted to the AER on 1 July 2009. PB was provided with a copy of the proposal on 3 July 2009. The AER is expected to make its Draft Determination in by the end of November 2009 and its Final Determination by the end of April 2010.

1.2 Terms of reference

The main objective of the PB's review is to provide the AER with independent technical advice regarding the efficiency and prudence of the capital expenditure (capex) and operating expenditure (opex) proposals submitted by ETSA Utilities and also to provide input to assist the AER in its assessment of the opex and capex objectives, criteria and factors set out in clauses 6.5.6 and 6.5.7 of the NER. Specifically, this review by PB involves a review of ETSA Utilities' historical and forecast capex and opex, the associated policies and procedures, and the service standards proposals for the next regulatory control period.

PB's terms of reference do not include the review of external factors and obligations[4], cost pass-through items, or the review of submissions from interested parties on PB's report or the AER's draft or final determination. The review of equity raising and superannuation costs is also outside of the scope of PB's engagement.

PB's final report to the AER on the ETSA Utilities Regulatory Proposal was submitted on 10 October 2009.

2 Please refer to Appendix B for a summary about PB and PB's relevant experience
3 ETSA Utilities 2009, *Regulatory Proposal 2010-2015*
4 Other than to the extent required to develop an independent recommendation on the prudence and efficiency of the expenditure proposed by ETSA Utilities.

1.3 Report structure

In Section 2 of this report we set out the overarching methodology PB adopted for this review. Section 3 discusses the application of cost escalation to the forecast expenditures and the allocation of overheads. Sections 4, 5 and 6 deal with the ETSA Utilities' system capex, non-system capex and opex proposals respectively. In Section 7 we provide our recommendations in respect of the ETSA Utilities proposed Service Standards. Generic limitations of the report are provided in Section 8.

2. Review methodology

In this section we describe the overarching methodology PB adopted in its review of the ETSA Utilities Regulatory Proposal. This includes an outline of our approach to the review and details of aspects of the proposal that were examined.

2.1 PB's phased approach

PB has adopted a phased approach to review ETSA Utilities. The process has been specifically designed to provide broad coverage of the expenditure proposal while enabling a more detailed examination of key issues — as required. In summary, the three stages of the PB review are:

- a high level 'portfolio' review
- a more detailed, 'focused' review of specific areas identified in the high-level review
- a reporting stage.

The first two stages of the review process allow consideration of the complete expenditure proposal while supporting and facilitating a more detailed examination of selected aspects of the proposal. The process inherently recognises the need for a high-level review of the entire regulatory submission *before* it is possible to determine which aspects warrant further review effort and scrutiny.

In this way PB has been able to ensure that effort is expended in areas of the proposal likely to be important in providing credible and sound independent advice on the prudence and efficiency of the ETSA Utilities Regulatory Proposal.

This phased approach to the review is represented in Figure 2.1.

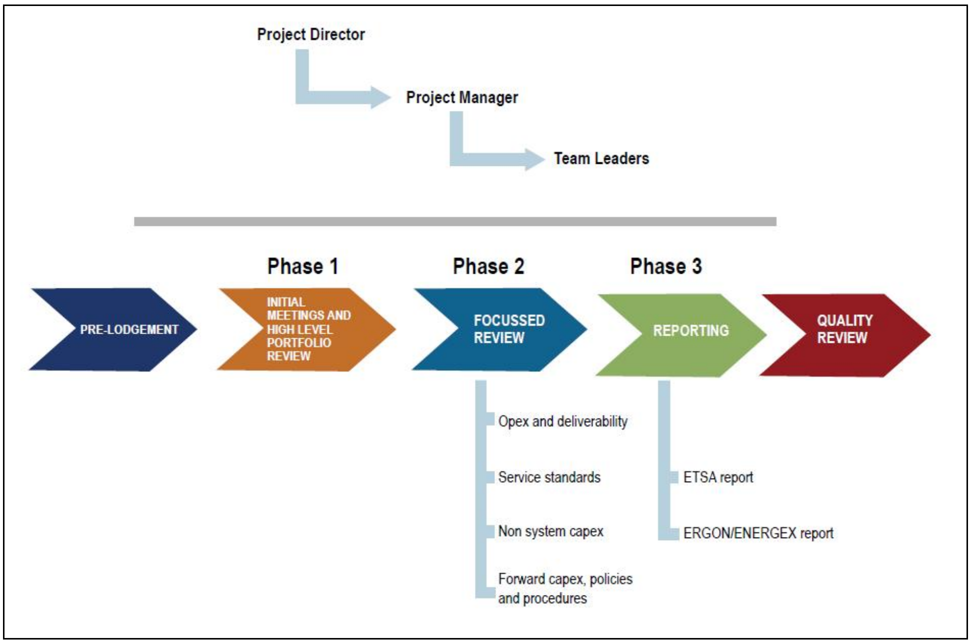

Figure 2.1 PB's approach to the review

The phased approach adopted by PB involved the following steps:

- detailed desk-top review of the information provided in the Regulatory Proposal
- onsite meetings with ETSA Utilities staff to discuss essential elements of the Regulatory Proposal (PB provided ETSA Utilities with details of specific areas for discussion beforehand)
- development of a preliminary view on key issues at a portfolio level and discussion and agreement with the AER to a scope of works for the focussed review stage
- formulation of detailed questions for ETSA Utilities on its expenditure proposals
- consideration of ETSA Utilities' responses
- a second on-site meeting with ETSA Utilities to discuss key issues and PB's preliminary views and findings on the expenditure proposals
- further questions and responses to establish full understanding of specific expenditure items.

In meeting its primary objective of providing an independent view on the prudence and efficiency of the ETSA Utilities expenditure proposal, PB has given due regard to the opex and capex objectives, criteria and factors set out in clauses 6.5.6 and 6.5.7 of the NER.

In assessing the prudence and efficiency of proposed expenditures, PB has considered the need or driver for the expenditure, the timing of the expenditure and, where appropriate, has used business-as-usual levels of recurrent expenditures to develop a view about the appropriate level of forecast expenditures. Given that ETSA Utilities is incentivised to be efficient by the nature of the incentive based CPI-x form of price regulation, PB considers that business-as-usual levels of expenditures can be considered as indicative of efficient expenditures.

PB notes that historical expenditures may differ from business-as-usual expenditures in that historical expenditures may contain abnormal under or over spends. Discussion with ETSA Utilities about historical expenditures has therefore occurred. Further information about PB's review of the capex and opex proposed by ETSA Utilities is set out in the following sections.

2.1.1 Capex review

In assessing whether proposed capital investments are prudent and efficient, PB has:

- assessed whether ETSA Utilities is acting efficiently in accordance with good electricity industry practice through a review of capital governance, policy and procedures, cost estimating practices, and specific reviews of certain expenditures
- assessed whether there is a justifiable need for the proposed investment within each expenditure category
- after confirming the need for an investment, assessed whether all reasonable options have been considered and the most efficient investment selected to satisfy that need
- where an investment is based on assumptions about future conditions, assessed whether those assumptions are reasonable[5].

[5] PB's review did not include assumptions made about the future demand for electricity.

PB's review of ETSA Utilities' forecast capex allowance has specifically excluded the following matters from our scope of work:

- benchmarking of unit costs
- the level of forecast demand
- the deliverability of the proposed works program.

2.1.2 Opex review

PB's review of ETSA Utilities' proposed opex included an assessment of:

- the efficiency of the forecast opex for each year of the next regulatory control period, and whether there is any further scope for efficiencies
- the appropriateness of the allocation of opex costs to specific activities
- the effectiveness of operating practices, procedures, and asset management systems at ensuring only necessary and efficient opex occurs
- the major factors (drivers) that may affect the level of efficient opex required over the next regulatory control period
- the appropriateness of the opex forecasting methodology, including:
  - assessing the efficiency of the base year selected
  - the reasonable application of escalation factors used to forecast expenditures
  - assessing the appropriateness of efficiency factors used to reflect the impact economies of scale and scope
  - assessing the efficiency of labour and material costs used to forecast expenditures
  - investigating the design and output of the SEM opex model, which informs the directly attributed regulated opex services in terms of 24 separately identified services and through 41 separately identified allocated cost categories
  - whether insurance costs captured by self insurance have been appropriately excluded
- the impact of proposed capital works to be commissioned during the next regulatory control period on forecast opex.

A two-stage process has been carried out covering an initial high-level review, followed by a more detailed investigation into areas of particular materiality or variance. Fundamentally, the objective of the process has been aimed at:

- reviewing and understanding the business-as-usual asset management approach and practice, including relevant policies and procedures, from both a technical and commercial perspective
- reviewing and understanding the expenditure forecasting methodology and modelling used, with a strong view to being informed of the scope of work proposed; understanding changes proposed by the business; and the drivers presented by the business for any notable and material changes

- forming an independent view on the prudence and efficiency of the proposed scope of work and expenditure, to advise and assist the AER in determining how the opex complies with the requirements and objectives of the NEL and the NER.

PB's review of ETSA Utilities forecast opex allowance has specifically excluded the following matters from our scope of work:

- self-insurance arrangements and allowances ($12.6m included in 'other' operating costs)
- superannuation ($55.2m included in 'other' operating costs)
- debt raising costs ($22.4m included in 'other' operating costs)
- equity raising costs (not included by ETSA Utilities)
- the magnitude of the labour and material escalation factors applied to the forecast opex (noting that the application methodology is included in PB's review)
- high-level, inter-business comparative benchmarking - for example, opex/RAB, or opex/composite size ratios (to be carried out by the AER)
- a high-level review of historical expenditure variations in the current period compared with regulatory allowances (to be undertaken by the AER)
- a detailed review of the indentified external factors and obligations (to be carried out by the AER) and identification of external factors and obligations that have been omitted and may be material
- systematic and formal comparative review or analysis of unit costs informing opex
- review of submissions from interested parties
- ETSA Utilities' capacity to deliver the proposed operating and capital works programs.

2.1.3 Service standards

ETSA Utilities proposes to improve its reliability of supply service performance over the next regulatory control period in line with its regulatory obligations under the *Electricity Industry Code*. PB examines the costs associated with this improvement as a part of its capex review.

ETSA Utilities is also subject to a Service Target Performance Incentive Scheme (STPIS), including a reliability of supply component and a customer service component. The outcome of the PB review is the recommendation of appropriate reliability of supply and customer service performance targets to be applied to ETSA Utilities over the next regulatory control period. PB has assessed the STPIS values proposed by ETSA Utilities against both the principles outlined in the STPIS and clause 6.6.2 of the NER.

In determining the future performance targets, PB has given due regard to historical performance as outlined in the STPIS, as well as the impact that the forecast capex and opex programs may have on performance.

Specifically, in its review, PB has:

- examined any reliability improvements completed or planned to be completed within the current regulatory control period and any other factors that are likely to materially affect reliability performance
- ensured the defined exclusions to the scheme are appropriately removed from the performance data on which targets are based
- assessed the appropriateness of proposed targets, incentive rates and other values proposed for each parameter
- ensured the overall revenue at risk, and the revenue at risk for each customer service parameter, is limited as required by the scheme.

From this review, PB has provided its recommendations of appropriate reliability of supply and customer service performance targets to be applied to ETSA Utilities over the next regulatory control period.

2.2 Specific aspects under review

Significant aspects of PB's review of the proposed expenditures are the assessments of:

- capital governance
- business polices and procedures
- programs of work
- individual projects.

Each of these aspects is described below.

2.2.1 Capital governance

PB recognises sound capital governance as an important cornerstone of prudent and efficient asset management, as it acts to establish and define the business' investment approach. PB has undertaken a high level review of ETSA Utilities' capital governance framework as an integral element of assessing the prudency and efficiency of the proposed network capex for the next regulatory control period.

In our view, good practice capital governance in the context of an asset manager, involves both good practice asset management principles as well as good practice investment management principles. In forming a view on the soundness of capital governance practices, PB relies upon our industry experience and our knowledge of the broader principles of sound business management practice. We also draw upon the principles set out in asset management standards such as PAS 55, IIMM , and TAM , as well a range of Australian and International Standards . Broadly, these asset management standards define an approach that starts with the overarching strategy, devolving this through policies, procedures and plans into all aspects of the business' operations. PB anticipates that good asset governance practice, as set out through such standards, would be evidenced by a well developed and integrated framework of documentation that forms part of the business' culture.

Further to this, PB expects sound capital governance to embody the principles good practice investment management as evidenced through prudent business management practices.

Specifically, formal delegations from the Board level through to business' operational levels, supporting policies and procedures to control capital investment (including audit practices), as well as control of capital investment as evidenced through business documentation which establishes the business case for investment throughout the entire asset lifecycle. These practices should be integral with the business' risk management practices, quality practices, compliance practices, OH&S practices, and environmental management practices amongst others.

2.2.2 Policies and procedures

ETSA Utilities has been asked to specify the policies and procedures by which it makes its operational and investment decisions. Such policies are expected to relate to, for example, augmentation, replacement, opex, cost allocation, capitalisation and demand management. PB has made a detailed review of these policies and procedures. This has included a review of network performance targets and associated forecasts, augmentation models and opex and replacement models where applicable. In making its assessment and recommendation PB has considered the extent to which it believes ETSA Utilities' policies and procedures align with good electricity industry practice and clauses 6.5.6(c) and 6.5.7(c) of the NER.

PB considers this aspect of the review as critical to assessing the prudence and efficiency of expenditure. Electricity distribution businesses engage in a large volume of activities — particularly when compared with gas or electricity transmission businesses. This large volume of activities results in many investment decisions, particularly involving minor network augmentation and asset replacement activities. As it is impractical to individually assess the reasonableness of each of these expenditure decisions, it is necessary to review the framework in which the decisions are made to determine whether the approach taken by the business is likely to result in appropriate expenditure.

PB has developed its view on ETSA Utilities policies and procedures through a desk-top review of documentation, through discussions with ETSA Utilities staff and as an integral part of its more focused review of specific programs of work and projects. Reviewing policy and procedure in the context of proposed expenditure has also provided the opportunity to confirm appropriate application and implementation.

The review of policy and procedure has been for opex, capex and service standards.

2.2.3 Programs of work

It is recognised that there is a notable difference between the approach required for the review of electricity distribution and that for electricity transmission. A significant difference is the predominance of 'programs' of expenditure and the significantly higher number of lower value assets. PB's review recognises the importance of this difference in the context of reviewing the proposed ETSA Utilities expenditure. Planned programs of work can apply to high volume asset fleets and can extend over many years. The link between strategic priorities, policies and procedures, and programs of work is therefore an important aspect of developing an expert opinion on prudence and efficiency. Planned work programmes can have a considerable influence on opex as well as on investment decision-making.

PB's review of the ETSA Utilities work programs has been informed by the Regulatory Proposal and supporting documentation as well as through further discussions with ETSA Utilities staff. Some work programs have been subject to a more focused examination following the portfolio level review of proposed expenditures.

2.2.4 Projects

A significant proportion of DNSP capex is associated directly with the implementation of major distribution projects. As distinct from programs of work, project work often results in large one-off expenditures to establish a large asset — such as new major substation site. Equally, project expenditure can comprise a large number of smaller discrete work activities.

PB’s review of specific projects includes a high level review of all significant projects (Phase 1) and a focused review of a number of projects. PB’s review has examined links between projects and larger work programs, and also the association with particular business strategies and policies.

3. Cost escalation and allocation of overheads

In this section we describe the method used by ETSA Utilities to escalate forecast costs to account for increases in materials and labour above CPI, and to allocate overhead costs across expenditure categories.

In relation to general escalation, PB has only reviewed the reasonableness of the methodology ETSA Utilities has used to apply these escalators and not the quantity of the real escalation applied. This aspect of the review will be carried out by the AER.

3.1 Cost escalation

Cost escalation refers to the potential for input costs to change at a rate greater or less than CPI. ETSA Utilities has incorporated real cost escalation factors into the forecasts for capex and opex in the proposal to the AER. ETSA Utilities has used a range of inputs and advice from consultants in order to establish appropriate cost escalation factors as described in this section.

ETSA Utilities has applied the same escalators to its opex forecasts as it has to its capex forecasts.

3.1.1 Application to capex forecast

To determine appropriate cost escalators for the capex forecast ETSA Utilities engaged SKM to develop cost escalators for materials. The methodology and results of the SKM analysis are presented in Attachment E.5 to the Regulatory Proposal. The methodology involves the determination of raw input commodity escalation forecasts and the subsequent application of weightings comprising two parts:

- weightings of input commodities within asset classes
- weightings of asset classes within ETSA Utilities' network

This approach results in an escalation index that is representative of ETSA Utilities' network and is applicable to the aggregated forecast capex values. This methodology is therefore considered to be a sufficiently detailed approach that is suitable for application to ETSA Utilities' forecast capex.

The weightings of input commodities within asset classes have been reviewed by PB and are considered appropriate as they align with PB's expectations and do not appear to be significantly skewed towards any particular input commodity. The weightings of asset classes within ETSA Utilities' network are calculated in RIN spreadsheet 25[6] based on the classification of activity accounts. The calculations within this spreadsheet have been verified by PB and the resultant weightings are considered suitable for use in the application of cost escalators.

[6] ETSA Utilities spreadsheet RIN25 Materials Component Categorisation Summary

BIS Shrapnel were engaged to develop labour and services escalators. PB has reviewed the reasonableness of the methodology ETSA Utilities has used to apply these escalators. We have not reviewed the quantity of the real escalation applied as this aspect of the review will be carried out by the AER.

ETSA Utilities apply annual cost escalators for the general categories of materials, labour, general services and construction services. The materials, labour and services real cost escalators proposed by ETSA Utilities for each year of the next regulatory control period are presented in Table 3.1.

Table 3.1 ETSA Utilities proposed real annual cost escalators

Expenditure category	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Materials	(12.2%)	(6.0%)	1.7%	2.0%	1.4%	1.4%	1.3%
Labour	4.3%	3.8%	2.7%	3.8%	3.5%	3.3%	3.5%
Services general	1.0%	0.1%	0.8%	0.5%	0.8%	1.0%	1.0%
Services construction	0.0%	0.7%	1.1%	1.7%	2.5%	2.5%	1.5%

Source: ETSA Regulatory Proposal, section 6.4.5, pp 102-105

In order to apply the escalators, ETSA Utilities break down their forecast capex into the same categories as the escalators and directly apply the relevant escalator. This process is undertaken in the spreadsheet model "ETSA SEM Capex Model.xls". PB has identified two material issues with the application of escalation in this model:

- Input values are in 2007-08 dollars, however in calculating nominal values over the next regulatory period, the model ignores the 2008-09 escalators and starts escalation from 2009-10 onwards. Given that the 2008-09 materials escalator is strongly negative, this omission has the effect of over-estimating capex for the next regulatory control period.

  ETSA Utilities has stated that this approach was undertaken to ensure consistency with the treatment of escalation in the opex forecast and that ETSA Utilities recognises that this approach may not align with the real cost increases over the period[7]. Due to the differences in the process used to develop the opex and capex forecasts highlighted in ETSA Utilities' Regulatory Proposal[8], the use of 2008-09 as the base year for capex escalation is not supported. Therefore PB concludes that ETSA Utilities application of real cost escalators in the development of its capex forecast is not efficient and the real annual cost escalators for 2008-09 should also be applied.

- A 2.5 year period is used to inflate from 2007-08 dollars to 2009-10 dollars rather than a 2 year period.

  ETSA Utilities has stated that its bottom up capex estimates have been derived from costs in the 2007-08 financial year and have subsequently been treated as December 2007 costs in ETSA Utilities' modelling[9]. PB notes that the costs are identified as 2008 costs in ETSA Utilities Asset Management Plan (AMP) documentation and costing spreadsheets[10] and that unit costs are specifically stated to have been escalated from

7 ETSA Utilities Response to question PB.ETS.EM.67
8 ETSA Utilities Regulatory Proposal 2010-2015, 1 July 2009, p. 99, 147
9 ETSA Utilities Response to question PB.ETS.EM.66
10 ETSA Utilities spreadsheet CX001 Summary Sheets version Opt10a (moderate), 1 June 2009

2007 costs to 2008 costs[11] in ETSA Utilities Unit Cost report. Therefore PB concludes that ETSA Utilities application of CPI escalation in the development of its capex forecast is not efficient and that ETSA Utilities bottom up estimates should be treated as June 2008 costs.

Correction of these issues results in a 6.0% downward revision to forecast capex over the next regulatory control period. The annual and total adjustments are shown in Table 3.2 on the basis of ETSA Utilities proposed gross capex. The annual percentage adjustments shown in Table 3.2 have been applied proportionally to the total system capex recommendations by PB in sections 4.2.9 and 4.3.10 and the non-system capex recommendations in section 5.3.5.

Table 3.2 PB recommended adjustment – cost escalation

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA proposed gross capex	493.9	592.7	572.7	562.8	550.3	2772.4
Adjustment for real escalation 2007-08 to 2008-09	(19.7)	(22.1)	(22.0)	(21.5)	(20.4)	(105.7)
Adjustment for CPI inflation 2007-08 to 2009-10	(10.6)	(12.8)	(12.3)	(12.1)	(11.9)	(59.7)
Total Adjustment ($m)	(30.3)	(34.8)	(34.4)	(33.6)	(32.3)	(165.4)
Total Adjustment (%)	(6.1%)	(5.9%)	(6.0%)	(6.0%)	(5.9%)	(6.0%)

Source: ETSA Utilities Spreadsheet Capex SEM and PB analysis

3.1.2 Application to opex forecast

ETSA Utilities has applied individual forecasts to the growth of its key cost inputs, namely labour, materials and services (construction) and services (general) as per Table 3.3.

Table 3.3 General input cost escalators (%)

General escalation (%)	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Labour	-	3.76	2.72	3.77	3.46	3.27	3.49
Materials	-	6.05	1.67	2.01	1.42	1.35	1.33
Services - construction	-	0.68	1.06	1.71	2.49	2.52	1.53
Services - general	-	0.06	0.84	0.53	0.76	1.00	1.02
CPI (Dec 04 base)		2.5	1.5	2.5	2.5	2.5	2.5

Source: ETSA Utilities, ETSA Utilities Attachment F.1 SEM-Opex Model Ver7.2 - VP.xls

The real wage growth to apply to ETSA Utilities labour was informed by BIS Shrapnel[12], as were the services construction and service general escalators, while SKM were engaged to prepare the forecast of the real cost changes associated with materials[13].

11 ETSA Utilities CX009 Unit Cost Methodology v1.1, pp. 19-25
12 Attachment E.4 BIS Shrapnel-Labour Services Escalators CustomerConnect-FINAL.pdf
13 Attachment E.5 SKM Materials Cost Escalation.pdf

Figure 3.1 and Figure 3.2 detail how the general escalators are applied to each of the expenditure templates (worksheets) for each of the 63 operational expenditure cost activities where applicable.

Expenditure Template	Service	Labour	Materials	Services - Construction	Services - General
DA-2	Network Access, Monitoring and Control	X	X		X
DA-3	Customer Service	X	X		X
DA-4	Standards Development and Maintenance	X	X		X
DA-5	Asset Strategy and Planning	X	X		X
DA-6	Maintenance Planning	X	X		X
DA-7	Maintenance of Asset Information	X	X		X
DA-8	Network Telephony	X	X	X	
DA-10	Regulatory Compliance	X	X		X
DA-11	Outage Management System	X	X		X
DA-12	Inspections	X	X		X
DA-13	Maintenance	X	X		X
DA-14	Vegetation Management	X	X		X
DA-15	Emergency Response	X	X		X
DA-16	Meter Reading Charges	X	X		X
DA-17	Call Centre Charges	X	X		X
DA-18	Demand Management	X	X		X
DA-21	Property – Substation Sites	X	X	X	
DA-23	Retail Contestability Charges	X	X		X

Figure 3.1 ETSA Utilities application of general input cost escalators to direct cost activities

Source: ETSA Utilities, Attachment F.4 Derivation and application of scale escalators.xls

		Labour	Materials	Services - Construction	Services - General
A-1	CEO	X	X		X
A-2	Strategic Planning	X	X		X
A-3	Communications	X	X		X
A-4	Audit Services	X	X		X
A-5	eral Manager Regulation & Company Secretary	X	X		X
A-6	Regulation	X	X		X
A-7	CFO	X	X		X
A-8	Accounts Receivable – Asset Damage	X	X		X
A-9	Taxation – Specific Allocation	X			X
A-10	Corporate Finance	X	X		X
A-11	Operational Finance	X	X		X
A-12	Regulatory Finance	X	X		X
A-13	Accounts Payable	X	X		X
A-14	Payroll	X	X		X
A-15	Purchasing and Contracts	X	X		X
A-16	Finance - Adjustments				
A-17	General Manager Corporate Services	X	X		X
A-18	Employee Relations	X	X		X
A-19	Workforce Development	X	X		X
A-20	Training Centre	X	X		X
A-21	Apprentice Training	X	X		X
A-22	Training Centre Management	X	X		X
A-23	Information Technology	X	X		X
A-24	Property – Offices and Depots	X	X	X	
A-26	OHS	X	X		X
A-27	Environment	X	X		X
A-28	Printing	X	X		X
A-29	isk & Insurance – Shared Insurance Premiums	X	X		
A-30	Risk & Insurance – Support Costs	X	X		
A-31	Legal Services	X	X		X
A-32	General Manager Services	X	X		X
A-33	Customer Relations, excluding Call Centre	X	X		X
A-34	Business Improvement and Planning	X	X		X
A-35	Works Coordination	X	X		X
A-36	Employee Bonuses	X			
A-37	Voluntary Separation Packages (VSP's)	X			
A-39	Self-insurance	X	X	X	

Figure 3.2 ETSA Utilities application of general input cost escalators to direct cost activities

Source: ETSA Utilities, Attachment F.4 Derivation and application of scale escalators.xls

While it is not within PB's scope of work to review the value of the actual general input cost escalators ETSA Utilities has incorporated into its expenditure forecasts, we are required to comment on the reasonableness and suitability of the methodology used.

The process taken by ETSA Utilities to identify the split in expenditure across each opex activity has involved using the information within its business systems which informs the base year. All direct costs and allocated costs in 2008-09 have been identified in the cost escalation categories and these ratios have been keep fixed across the forecast period, except in the case of vegetation management and demand management initiatives which have been informed through bottom-up forecasts.

In context of how the historical and forecast opex is apportioned into the four escalation categories, Figure 3.3 shows the year-on-year trend, indicating that ETSA Utilities is not anticipating any significant variation in its approach over the next regulatory control period, with a slight increase in the use of internal labour compared with contracted services.

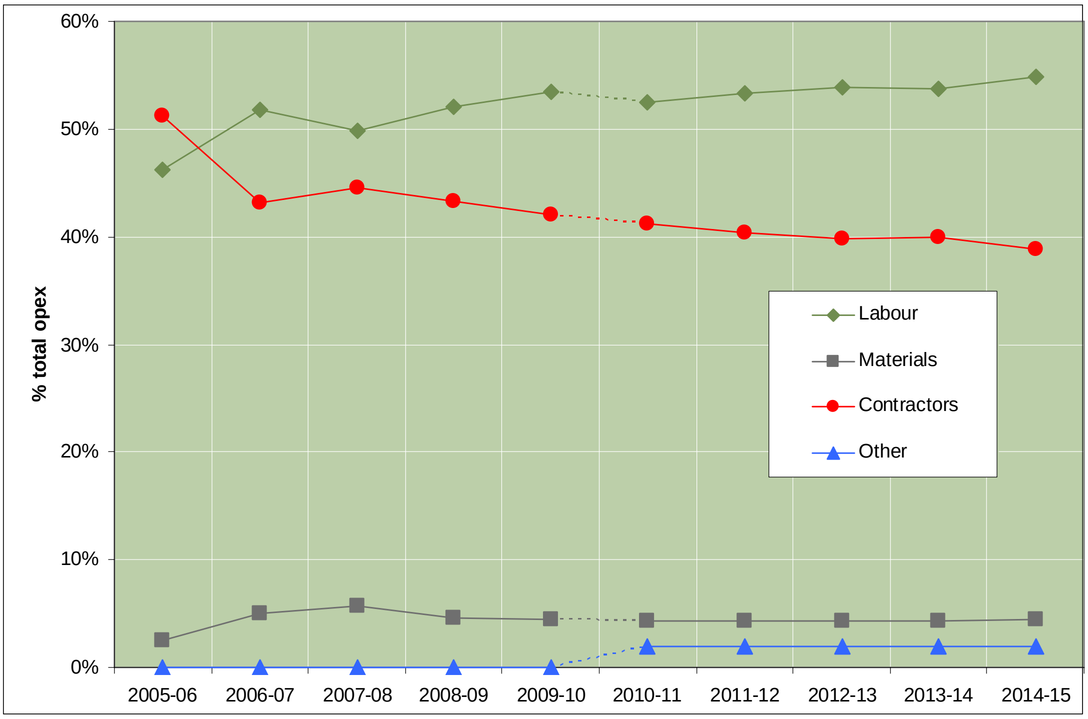

Figure 3.3 Historical and forecast split across escalation categories

Source: PB analysis

Some of the key activities (not necessarily completely) outsourced by ETSA Utilities include:

- network telephony
- inspections
- vegetation management
- meter reading
- call centre activities
- demand management
- property
- retail contestability
- communications

3.2 Overhead allocations

Allocated costs are all shared business overheads. This includes the costs associated with the CEO, planning and audit, communications, regulation and company secretary, HR and training, property, information systems and risk management.

ETSA Utilities treats all overheads as an expense. PB has reviewed the overheads as a part of each expenditure category in the opex review section 6 of this report.

4. System capex review

This section presents PB's review of ETSA Utilities' proposed system capex for the next regulatory control period. A high level review is provided, including an analysis of trends in expenditures. This is followed by factors affecting the forecast expenditures, an overview of the relevant processes and procedures, and discussion on specific expenditure categories. A summary of PB's findings and recommendations concludes the section.

4.1 High level review

ETSA Utilities has submitted a system[14] capex proposal of $2,309.9m[15] for the next regulatory control period as summarised in Table 4.1. This expenditure comprises approximately 83% of the total proposed capex.

Table 4.1 Proposed system capex for the next regulatory control period

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Demand driven						
Capacity	146.6	194.4	147.6	144.6	142.6	775.7
Customer connection*	130.6	139.1	127.6	141.0	143.0	681.3
Quality, reliability and security of supply						
Asset replacement	79.7	91.4	96.8	98.9	99.9	466.8
Security of supply	15.5	45.9	65.3	33.8	9.9	170.4
Reliability	4.9	5.0	5.0	5.1	5.2	25.2
Safety and environment						
Safety	18.4	24.6	27.9	29.9	30.2	131.0
Environmental	2.7	3.2	3.3	3.3	3.4	15.9
Network Other	8.4	8.6	8.7	8.9	9.0	43.6
Total system capex	406.7	512.2	482.2	465.4	443.4	2,309.9

Source: RIN999 Final ETSA Utilities pro formas

*Note: * includes customer capital contributions*

Demand-driven capex represents 63% of the total system capex proposed, while quality, reliability and security of supply represents 29%, and safety and environment represents 8%. A detailed breakdown of the proposed system capex portfolio is shown in Figure 4.1 below.

14 In its Regulatory Proposal, ETSA Utilities uses the term 'network' rather than 'system'. For consistency with the RIN, this report also uses 'system'.

15 Excluding capitalised superannuation and equity raising costs

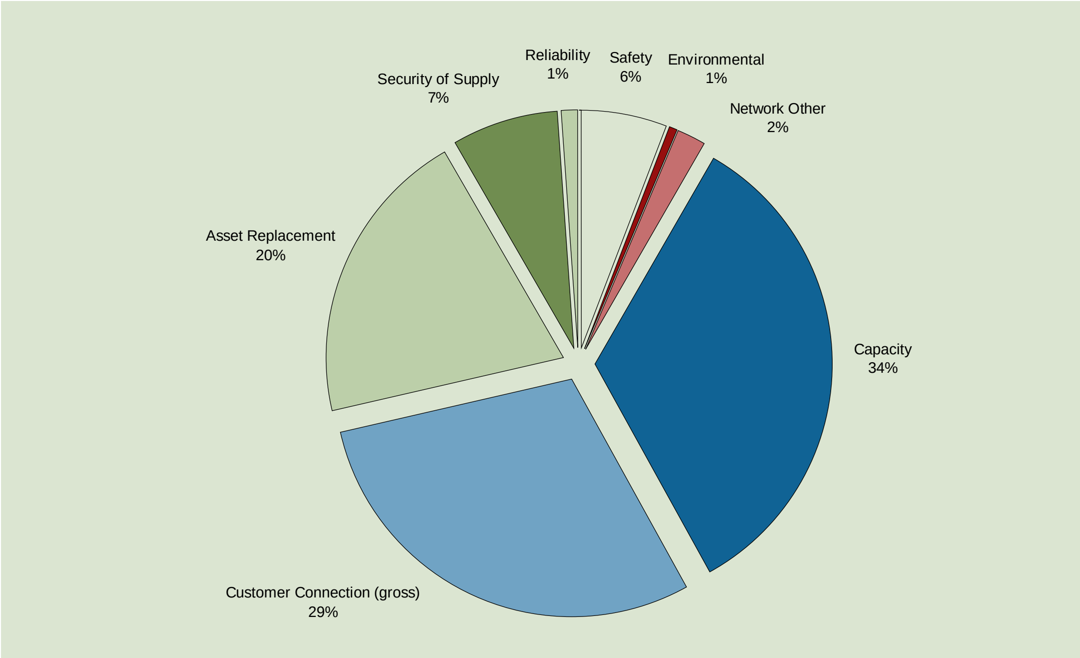

Figure 4.1 Proposed system capex portfolio breakdown

Source: RIN999 Final ETSA Utilities pro formas & PB Analysis

4.1.1 Trends and comparative analysis

PB has reviewed historical variances between the Essential Services Commission of South Australia's (ESCoSA) Electricity Distribution Price Determination (EDPD) and ETSA Utilities' actual historical system capex[16].

Figure 4.2 shows the actual system capex for the previous and current regulatory control periods, the EDPD allowance for the current regulatory control period, and the forecast capex for the next regulatory control period. The figure shows ETSA Utilities has underspent the capex approved by ESCoSA over the first three years of the current regulatory control period.

For the remaining two years, the AER[17] identifies that ETSA Utilities has forecast a total $238m (nominal) overspend of the approved capex, with the majority of this overspend in 2009-10. This overspend is expected to result in ETSA Utilities' actual capex for the current regulatory control period exceeding the ESCoSA allowance by $190m in nominal terms.

16 The AER has made a comparative analysis of ETSA Utilities' historical expenditure. Refer Australian Energy Regulator 2009, *Queensland and South Australia Electricity Distribution Determination 2010–15 Review of Historic Capital Expenditure*.

17 AER 2009, Queensland and South Australia Electricity Distribution Determination 2010–15 — Review of Historical Capex.

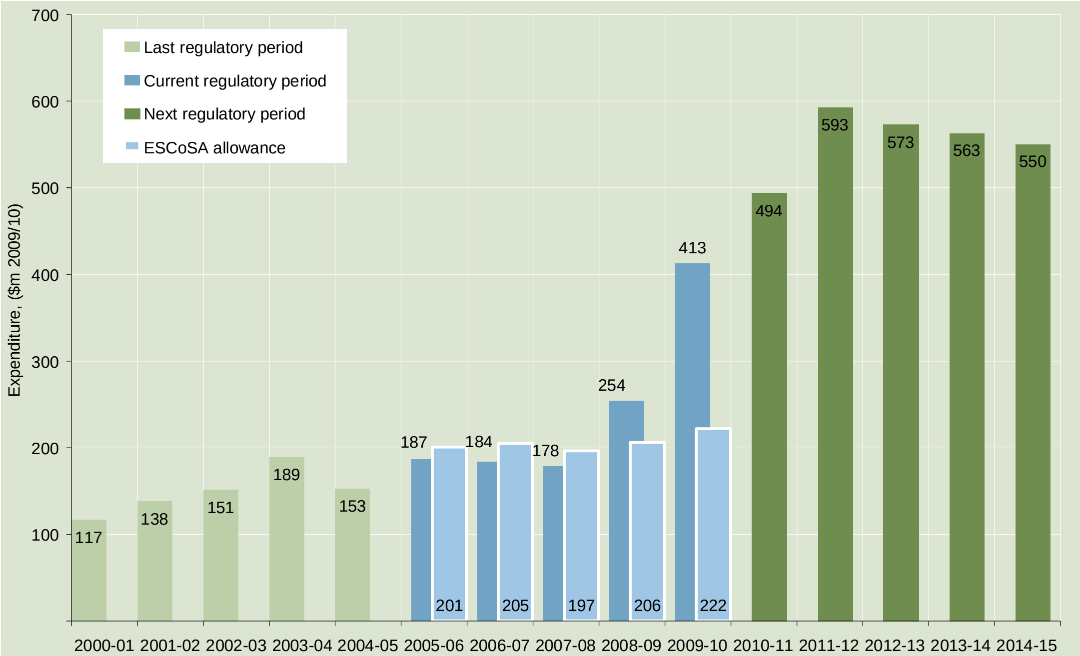

Figure 4.2 ETSA Utilities historical and proposed capex

Source: RIN999 Final ETSA Utilities pro formas, AER Historic Capex review & PB Analysis

The AER's review of historical expenditure[18,19] noted ETSA Utilities' total system capex allowance for the current regulatory control period represented a 115% nominal increase over the capex allowance approved for the previous regulatory control period. Furthermore, the AER identified the total system capex has been 7–11% below the Electricity Distribution Price Determination (EDPD) forecast in each of the three years of the current regulatory control period where actual expenditure data has been provided. The AER also notes that:

> "Over the first three years of the current period, significant overspends on asset replacement, and reliability and quality improvements, were more than offset by underspends in the demand related and other expenditure categories. No explanation for these variances has been provided through ESCoSA's annual performance reports."[20]

The AER has identified that a large proportion of the historical underspend was related to the 21–37% annual underspend in the 'reinforcements and upgrade' (capacity) category over the available actual results for the current regulatory control period. PB notes ETSA Utilities has forecast a further increase in this expenditure category over the next regulatory control period and therefore the timing of this capex is likely to be a material consideration for the next regulatory control period.

The AER report identified the overspend in the latter part of the current period was to the result of a $103m one-off forecast increase in new customer connection expenditure, which is not expected to continue through the next regulatory control period[21].

For comparison Figure 4.3 illustrates ETSA Utilities' gross historical and forecast system capex.

18 AER 2009, Queensland and South Australia Electricity Distribution Determination 2010–15 — Review of Historical Capex.

19 The AER review of historical expenditure refers to total gross capex (i.e. inclusive of non-network capex, and other-superannuation and equity raising costs).

20 ibid., p .4.

21 ibid., p. 5.

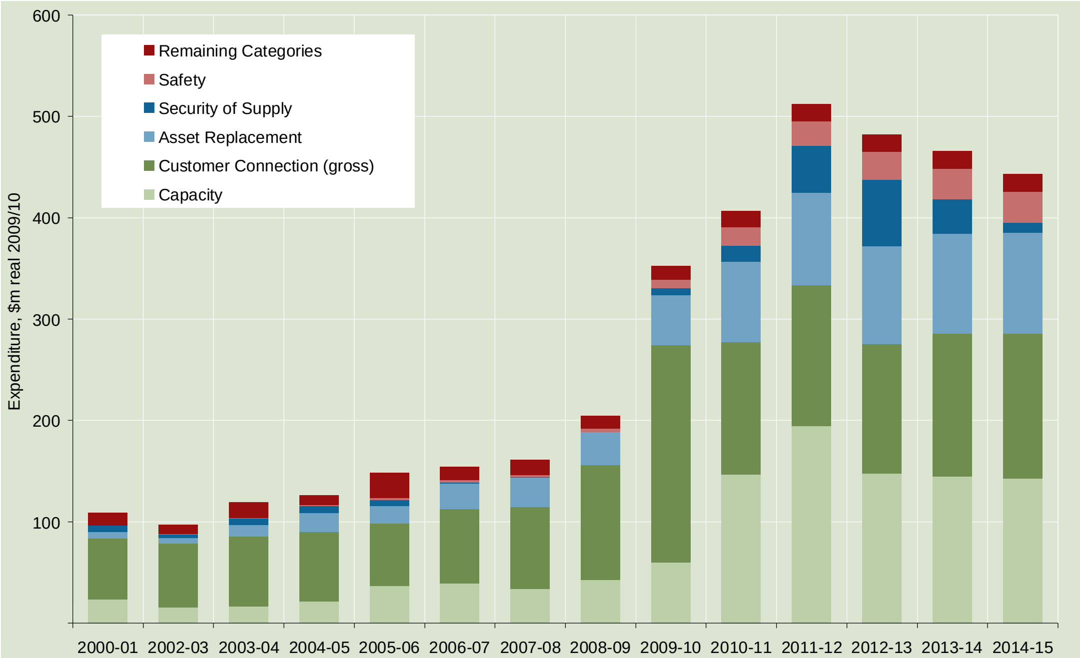

Figure 4.3 Historical and proposed system capex

Source: RIN999 Final ETSA Utilities pro formas & PB Analysis

Note: excluding the other superannuation and equity raising cost category

ETSA Utilities' proposed system capex for the next regulatory control period represents a 126% real increase over the current regulatory control period[22]. Figure 4.4 illustrates these increases broken down into ETSA Utilities' regulatory expenditure categories.

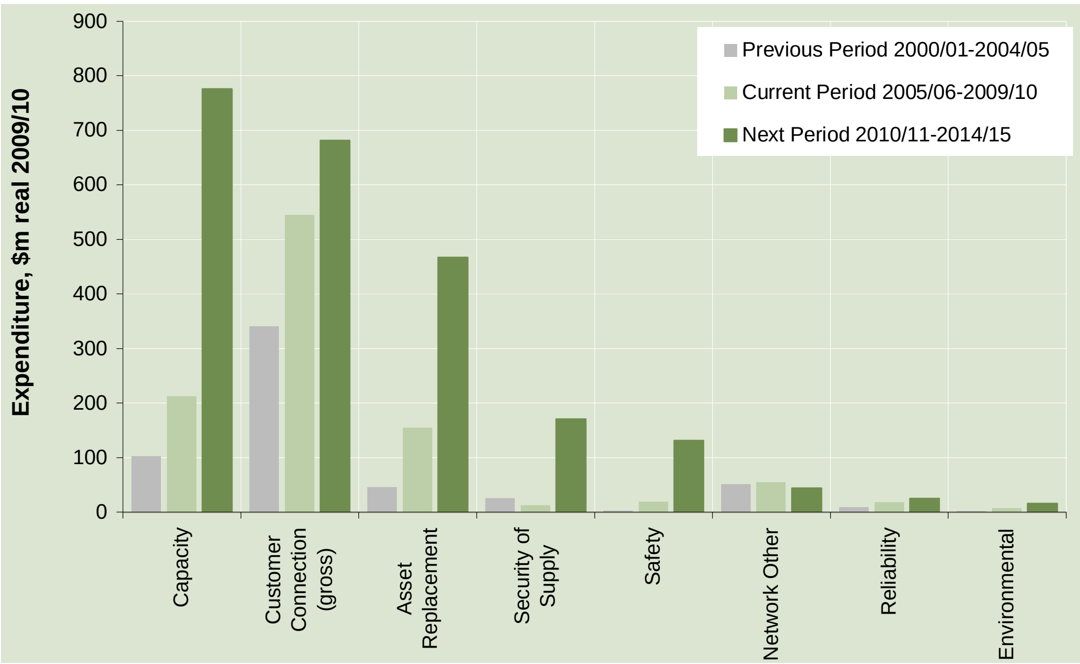

Figure 4.4 Proposed system capex by expenditure category

Source: RIN999 Final ETSA Utilities pro formas & PB Analysis

22 Excluding the other- superannuation and equity raising costs category.

PB has analysed the principal growth drivers for the five major expenditure categories, and this is presented in sections 4.2 and 4.3 of this report. PB has also considered the drivers for the remaining categories, which total $6m, or 0.5% of the overall $1.29b proposed system capex increase (excluding superannuation and equity raising costs), through our review process. Table 4.2 presents the principal drivers for the increase in the proposed system capex for each of ETSA Utilities' regulatory expenditure categories.

Table 4.2 Drivers for the increase in proposed capex[23]

Expenditure category	Variance* $m (%)	Principal drivers
Major expenditure categories		
Capacity	$564 (266%)	▪ transmission code change requiring the construction of the City West connection point ▪ change in low voltage planning approach to mitigate the impact of higher diversified maximum demands on transformers during heatwave events
Customer connections	$137 (25%)	▪ significant increase in forecast major customer connections (>$100k) ▪ major one-off infrastructure connections (e.g. desalination plant)
Asset replacement	$313 (203%)	▪ change in asset management approach from 'run to failure' to proactive replacement
Security of supply	$158 (1,236%)	▪ Kangaroo Island undersea cable duplication and 66 kV network upgrade ▪ network control project replacing the network operations centre (NOC) and SCADA system.
Safety	$112 (591%)	▪ acceleration of existing replacement programs ▪ CBD aged asset replacement program ▪ introduction of new safety related replacement programs to address assets assessed by ETSA as high risk
Remaining categories		
Reliability improvements	$8 (44%)	▪ increase expenditure to maintain current network reliability levels (Total $25m)
Environmental	$10 (152%)	▪ increase in oil containment, fire and noise control treatment at high risk substation sites (total $16m).
Network other	-$11 (-20%)	▪ expenditure for easement acquisition, undergrounding, distribution training centre equipment costs, and condition monitoring strategy (total $44m) ▪ majority ($37m) associated with PLEC (undergrounding) works with a statutory compliance driver ▪ reduction due to changes in the projects allocated to the 'other' expenditure category

23 Source: RIN999 Final ETSA Utilities pro formas & PB Analysis.

** Variance is the real difference between the historical capex in the 2004-05 to 2009-10 regulatory control period and ETSA Utilities proposed allowance for the 2009-10 to 2014-15 regulatory control period.*

Source: RIN999 Final ETSA Utilities pro formas & PB Analysis

Comparative benchmarking

The AER has made a comparative benchmarking study[24] of ETSA Utilities' historical and proposed capex against other Australian DNSPs[25]. In forming our view on the prudency and efficiency of ETSA Utilities' proposed system capex for the next regulatory control period, PB has taken into consideration the lower actual Capex/RAB ratio of ETSA Utilities in comparison to its industry peers and the following conclusions from the AER's report:

> "The lower benchmark figure for ETSA Utilities may be a reflection of a relatively low forecast capex allowance determined by the regulator for the 2007–08 year…ETSA Utilities' actual & forecast capex/RAB ratio reflects significant increases in its proposed capex during the next regulatory control period"[26]

Despite the above, PB notes there are significant differences in ETSA Utilities' cost allocation in regard to corporate overheads and capitalisation, and that variations in network characteristics and environmental factors influence benchmarking evaluations. Therefore, PB considers such benchmarking as indicative only.

4.1.2 Capital governance framework

ETSA Utilities' capital governance framework is outlined in its capex directive[27] and is supported by detailed procedures covering budgeting, project evaluation and approval, project monitoring, project review, procurement and cost allocation. An outline of these documents is given in Table 4.3 below.

24 AER 2009, "Working paper on capex benchmarking".
25 Distribution Network Service Providers.
26 ibid., p. 2.
27 ETSA Utilities 2009, *BO17 Capex Directive*, July 2009.

Table 4.3 Capital governance policies and procedures

Document	Description
Capex directive	Provides direction for the budgeting, evaluation, approval and monitoring of capex.
Cost allocation method 2008[28]	Sets out the cost allocation method adopted in ETSA Utilities' regulatory reporting from 1 July 2010.
Capital budgeting procedures[29]	Details the principles and practices that govern ETSA Utilities' capex budgeting.
Capital evaluation and approval[30]	Details the principles and practices which govern ETSA Utilities' evaluation and approval of capital expenditure projects.
Risk management policy[31]	Details ETSA Utilities' risk management approach. Attachment 3 to the Capital Budgeting Procedures[32] includes the definition of acceptable risk levels.
Procurement directive[33]	Details ETSA Utilities' procurement strategy.
Capital monitoring and post-implementation review procedures[34]	Details the principles and practices that govern ETSA Utilities' monitoring and post-implementation review of capex projects.

Source: As noted in descriptions above, and PB analysis

PB has reviewed ETSA Utilities' Regulatory Proposal and its capital governance documentation as set out in Table 4.3, and held discussions with relevant ETSA Utilities staff. Throughout our enquiries we also reviewed a range of capital investment documentation, such as business cases, asset management plans (AMPs), and network planning documents. PB has also reviewed the business strategic business plan, as well as programs, relevant policies, delegation arrangements, and the investment approvals process to assess the business alignment of the principles of good capital governance as discussed above.

Through our review and enquiries, PB found that ETSA Utilities has a well-developed documentation framework, which demonstrates thorough capital governance practices. PB's review of ETSA Utilities' delegations structure and investment approvals process, as evidenced by the business' policies, AMPs, and business case documentation, also found the business' practices relating to capital investment management were generally sound. However, PB notes the coarseness of the risk assessment process is of concern as it does not allow for the consistent detailed ranking of projects and analysis of alternative options, which could lead to inferior investment decisions. This is discussed further in section 4.2 below.

From our review we have found ETSA Utilities' capital governance framework sets out clear processes of delegations of authority that ensure a consistent approach is taken in making capital investment decisions. We also note that procedures are subject to an annual internal audit, last made in 2008-09 by KPMG[35]. PB has seen this audit report and notes it does not identify any material issues about applying the capital governance processes. From our high

28 ETSA Utilities 2008, BO11 Cost Allocation Method, September 2008.
29 ETSA Utilities 2009, BO15 Capital Budgeting Procedures, May 2009.
30 ETSA Utilities 2009, BO14 Capital Evaluation and Approval Procedures, May 2008.
31 ETSA Utilities 2006, BO27 Risk Management Policy, September 2006.
32 ETSA Utilities 2009, BO15 Capital Budgeting Procedures, May 2009.
33 ETSA Utilities 2007, BO18 Procurement Directive, January 2007.
34 ETSA Utilities 2009, BO16 Capital Monitoring and Post Implementation Review Procedures, April 2009.
35 KPMG 2009, Internal Audit Report of Capital Investment and Budgeting, February 2009

level review we have concluded that ETSA Utilities' capital governance framework is generally in accordance with the principles of good asset management, and good electricity industry practice.

4.1.3 PB assessment and findings

This section summarises the main observations and findings from the high level review of ETSA Utilities' system capex proposal.

PB's principal observations are:

i) The business is proposing a real increase of 126% in system capex over the current regulatory control period.

ii) Changes in LV planning criteria, the transmission code, asset management approach and the forecast demand growth are driving significant system capex growth.

iii) ETSA Utilities historically benchmarks well using a capex/RAB ratio, but this comparative performance declines significantly during the next regulatory control period.

iv) ETSA Utilities' capital governance framework demonstrates thorough capital governance practices and is generally in accord with good asset management practices, and good electricity industry practice.

PB is concerned that:

i) ETSA Utilities has proposed a large increase in demand driven expenditure against a history of under spending in this category. This is discussed further in section 4.2 below.

ii) The coarseness in application of the risk management procedures at the detailed project level is not sufficient to support a consistent detailed ranking of projects and analysis of alternative options, and that this could lead to inefficient outcomes. This is discussed further in section 4.3 below.

4.2 Demand driven capex

The demand driven category of system capex relates to the growth of the network, including expenditures for capacity augmentation and for new customer connections.

4.2.1 Proposed expenditure

As shown in Table 4.4, ETSA Utilities is proposing to spend a total of $1,457m on demand-driven capex over the next regulatory control period, which represents 63% of the system capex reviewed by PB. Figure 4.5 shows the forecast capex represents a real increase of 93% over the current period capex of $756.3 m.

Table 4.4 Proposed system capex for demand driven

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Capacity	146.6	194.4	147.6	144.6	142.6	775.7
Customer connection	130.6	139.1	127.6	141.0	143.0	681.3
Total demand driven	277.3	333.4	275.3	285.5	285.5	1,457.0

Source: RIN999 Final ETSA Utilities pro formas

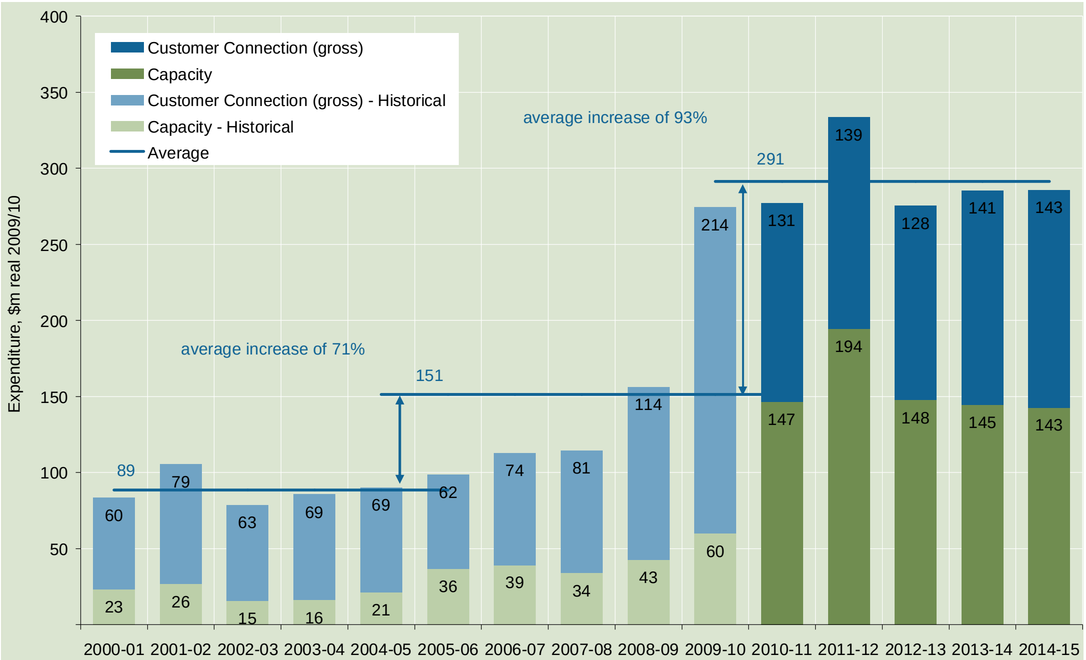

Figure 4.5 Demand driven capex – historical and proposed

Source: RIN999 Final ETSA Utilities pro formas & PB Analysis

4.2.2 Demand expenditure drivers

ETSA Utilities has identified the principal growth drivers in the demand driven capex over the next regulatory control period as[36]:

- additional capacity augmentation required to meet ETSA Utilities' revised LV planning criteria
- augmentation arising from changes in the *Electricity Transmission Code* requirements — principally associated with the City West connection point
- forecast network constraints arising from the forecast peak demand growth
- forecast increases in major customer connections — mainly South Australian infrastructure projects.

These drivers result in an overall real increase of 266% in capacity capex, and a real 25% increase in customer connection capex over the current regulatory control period.

36 ETSA Utilities 2009, *Utilities Regulatory Proposal 2010–2015*, 1 July 2009, p. 111.

To assess the impact of these drivers on the overall prudency and efficiency of the proposed demand driven expenditure, PB has reviewed the application of the demand forecast, considered the use of non-network alternatives, and made specific reviews of the $138.8m LV network upgrade program, and the $390m major customer connection forecast.

PB observes that ETSA Utilities' proposed demand forecast indicates significant demand growth over the next regulatory control period. This follows from two years of significant demand growth in the current regulatory control period after a relatively stable actual demand over the previous regulatory control period.

We also note the development and reasonableness of ETSA Utilities' maximum demand and sales forecasts are being reviewed by the Australian Energy Market Operator (AEMO), and the customer connection forecast is being reviewed by McLennan Magasanik Associates (MMA). Therefore a review of these forecasts is not within the scope of PB's review. PB has reviewed the application of the demand forecasts to the development of the capex for capacity augmentation as presented in section 4.2.4 below.

4.2.3 Application of policy and procedures

In this section PB considers the application of ETSA Utilities' key policies and procedures to the development of the demand driven capex forecasts. Specifically, the application of ETSA Utilities' planning criteria is crucial to developing the demand driven capex forecast, as is developing recommended options to address constraints identified through applying the planning criteria. Section 4.2.4 below examines the demand forecast, a further vital element of the demand driven capex forecast.

Planning criteria

The role of planning criteria within a DNSP's investment process is to define a set of rules, which, when used in conjunction with the application of a given demand forecast, allow the business to identify future network constraints and determine the required implementation timing of non-network strategies or network augmentation. Hence these criteria are fundamental to informing the need and timing of demand-related investment in a transparent manner.

Within Australia, deterministic planning criteria are applied in the majority of electricity distribution network businesses. PB notes that while deterministic planning is inherently more conservative than other risk-based approaches, or probabilistic methods, the longstanding application of deterministic approaches, and their broad jurisdictional acceptance, make them a central feature of contemporary electricity industry practice.

Within the industry, deterministic planning criteria for sub-transmission and zone substations mostly involve the 'N', 'N-1', or 'N-2' principles (or variations thereof). These basic criteria are often modified to account for different equipment rating standards, criticality and size of the connected load, interruption and restoration time limits, or contingency capabilities (e.g. transferable or controllable load, mobile generation, mobile substations, and so forth)[37].

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37 Further details of typical industry planning practice within Australia, including a comprehensive account of the planning criteria applied within the industry, can be found in Sinclair Knight Merz's (SKM) report to the Australian Energy Market Commission (AEMC), *Advice on Development of a National Framework for Electricity Distribution Network Planning and Expansion*.

ETSA Utilities' deterministic planning criteria are described in detail in chapter 9 of the Demand and Network Management (DaNM) Asset Management Plan[38]. PB has reviewed the Asset Management Plan, and in particular ETSA Utilities' planning criteria, and notes these criteria are based on N and N-1 principles, with specific and clearly tabulated variations to account for the size and criticality of the load, feeder transfers, the use of mobile substations outside the CBD area, and restoration time parameters. The comprehensive detail contained within the planning criteria, the transparent definitions, guidelines and general design of the documentation ensure they are easy to understand and provide confidence that the criteria can be interpreted and applied appropriately.

As an integral part of PB's review process, the application of the criteria was discussed in meetings with ETSA Utilities, and appraised through a review of a range of specific capex projects (refer section 4.2.4). In all cases the application of the planning criteria aligned with the principles of ETSA Utilities' policies.

While ETSA Utilities' deterministic planning criteria are inherently conservative, as is their application, they are nonetheless typical of the broader industry practice, as noted above. Based on PB's observations, we consider the planning criteria suitable for forecasting ETSA Utilities' demand-driven investment, and that they are appropriately applied through the planning process. Therefore, PB concludes ETSA Utilities' planning criteria and their application to planning demand-driven sub-transmission and zone substations is prudent in the sense that it is in accordance with good electricity industry practice.

It is important to note ETSA Utilities' revised planning approach to low voltage capacity is considered separately, and is discussed as a specific issue in section 4.2.6 of this report.

Cost estimation

The consistent application of accurate costs in planning estimates is critical to the development of a realistic forecast to capacity augmentation costs and to provide a valid evaluation of alternative options for projects.

Australian distribution and transmission businesses typically use bottom-up costs for planning estimates. In a number of cases, common building blocks are identified to simplify and standardise the cost-estimation process so that costs of a comparable level of detail can readily be provided to facilitate budget estimation and options evaluation. Costs are typically updated on an annual basis to ensure that current cost information is consistently reflected in planning estimates.

PB has reviewed the costing methodology used by ETSA Utilities to develop the capacity plan, as outlined in the Unit Cost Methodology[39] document, and the build up of the capacity plan from the building-block costs demonstrated in a spreadsheet[40] to detail the costs for each of the 258 line items included in ETSA Utilities' capacity expenditure plan. We note the estimation process used for the capacity plan differs from the estimation process used for the asset replacement plans, which is discussed in section 4.3.3.

As part of PB's review process, we discussed the cost-estimating process applied to develop the capacity-driven expenditure in meetings with ETSA Utilities, and appraised through reviewing the costing spreadsheet and considering key unit costs used in the specific reviews.

38 ETSA Utilities 2009, *DaNM Asset Management Plan*, 2009 Issue, pp. 9-16–9-20
39 ETSA Utilities, Unit Costs Version 1.1, document CX009.
40 ETSA Utilities spreadsheet SI12 PB.ETS.EM.36 AMP.1.1.01.xls.

PB found the cost-estimating process was transparently applied in the build up of the capacity-driven expenditure forecast, although we note that $331m of the $800m (2008 dollars) base capacity driven capex estimate included for the 2010–2015 calendar year period[41] was comprised of costs built up outside the building-block estimation process. These costs relate to annual programs of capacity-driven expenditure or major projects where specific estimates have been separately calculated, such as the Low Voltage Network Capacity Upgrade program (reviewed in section 4.2.6) and the City West Connection Point project that together account for approximately 70% of the $331m expenditure.

PB notes that using project-specific estimates in cases where there has been more detailed analysis is not unusual in the electricity industry.

From our review, we conclude the cost-estimating process applied to derive ETSA Utilities' capacity-driven expenditure is based on reasonable building-block costs, is transparently applied and appropriate for forecasting ETSA Utilities' capacity expenditure.

Options analysis

Effective evaluation of alternative project options is important to ensure the full range of feasible options is considered and the least cost or highest NPV option is selected so there is the maximum economic benefit from asset investment.

In accordance with the process outlined in the Demand and Network Management (DaNM) AMP[42], ETSA Utilities formally documents its options analysis in the business case document presented for funding approval. PB notes that as this typically occurs in the year before the project starts limited formal business case documentation relevant to the projects scheduled for the next regulatory control period was available for review. In the absence of the formal documentation, PB considered the summary of options identified for the ten largest major capacity augmentation projects included in the Distribution System Planning Report[43] to test the veracity of the options analysis ETSA Utilities used to support the major capacity projects included in the Regulatory Proposal.

We have also considered the options analysis documented in the regulatory tests for the City West Connection Point project, Southern Inner Metropolitan sub-transmission augmentation, the Kangaroo Island security of supply project reviewed in section 4.3.7 and ETSA Utilities' responses to our detailed questions, which included more detailed analysis than is contained in the AMP documentation.

For the capacity augmentation projects summarised in chapter 7 of the Distribution System Planning Report, PB noted that while the option costs are not provided, a reasonable range of options have been identified for each augmentation project, including non-network solutions and ETSA Utilities identified that the selected option was chosen on the basis of its NPV, timing and effectiveness.

PB found that the options analysis for major augmentation projects as documented in the regulatory test publications[44] [45] for the City West Connection Point project and Southern

41 ETSA Utilities AMP's are developed on a calendar year basis rather than the financial year basis of the Regulatory Proposal.

42 ETSA Utilities 2009, *DaNM Asset Management Plan*, 2009 Issue, p. 6-2.

43 ETSA Utilities, Attachment E.9 AMP1.1.01 Distribution System Planning Report 2010 to 2020.

44 ElectraNet & ETSA Utilities 2009, Proposed New Large Network Asset, Adelaide Central Region Final Report, July 2009.

45 ETSA Utilities & ElectraNet, Evaluation Report RFP-ER003/04, Electrical Supply to the Southern Inner Metropolitan Region of Adelaide, South Australia, Issue 3.0, November 2007.

Inner Metropolitan Supply project was well documented, considered all reasonable alternative options, including comprehensive sensitivity testing, and clearly resulted in the selection of the most efficient option.

Despite our comments in section 4.3.7 about the Kangaroo Island augmentation project being driven by the need for security of supply, and where a formal business case or regulatory test document has not yet been prepared, in response to PB's queries, ETSA Utilities provided a detailed option analysis to support the upgrade option for the proposed 66 kV sub-transmission line that demonstrated the selected option represented the least cost[46].

PB concludes that ETSA Utilities considers a reasonable range of options in its capacity planning decisions, and that despite the absence of formal business case documentation until close to the approval of project expenditure, the options analysis for the reviewed network augmentation projects was available to adequately support the proposed solution.

4.2.4 Application of demand forecast

ETSA Utilities' demand driven capex proposal is based on the application of the business' demand forecast, which, in conjunction with the planning criteria, is used to determine the emerging need and timing of system capex. ETSA Utilities' Distribution Network Planning Report[47] details how the forecast growth rates are applied, in conjunction with the planning criteria, for each major augmentation project.

PB has reviewed ETSA Utilities' application of its demand forecast to determine the timing of the ten largest augmentation projects identified in the Distribution System Planning Report. PB found that ETSA Utilities had applied the demand forecast appropriately in identifying the efficient timing of capacity capex. PB also noted that ETSA Utilities had considered the use of feeder transfers and mobile substations in accordance with its planning criteria.

ETSA Utilities' capex proposal is based on spatial demand forecasts for medium growth. With the exception of the compliance-driven, new connection point projects arising from the *Electrical Transmission Code* changes, the timing of the majority of the $775.7m capacity-driven capex is dependent on the demand forecast.

AEMO has reviewed the ETSA Utilities' demand forecast and concluded that despite ETSA Utilities adopting a more pessimistic set of economic assumptions:

> AEMO's and ETSA Utilities' network-wide peak demand forecasts are reasonably close for all years throughout the forecast period... [48]

AEMO's review also included a review of the data sources and approach to reconciling ETSA Utilities' spatial demand forecasts. AEMO states:

> AEMO also conducted a pre-lodgement review of ETSA Utilities' data sources and approach to compiling its spatial demand forecasts at three different levels within the distribution network and its approach to reconciling these forecasts with one another. This was a sound approach that offered a self-checking mechanism to ensure the forecasts are internally consistent with one another and that consistent data had been

46 ETSA Utilities response to question PB.ETS.EM.48

47 ETSA Utilities 2009, Attachment E.9 AMP1.1.01, *Distribution System Planning Report 2010 to 2020,* AMP.1.1.01, May 2009, Section 7, p. 48.

48 AEMO 2009, Review of ETSA Utilities Sales and Demand Forecasts, September 2009, p. 55.

> used in the preparation of the forecasts. AEMO therefore concludes that ETSA Utilities' connection point peak demand forecasts are reasonable. [49]

In addition to capacity augmentation, the customer connection component of the ETSA Utilities demand driven capex is dependent on the forecast of customer numbers. ETSA Utilities engaged BIS Shrapnel[50] to prepare an estimate of the minor and medium customer connection costs on the basis of forecast changes in South Australian construction activity.

PB has reviewed the application[51] of the customer connection forecasts and considers that the forecast annual changes in construction activity are appropriately reflected in ETSA Utilities proposed expenditure. PB notes that the major (>$100k) customer connection expenditure has been subject to the specific review outlined in section 4.2.7.

Based on our assessment, PB concludes the application of the demand forecasts set out in the Regulatory Proposal has been appropriately incorporated into forecast expenditures.

4.2.5 Consideration of non-network alternatives

ETSA Utilities highlights in its Strategic Business Plan that it aims to 'be the leading distribution business in Australia in terms of the use of demand management solutions as an adjunct to supply side constraints to network capacity constraints'[52]. Therefore ETSA Utilities is well advanced in the development and implementation of demand management initiatives.

ETSA Utilities' approach to demand management and non-network alternatives is described in its Regulatory Proposal[53] and the DaNM Asset Management Plan[54]. The business considers economically viable non-network alternatives as a matter of course before applying network solutions. An assessment is made in conjunction with existing capital works planning and investment approval processes to find out whether a suitable non-network alternative is more efficient than a more traditional network augmentation option[55]. ETSA Utilities' assessment processes require that the financial viability of a demand management project is assessed against the value of the deferred network expenditure to determine a $/kVA value for potential demand management solutions. Where the $/kVA deferral benefit indicates that demand management solutions are likely to be viable, a number of different demand management options are considered in tandem with network solutions to identify the most efficient option to address the network constraint.

ETSA Utilities notes that because of the peaky nature of the South Australian summer load profile, managing demand has been a focus of the business for a number of years. In recent years, ETSA Utilities has trialled a number of demand management options under a $20m demand management provision from ESCoSA over the current period[56]. This has involved:

- power factor improvements in business and manufacturing
- voluntary load curtailment programs for large customers

49 ibid., p. 58.
50 BIS Shrapnel 2009, *Outlook for Wages, Contract Services and Customer Connections to 2014/15*, May 2009.
51 A review of the forecast customer connection numbers is being undertaken separately by MMA.
52 ETSA Utilities 2009, *Strategic Business Plan 2009–2013*, November 2008, p .5.
53 ETSA Utilities2009, *Regulatory Proposal 2010–2015*, 1 July 2009, pp. 195-201.
54 ETSA Utilities 2009, *DaNM Asset Management Plan*, 2009 Issue, p. 9-26–9-28
55 ibid p.9-26
56 ETSA Utilities 2009, *Regulatory Proposal 2010–2015*, 1 July 2009, p. 196.

- direct load control trials of residential air conditioners
- standby generation
- customer incentives to reduce demand at peak times.

In discussions with PB, ETSA Utilities stated it is committed to the development of non-network alternatives[57]. This is evidenced by the historical implementation of the Kingscote power station on Kangaroo Island, which avoided the need for a second undersea cable, the selection of a non-network solution for Pinnaroo peak lopping power station project[58] and the documented consideration of non-network solutions for the Glynde substation[59] and Keith to Wirrega[60] second 33 kV line projects. In each of these cases, the proposed option has been selected on the basis of the NPV, timing and effectiveness of the solution[61] to ensure the most efficient network or non-network option has been selected.

ETSA Utilities also demonstrated successful trials of the 'Peakbreaker+' direct load control device for residential air conditioners, which the business is seeking to expand to 10,000 customers. It was apparent to PB that ETSA Utilities is actively investigating and progressively implementing non-network alternatives into its operations.

Our discussion with ETSA Utilities did not reveal any significant barriers to the continued increasing business-as-usual incorporation of non-network alternatives into its planning processes. PB notes, however, that the roll out of the 'Peakbreaker+' project is expected to present a net cost to ETSA Utilities despite the positive societal benefit[62]. PB understands that the AEMC is considering a rule change so a state government minister can direct the roll out of smart metering and ETSA Utilities has made a submission for this rule change to cover the 'Peakbreaker+' device[63].

PB considers ETSA Utilities' claims and strategic goals of industry leadership in the research and development of demand management solutions are supported by its demonstrated progress of its demand management trials and implementation of non-network solutions. ETSA Utilities has evidenced the active development and implementation of demand management practices, such as peak lopping, incentive schemes, and energy efficiency programs and so on, to proactively manage a reduction in expected peak demand. Therefore PB agrees that ETSA Utilities' consideration of non-network solutions and demand management opportunities is consistent with good electricity industry practice.

4.2.6 Review of low voltage network upgrade program

PB specifically reviewed the low voltage (LV) network upgrade program, as outlined in ETSA Utilities' Distribution Network Planning Report[64]. This program aims to increase the capacity of the low voltage network to reduce the incidence of transformer overload during heat waves, and involves the widespread infill or upgrade of distribution substations as well as LV network augmentation, and monitoring. The proposed cost of the program is $300.5m (2008

57 Meeting between PB and GM Demand and Network Management July 21 2009.
58 ETSA Utilities 2009, Attachment E.9 AMP1.1.01 *Distribution System Planning Report 2010 to 2020*, AMP.1.1.01, May 2009, p. 122.
59 ibid., p. 74.
60 ibid., p. 93.
61 Ibid., p.123
62 ETSA Utilities 2009, *Regulatory Proposal 2010–2015*, 1 July 2009, p. 200.
63 The Peakbreaker device does not meet the definition of smart metering infrastructure.
64 ETSA Utilities 2009, "AMP1.1.01 Distribution System Planning Report 2010 to 2020", May 2009, pp. 174–179.

dollars) over the 2010-2020 period, and ETSA Utilities has included $124.5m (2008 dollars) in its capex proposal for the next regulatory control period.

AMP 1.1.01[65] outlines the method of developing the estimate for this program, and two versions of the program's risk assessment have also been provided[66][67]. In addition PB has sought further supporting documentation[68].

ETSA Utilities' risk assessment is identified as the main basis to include this program in the capex budget[69]. Both the originat and revised risk assessments state the need for the project as being :

> To maintain ETSA's Distribution Code obligations and reduce the re-occurrence risk of ETSA Utilities street transformer and mains outage events during peak demand periods similar to those experiences during March 2008 and January 2009 heatwave conditions – removing limitations (risk) is considered more efficient and prudent with industry practices than managing avalanve events[70].

The original risk assessment identifies the risk as 'extreme', based on an event likelihood of 'almost certain'. This equates to the expectation of the event occurring at least once a year under ETSA Utilities' risk assessment framework[71]. PB notes the residual risk is assessed as 'high', and this categorises it as a priority project under ETSA Utilities' capital governance procedures. PB also notes that ETSA Utilities states a heatwave equivalent to the 2009 event has a 1 in 50 year likelihood of reoccurrence[72] based on Bureau of Meteorology statistics[73], and that the risk assessment provided was not done on an annual basis, as required under ETSA Utilities' Capital Budgeting Procedures[74]. These factors result in a significant overstatement of the risk.

PB has enquired regarding this risk assessment, particularly in relation to the likelihood estimation. In response, ETSA Utilities provided two revised risk assessments based on the risk in a 'normal' summer, and the risk in a '1 in 10 year' summer heatwave[75]. For a 'normal' summer, the revised risk was assessed as 'medium', and the '1 in 10 year' heat wave summer as 'high'. PB notes the revised heat wave risk assessment has been undertaken on the assumption that a heatwave occurs in that year (i.e. probability of 1). Hence this revised risk assessment is assessing the risk associated with outages of street transformers and mains during peak demand periods in a heat wave summer. The 'high' risk assessed by ETSA Utilities is only applicable to that year and should be weighted by the likelihood of experiencing an extreme heatwave summer in order to establish the actual likelihood of the failure events occurring. On this basis, PB considers that ETSA Utilities' revised risk analysis overstates the risk faced by the business as a consequence of heat waves.

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65 ibid.
66 ETSA Utilities 2009, CX013 Risk Assessment LV Planning 3, Risk Management Worksheets, February 2009.
67 ETSA Utilities 2009, *LV Planning Program risk assessment*, SI227 — response to PB question PB.ETS.EM.68, August 2009
68 ETSA Utilities 2009, responses to questions PB.ETS.EM.28 to 31, Received 30 July 2009.
69 ETSA Utilities 2009, *Capital Budgeting Procedures*, May 2008, p. 12.
70 ETSA Utilities 2009, *LV Planning Program risk assessment*, SI227 — response to PB question PB.ETS.EM.68, August 2009, p.2
71 ibid. p.5 & p.8
72 ETSA Utilities 2009, Network Performance Summer Report 2008/2009, May 2009, p. 2.
73 PB recognises that because of the increase in the frequency of extreme heatwaves over the past ten years, ETSA Utilities considers this probability is understated.
74 ETSA Utilities 2008, *Capital Budgeting Procedures*, May 2008, p. 12.
75 ETSA Utilities 2009, *LV Planning Program risk assessment*, SI227 — response to PB question PB.ETS.EM.68.

Based on a probability of a heatwave event occurring of 1 in 50 years and the 5-year regulatory period, ETSA Utilities' revised likelihood of a heatwave event is 1 in 10 years, that is, a heatwave has a 10% probability of occurrence. We note that ETSA Utilities' revised risk assessment found the consequence of a heatwave was major, which corresponds to a level 4 under ETSA Utilities' risk assessment framework. Figure 4.6 shows ETSA Utilities' qualitative measures of probability (likelihood), which assign a rating of 2 for an event with a 10% probability.

Rating	Description	Description	Probability	Typical Frequency
5	Almost certain	Is expected to occur	96-100%	At least one event per year
4	Likely	Will probably occur	81-95%	One event per year on average
3	Possible	May occur	21-80%	One event per 2-10 years
2	Unlikely	Not likely to occur	6-20%	One event per 11-50 years
1	Rare	Most unlikely to occur	0-5%	One event per 51-100 years

Figure 4.6 ETSA Utilities' qualitative measures of probability (likelihood)

Source: ETSA Utilities' Form No DaNM-F-130, Issue Feb 2009, p. 8.

We note also that ETSA Utilities has also stated that the probability of outages of street transformers and mains during an extreme heatwave year is not certain but is in the range of 81-95% (i.e. likely from Figure 4.6). Given the 10% probability of experiencing a heatwave year and 81-95% probability of adverse consequences occurring in that year, the combined probability is in the range of 8.1-9.5% or 2 under ETSA Utilities qualitative measures. Figure 4.7 shows ETSA Utilities' qualitative risk analysis matrix (level of risk), which states the risk is medium for a probability of 2 and a consequence level of 4. Additionally, if the original 1 in 50 year (2%) likelihood estimate for an extreme heatwave year is considered, then the risk would be assessed as low on the basis of a 'rare' probability of occurrence and a 'major' consequence.

		Consequences				
Probability		Minimal 1	Minor 2	Moderate 3	Major 4	Catastrophic 5
5	Almost Certain	Medium	High	High	Extreme	Extreme
4	Likely	Low	Medium	High	High	Extreme
3	Possible	Low	Low	Medium	High	High
2	Unlikely	Negligible	Low	Low	Medium	High
1	Rare	Negligible	Negligible	Low	Low	Medium

Figure 4.7 ETSA Utilities' qualitative risk analysis matrix (level of risk)

Source: ETSA Utilities' Form No DaNM-F-130, Issue Feb 2009, p.10.

Based on the application of ETSA Utilities' risk assessment framework to the information provided, PB considers the true risk faced by the business from heatwave events is in the range of medium to low. On this basis, PB concludes the revised risk assessment, which ETSA Utilities identifies as a primary basis for including a project into proposed capex[76], overstates the risk and does not support the full scope of the proposed program.

76 ETSA Utilities 2008, *Capital Budgeting Procedures*, May 2008, p. 12.

Furthermore, ETSA Utilities risk assessment of a 'normal' summer indicates a medium risk. However, PB notes that the risk assessment table is based on <200 transformer events per year[77] against the <100 transformer events per year stated in the accompanying explanatory notes provided by ETSA Utilities[78][79]. Therefore the risk of avalanche events occurring in a 'normal' summer also appears to be overstated due to ETSA Utilities risk assessment using a higher degree of transformer events.

Therefore PB considers that the risk in a normal summer is also within the low to medium risk range. Given ETSA Utilities statement that the operational consequences in a normal summer can be 'absorbed with minimal management activity'[80], PB considers that the risk in a normal summer is consistent with the level that has been historically managed by ETSA Utilities.

Program scope

This program involves replacing or augmenting approximately 65% of the 12,451 distribution transformers in the greater Adelaide metropolitan region over 11 years[81]. Table 4.5 shows a breakdown of the scope of the proposed program.

Table 4.5 LV network upgrade program

Distribution transformer type	Existing population (metropolitan)	Proposed replacement/ augmentation	% Population replaced/ augmented
Pad mount	5,496	2,647	48%
Pole mount	6,955	5,435	78%
Total	12,451	8,082	65%

Source: ETSA Utilities LV program modelling spreadsheet SI12 PB.ETS.EM.31

This scope has been determined by ETSA Utilities on the basis of the revised LV planning criteria, and the revised load assumptions. The program aims to comply with ETSA Utilities' proposed criteria by 2015 for pad-mount transformers, and by 2020 for pole-mount transformers, at a cost of approximately $20.8m (2008 dollars) a year. This corresponds to approximately 715 transformer replacements a year at the proposed unit cost of $29.2k (2008 dollars).

LV planning criteria

ETSA Utilities has adopted target planning criteria to ensure that by 2020 distribution transformers are not loaded above 100% under peak load conditions[82]. ETSA Utilities states this is intended to be consistent with the approach adopted by Energy Australia in its

77 ETSA Utilities 2009, *LV Planning Program risk assessment*, SI227 — response to PB question PB.ETS.EM.68, August 2009, p.9
78 ETSA Utilities 2009, *LV Planning Program risk assessment*, SI227 — response to PB question PB.ETS.EM.68, August 2009 p.3
79 ETSA Utilities 2009, Response to PB question PB.ETS.EM.68 and 70, p.1
80 ETSA Utilities 2009, *LV Planning Program risk assessment*, SI227 — response to PB question PB.ETS.EM.68, August 2009, p.9
81 ETSA Utilities LV program modelling spreadsheet SI12 PB.ETS.EM.31 provided in response to PB question PB.ETS.EM.31.
82 PB notes that whilst interim loading criterion of130% for pole mount transformers and 100% for pad mount transformers has been proposed by ETSA Utilities for 2015, the expenditure smoothing undertaken by ETSA Utilities over the 2010-2020 period is such that the interim criteria will not be achieved by 2015. Therefore only the 2020 criteria have been considered by PB.

regulatory submission, and the ENA draft National Guidelines for Electricity Network Development.

PB notes the draft ENA guidelines relating to distribution transformer ratings are indicative only, and they highlight that the relevant Australian standard should be consulted with regard to transformer loading and cyclic ratings[83]. We also note the Australian standard has been current since 1997, and no change to ETSA Utilities' technical obligations with regard to distribution transformers has occurred. Furthermore, the practice of running distribution transformers above nameplate ratings during peak load events is normal industry practice. We note Energy Australia's criteria for distribution transformers is based on loading to 95% of the fuse rating, with the fuse rating determined by the emergency rating of the transformer[84]. The approach of using the transformer's emergency rating as the basis for fusing is also consistent with ETSA Utilities' stated approach of applying emergency plant ratings during contingency events[85]. Therefore, ETSA Utilities' proposed LV planning criteria are more conservative than those applied by Energy Australia and other Australian DNSPs.

Load assumptions

The scope of the proposed low voltage network upgrade program is based on an average assessed After Diversity Maximum Demand (ADMD) of 4.5 kVA for each customer against the recorded ADMD for an average residence or 3.9 kVA[86]. To support this figure, ETSA provided measurements at 168 points that were available during the 2009 heat wave[87] which indicated a measured average ADMD of 4.2 kVA. These data included measurement points where ETSA Utilities expected network constraints (proactive monitoring), or where customer complaints had been received (reactive monitoring). In addition, some points were available from locations where ETSA Utilities was running demand management trials, and where demand-based metering data are routinely collected.

PB notes a proportion of these measurements were taken at locations where overloads had occurred (reactive monitoring) or were anticipated (proactive monitoring). Furthermore, measurements from the demand management trials held in Glenelg and Mawson Lakes comprise 95 of the total 168 monitoring locations. We note these are areas where air conditioning penetration is sufficiently high to enable measureable benefits from the installation of the peak breaker direct load control devices to be determined. PB is concerned the nature of these measurements is such that the sample is biased, and this could lead to an overstatement of the average ADMD applicable to ETSA Utilities' LV network.

Importantly, ETSA Utilities has not considered the actual peak load on individual transformers in determining the program scope. Instead, a load has been inferred from the number of customers connected to a substation and the average ADMD. PB also notes the large variance in the measured ADMD, which ranges from 2.3 kVA to 11.3 kVA[88] in the sample monitoring results. With such a large variance in the ADMD, the application of a single global average ADMD for retrospective planning purposes may not be reasonably consistent with the variation in local demand on individual distribution transformers.

83 AS2374.7-1997 – Power transformers – Loading guide for oil-immersed power transformers
84 Energy Australia, Regulatory Proposal, June 2008, p.69.
85 ETSA Utilities 2009, *DaNM Asset Management Plan*, 2009 Issue, pp. 9–22.
86 ETSA Utilities 2009, AMP1.1.01 Distribution System Planning Report 2010 to 2020, May 2009, p. 174
87 ETSA Utilities, LV Planning Program risk assessment, SI227 — response to PB question PB.ETS.EM.68, p. 7.
88 ETSA Utilities spreadsheet SI205 EM75TotalReadings.xls provided in response to PB question PB.ETS.EM.75.

To test the validity of the program scope, PB used the monitoring results and ETSA Utilities' forecast methodology[89]. This test was done to assess the level of additional works that are implicitly included owing to the simplifying assumptions used in ETSA Utilities' methodology. This analysis demonstrated that:

- Of the 168 distribution transformer monitoring points, 73 had an ADMD below 4.5 kVA per customer and remained below a 100% loading during the 2009 heatwave.
- Of the 73 distribution transformers identified above, 50 (or 68%) would be included in the augmentation forecast if an ADMD of 4.5 kVA per customer were applied in the same manner as ETSA Utilities' forecast spreadsheet. This is despite the actual monitoring results indicating these substations were below 100% loaded during an extreme peak load event.
- Of the 168 monitoring points, 15 had an ADMD above 4.5 kVA, and yet were below 100% loaded during the 2009 heatwave. These substations would also be included in the augmentation forecast under ETSA Utilities' proposed methodology, despite the actual monitoring results indicating they are below 100% loaded during an extreme peak load event.

Therefore when ETSA Utilities' methodology is applied to its actual monitoring results for the 168 monitoring points, 65 additional transformer augmentations would be included in the program despite the fact this is not supported by the actual 2009 monitoring results. We therefore conclude that ETSA Utilities' load assumptions, and the use of a single average ADMD figure to forecast the number of overloaded transformers, result in the overstatement of the volume of transformer capacity augmentations required.

PB recommendation

Our analysis has found the risk assessment that is the primary basis for proposing expenditure on the low voltage network upgrade program overstates the risk, and does not support the full scope of the proposed program. We also concluded ETSA Utilities' proposed LV planning criteria are more conservative than those applied by other Australian DNSPs, and the loading assumptions and volume forecast lead to an overstated scope of work. Hence PB concludes the proposed capex for this program is not prudent or efficient.

However, PB recognises that recent heatwaves have resulted in constraints that a prudent network operator would seek to address to maintain service standards. PB considers that a prudent and efficient approach would involve the increased monitoring of suspect substations based on a soundly developed substation loading model. Targeted augmentation work would then take place on a case-by-case basis following a rigorous assessment of the root causes of the identified constraint. Hence the level of prudent and efficient capex would be based on such an approach. This is essentially a business-as-usual approach, with additional targeted expenditure to address identified constraints.

Based on the figures contained in ETSA Utilities' Asset Management Plan 1.1.01, the average historical planned transformer and line augmentation capex is $4.6m (2008 dollars)[90], exclusive of heatwaves. PB considers this level of expenditure to be efficient on the basis of ETSA Utilities' existing low system capex when compared to its industry peers[91].

89 (Assumed Average ADMD x No. customers) /Transformer Capacity.

90 ETSA Utilities 2009, AMP1.1.01 Distribution System Planning Report 2010 to 2020, May 2009, pp. 174–179.

91 AER Working Paper on Capex Benchmarking, August 2009, p.2

Therefore, PB has taken this as a reasonable estimate of business-as-usual LV network expenditure.

As noted above, PB does concur with ETSA Utilities that some action is needed to address the constraints that arise from heatwaves. To estimate the capex required for this targeted augmentation, PB notes 51 additional distribution transformer replacements are consistent with the number of failures that occurred during the 2009 heatwave[92] and is consistent with the midpoint of the number of failures that occurred during the 2006 and 2008 heat waves[93]. At ETSA Utilities' average unit cost of $29.2k, replacement of 51 transformers a year equates to $1.5m (2008 dollars) for additional targeted transformer augmentations above business as usual levels. To estimate the targeted LV augmentation associated with targeted transformer augmentations, PB has calculated pro rata ETSA Utilities' specific additional LV network augmentation expenditure in proportion to the recommended reduction in the transformer capex, which results in a total, targeted LV augmentation expenditure of $1.6m (2008 dollars) over the next regulatory control period.

PB notes that ETSA Utilities has included an annual $0.8m (2008 dollars) for 'QoS LV planning & monitoring' for management of the LV network planning and field based proactive load monitoring by the quality of supply team[94]. PB considers that such costs are opex related and recommends their removal from the proposed capex.

Table 4.6 details the recommended adjustments to ETSA Utilities' LV network upgrade program capex, inclusive of overheads.

Table 4.6 PB recommended adjustment – LV network upgrade program base estimate ($m real 2008)

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal						
QoS LV planning and monitoring	0.8	0.8	0.8	0.8	0.8	4.0
LV transformer upgrades	20.9	20.9	20.9	20.9	20.9	104.3
LV network augmentation	2.3	2.8	3.3	3.9	4.6	16.9
Total proposal	23.9	24.3	24.8	25.4	26.1	124.5
Total adjustment ($m)	(17.6)	(17.9)	(18.4)	(18.9)	(19.6)	(92.4)
PB recommendation						
QoS LV planning and monitoring	0.0	0.0	0.0	0.0	0.0	0.0
LV network augmentation	4.6	4.6	4.6	4.6	4.6	23.1
Targeted transformer upgrades	1.5	1.5	1.5	1.5	1.5	7.4
Targeted LV network augmentation	0.2	0.3	0.3	0.4	0.4	1.6
PB recommended total	6.3	6.4	6.4	6.5	6.5	32.1

Source: ETSA Utilities Spreadsheet CX001 and PB Analysis

Note: expenditures include overheads

92 ETSA Utilities, LV Planning Program risk assessment, SI227 – response to PB question PB.ETS.EM.68 p. 7.

93 ETSA Utilities, Network Performance Summer Report 2008-09, May 2009 SI11 – response to PB.ETS.EM.29. p. 3.

94 ETSA Utilities 2009, AMP1.1.01 Distribution System Planning Report 2010 to 2020, May 2009, p. 178

Table 4.7 outlines the total adjustment to ETSA Utilities' capex proposal based on its capital accumulation spreadsheet [95] and roll-up model[96]. These figures are inclusive of real escalation and exclude the overheads that are implicit in ETSA Utilities' base capex forecasts. Therefore they are consistent with the figures contained in the Regulatory Proposal.

Table 4.7 PB recommended adjustment – LV network upgrade program inclusive of ETSA Utilities' real escalation

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	25.3	26.4	27.6	28.9	30.4	138.8
PB adjustment ($m)	(18.6)	(19.5)	(20.5)	(21.6)	(21.9)	(102.1)
PB recommendation	6.7	6.9	7.2	7.4	8.5	36.7

Source: ETSA Utilities Spreadsheets CX001, Capex SEM and PB Analysis

4.2.7 Review of major customer connections program

PB made a specific review of the major customer connections program. ETSA Utilities is proposing a total capex of $572.7m (2008 dollars) for customer connections in the next regulatory control period, which is a real increase of 25% over total current period expenditure in this category. Of this, $349.8m (2008 dollars) is forecast for major customer connections, and this accounts for the majority of the proposed increase.

Major customer connections are defined as customer connection projects where the cost exceeds $100k. This expenditure is driven largely by major infrastructure projects, major private sector projects and large sub-divisions.

ETSA Utilities engaged BIS Shrapnel to forecast customer connection expenditure[97]. In the minor and medium customer connection categories, the forecast is based on BIS Shrapnel's forecasts, which we have found to be generally consistent with historical levels and growth expectations. In contrast, the forecast for major customer connections is a combination of BIS Shrapnel and ETSA Utilities' estimates associated with specific projects[98]. PB notes the ETSA Utilities' estimates comprise approximately 88% of the total major customer connection expenditure over the next regulatory control period.

ETSA Utilities' estimates have been based on a site specific assessment of the connection costs associated with known major projects that are scheduled to occur during the next regulatory control period, based on the estimated or advised loads for the site.

To test the efficiency of the estimating process that was used, PB made a comparison of the average annual cost per kVA for major customer connections over the previous regulatory control period and the proposed cost per kVA over the next regulatory control period. We found that, with the exception of 2010-11, they were consistent with the range of average annual costs experienced over the period from 2004 to 2008. Given the variability caused by connection type, location and major customer connection mix, PB considers that this level of variance is reasonable. For 2010-11, the cost per kVA is significantly higher due to the inclusion of a project containing 670 school services upgrades arising from the state

95 ETSA Utilities spreadsheet CX001 Summary Sheets version Opt10a (moderate), 1 June 2009.
96 ETSA Utilities Attachment E.1 SEM-Capex Model Ver 7.2.
97 BIS Shrapnel 2009, *Outlook for Wages, Contract Services and Customer Connections to 2014/15*, May 2009.
98 ibid., p. 59.

government's stimulus measures. Given the smaller nature of these projects, PB considers that a higher cost per connection in this year is appropriate.

The forecast of major customer expenditure includes projects assessed as having a greater than 50% probability of proceeding. Discussions with ETSA Utilities confirmed the assessment of the likelihood of a project proceeding was based on judgement and discussions with developers rather than specific measures of actual project progress or levels of commitment. While PB is concerned with the nature of this simplistic approach, we note that ETSA Utilities' likelihood assessment has been screened by BIS Shrapnel against its major projects database and is considered to be reasonable.

In addition to the forecast of known projects, ETSA Utilities has included a contingency allowance of $27.8m for 'unidentified projects' over the next regulatory control period to account for unidentified major projects and medium projects that change to major projects during the project life[99]. These unidentified projects account for approximately 8% of ETSA Utilities' forecast major customer connection capex. ETSA Utilities has also based its assessment for including projects into the forecast on an arbitrary 50% probability of proceeding, and acknowledged the susceptibility of forecast projects to be deferred or cancelled. ETSA Utilities has advised should deferral or cancelation occur, it expects that other projects would substitute. Therefore, PB considers that an allowance for unknown projects is implicit in the approach ETSA Utilities used to develop its major customer connection forecast, and hence no further contingency is required. On this basis, PB recommends removing the allowance for 'unidentified projects' from ETSA Utilities' capex proposal.

Table 4.8 PB recommended adjustment – major customer connections base estimate ($real 2008)

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	68.0	75.6	63.2	72.8	70.2	349.8
PB adjustment ($m)	(6.2)	(5.5)	(5.0)	(5.3)	(5.8)	(27.8)
PB recommendation	61.8	70.1	58.2	67.5	64.4	321.9

Source: ETSA Utilities Spreadsheet CX001 and PB Analysis

Note: expenditures include overheads

Table 4.9 outlines the total adjustment to ETSA Utilities' capex proposal based on its capital accumulation spreadsheet [100] and roll-up model[101]. These figures are inclusive of real escalation and exclude the overheads implicit in ETSA Utilities' base capex forecasts. Therefore they are consistent with the figures contained in the Regulatory Proposal.

99 ETSA Utilities response to PB question PB.ETS.EM.89 p.1.
100 ETSA Utilities spreadsheet CX001 Summary Sheets version Opt10a (moderate), 1 June 2009.
101 ETSA Utilities Attachment E.1 SEM-Capex Model Ver 7.2.

Table 4.9 PB recommended adjustment – major customer connections inclusive of ETSA Utilities real escalation

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	72.3	82.4	70.5	83.0	81.7	390.0
PB adjustment ($m)	(6.6)	(6.0)	(5.6)	(6.0)	(6.7)	(31.0)
PB recommendation	65.7	76.4	64.9	77.0	75.0	359.0

Source: ETSA Utilities Spreadsheets CX001, Capex SEM and PB Analysis

4.2.8 PB assessment and findings

PB's has reviewed ETSA Utilities' demand driven capex proposal and made a number of key observations and findings.

PB's main observations are:

i) ETSA Utilities is proposing an overall real increase of 266% in capacity capex, and a real increase of 25% in customer connection capex for the next regulatory control period.

ii) The drivers for the increase are a significant increase in the forecast load growth following a period of relatively stable actual peak demand and an increase in major customer connections.

iii) The major components of the increase relate to the LV network capacity upgrade program, and the establishment of the additional City West connection point.

PB's main findings are:

i) ETSA Utilities' planning criteria and their application to planning demand driven, sub-transmission and zone substation is prudent in the sense it is in accordance with good electricity industry practice.

ii) The cost-estimating process used to derive ETSA Utilities' capacity-driven expenditure is based on reasonable building block costs, is transparently applied and is appropriate for the purposes of forecasting its capacity expenditure.

iii) ETSA Utilities considers a reasonable range of options in its capacity planning decisions and despite the absence of formal business case documentation until close to the approval of project expenditure, the options analyses for the reviewed network augmentation projects were available to adequately support the proposed solution.

iv) Given that no adjustment to the demand forecast has been recommended by AEMO, PB recommends no demand forecast-related adjustment to the capex forecast.

v) ETSA Utilities has evidenced the active development and implementation of demand management practices to proactively manage a reduction in expected peak demand. Therefore PB believes that ETSA Utilities' consideration of non-network solutions and demand management opportunities is consistent with good electricity industry practice.

vi) The risk assessment for the LV network capacity upgrade project overstates the risk and does not support the full scope of the proposed program. Therefore PB concludes the proposed capex for this program is not prudent or efficient and has recommended a $102.1m reduction to its scope.

vii) In addition to the forecast of known major customer connections, ETSA Utilities has included an unsupported contingency allowance for 'unidentified projects' over the next regulatory control period. Therefore PB concludes the proposed capex for major customer connections is not prudent or efficient and has recommended a $31.0m reduction to the scope of this program.

viii) The remaining demand driven capex portfolio has been derived from the application of planning criteria and cost estimating processes which are considered to be prudent and efficient and the application of ETSA Utilities demand and customer forecasts are considered to be appropriate. On this basis, the remainder of the demand driven capex portfolio is considered to represent prudent and efficient expenditure.

4.2.9 PB Recommendations

Based on the findings of our review as discussed above, PB recommends the revised demand driven capex as set out in Table 4.10.

Table 4.10 PB recommended demand driven capex adjustments

$m	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	277.3	333.4	275.3	285.5	285.5	1457.0
PB adjustment - LV network upgrade program	(18.6)	(19.5)	(20.5)	(21.6)	(21.9)	(102.1)
PB adjustment - Major customer connections	(6.6)	(6.0)	(5.6)	(6.0)	(6.7)	(31.0)
PB adjustment - escalation[102]	(15.5)	(18.1)	(14.9)	(15.4)	(15.1)	(79.0)
PB recommendation	236.6	289.8	234.2	242.5	241.8	1,244.9

4.3 Non-demand driven capex

The non-demand driven category of system capex relates to asset replacement, security of supply, and safety. Asset replacement — planned, unplanned, and safety-related programs, as well as the Kangaroo Island and Network Control security of supply projects — comprise approximately 90% of the total non-demand driven capex. The reliability, environmental and other categories make up the remaining 10% of the forecast.

4.3.1 Proposed expenditure

ETSA Utilities is proposing to spend a total of $852.9m on non-demand driven capex during the next regulatory control period. This expenditure represents a real increase of 223% over expected expenditure of $264.1m in the current regulatory control period.

102 Refer section 3.1.1 of this report

Table 4.11 shows ETSA Utilities' forecast non-demand driven capex, which represents approximately 29% of its total gross capex proposal. Historical and forecast non-demand driven capex is shown in Figure 4.8.

As noted in section 4.1.1, the total increase in environmental, reliability and other expenditure categories comprises a total of $6m, or 0.5% of the overall $1.29b proposed system capex increase. To test the efficiency of these expenditure categories PB conducted a high level review of the drivers and changes in expenditure in these categories. We found that the proposed expenditure is largely consistent with total historical expenditure for these categories, and is driven primarily by compliance issues such as mandatory PLEC undergrounding work, maintaining current levels of reliability and oil containment upgrades at high risk substations. Therefore PB has not considered the environmental, reliability and 'other' expenditure categories in detail.

Table 4.11 ETSA Utilities proposed non-demand driven system capex

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Asset replacement	79.7	91.4	96.8	98.9	99.9	466.8
Security of supply	15.5	45.9	65.3	33.8	9.9	170.4
Safety	18.4	24.6	27.9	29.9	30.2	131.0
Subtotal asset replacement, security of supply and safety	113.5	161.9	190.0	162.6	140.1	768.1
Reliability	4.9	5.0	5.0	5.1	5.2	25.2
Environmental	2.7	3.2	3.3	3.3	3.4	15.9
Network other	8.4	8.6	8.7	8.9	9.0	43.6
Subtotal remaining categories	16.0	16.8	17.0	17.2	17.6	84.8
Total non-demand driven system capex	129.6	178.7	207.0	179.8	157.7	852.9

Source: RIN999 Final ETSA Utilities pro formas

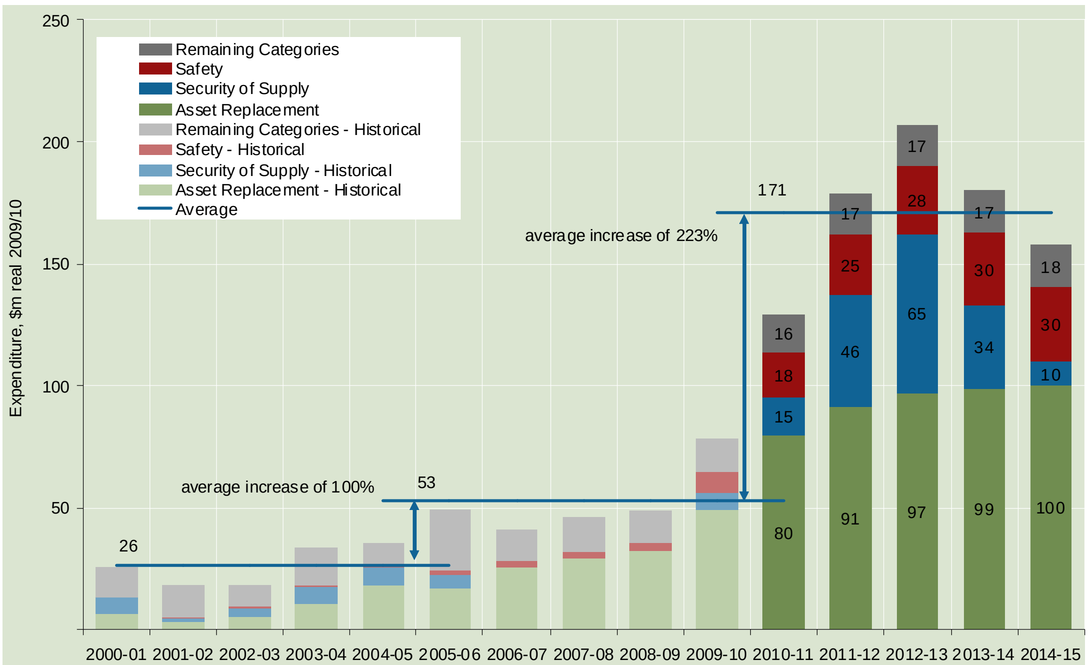

Figure 4.8 ETSA Utilities gross non-demand driven expenditure

Source: RIN999 Final ETSA Utilities pro formas & PB analysis

4.3.2 Drivers

ETSA Utilities has identified that the significant increase in asset replacement expenditure arises from a review of asset management practices during the current regulatory control period, and the wider adoption of a condition monitoring based approach to replacement over the 'replace on failure' approach that has historically been adopted[103].

ETSA Utilities' Regulatory Proposal states that its proposed asset replacement program has been determined on the basis of maintaining an appropriate level of risk, based on the age and condition of its assets[104], and the principal drivers are:

- asset condition
- asset age
- ETSA Utilities' acceptable risk level
- ETSA Utilities' approach to risk assessment.

The proposed safety capex relates mainly to mitigating safety risks associated with aged assets, or assets that are not compliant with current safety standards. Hence the majority of the proposed $131.0 m safety capex is also related to asset replacement.

Similarly, the $170.4 security of supply capex relates mainly to the duplication of the Kangaroo Island undersea cable and sub-transmission backbone, and the duplication of the network operations centre (NOC) and SCADA master station replacement.

To assess the impact of these drivers on the prudency and efficiency of the proposed non-demand driven expenditure, PB has reviewed the application of the major asset management, risk assessment, and cost estimating policies and procedures, as well as made specific reviews of the major components of the proposed network asset replacement program, safety-related replacement program and security of supply expenditure. Together the reviewed components comprise approximately 52% of ETSA Utilities' proposed non-demand driven capex proposal.

4.3.3 Policies and procedures

In this section PB considers the application of ETSA Utilities' principal policies and procedures to the development of the non-demand driven capex forecasts. These documents are listed in Table 4.12. PB has reviewed these documents, and in particular considered their application within the business.

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103 ETSA Utilities 2009, *Regulatory Proposal 2010–2015*, 1 July 2009, p. 199.
104 ibid.

Table 4.12 ETSA Utilities' principal asset management documents

Asset management	
Asset management policy	Policy to document, at a high level, how ETSA Utilities will approach the management of its assets.
Asset management plan – manual 15	High level plan to document ETSA Utilities' approach to the management of its assets. Outlines the risk assessment procedure applied to network projects in the planning process for asset management.
Detailed asset management plans	Detailed plans to document ETSA Utilities' approach to the management of its assets by asset type.

Source: RIN999 Final ETSA Utilities pro formas

Asset management

ETSA Utilities' historical approach to asset replacement involved replacement on failure, a strategy that is not uncommon within the industry, particularly in relation to lower cost, less critical assets. While this can be a higher-risk approach, the level of risk is related to the way in which the strategy is applied and managed.

ETSA Utilities has historically managed the risk exposure of asset failure through the network redundancy under its planning criteria[105], the use of mobile substations[106], feeder capacity management[107], and monitoring and testing the routine condition of essential assets (e.g. power transformers[108]). ETSA Utilities has proposed a large increase in asset replacement capex due to a change in asset management approach to incorporate a greater degree of condition monitoring and age based replacements.

Given that ETSA Utilities has historically managed these risks, but has recently adopted a revised approach to asset management, PB sought clarification of the rationale for this change. PB considers that the need for a significant change in the approach to asset management should be clearly demonstrated through a sound economic evaluation of the risks, costs and benefits associated with various options. PB requested the business case that supported ETSA Utilities' decision to adopt the proposed asset replacement strategy[109]; however, the provided documentation asserted but did not demonstrate that the proposed strategy was the least cost or highest NPV option when compared with a business-as-usual approach[110]. We also note that ETSA Utilities' asset management plans comprise 53 individual plans that define the volume of asset replacement. PB has reviewed a number of these plans (see section 4.3.4 for more detail), and found limited consideration of cost efficiency, or non-replacement options (e.g. refurbishment and opex solutions). PB also found that in most cases approaches to asset management are selected on the basis of ETSA Utilities' risk assessment without consideration of the cost-effectiveness of addressing the identified risk.

While PB considers that condition-based asset management is a prudent means to manage an ageing asset base, we are concerned the efficiency of the proposed replacement program has not been demonstrated through the asset management documentation. On this basis, we have made a specific review of ETSA Utilities' asset replacement as set out in section 4.3.4 of this report to ascertain the extent to which the proposed expenditure aligns with prudent and efficient asset management practice.

105 ETSA Utilities, 2009, *DaNM's Asset Management Plan*, May 2009, p. 9-18.
106 ibid., p. 9-19.
107 ibid., p. 9-20.
108 ETSA Utilities, AMP 3.2.01 Substation Power Transformers, March 2009, p. 15.
109 PB Question PB.ETS.EM.86.
110 Refer to section 4.3.4 for more detail

Risk assessment

The consistent assessment of risk to identify and prioritise the business' response to the threats it faces is necessary to demonstrate that asset investment decisions are prudent and the allocation of capital is efficient in timing and scope. In regard to non-demand driven capex, this relates principally to the need to address and manage the risks associated with asset failure with due respect to the condition and criticality of the asset.

ETSA Utilities' risk management framework is well implemented at a corporate level with a strong understanding across the business of the need for risk-based justification to facilitate capital budgeting decisions[111]. The specific approach to risk management adopted for network asset management decisions is detailed in the DaNM AMP[112] where the likelihood and consequences used to ensure consistent risk assessment results are clearly defined.

PB considers that risk-based decisions for large-scale, planned asset replacement should be supported by:

- a documented performance/incident history for the asset (or asset class)
- condition assessment identifying the need for the replacement
- a risk assessment that considers the criticality of the asset (or asset class) in the network
- an economic assessment that considers 'do nothing', replacement and refurbishment options inclusive of the capex/opex trade-off and an assessment of the probability weighted cost of failure.

To test the application of ETSA Utilities' risk management framework to its asset investment decisions, PB has reviewed the risk assessments contained in the detailed asset management plans discussed in section 4.3.4 and the formal detailed risk assessment of the LV network capacity upgrade program[113] that is reviewed in section 4.2.6.

From our review of the application of ETSA Utilities' risk assessment processes in the specific reviews contained in section 4.3.4, PB found:

- That the risk assessment approach had not been consistently applied across the individual asset management plans.
- That in some cases, arbitrary and unsupported adjustments to the likelihood criteria were made to attempt to align the likelihood of failure to asset age, rather than to the known performance history or known condition of the asset class.

  PB notes that this practice effectively nullifies the real benefits of the historical and proposed condition-based, asset management approach in the expenditure forecast by including the backlog of 'over age' assets as age based replacements in addition to those supported by known condition or performance issues.

111 ETSA Utilities, *Capital Budgeting Procedures*, May 2008, p.1 3.
112 ETSA Utilities, *DaNM Asset Management Plan*, 2009 Issue, p. 7-6.
113 ETSA Utilities 2009, CX013 Risk Assessment LV Planning 3, Risk Management Worksheets February 2009.

- That the coarseness in application of the risk assessment framework is such that the risk assessment scores are unable to identify the most cost-effective projects to reduce the overall business risk exposure.

  PB notes that ETSA Utilities attempts to address this through the application of 'micro' risk rankings to rank projects for the annual budget[114], however, we also note that no such ranking of discretionary projects has occurred in preparing the capex forecast used to support the Regulatory Proposal. In addition, the historical level of risk accepted under this micro-ranking scheme is higher than that used to derive the Regulatory Proposal budget.

- That risk assessments in the detailed AMPs are not consistently made on the basis of establishing the risk associated with deferring the proposed project from the budgeted year, as outlined in the Capital Budgeting Procedures[115]. Risk has generally been assessed on the basis of the risk of the event occurring within the 10-year AMP planning horizon.

  PB notes that the longer-term view taken in the AMP risk assessments does not demonstrate that efficient timing of expenditure is fully considered in ETSA Utilities' forward replacement planning and overstates the risk when interpreted on the basis of the capital budgeting procedures. As a consequence, ETSA Utilities relies heavily on the annual capital budgeting process to ensure the timing of project expenditure is appropriate.

- That limited attempts have been made to quantify risk for the purpose of options assessment or to support investment decisions beyond the allocation of projects to a wide financial consequence band[116].

  Contrary to ETSA Utilities' assertion that it is moving towards a quantitative risk assessment approach[117], PB did not find any evidence of approaches to quantitative risk management being adopted in the detailed AMPs or the options analyses for the portion of the capex portfolio that was subject to detailed investigation.

PB concludes the risk assessment process ETSA Utilities applied in developing its forward capex proposal is appropriate for high level project ranking at a corporate level; however, the detailed assessment of risk within a project or program is simplistic and does not ensure efficient expenditure.

PB has made a number of specific recommendations concerning ETSA Utilities' application of risk assessment in the specific reviews of the proposed non-demand driven capex. These are detailed in section 4.3.4

Cost estimation

The consistent application of accurate costs in asset replacement estimates is critical to the development of a realistic forecast of asset replacement costs and to provide a valid evaluation of alternative management approaches for assets as they approach the end of their life.

114 ETSA Utilities 2009, *DaNM Asset Management Plan*, 2009 Issue, p. 7-7.
115 ETSA Utilities 2008, *Capital Budgeting Procedures*, May 2008, p. 12.
116 ETSA Utilities, *DaNM Asset Management Plan*, 2009 Issue, p. 7-3.
117 ibid., p. 7-3.

PB notes the estimation process used for the asset replacement plans differs from that used for the capacity plan, which is discussed in section 4.3.2.

As part of PB's review process, the cost-estimating process applied to develop the asset replacement expenditure forecast was discussed in meetings with ETSA Utilities, and appraised through a review of the costing spreadsheets[118]. Key costs affecting the specific reviews were also checked for consistency against comparable costs ETSA Utilities advised for the capacity program[119], the O'Donnell Griffin unit cost report[120] [121] and ETSA Utilities' historical expenditure[122].

PB found that the unit costs that were applied were reasonable and that the cost-estimating process was transparently applied in the build-up of the majority of the replacement capex expenditure forecast from the low-level unit costs.

However, we note that approximately $71.2m (real 2008) comprising 19% of the base replacement capex forecast relating to the unplanned lines replacement category has been determined on the basis of a 'top-down' extrapolation of recent expenditure and failure trends, which PB considers to overstate the actual expenditure required. Therefore, PB does not consider this cost-estimation process results in efficient expenditure, and an adjustment has been applied as detailed in section 4.3.4

Therefore, PB concludes the cost-estimating process applied to derive the majority of ETSA Utilities' asset replacement expenditure is based on a reasonable build-up from the quantities identified in the AMPs, is transparently applied and appropriate for the purposes of forecasting ETSA Utilities' non-demand driven asset replacement expenditure.

Options analysis

With regard to asset replacement expenditure, the effective evaluation of replacement, refurbishment, run-to-failure or increased monitoring strategies is important to ensure the full range of feasible options is considered and the least cost or highest NPV option is selected to ensure the maximum economic benefit from the historical and future investment in assets.

In accordance with the process outlined in the Demand and Network Management (DaNM) AMP[123], ETSA Utilities considers the asset management strategy that is applicable to each asset sub-class and documents the appropriate strategy in the individual AMPs.

To test the veracity of ETSA Utilities' options analysis as applied to asset replacement expenditure, PB considered the asset management approach outlined in the AMPs covered in the specific reviews in section 4.3.4 and noted that there is limited specific consideration of replacement versus refurbishment options. However, PB also recognises ETSA Utilities' maintenance practices have historically focused on asset refurbishment on failure for certain asset classes, such as circuit breakers, and that ETSA Utilities was able to demonstrate its consideration of transformer refurbishment following failure or removal from service.

Therefore, while limited consideration of replacement versus refurbishment options are documented in the asset management plans, PB recognises the maintenance strategies ETSA Utilities adopts generally aim to extend the life of the asset as far as practical at the

118 ETSA Utilities spreadsheets SI206 to SI215 provided in response to question PB.ETS.EM.65.
119 ETSA Utilities, Unit Costs Version 1.1, CX009.
120 ETSA Utilities Spreadsheet CX010 Unit Costs Comparison.
121 O'Donnell Griffin, Estimate Verification for Regulatory Pricing, 25 May 2009.
122 ETSA Utilities response to question PB.ETS.EM.72
123 ETSA Utilities 2009, *DaNM Asset Management Plan*, 2009 Issue, p. 6-2.

least cost. Furthermore, the consideration of repair, refurbishment and redeployment of assets recovered through capacity upgrade or failure appears to be well established for major asset classes.

Given the extended service life of assets that ETSA Utilities has historically been able to achieve when compared to standard industry expectations, and the level of sub-class categorisation applied in the AMPs to select an appropriate asset management approach, ETSA Utilities has been able to demonstrate that it does consider refurbishment options in carrying out its maintenance and asset investment activities.

However, apart from qualitative considerations of 'higher opex' associated with some types of equipment, ETSA Utilities was unable to demonstrate the routine consideration of differences in opex in making asset replacement decisions. Therefore, PB considers that ETSA Utilities' analysis and selection of management strategies for individual asset classes is not well supported by economic assessment and therefore does not result in efficient expenditure.

4.3.4 Review of network asset replacement program

ETSA Utilities has proposed a significant increase in asset replacement expenditure arising from a change in asset management approach to incorporate a greater degree of condition monitoring. PB is concerned that ETSA Utilities revised approach also includes a large degree of age based asset replacement forecasts that are not supported by the known condition of the assets and subsequently does not represent efficient expenditure. Therefore PB carried out a specific review of the network asset replacement program to identify the prudent and efficient level of expenditure that is supported by known asset condition and historical performance.

ETSA Utilities has forecast an asset replacement capex of $466.8m over the next regulatory control period. This represents a 203% real increase over the expected expenditure of $153.9m in the current regulatory control period. PB notes the figures provided for 2008-09 and 2009-10 are forecast figures. The 2008/09 figures are supported by the audited regulatory accounts[124]. However given the under spend in this area to date and step change increase proposed in 2009/10 the forecast figure may not be realised. As shown in Figure 4.9, when the forecast figures are removed from the analysis, ETSA Utilities' proposed asset replacement capex represents a 289% real increase over current period actual average expenditure.

124 ETSA Utilities, ESCOSA Regulatory Account Templates.xls, Year ending 30 June 2009. Sheet 23

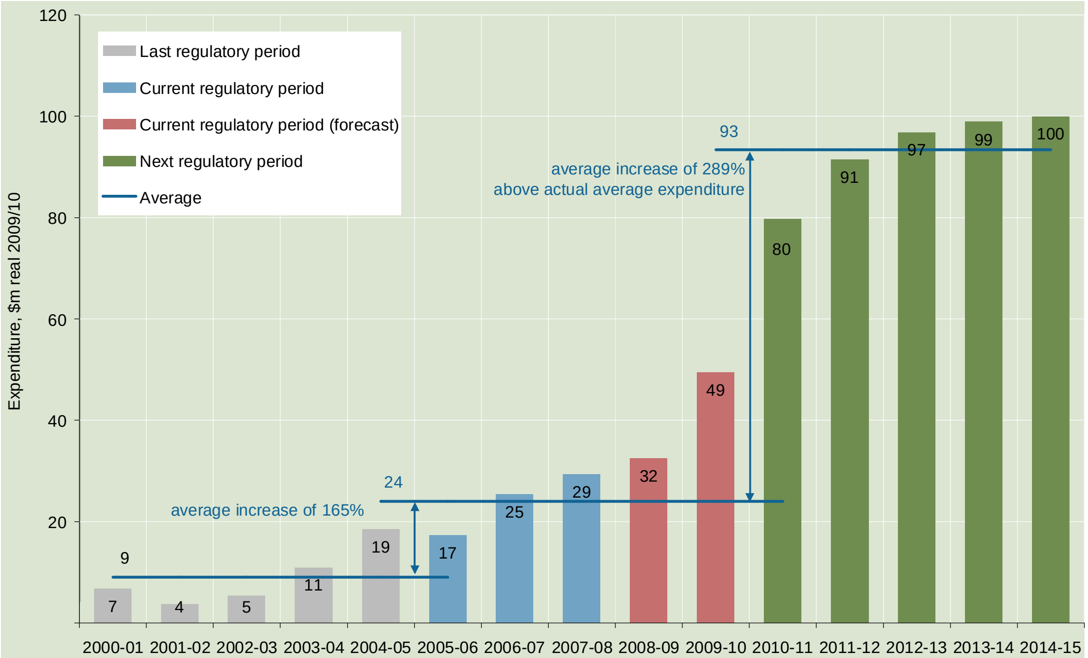

Figure 4.9 ETSA Utilities asset replacement expenditure

Source: RIN999 Final ETSA Utilities pro formas & PB analysis

PB's review has focused on the approach ETSA Utilities adopted in determining its asset replacement expenditure, and how this has been applied in the asset management plans for the major asset replacement expenditure areas.

Change in asset management strategy

As discussed in section 4.3.3 above, ETSA Utilities has stated that the main reason for the proposed increase in asset replacement capex is the broader application of condition monitoring and the need to manage the risk associated with an ageing asset base[125]. However, as also noted, PB is concerned that the fundamental need for a significant change in approach has been demonstrated and that the prudency and efficiency of the proposed program has been asserted but not demonstrated.

ETSA Utilities' historical asset replacement approach has been based on a run-to-failure approach with monitoring of the condition of crucial assets, and ETSA Utilities has managed the resulting risk exposure through a range of strategies outlined in section 4.3.3 above. ETSA Utilities' historical SAIDI performance for 2000-01 to 2008-09, as shown in Figure 4.10, demonstrates relatively consistent normalised[126] performance throughout the period, and suggests that ETSA Utilities' management of its risks has been relatively successful.

125 ETSA Utilities 2009, *Regulatory Proposal 2010–2015*, 1 July 2009, p. 119.
126 Normalised to remove extreme events outside ETSA Utilities' reasonable control.

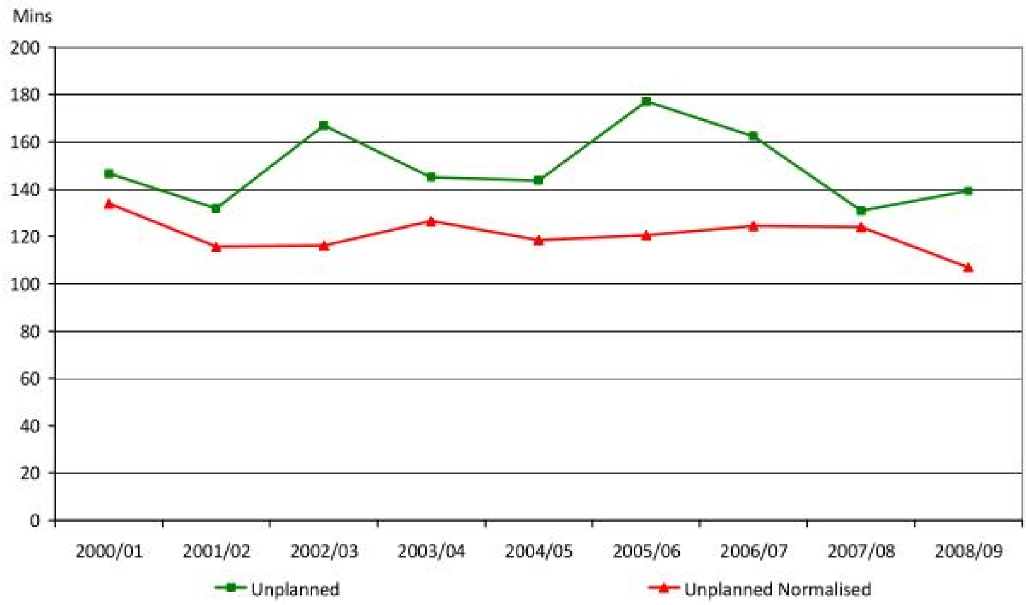

Figure 4.10 ETSA Utilities SAIDI performance 2000-01 to 2008-09

Source: ETSA Utilities response to question PB.ETS.VP.50

Similarly, the recent below-average summer HV SAIDI performance shown in Figure 4.11 indicates that ETSA Utilities' practices have maintained its summer peak reliability performance. PB has concluded that, on the basis of ETSA Utilities' historical SAIDI performance, there seems to be no evidence of declining performance.

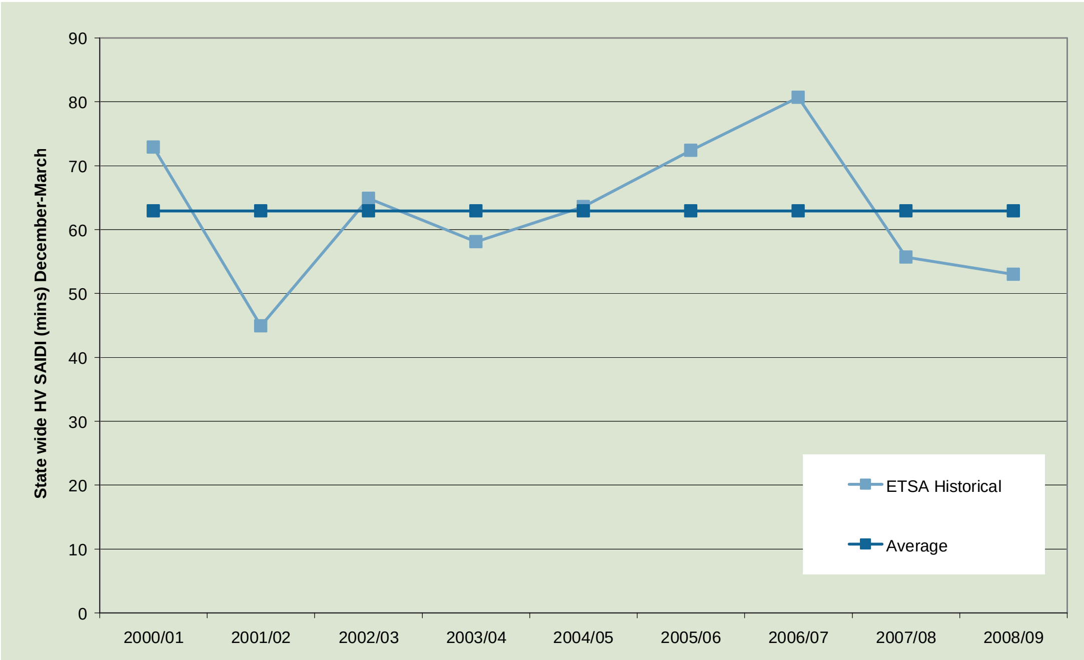

Figure 4.11 ETSA Utilities statewide HV SAIDI December–March

Source: ETSA Utilities, Network Performance Summer Report 2008-09 p. 9

Efficiency of the proposed asset management strategy

An approach to get the best out of asset management should seek to maximise the service life of individual assets by replacing or refurbishing the asset only when the condition indicates imminent failure or when economically justified.

Given ETSA Utilities' consistent historical reliability performance and comparatively lower capex when compared to its industry peers[127], the efficiency of a significant change in asset management strategy should be demonstrated. PB specifically requested information to establish that the proposed strategy was the least cost or highest NPV option against a range of reasonable options[128]. In response, ETSA Utilities provided an unquantified list of potential risks, including increases in opex, capex and supply restoration times (among others), which would arise from retaining a business-as-usual approach[129]. PB notes that while these risks are inherently quantifiable in dollar terms, ETSA Utilities states that:

> Retaining this strategy, essentially a 'do nothing' option, would be neither prudent nor efficient. ETSA Utilities has not attempted to cost these impacts and does not consider it would be meaningful to do so. The risks are clearly unacceptable.[130]

Similarly, ETSA Utilities' Condition Monitoring and Life Assessment Methodology[131], dismisses the need to estimate the cost of a business as usual approach, stating that:

> Within the industry it is generally [held] that unplanned replacement costs significantly more than planned replacement (up to nine times more cost). For the above reasons, the continuation of the 'fix on failure' strategy was not considered for the current regulatory control period.[132]

PB notes ETSA Utilities' November 2006 board status report for the Asset Management Strategic Plan, which states:

> 3.6. An individual asset management plan for each asset sub-class, is determined by combining known asset failure mode(s) with the consequences and likelihood of failure, the availability of the spares and skills to repair or replace, and a cost benefit analysis. The asset strategy can vary within an asset class owing to these factors or the inherent design weaknesses or strengths of a particular asset type.[133]

This report appears to set a specific requirement for a cost-benefit analysis for each asset sub-class within the asset management plans.

A cost-benefit analysis is not included by asset class in the individual asset management plans[134], and no other economic analysis was provided to support the change in asset management approach. Therefore PB has concluded that ETSA Utilities is unable to demonstrate that the strategy leading to the $467m asset replacement capex proposal is more efficient than its historical asset management approach.

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127 ETSA Utilities 2009, *Regulatory Proposal 2010–2015*, 1 July 2009, p. 98.
128 PB Question PB.ETS.EM.86.
129 ETSA Utilities response to PB Question PB.ETS.EM.86, p. 1.
130 ibid.
131 ETSA Utilities, AMP 3.0.01, Condition Monitoring and Life Assessment Methodology, p. 16.
132 ibid.
133 ETSA Utilities, SI232 Asset Management Risk Committee 01112006, p. 3.
134 PB notes that the individual asset management plans have generally been prepared on the basis of defining the volume of work associated with each replacement program and not the cost. Therefore, limited consideration has been given to the economic optimisation of the individual plans.

Age-based asset replacement

Despite the absence of an assessment of the business-as-usual costs, ETSA Utilities has proposed two alternative scenarios, namely replace on age at an asset's nominal life, or replace on condition[135]. Two reports involving high-level, age-based asset replacement modelling have been provided to demonstrate the additional cost of an age-based approach.

PB accepts that age is a useful, high-level indicator of the quantum of asset replacement expenditure that may be required in the longer term, and is typically applied as an upper estimate for planning long-term strategic asset replacement over 20 to 30 years. However, over the shorter term, under a condition-based approach, asset population statistics and/or asset condition information should be used to ensure the efficient timing of replacement expenditure forecasts. Given that ETSA Utilities has condition information and failure rate data to inform its medium-term asset replacement plans, we recommend that condition and failure history information be used as far as practicable to establish the efficient level of asset replacement capex over the next regulatory control period.

With regard to the modelling presented, the SKM report[136] outlines a purely age-based replacement scenario, indicating that approximately $6b in assets exceed their assumed lives. In contrast, the PB report[137] identifies a purely age-based replacement backlog in the order of $417m[138]. The difference between the two estimates highlights the sensitivity of age-based replacement models to the input assumptions about asset lives, replacement unit costs, and the specific modelling methodology adopted. ETSA Utilities also explores the sensitivity of age-based replacement models to age assumptions in its AMP 3.0.01[139], which indicates an approximate doubling in replacement expenditure for a 10% increase in average age, and almost tripling for a 20% average age increase.

The presence of a large proportion of assets beyond their standard life should be expected under effective condition monitoring and maintenance programs where asset lives are extended as far as economically practical. In the DaNM AMP[140], ETSA Utilities identifies that asset life decisions will be made at points following an in-service failure due to poor performance, or after the asset is removed from service. PB notes that no provision is made for purely age-based replacement and ETSA Utilities' statement that 'assets are not automatically replaced at the end of their normal lives but considered on their condition and performance' [141] clearly demonstrates that ETSA Utilities expects assets will remain in service beyond their standard life.

Similarly, a higher average asset age in comparison to other DNSPs is not unexpected for ETSA Utilities because of the exclusive use of stobie poles (with an expected average life of 100 years[142] in low corrosion zones), and the relatively light loading of network assets for the majority of the year to accommodate the 'peakier' profile of the South Australian summer load[143].

On the basis that further deferral of the $417m to $6b of deferred replacements identified in the reports at ETSA Utilities' nominal WACC of 9.04% represents an annual benefit of

135 ETSA Utilities response to PB Question PB.ETS.EM.86, p. 1.

136 SKM 2009, Distribution Network Asset Age Projections and Impact on Network Operating Costs, May 2009.

137 PB, Replacement Capex Modelling, 2009 EDPR, July 2009, p. 19.

138 ibid., p. 23.

139 ETSA Utilities, AMP 3.0.01, Condition Monitoring and Life Assessment Methodology, p. 16.

140 ETSA Utilities 2009, *DaNM's Asset Management Plan Manual 15*, May 2009, p. 10-6.

141 ibid.

142 ETSA Utilities, AMP 3.1.05 Poles, February 2009, p. 10.

143 ETSA Utilities Regulatory Proposal 2010-2015, 1 July 2009, p. 89.

between $40m and $540m, PB considers the prudent deferral of asset replacement expenditure should be continued.

The PB report [144] also identifies a second analysis, which occurred to allow additional age modifiers as a proxy for condition and asset risk, again took place on the basis of ETSA Utilities' model inputs. Noting the stated limitations on the ability of a deterministic model to fully reflect condition-based asset replacement[145] and on the basis of the following observations:

- the model has been calibrated down from a higher initial value to better align with ETSA Utilities' high-level internal forecast for replacement assets by making adjustments to asset lives, replacement costs and condition assessment factors[146]
- the adjusted input factors vary from those assumed in deriving ETSA Utilities' replacement capex forecast[147]
- appropriate risk limits have not been investigated and therefore default risk limits have been used in the alternative 'Age + condition + risk scenario'[148]
- that the risk adjustment factors have a significant effect in shaping the predicted expenditure profile[149].

We consider that the modelling outlined in our report provides another indication of the upper limit of costs that may be expected under an age, condition and risk-based approach. Given ETSA Utilities' statements that it is able to manage a higher level of residual risk than other Australian DNSPs[150], we also note that ETSA Utilities has provided no analysis to demonstrate whether the default risk adjustment settings in the model are aligned with ETSA Utilities' corporate risk framework or whether they are representative of a more conservative risk position.

Therefore, we accept that the age-based modelling approaches put forward by ETSA Utilities demonstrate the proposed asset management strategy is more efficient than adopting a purely age-based approach. However, we restate our concern that ETSA Utilities has not demonstrated the efficiency of the proposed program relative to its historical approach. We are also concerned at the level of age-based replacement included in ETSA Utilities' proposed replacement capex.

For this reason, PB has reviewed ETSA Utilities' proposed asset replacement program on the basis of the known condition and historical failure rates. The aim of PB's review was to establish an efficient level of asset replacement expenditure that reflects a condition-based rather than age-based asset management approach.

Asset replacement approach

ETSA Utilities has generally divided its asset replacement forecasts into planned and unplanned categories, with a third, age-based replacement category included in some cases.

144 PB, Replacement Capex Modelling, 2009 EDPR, July 2009, p. 19.
145 ibid., p. 8.
146 ibid., p. 25.
147 ibid., p. 18.
148 ibid., p. 24.
149 ibid., p. 8.
150 ETSA Utilities 2009, *Regulatory Proposal 2010–2015*, 1 July 2009, p. 121.

As outlined in section 4.3.3, PB considers that risk-based decisions for large-scale, planned asset replacement should be supported by a documented performance/incident history for the asset and a condition assessment identifying the need for the replacement,

In cases where no need can be demonstrated, other than the increasing asset age, a detailed analysis of the cost of mitigating measures – such as increased spares holding, increased maintenance costs, criticality of the asset in the network and the extent to which redundant capacity is available – should be prepared to demonstrate the replacement of the aged asset is economically preferable.

ETSA Utilities' assessment of the criticality and subsequent risk associated with aged assets is structured such that the majority of asset replacements are based on asset age alone through the unsupported adjustments to the likelihood component of the risk assessment rather than on asset condition.

For example, under ETSA Utilities' age based risk assessment framework[151], the likelihood of circuit breaker failure typically increases from a score of 3 to a score of 4 upon reaching 55 years of age, irrespective of the number of operations, condition or failure history of the unit, and in many cases triggers the replacement of the unit based on age alone. On this basis, ETSA Utilities' age-related replacement provisions do not represent prudent asset management practice and the scope of the proposed asset replacement program is contrary to the goal of using condition monitoring to maximise asset lives at the least long-run cost.

PB has reviewed the four asset management plans and the unplanned line component replacement forecast detailed in Table 4.13, which together comprise $244.9m or 52% of ETSA Utilities' $466.8m proposed asset replacement capex over the next regulatory control period.

Table 4.13 PB's reviewed asset replacement components

Items reviewed	Total ($m)
Conductor planned	31.9
Poles planned	42.3
Power transformers planned	40.3
Circuit breakers planned	50.5
Lines unplanned	79.9
Total expenditure reviewed ($m)	244.9
ETSA Utilities proposed total ($m)	466.8

Source: ETSA Utilities Spreadsheet CX001, Capex SEM and PB analysis

PB's review has recommended a level of expenditure that is reflective of the known condition (planned) and verifiable failure history (unplanned) associated with each asset class for each of the asset classes reviewed below.

Unplanned line replacement

In section 4.3.3, PB noted that despite the bottom-up cost estimating approaches documented in the detailed asset management plans, ETSA Utilities has adopted a 'top-

151 ETSA Utilities, AMP 3.2.05 Substation Circuit Breakers, April 2009, p. 23.

down' approach to forecasting the required unplanned line replacement expenditure over the next regulatory control period[152]. This approach has involved the application of compounding growth factors to replacement expenditure based on ETSA Utilities' analysis of historical failure rates and expenditure. ETSA Utilities' explanation for the change is as follows:

> During ETSA Utilities' internal review process, it was determined that some of the zero-based plans were inadequately supported and so a consistent top-down 'failure-rate based' forecast was undertaken…
>
> …as detailed in CX020 (provided with ETSA Utilities' Proposal) that for a number of asset classes, the failure rates derived in SI241 have been curtailed to reflect the trade-off between planned and unplanned replacement. This adjustment has been applied as a separate line (146) of CX001.

PB accepts that ETSA Utilities has considered that the unplanned line asset replacement forecasts contained in the individual AMPs are not well supported and that a top-down approach based on the historic expenditure is appropriate. However, ETSA Utilities' derivation of historical trends and application of compounding growth factors into the future is not reasonable and is unlikely to result in forecast expenditures that are prudent and efficient.

On analysis of the underlying assumptions contained in the spreadsheet provided by ETSA Utilities[153], PB does not consider that a compounding annual growth function is representative of the linear trend used. In most cases, the underlying linear trend parameters used by ETSA Utilities are generally based on a weak correlation with the historical data and the additional adjustment applied in the capital roll-up spreadsheet (CX001) is fundamentally due to the need to restrain the compounding annual growth rate.

For example, the scope of ETSA Utilities' unplanned pole replacement program was originally estimated on the basis of an allowance of 1% of the predicted age-based pole failures a year. However, the basis for this estimate was not provided in the pole AMP or modelling spreadsheet. PB understands that ETSA Utilities has since rejected the 'bottom-up' estimates for unplanned replacement expenditure outlined in the relevant AMPs and substituted a 'top-down' approach based on a compounding annual growth rate derived from linear trending of historical expenditure and failure rates.

152 ETSA Utilities' response to question PB.ETS.EM.96 Unplanned Asset Replacement.
153 ETSA Utilities SI241 EM 96 LinesUnplannedReplacement.

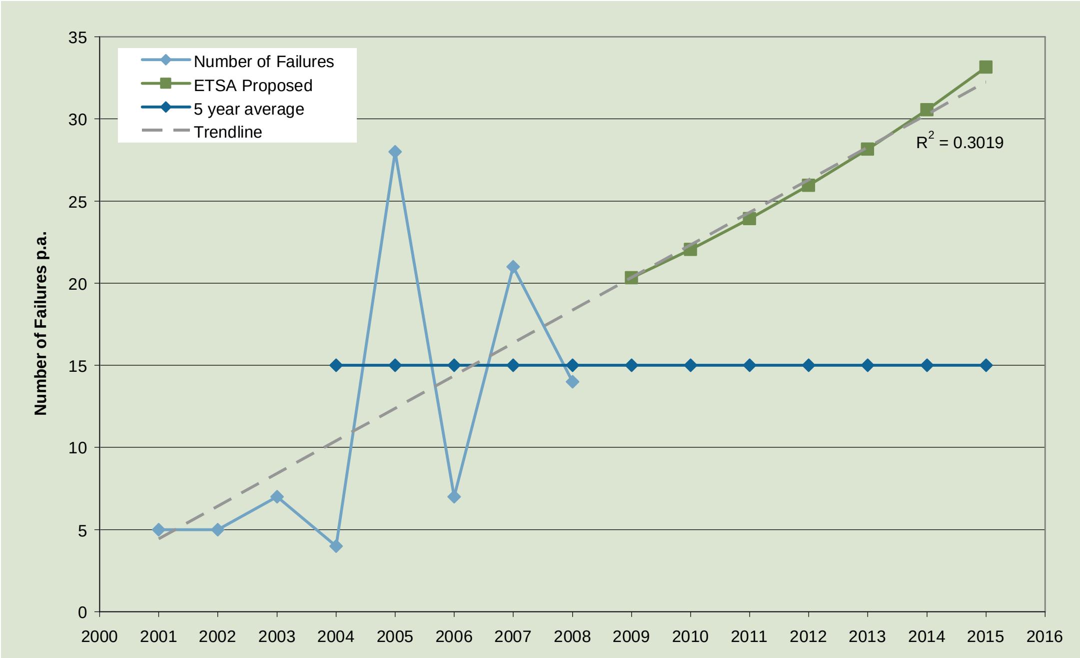

Figure 4.12 ETSA Utilities unplanned pole failures

Source: ETSA Utilities SI241 EM 96 Lines Unplanned Replacement & PB analysis

Based on the pole failure history presented in Figure 4.12 ETSA Utilities evaluated a compounding annual failure growth rate of 12% to correlate with the linear trend line shown. Similarly, based on the expenditure history presented in Figure 4.13, ETSA Utilities evaluated an expenditure growth rate of 8.5% per annum[154]. On the basis of these two growth rates, ETSA Utilities has arbitrarily assumed an annual compounding growth rate of 11% and applied this rate to its 2009 budgeted (forecast) expenditure figures in its capital roll-up spreadsheet[155].

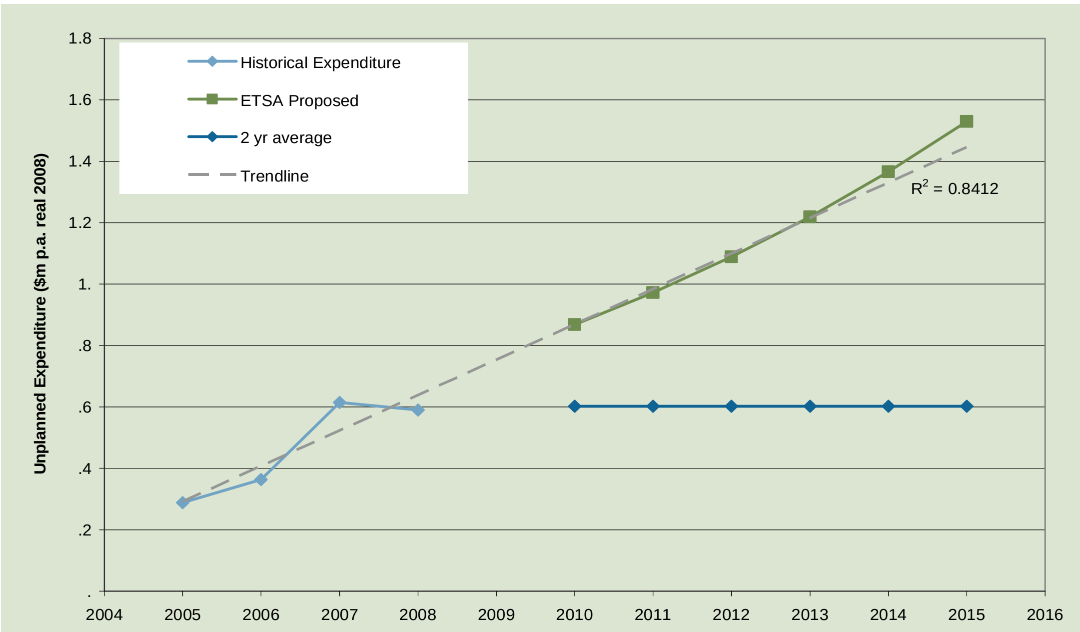

Figure 4.13 ETSA Utilities unplanned pole failure expenditure

Source: ETSA Utilities Spreadsheet SI241, Response to PB.ETS.EM.85 & PB analysis

154 ETSA Utilities spreadsheet SI241 EM 96 LinesUnplannedReplacement.xls.

155 ETSA Utilities spreadsheet CX001 Version Opt10a (moderate).

A subsequent adjustment has been made by ETSA Utilities to curtail the expenditure growth arising from this methodology and this adjustment is shown in Figure 4.15 for the total unplanned lines replacement capex. PB notes that identical approach has been applied to each of the major components of the unplanned lines replacement capex forecast.

As shown in Figure 4.14, PB also notes that the step change in historical expenditure from 2006 to 2007 and the flattening out in 2008 is repeated across the sub-categories included in the unplanned lines expenditure forecast and is not driven by a trend in any single sub-category. Therefore, PB does not consider that ETSA Utilities' 'top-down' expenditure forecast is reasonable and the proposed approach does not result in a reasonable expectation of the forward capex requirement for the unplanned lines category. On this basis we recommend that an average of the 2007 and 2008 total expenditure for unplanned line replacements be used as the basis for the forecast as it reflects the step change observed for 2007 and the flattening out observed in 2008. Therefore the proposed adjustment is consistent with ETSA Utilities recent business-as-usual unplanned line replacement expenditure and reflects the recent step change.

This results in a total expenditure for unplanned lines of $9.7m p.a. (real 2008) for the next regulatory control period.

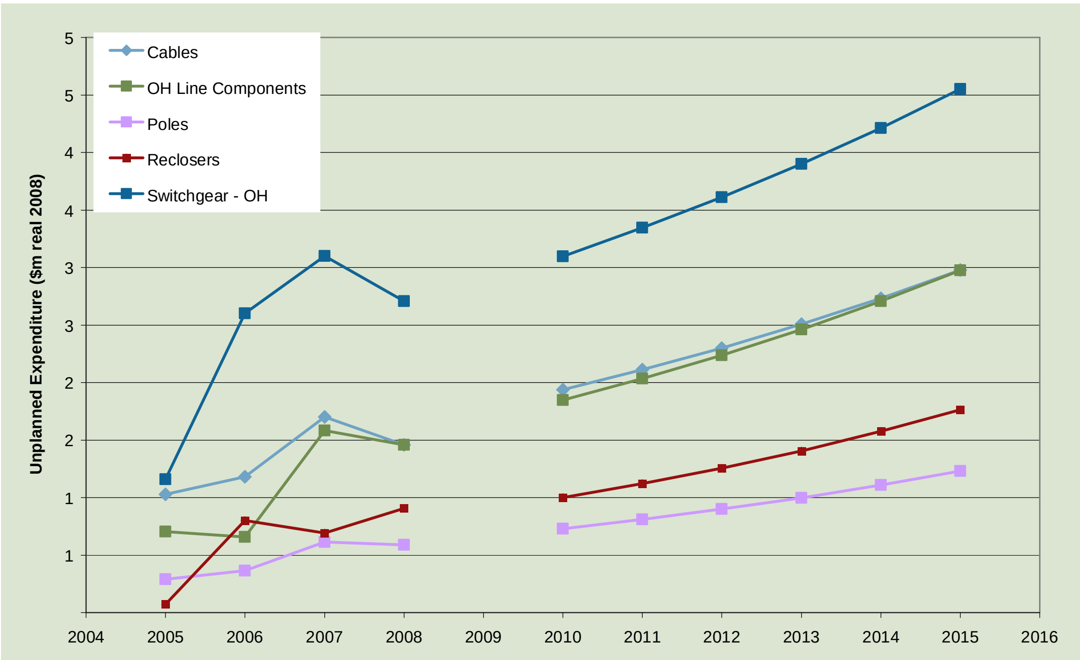

Figure 4.14 ETSA Utilities unplanned line replacement expenditure by major component

Source: ETSA Utilities Spreadsheet SI241 & PB analysis

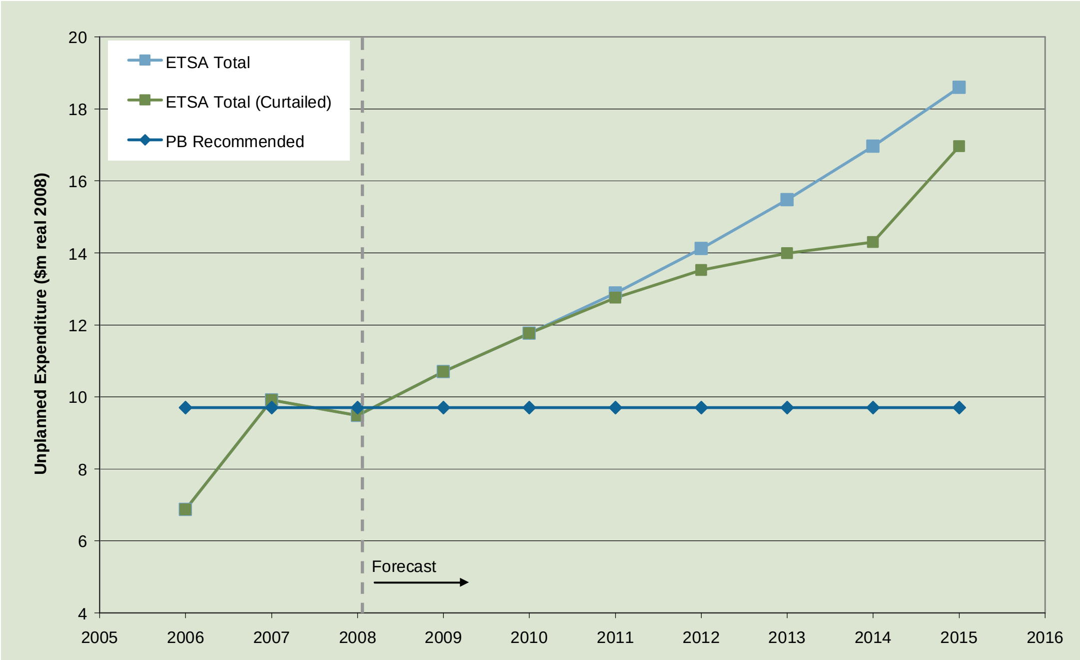

Figure 4.15 ETSA Utilities unplanned total line replacement expenditure

Source: ETSA Utilities Spreadsheet CX001 & PB analysis

PB is of the view that the adjustments as outline above will provide expenditures that are prudent and efficient. On this basis, PB's recommended adjustment to ETSA Utilities' proposed unplanned line expenditure from the application of unreasonable compounding annual growth rates is summarised in Table 4.14.

Table 4.14 PB's recommended adjustment to unplanned line asset replacement capex – base estimate ($m real 2008)

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	12.3	13.3	14.3	15.2	16.1	71.2
PB adjustment ($m)	(2.6)	3.6)	(4.6)	(5.5)	(6.4)	(22.7)
PB recommendation	9.7	9.7	9.7	9.7	9.7	48.5

Source: ETSA Utilities Spreadsheet CX001& PB analysis

Table 4.15 outlines the total adjustment to the capex portfolio, as calculated by ETSA Utilities' capital accumulation spreadsheet [156] and roll-up model[157]. These figures are inclusive of real escalation and exclude the overheads that are implicit in ETSA Utilities' base capex forecasts. Therefore they are consistent with the figures contained in the Regulatory Proposal.

156 ETSA Utilities spreadsheet CX001 Summary Sheets version Opt10a (moderate), 1 June 2009.
157 ETSA Utilities Attachment E.1 SEM-Capex Model Ver 7.2.

Table 4.15 PB's recommended adjustment – unplanned line replacement inclusive of ETSA Utilities' real escalation

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	13.1	14.6	16.0	17.4	18.9	79.9
PB adjustment ($m)	(2.8)	(4.0)	(5.2)	(6.3)	(7.5)	(25.6)
PB recommendation	10.3	10.6	10.9	11.1	11.4	54.2

Source: ETSA Utilities Spreadsheets CX001, Capex SEM and PB analysis

Substation circuit breakers

ETSA Utilities has proposed $50.5m in capex for substation circuit breaker replacement over the next regulatory control period. At an average of $10.1m a year, this represents a real increase of 363% over the average annual expenditure in the current regulatory control period[158].

The circuit breaker asset management plan[159] identifies the volume of planned replacements based on known issues for specific classes of circuit breakers, and makes allowance for unplanned replacements based on the documented failure history of that asset class.

The AMP outlines the existing condition monitoring approach for circuit breakers that has been applied by ETSA Utilities to date. This includes routine circuit breaker condition and performance diagnostics and targeted testing programs. The AMP also notes that the major spares holdings for each of the asset classes are complemented by additional decommissioned circuit breakers from substation upgrades. ETSA Utilities also identifies that sufficient spares are available to enable the timely repair by the replacement of components rather than the complete replacement of the unit in most cases[160]. This is reflected in the extended lives ETSA Utilities achieved for circuit breakers when compared to industry averages.

Given that ETSA Utilities has based its planned and unplanned asset replacement program for circuit breakers on historical failure rates, known condition and known type issues associated with their circuit breaker population, PB considers the planned circuit breaker replacement capex is prudent. On the basis that ETSA Utilities' maintenance practices for circuit breakers generally favour their repair rather than replacement in the event of a failure, and that the planned replacements to address known type and condition issues have been staged over the period to manage the risk of non-reparable failure, PB considers the proposed planned and unplanned circuit breaker replacement capex is efficient.

ETSA Utilities states the current realised service life of its circuit breaker population stretches to over 70 years, and it considers that the current condition and performance monitoring of circuit breaker assets is sufficient to manage the efficient replacement of its assets[161]. However, despite the well-established condition monitoring and diagnostic testing that is in place to identify problematic circuit breakers, the adequate management of spares and the ability to isolate and bypass a unit in the event of a failure[162], ETSA Utilities has proposed a replacement program for aged circuit breakers, which comprises approximately 52% of the volume of circuit-breaker replacement proposed over the next regulatory control period.

158 ETSA Utilities Response to question PB.ETS.EM.85.
159 ETSA Utilities, AMP 3.2.05 Substation Circuit Breakers, April 2009, p. 11.
160 ibid., p. 20, 29, 38, 45, 49.
161 ibid.
162 ibid., p. 12.

Within the age-based replacement categories, ETSA Utilities identifies two classes of circuit breakers that are described as 'problematic' because of condition-related issues:

- Outdoor 11 kV circuit breakers are noted to have a history of failures related to weatherproofing associated with enclosures[163]. ETSA Utilities states that all major failures of 11 kV circuit breakers since 2002 were rectified by repairing the unit from stock components[164]. ETSA Utilities is proposing to replace these units with a resulting 10-year reduction in service life. It is apparent to PB that ETSA Utilities is able to maintain this switchgear and that its wholesale replacement seems unsupported

- One switchboard has been proposed for age-based replacement on the basis of its assessed age-related risk. ETSA Utilities has assessed the risk of failure as medium based on age, and notes that a deferral to 2015 is possible subject to continued condition assessment[165]. However, the switchboard is the only one of its type on ETSA Utilities network and limited spares holdings are available to support it. PB accepts that the condition and risk posed by this asset are such that its replacement is prudent and the co-ordination with expected customer augmentation works in 2011 is efficient.

From our review, PB has concluded the information presented demonstrates a prudent, effective condition based replacement strategy is in place, and that further provision for a purely age-related replacement of circuit breakers is not required. Therefore, the proposed scope of ETSA Utilities substation circuit breaker replacement program is not efficient. To reflect an efficient scope, PB recommends that 106 of the 173[166] age-based circuit breaker replacement expenditure items scheduled for calendar years 2010–2015 are removed from the proposed capex allowance. PB notes that the age based replacements recommended to be removed include four switchroom buildings and a number of large switchboards resulting in a disproportional reduction in cost. As outlined in Table 4.16, PB has calculated the reduction on the basis of ETSA Utilities cost estimating spreadsheets and the planned and unplanned replacement quantities noted in the AMP. This results in a $36.7m reduction in ETSA Utilities' base capex proposal.

Table 4.16 PB's recommended adjustment to circuit breakers base estimate ($m real 2008)

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	8.4	10.3	10.2	8.9	7.2	45.0
PB adjustment ($m)	(5.4)	(7.2)	(7.8)	(6.7)	(5.5)	(32.6)
PB recommendation	3.0	3.1	2.4	2.3	1.7	12.4

Source: ETSA Utilities Spreadsheets SI208, CX001 and PB analysis

Table 4.7 outlines PB's recommend capex adjustment calculated from the accumulation spreadsheet [167] and roll-up model[168]. These figures are inclusive of real escalation and exclude the overheads implicit in ETSA Utilities' capex forecasts. Therefore they are consistent with the figures contained in the Regulatory Proposal.

163 ibid., p. 40.
164 ibid., p. 37.
165 Ibid., p. 50.
166 Ibid.. p. 57.
167 ETSA Utilities spreadsheet CX001 Summary Sheets version Opt10a (moderate), 1 June 2009.
168 ETSA Utilities Attachment E.1 SEM-Capex Model Ver 7.2.

Table 4.17 PB's recommended adjustment – circuit breaker program inclusive of ETSA Utilities' real escalation

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	9.0	11.3	11.5	10.3	8.5	50.5
PB adjustment ($m)	(5.8)	(7.9)	(8.8)	(7.7)	(6.5)	(36.7)
PB recommendation	3.2	3.4	2.7	2.6	2.0	13.9

Source: ETSA Utilities Spreadsheets CX001, Capex SEM and PB analysis

Power transformers

ETSA Utilities has proposed $40.3m in capex to replace substation power transformers over the next regulatory control period. This represents a real increase of 319% over current period expenditure[169].

The asset management plan for substation power transformers[170] identifies the volume of planned replacements based on known issues for specific classes of power transformers, and makes allowance for unplanned replacements based on the documented failure history of the transformer population. Furthermore, the AMP notes the spares holdings for power transformers is well planned, and presents a well-considered spares strategy for each transformer class[171]. The AMP also outlines the existing approach to monitoring the condition of power transformers, which includes routine monitoring tests for transformer condition, such as dissolved gas analysis, oil quality and visual inspection. Importantly, ETSA Utilities notes its condition monitoring program identified the 2006 Keswick and 2007 New Richmond transformer failures through dissolved gas analysis, and was able to plan the replacement of these transformers before actual in-service failure[172]. However, despite the proven effectiveness of the established program to monitor the condition of transformers, ETSA Utilities has proposed an age-based replacement approach whereby approximately 57% of the forecast transformer replacements between 2010 and 2020 are on the basis of age-related risk.

The AMP states that 'the majority of the power transformer failures can be predicted by adequate condition monitoring'. It also states that 'the replacement schedule will ultimately be determined by condition and performance monitoring and unplanned catastrophic failures'[173]. As ETSA Utilities' actual replacement decision will be based on condition rather than asset age, a large-scale, age-based replacement program does not represent a reasonable forecast of efficient expenditure. Therefore, PB recommends removing the age-based transformer replacements from the capex proposal to reflect a prudent and efficient scope of works.

PB has also reviewed the proposed planned and unplanned power transformer replacement program and is concerned that the proposed number of replacements is greater than that supported by ETSA Utilities' historical data. With regard to the unplanned 66 kV (>20 MVA) transformer replacements, ETSA Utilities has proposed to replace one unit a year based on five failures occurring between 2000 and 2008, and two recent failures occurring in the space of 12 months. ETSA Utilities claims the recent failures are indicative of a rapid increase in failure rates, and has increased its unplanned replacement forecast as a result. However, PB notes that these failures followed three years where no failures occurred, and

169 ETSA Utilities Response to question PB.ETS.EM.85.
170 ETSA Utilities, AMP 3.2.01 Substation Power Transformers, March 2009, p. 15.
171 ibid., p. 23, 34, 30.
172 ibid., p. 27.
173 ibid., p. 6.

we would not consider the occurrence of two failures in a single twelve months to be statistically significant, or as a basis upon which to conclude a fundamental change in population condition. In addition, ETSA has identified that three failures of medium and large transformers have occurred in 2009[174] (excluding a repeat failure of a unit returned to service after a failure in 2006). After examining ETSA Utilities' data for the five years to 2008 contained in the Substation Transformers AMP and considered the additional 2009 data, PB has concluded that it supports a failure rate of three in five years. Similarly, ETSA Utilities has also proposed an unplanned replacement rate of one transformer a year for the 66 kV (5-20 MVA) transformer class, while the five-year historical average to 2009 indicates that four failures in five years would be expected. Consequently, PB recommends that two transformers are removed for the unplanned 66 kV (>20MVA) and one from the 66 kV (5-20 MVA) replacement proposal to represent a prudent and efficient scope of works.

With regard to the planned transformer replacement forecast, ETSA Utilities has proposed replacing the Tyree E465 66/11 kV transformer class owing to a known design weakness. However, the justification for replacement is based on adopting a reduction in the expected age of ten years in the risk assessment.

PB notes that no justification has been provided for the magnitude of the proposed reduction in the expected life. We also note that two failures of this transformer type occurred between 2001 and 2003. ETSA Utilities has identified that a severe fault in 1987 contributed to the most recent 2003 Norwood transformer failure, and that the Croydon ST12555 transformer was subjected to an identical fault. Therefore ETSA Utilities expects that the Croydon transformer will experience a shorter-than-expected life.

In contrast, no fault history has been identified for the remaining units, and no load is currently at risk[175] for each of the remaining Tyree 465 transformers that are in service. Therefore, the justification for replacement in the risk assessment is based on an apparently arbitrary adjustment to the expected transformer life alone. Hence PB has concluded that the replacement of the Tyree 465 class transformers is not supported on the basis of known asset condition or risk, and is not prudent or efficient expenditure. PB recommends that the Croydon transformer replacements of this class are retained, and that the remaining Tyree 465 class transformers replacements are removed from the capex proposal to reflect a prudent and efficient scope of works.

Table 4.18 shows PB's recommended changes to ETSA Utilities' proposed power transformer replacement capex proposal to reflect a prudent and efficient scope of works.

Table 4.18 PB's recommended adjustment to substation transformer replacement base estimate ($m real 2008)

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	8.4	7.7	7.4	6.2	6.5	36.2
PB adjustment ($m)	(4.0)	(3.6)	(3.7)	(2.1)	(2.3)	(15.7)
PB recommendation	4.4	4.2	3.6	4.2	4.2	20.5

Source: ETSA Utilities Spreadsheet CX001 and PB analysis

174 ETSA Utilities, AMP 3.0.01 Condition Monitoring and Life Assessment Methodology, p.13
175 ibid., p. 26.

Table 4.19 outlines the total adjustment to the capex portfolio, as calculated by ETSA Utilities' capital accumulation spreadsheet [176] and roll-up model[177]. These figures are inclusive of real escalation and exclude the overheads that are implicit in ETSA Utilities base capex forecasts. Therefore they are consistent with the figures contained in the Regulatory Proposal.

Table 4.19 PB's recommended adjustment – substation transformers replacement inclusive of ETSA Utilities' real escalation

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	9.0	8.5	8.3	7.0	7.5	40.3
PB adjustment ($m)	(4.3)	(3.9)	(4.2)	(2.3)	(2.7)	(17.5)
PB recommendation	4.7	4.6	4.1	4.7	4.8	22.8

Source: ETSA Utilities Spreadsheets CX001, Capex SEM and PB analysis

Poles

ETSA Utilities is proposing $42.3m in capex for pole replacements over the next regulatory control period. At an average of $8.5m a year, this represents a real increase of 267% over the $2.3m average annual expenditure in the current period[178].

ETSA Utilities' proposed pole replacement for the next regulatory control period is based on a model of pole age and corrosion zones[179]. ETSA Utilities states that the age of individual poles is unknown[180]; however, pole age can be implied from the manufacturing history and an assumed age-based failure profile for each corrosion zone. PB notes that ETSA Utilities' replacement model is fundamentally age-based, and as such it is sensitive to the input assumptions of age and failure profile[181].

ETSA Utilities established the expected pole age by corrosion zone from a 1990s study made before significant levels of stobie pole failure were observed, and ETSA Utilities has used a normal distribution to smooth the failure rates that have been applied to each corrosion zone. No justification for the selection of a normal distribution or the standard deviations that are applied has been included in the AMP or related model[182].

To test ETSA Utilities' model PB requested defect information from pole inspections over the past five years to determine the extent to which the model's predictions concurred with currently available condition information[183]. Based on this information[184], PB estimated the proportion of the poles required to be replaced on the basis of the number of defects, by priority, reported for each corrosion zone. Table 4.20 shows the information that was used as an input to this process.

176 ETSA Utilities spreadsheet CX001 Summary Sheets version Opt10a (moderate), 1 June 2009.
177 ETSA Utilities Attachment E.1 SEM-Capex Model Ver 7.2.
178 ETSA Utilities Response to question PB.ETS.EM.85.
179 ETSA Utilities, AMP 3.1.05 Poles.
180 ibid., p. 9.
181 Refer p.48 of this report for discussion regarding the limitations of age-based modelling approaches.
182 ETSA Utilities spreadsheet SI18 PB.ETS.EM.44-Poles.xls.
183 ETSA Utilities response to PB question PB.ETS.EM.81.
184 ETSA Utilities spreadsheet SI218 EM81PoleDefects.xls.

Table 4.20 Pole population characteristics used in PB's assessment.

	High corrosion zone	Medium corrosion zone	Low corrosion zone
Population characteristics			
Pole population[185]	34,000	215,000	474,000
Expected average life (years) [186]	50	75	100
Expected corrosion rate p.a. [a]	1.00%	0.67%	0.50%
% of population covered by annual inspection[187]			
Prior to 2007	10%	10%	10%
2007	100%[b]	10%	10%
2008 onward	20%	10%	10%

a. based on expected average life and 50% corrosion limit for poles

b. PB notes that a targeted pole inspection program of the high corrosion zone occurred in 2007

Source: ETSA Utilities and PB analysis

PB took the defect history provided by ETSA Utilities as a percentage of the population that was inspected each year and made an allowance for continued deterioration from the known condition to estimate the state of the pole population at the start of the regulatory control period.

On the basis of this analysis, PB calculates that approximately 4,300 poles (including the scheduled backlog replacements described in the AMP) would be expected to exceed the 50% metal loss criterion during the next regulatory control period and approximately 19,000 would be expected to fall in the Priority 2 band, equating to 30–50% metal loss. These figures represent the upper and lower limits of the volume of poles expected to exceed the 50% metal loss criterion ('failure') over the next regulatory control period.

There is a significant cost benefit associated with refurbishment ($410) over replacement ($6,200) of a stobie pole. This benefit equates to a deferral of over 30 years at a discount rate of 9%. Therefore, a prudent operator acting in an efficient manner would mitigate the risk of incurring the higher replacement cost by aiming to refurbish poles before reaching the 50% metal loss criterion. ETSA Utilities has identified this benefit as a major consideration in their proposed management strategy for stobie poles[188].

To determine the level of the pole treatment (replacement or refurbishment) that is supported by the condition monitoring results, PB has assumed the poles would be refurbished before breaching the 50% metal loss criterion (using the expected annual corrosion rates outlined in Table 4.20). This allowance would enable the best forward scheduling of the work, and allow for variance in the actual local corrosion rate or failure modes that do not allow for refurbishment. As shown in Table 4.21, PB estimates that approximately 7,837 pole treatments would be supported by ETSA Utilities' historical pole condition inspection data if poles were refurbished nominally within five years before reaching the 50% corrosion criterion, or approximately 11,360 poles if poles were refurbished nominally within 10 years before reaching the criterion.

185 ETSA Utilities, AMP 3.1.05 Poles, p. 10.
186 ibid., p. 7.
187 ibid., p. 12, 17, 20.
188 ibid., p. 8.

Table 4.21 Estimated pole replacements/refurbishments next regulatory control period

Criteria	Total
PB estimated – replace on failure only	4,313
PB estimated – refurbish within five years before failure	7,837
PB estimated – refurbish within ten years before failure	11,360
ETSA Utilities proposed	11,687

Source: PB analysis of ETSA Utilities information

Therefore ETSA Utilities' proposed 11,687 pole treatments is comparable to a 10-year refurbishment criterion and lies at the conservative end of our expectations based on the known condition data. PB also recognises that a 10-year safety factor is well within the 30+ year deferral benefit associated with refurbishment over replacement. Hence we conclude that ETSA Utilities' refurbishment strategy is efficient.

Despite the above, PB notes that while the total number of pole refurbishments or replacements is comparable to the upper end of our expected range, our assessment predicts a lower proportion of replacements/refurbishments in the high corrosion zone, and a greater proportion in the medium corrosion zone than indicated by ETSA Utilities' modelling. This implies the assumed failure or population distributions in ETSA Utilities' model are not consistent with the actual failure profile.

Given the historical 10-year inspection cycle, the increased focus on pole refurbishment[189], and the level of refurbishment that ETSA Utilities expects to be required beyond the next regulatory control period, PB considers that ETSA Utilities' adoption of a conservative approach to pole refurbishment is reasonable. On this basis, PB considers the increased focus on refurbishment is prudent, and that the total volume of ETSA Utilities' pole failure forecasts is efficient.

PB notes, however, that adopting a conservative approach to ensure refurbishment occurs in preference to replacement should result in a significantly higher degree of refurbishment over replacement than has been experienced in the past. Consistent with this expectation, ETSA Utilities has based its cost forecast in the low and medium corrosion zones on reducing pole replacements as a proportion of total 'failures' to 5% and 15% respectively. PB understands the 15% applied in medium corrosion zones is principally due to the increased incidence of above ground corrosion failure[190]. Based on ETSA Utilities' historical 39% replacement/refurbishment defect ratio in medium corrosion zones, 15% represents a significant reduction, consistent with the increasing proportion of pole refurbishments. In contrast, for high corrosion zones, ETSA Utilities has assumed that replacements will comprise a total of 80% of the predicted failures[191]. No justification for this figure has been provided in the AMP, and hence PB has based its assessment on the pole defect history for the period 2004-05 to 2008-09. The total number of defects is summarised in Table 4.22 for high and medium corrosion zones[192].

189 ibid., p. 8.
190 ibid., p. 16.
191 ibid., p. 19.
192 PB notes that due to the relatively good condition of poles in the low corrosion zone very few defects are reported. Therefore, the defect history for the low corrosion zone strongly favours replacement, which is consistent with unusual localised factors that affect individual poles within the zone. Therefore the low corrosion zone defect history is not considered to be indicative of the total population.

Table 4.22 ETSA Utilities' pole inspection defects 2004-05 to 2008-09

Expenditure category	2004-05	2005-06	2006-07	2007-08	2008-09	Total
High corrosion zone						
Refurbishment defects	68	148	748	1,351	750	3,065
Replacement defects	53	94	300	657	357	1,461
% Replacement	44%	39%	29%	33%	32%	32%
ETSA Utilities' proposed replacement						80%
Medium corrosion zone						
Refurbishment defects	83	489	768	742	407	2,489
Replacement defects	180	343	394	362	285	1,564
% Replacement	68%	41%	33%	33%	41%	39%
ETSA Utilities' proposed replacement						15%

Source: ETSA Utilities Spreadsheet SI218 EM81PoleDefects.xls and PB analysis

This pole defect history demonstrates that historically, medium corrosion zone pole defects result in pole replacements at a proportionally higher rate than in high corrosion zones (39% replacement rate versus a 32% replacement rate respectively)[193]. ETSA Utilities' proposed replacement is counter to this historical view, and is not supported in the AMP. Therefore ETSA Utilities proposed pole replacement scope does not represent prudent and efficient expenditure.

ETSA Utilities has stated that it expects its proposed refurbishment strategy will reduce replacements in medium corrosion zones to 15%. For high corrosion zones, PB considers the historical replacement rate of 32% represents the upper limit of expectations, and given ETSA Utilities' proposed refurbishment strategy, an improvement in this historical rate should be anticipated. Based on the expected reduction in pole replacements in the medium corrosion zone from 39% to 15%, PB considers that a reduction in pole replacements in the high corrosion zone from 32% to 15% can also be expected.

Based on our review, PB recommends the proportion of pole replacements in high corrosion zones in ETSA Utilities' capex proposal is reduced from 80% to 15% to reflect a prudent and efficient scope. PB's recommended adjustment for ETSA Utilities' planned pole replacements capex proposal is shown in Table 4.23.

Table 4.23 PB's recommended adjustment to planned pole replacement base estimate ($m real 2008)

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	7.2	7.4	7.6	7.8	8.0	38.0
PB adjustment ($m)	(3.7)	(3.8)	(3.9)	(4.0)	(4.0)	(19.4)
PB recommendation	3.5	3.6	3.7	3.8	4.0	18.7

Source: ETSA Utilities Spreadsheets CX001, SI208 and PB analysis

193 ETSA has subsequently advised that prior to 2007, areas were not defined in corrosion zones. PB has assumed that the corrosion zone based defect data provided by ETSA Utilities for years prior to 2007 is based on ETSA Utilities best estimates.

Table 4.24 outlines the total adjustment to the capex portfolio, as calculated by ETSA Utilities' capital accumulation spreadsheet [194] and roll-up model[195]. These figures are inclusive of real escalation and exclude the overheads that are implicit in ETSA Utilities' base capex forecasts. Therefore they are consistent with the figures contained in the Regulatory Proposal.

Table 4.24 PB's recommended adjustment – planned pole replacement inclusive of ETSA Utilities' real escalation

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	7.7	8.1	8.5	8.9	9.2	42.3
PB adjustment ($m)	(4.0)	(4.2)	(4.4)	(4.6)	(4.7)	(22.0)
PB recommendation	3.7	3.8	4.0	4.3	4.5	20.3

Source: ETSA Utilities Spreadsheets CX001, Capex SEM and PB analysis

Conductor

ETSA Utilities has proposed $31.9m in capex for conductor replacement over the next regulatory control period. At an average of $6.4m pa, this represents a real increase of 1169% over the average annual expenditure in the current period[196].

ETSA Utilities has based its proposed conductor replacement capex on a model based on age and corrosion zone[197]. Beyond the consideration of the different corrosion zones, PB notes that the model is fundamentally age-based and sensitive to the input assumptions of age and failure profile[198]. Significantly, ETSA Utilities states that:

> Although "conductor age" has not yet been distinguished as a major contributing factor with regards to repair, refurbishment, replacement or disposal of line conductor, it will be reasonable at this stage to include it as a factor in the Asset Management Plan because of the ageing EU distribution and sub transmission lines.
>
> The life span of an overhead conductor varies. It is dependent on the aggregate effect of variables that include conductor type and size, load capacity (ampicity), temperature, age and recently the atmospheric corrosion…[199]

PB notes that ETSA Utilities has based the model ages on the 'useful asset life' for each corrosion zone derived from its AMP Manual 15[200] and industry sources[201]. We also note that useful life of an asset is generally used for depreciation calculations, and may not be reflective of the actual life achieved in practice. With respect to the definition of an asset's useful life, the Australian Accounting Standards Board (AASB) notes:

> The useful life of an asset is defined in terms of the asset's expected utility to the entity. The asset management policy of the entity may involve the disposal of assets after a specified time or after consumption of a specified proportion of the future economic benefits embodied in the asset. Therefore, the useful life of an asset may be shorter than

194 ETSA Utilities spreadsheet CX001 Summary Sheets version Opt10a (moderate), 1 June 2009.
195 ETSA Utilities Attachment E.1 SEM-Capex Model Ver 7.2.
196 ETSA Utilities Response to question PB.ETS.EM.85.
197 ETSA Utilities, AMP 3.1.10 Overhead Conductor. February 2009.
198 Refer p.48 of this report for discussion regarding the limitations of age-based modelling approaches.
199 ETSA Utilities, AMP 3.1.10 Overhead Conductor. February 2009, p. 7.
200 ETSA Utilities 2009, *DaNM Asset Management Plan,* 2009 Issue.
201 ETSA Utilities, AMP 3.1.10 Overhead Conductor. February 2009, p. 8.

> its economic life. The estimation of the useful life of the asset is a matter of judgement based on the experience of the entity with similar assets.[202]

Furthermore, for long-lived infrastructure assets, the AASB notes:

> Accounting Standard AASB 116 Property, Plant and Equipment requires the depreciable amount of an asset to be allocated on a systematic basis over the asset's useful life. Some commentators argue that depreciation methods that have conventionally been adopted in respect of long-lived physical assets, including infrastructure assets, are not appropriate for such assets, particularly when they are controlled by public sector entities, because, for example:
>
> a) These assets have very long useful lives, are often "complex" assets comprising a number of components and are constantly rehabilitated during the course of their lives, so that it is often not possible to develop a reliable estimate of their useful life.[203]

Given the sensitivity of aged-based replacement models to the input age assumptions (as demonstrated by ETSA Utilities in its AMP 3.1.01[204] where a 10% increase in asset life results in an approximate doubling of replacement expenditure) and the tendency for useful life for infrastructure assets to differ significantly from the asset's economic or physical life, particularly due to partial replacements, PB considers the adoption of useful asset lives in the conductor replacement model is likely to overstate replacement.

Despite our concerns about the reliance on assumed asset lives, ETSA Utilities' replacement model and AMP make allowance for corrosion zone and conductor type by assigning different expected age modifications to each. Furthermore the allowance for age-based replacement to occur over a relatively long period (13–15 years depending on corrosion zone)[205] [206] smoothes the expenditure volatility typically associated with simple age-based approaches where replacement is modelled to occur in a single year.

To test the model's validity, PB compared the model's predicted expenditure to the historical expenditure over the current regulatory control period. Table 4.25 shows this comparison. It can be seen from these results that the annual expenditure predicted by the model is approximately four to ten times the actual expenditure incurred during the period. Therefore the model underpinning ETSA Utilities' proposed conductor replacement expenditure forecast does not represent a reasonable forecast of the costs that would be incurred by a prudent network operator acting efficiently.

PB found that by increasing the average useful life input assumption by approximately eight years the adjusted model predicted results approximately aligned with the actual data. We note this is consistent with the results ETSA Utilities is experiencing in practice and with ETSA Utilities' historical condition-based replacement strategy for conductors.

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202 Australian Accounting Standards Board 2007, *AASB116 Property Plant and Equipment*, November 2007, p. 23.

203 Australian Accounting Standards Board 2004, Interpretation 1030, Depreciation of Long Lived Physical Assets: Condition Based Depreciation Related Methods, September 2004, p. 4.

204 ETSA Utilities, AMP 3.0.01, Condition Monitoring and Life Assessment Methodology, p. 16.

205 ETSA Utilities spreadsheet SI19 PB.ETS.EM.44 Conductor.xls.

206 PB notes that ETSA Utilities conductor replacement model divides the replacement cost of high corrosion zone conductor over 13 years rather than the stated 9 years to derive an annual replacement quantity. Therefore the nine-year spread noted for high corrosion zones is not used by the model. However, the annual replacement quantity has only been applied over nine years, which results in an underestimate of the total replacement quantities for high corrosion zones by a factor of 4/13 (i.e. four times the annual figure). PB has made allowance for this discrepancy by spreading the replacement volumes over an additional four years in the high corrosion zone resulting in a higher level of expenditure than predicted by ETSA Utilities.

Table 4.25 ETSA Utilities modelled conductor replacement v actual ($k real 2008)

	2005-06	2006-07	2007-08	2008-09	Total
ETSA Utilities model predicted[206]	2,816	3,266	3,709	4,154	13,945
ETSA Utilities actual	261	303	541	828	1,933
Adjusted model prediction[206]	304	441	577	844	2,166

Source: ETSA Utilities Spreadsheet SI19, response to PB.ETS.EM.85 and PB analysis

PB notes that ETSA Utilities' condition inspection data indicates a significant increase in defects arising from its existing conductor inspection program[207]. Many of the recent defects appear to relate to specific sections of the network. For example, the 6.9 km of conductor on the Pelican Point CN33 feeder, which has been proposed for replacement where 110 recent defect notifications had been raised following a full component inspection in December 2007[208]. Furthermore, the increase in actual expenditure in 2008-09 is consistent with the increase in second priority (P2) defects reported in the moderate corrosion zone in 2006-07, and mirrors the increase originally predicted by the model in 2000-01 associated with the onset of replacements in the moderate corrosion zone.

While PB does not consider that an aged-based replacement approach is in accordance with efficient asset management practices, in the absence of more detailed conductor condition information, we consider that the adjusted ETSA Utilities model[209] is reasonably aligned with historical expenditure, and recent defect history, when the high corrosion zone replacements are spread over 13 years. Hence as the adjusted model's predicted expenditure for the period 2005-06 to 2008-09 is consistent with the reported condition of ETSA Utilities' conductor, it could be used as a proxy for the efficient level of forecast capex over the next regulatory control period.

PB recognises the historical expenditure in this category has been low, and our recommended figure represents a significant increase in conductor expenditure. However, a significant increase in the volume of conductor replacement is prudent to manage the documented increase in the number of corrosion-related conductor defects.

Table 4.26 shows PB's recommended changes to ETSA Utilities' conductor replacement capex proposal to reflect a prudent and efficient scope.

Table 4.26 PB's recommended adjustment to conductor replacement base estimate ($m real 2008)

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	4.1	5.2	6.3	6.3	6.2	28.1
PB adjustment ($m)	(2.5)	(3.2)	(3.9)	(3.5)	(3.0)	(16.0)
PB recommendation	1.6	2.0	2.4	2.8	3.3	12.1

Source: ETSA Utilities Spreadsheet CX001, SI19 and PB analysis

Table 4.27 outlines the total adjustment to the capex portfolio, as calculated by ETSA Utilities' capital accumulation spreadsheet [210] and roll-up model[211]. These figures are

207 ETSA Utilities spreadsheet SI222 EM83ConductorDefects.xls provided in response to PB.ETS.EM.83.
208 ETSA Utilities, Approval Submission for Pelican Point CN33 Poles and Conductor Replacement. Network Order 80034806, p. 2
209 That is, the assumed useful lives for all corrosion zones are increased by eight years to reflect the extended lives achieved through ETSA Utilities' existing condition-based replacement program.
210 ETSA Utilities spreadsheet CX001 Summary Sheets version Opt10a (moderate), 1 June 2009.

inclusive of real escalation and exclude the overheads that are implicit in ETSA Utilities' capex forecasts. Therefore they are consistent with the figures contained in the Regulatory Proposal.

Table 4.27 PB's recommended adjustment – conductor replacement inclusive of ETSA Utilities' real escalation

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	4.4	5.7	7.1	7.3	7.4	31.9
PB adjustment ($m)	(2.5)	(3.4)	(4.3)	(3.9)	(3.5)	(17.7)
PB recommendation	1.8	2.3	2.8	3.4	3.9	14.2

Source: ETSA Utilities Spreadsheets CX001, Capex SEM and PB analysis

General adjustment

PB has reviewed 52% of ETSA Utilities' proposed $466.8m replacement capex, and based on our reviews, we have recommended adjustments totalling $119.4m. These adjustments are summarised in Table 4.28

Table 4.28 PB's recommended adjustments to the proposed asset replacement portfolio

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities' proposal	79.7	91.4	96.8	98.9	99.9	466.8
Items reviewed						
Conductor planned	4.4	5.7	7.1	7.3	7.4	31.9
Poles planned	7.7	8.1	8.5	8.9	9.2	42.3
Power transformers planned	9.0	8.5	8.3	7.0	7.5	40.3
Circuit breakers planned	9.0	11.3	11.5	10.3	8.5	50.5
Lines unplanned	13.1	14.6	16.0	17.4	18.9	79.9
Total reviewed ($m)	43.1	48.1	51.3	50.8	51.5	244.9
PB adjustments						
Conductor planned	(2.5)	(3.4)	(4.3)	(3.9)	(3.5)	(17.7)
Poles planned	(4.0)	(4.2)	(4.4)	(4.6)	(4.7)	(22.0)
Power transformers planned	(4.3)	(3.9)	(4.2)	(2.3)	(2.7)	(17.5)
Circuit breakers planned	(5.8)	(7.9)	(8.8)	(7.7)	(6.5)	(36.7)
Lines unplanned	(2.8)	(4.0)	(5.2)	(6.3)	(7.5)	(25.6)
PB adjustment ($m)	(19.4)	(23.4)	(26.9)	(24.8)	(24.9)	(119.4)
PB adjustment (%)	(45%)	(49%)	(52%)	(49%)	(48%)	(49%)
PB Recommendation	23.7	24.7	24.4	26.0	26.6	125.4

Source: ETSA Utilities Spreadsheet CX001 and PB analysis

PB's main concern throughout our reviews has been the inherent reliance on age-based forecasting in addition to ETSA Utilities' existing condition-based forecasts. The use of compounding annual growth rates, which are not supported by the underlying historical data,

211 ETSA Utilities Attachment E.1 SEM-Capex Model Ver 7.2.

and the limited use of known condition data as the basis for the proposed capex are also of concern. Given that similar approaches have been adopted across each of the asset categories, PB considers these issues are indicative of a systemic overestimation of replacement capex. After reviewing 52% of ETSA Utilities' proposed replacement capex, we have concluded that the same issues will be identified across the remaining 48% of the replacement capex proposal. Consequently, we consider the remainder of the asset replacement portfolio is not representative of prudent and efficient expenditure. To test this view PB examined (at a high level) other proposed replacement capex categories not included in our specific reviews. For example we found:

- The application of unsupported annual compounding failure escalation figures and a simplistic age-based insulator failure model to forecast the $40.2m planned expenditure in the Overhead Line Components AMP[212]. This expenditure is proposed to increase from an average of $1.5m p.a. (real $2008) in the current period to an average of to $8.0m p.a. (real $2008) in the next period, despite the flat or reducing trends in insulator failure rates[213], and low levels of high priority cross-arm failures identified through asset inspections[214].

- That the justification for the $27.0m expenditure in the Protection and Control AMP[215] is based on a risk assessment[216] that is inconsistent with consequences identified in the failure and effect analysis[217]. Similarly, the plan uses an age-based approach with retirement ages well below those accepted in ETSA Utilities' asset base to forecast the expenditure despite the statement that:

> …the replacement schedule will ultimately be determined by condition and performance monitoring, unplanned failures, regulatory obligations and system capacity upgrades. [218]

Hence, PB recommends that a general adjustment is applied to ETSA Utilities' proposed replacement capex to account for systemic overestimation of the efficient replacement capex. The recommended general adjustment would consist of a pro rata reduction to the remaining 48% of ETSA Utilities' replacement capex proposal that was not subject to specific review. As shown in Table 4.29 this results in a further adjustment of $108.3 m to ETSA Utilities' proposed asset replacement capex proposal to reflect a prudent and efficient asset replacement scope.

Table 4.29 PB's recommended general asset replacement capex adjustment inclusive of ETSA Utilities' real escalation

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Replacement capex not specifically reviewed ($m)	36.6	43.3	45.5	48.1	48.4	221.9
Adjustment derived from specific reviews (%)	(45%)	(49%)	(52%)	(49%)	(48%)	(49%)
Total adjustment ($m)	(16.5)	(21.1)	(23.8)	(23.4)	(23.4)	(108.3)
Total adjustment (%)	(45%)	(49%)	(52%)	(49%)	(48%)	(49%)

Source: ETSA Utilities Capex SEM and PB analysis

212 ETSA Utilities, AMP 3.1.06, Overhead Line Components, pp. 12, 14, 16, 18.
213 ibid., p .28.
214 ibid., p .27.
215 ETSA Utilities AMP 3.2.14 Protection and Control, p. 16.
216 ibid., pp. 50–51.
217 ibid., pp. 54–55.
218 ibid p. 5.

PB recommendation for the asset replacement program

On the basis of the above review, PB recommends that ETSA Utilities' proposed replacement capex allowance is reduced from $466.8m to $239.1, representing a total reduction of $227.7m, or 49% to ETSA Utilities' asset replacement capex proposal.

Table 4.30 PB's recommended adjustment – asset replacement program

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposed total	79.7	91.4	96.8	98.9	99.9	466.8
Total PB adjustment specific reviews	(19.4)	(23.4)	(26.9)	(24.8)	(24.9)	(119.4)
Total general adjustment	(16.5)	(21.1)	(23.8)	(23.4)	(23.4)	(108.3)
PB Recommendation	43.8	46.9	46.0	50.7	51.6	239.1

Source: ETSA Utilities Capex SEM and PB analysis

4.3.5 Review of substation security and fencing program

PB undertook a specific review of the substation security and fencing program. The program involves the replacement of 183 (or 57%) of ETSA Utilities' 319 outdoor substation fences.

ETSA Utilities notes that the Electricity (General) Regulations 1997 outline specific requirements for outdoor substation fences[219]. These requirements are applicable to substations installed after 1 July 1997, and are met by ETSA Utilities' current perimeter fence standard [220]. ETSA Utilities has also stated that its fencing standard is consistent with the standard used by other electricity companies throughout Australia and overseas[221]. Despite ETSA Utilities' fencing standard complying with mandatory requirements, and its consistency with domestic and international industry practice for distribution substations, ETSA Utilities has proposed imposing a more stringent standard for high security fencing for the substations sites that have been assessed as high risk after it applied the methodology outlined in an ENA guideline[222].

The principal driver for ETSA Utilities' proposed adoption of a higher standard for security fencing is the prevention of unauthorised entry. This is in response to the findings of a coronial enquiry that concluded that a reasonable level of security for a substation fence was over and above the minimum requirements outlined in the Australian Standards[223] resulting in potential liability concerns for distribution businesses. Furthermore, ETSA Utilities cites legal advice that it received in 2002 about its liability exposure in relation to substation fencing. ETSA Utilities identifies its duty of care as:

> The duty imposed on an occupier is to take reasonable care, not a duty to prevent any or all reasonably foreseeable injuries. Hence ETSA Utilities is not required to prevent a "determined" person from entering the sites but rather to ensure that all persons are warned of the associated risks and to take precautions to deter entry. Note that the

219 ETSA Utilities, AMP 5.1.03 Substation Fences and Security 2009 to 2020, p. 7.
220 ibid., p. 9.
221 ibid.
222 ENA National Guidelines for Prevention of Unauthorised Access to Electricity Infrastructure, ENA DOC 015-2006.
223 ETSA Utilities, AMP 5.1.03 Substation Fences and Security 2009 to 2020, p. 8.

> occupier is not required to make entry impossible but needs make it sufficiently difficult for the majority of potential trespassers.[224]

Given ETSA Utilities' statement that its fences meet or exceed the relevant Australian standard[225], PB considers that ETSA Utilities' fencing standards do not appear to be inconsistent with the level of security outlined above, and the fundamental need to replace approximately 57% of all of its substation fences over 10 years would not seem to be supported. Despite this, PB notes there has been a recent industry trend towards increased security arrangements at substations, mainly in response to an increase in copper theft following record high prices in 2006-07[226], and based around the ENA guideline[227]. ETSA Utilities' strategy follows this industry trend. PB notes, however, that the ENA guideline is mainly intended for new installations, and is not a retrospective standard. The guideline also recommends a site-specific risk assessment and the selection of an option justified on a site-specific basis.

In 2003, ETSA Utilities reviewed its existing substation fences, and has used the results in conjunction with a more recent site risk assessment based on the ENA guidelines to determine the proposed substation security and fencing program. PB has reviewed this approach and has found it results in a high risk being assigned to fences with condition problems even at sites with low or medium risk. For example, in metropolitan areas, ETSA Utilities has identified a total of ten, high-risk sites, with nine replacements scheduled in the next regulatory control period. ETSA Utilities has also assessed the risk following the planned substation security upgrades to be low risk. However, ETSA Utilities has included an additional 42 high security fence installations in the proposed program at substation where the existing site risk has been assessed as low or medium. In our opinion, ETSA Utilities' analysis is inconsistent with the ENA guideline as well as ETSA Utilities' risk management framework.

ETSA Utilities' proposal also includes provision for 30 CCTV installations and supporting research and development (R&D) for other security improvement measures. PB has reviewed the AMP documentation and notes that the CCTV installations and the supporting R&D essentially represent a provision to trial CCTV monitoring and investigate other security technologies. However, ETSA Utilities provides no further support in relation to the specific need for CCTV monitoring or its potential benefits for ETSA Utilities' circumstances. While PB is aware of the ENA guidelines consideration of monitoring technology, we note that the guidelines' approach is based on site-specific justification

ETSA Utilities identifies that the practicalities and effectiveness of CCTV monitoring are yet to be evaluated through trials at two sites. Given the considerable uncertainty surrounding the cost and the effectiveness of the proposed solution, PB does not consider the provision for a wide scale rollout is prudent.

PB accepts that a targeted approach to improving security at high-risk substation sites may be warranted where a site-specific need is identified, supported by a uniformly applied site-specific risk assessment, and where the business is applying an approach driven by security policy and based on a sound business case. However, this is not the situation that has been demonstrated through our review. Following our review and subsequent enquiries, we have concluded that, while addressing the security needs ETSA Utilities has identified is generally

224 ibid.
225 ibid.
226 ibid p. 7.
227 ENA National Guidelines for Prevention of Unauthorised Access to Electricity Infrastructure, ENA DOC 015-2006.

prudent, the efficiency of the scope of ETSA Utilities' proposed security fencing replacement program has not been demonstrated.

PB recommends a condition-based approach is followed that involves replacing fences in substandard condition at substations demonstrated to be high risk with high security replacement fencing. Other fencing condition matters should be addressed through replacement or modification (as appropriate) at substations assessed as low to medium risk.

Table 4.31 PB's recommended scope – substation security and fencing

Substation Category	Fence type	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Metropolitan							
High risk substations	High security	1.5	1.5	1.5	1.0	1.5	7.0
Poor condition Fences	New chain mesh	4.0	2.0	1.5	2.0	1.5	11.0
Medium condition fences	Upgrade existing fence	2.5	4.0	2.5	1.5	1.5	12.0
Non-metropolitan							
High risk substations	High security	-	-	-	-	-	-
Poor condition fences	New chain mesh	4.0	3.0	3.0	3.5	4.0	17.5
Medium condition fences	Upgrade existing fence	0.5	1.0	1.0	1.0	0.5	4.0
PB recommended (fence replacements)		12.5	11.5	9.5	9.0	9.0	51.5
CCTV installation		0.0	5.0	5.0	0.0	0.0	10.0
R&D		1.0	1.0	0.0	0.0	0.	2.0

Note: partial fence replacements are due to the conversion to financial year from the calendar year basis of ETSA Utilities AMP to the financial year basis of the submission.

Source: PB analysis

This approach essentially allows for:

- installing high security fencing at substations assessed as high risk
- installing new chain wire fences to replace the existing fences at substations assessed as low and medium risk where the fence condition is assessed as a high risk
- upgrading existing chain wire fences at substations assessed as low and medium risk where the fence condition is assessed as a medium risk
- installing CCTV at demonstrated high-risk installations following targeted R&D to demonstrate the business case.

PB has not applied separate criteria to metropolitan and non-metropolitan substation sites, as this is inherent in the locality, socio-economic, and site access factors considered in the

ENA methodology, as outlined by ETSA Utilities[228]. Table 4.31 outlines the results of applying the recommended strategy to ETSA Utilities' site replacement plans[229].

The capex resulting from the application of PB's recommended approach are set out in Table 4.32 below.

Table 4.32 PB's recommended base estimate – substation security and fencing ($k real 2008)

Substation category	Cost ($k per site)	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Metropolitan							
High risk sites	270[a]	405	405	405	270	405	1890
Poor condition fences	100[b]	400	200	150	200	150	1100
Medium condition fences	15[c]	38	60	38	23	23	180
Non-metropolitan							
High risk sites	270[a]	-	-	-	-	-	-
Poor condition fences	100[b]	400	300	300	350	400	1750
Medium condition fences	15[c]	8	15	15	15	8	60
Substation security							
CCTV installation	92[d]	-	460	460	-	-	920
R&D	50[d]	50	50				100
PB recommended (Total)		1,300	1,490	1,368	858	985	6,000

[a] based on high security fencing of a medium site (refer AMP 5.1.03, p.29)

[b] based on chain mesh fencing of a medium site (refer AMP 5.1.03, p.29)

[c] based on upgrading existing fence with bottom rails and tiger tape flat loops (refer AMP 5.1.03, p.15)

[d] refer AMP 5.1.03, p.29

Source: ETSA Utilities AMP 5.1.03 & PB analysis

As shown in Table 4.33 this results in an adjustment of 59% to ETSA Utilities base estimate for the substation security and fencing program.

Table 4.33 PB's recommended adjustment – substation fencing base estimate ($m real June 2008)

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	3.7	3.5	3.5	3.7	3.9	18.2
PB adjustment ($m)	(2.4)	(2.0)	(2.1)	(2.9)	(2.9)	(12.2)
PB recommendation	1.3	1.5	1.4	0.9	1.0	6.0

Source: ETSA Utilities Spreadsheet CX001 and PB analysis

Table 4.34 outlines the total adjustment to the capex portfolio, as calculated by ETSA Utilities' capital accumulation spreadsheet [230] and roll-up model[231]. These figures are

228 ibid., p. 14.
229 ibid., p. 24.
230 ETSA Utilities spreadsheet CX001 Summary Sheets version Opt10a (moderate), 1 June 2009.
231 ETSA Utilities Attachment E.1 SEM-Capex Model Ver 7.2.

inclusive of real escalation and exclude the overheads that are implicit in ETSA Utilities' base capex forecasts. Therefore they are consistent with the figures contained in the Regulatory Proposal.

Table 4.34 PB's recommended adjustment – Substation fencing inclusive of ETSA Utilities' real escalation

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	3.9	3.7	3.8	4.2	4.4	20.0
PB adjustment ($m)	(2.5)	(2.1)	(2.3)	(3.2)	(3.3)	(13.5)
PB recommendation	1.4	1.6	1.5	1.0	1.1	6.6

Source: ETSA Utilities Spreadsheets CX001, Capex SEM and PB analysis

4.3.6 Review of CBD aged asset replacement program

PB made a specific review of the CBD aged asset replacement program. Maunsell prepared the CBD Asset Management Plan to identify the asset replacement recommended for the CBD network over the period 2009 to 2020[232]. The plan essentially consolidates asset replacement information from ETSA Utilities' other AMPs.

The CBD aged asset replacement program intends to replace aged, obsolete and unsafe switchgear, cables and associated equipment in Adelaide's CBD. It is comprised of safety driven replacements of LV switchboards; 33 kV switchgear that cannot be operated due to safety bans; provision for additional duct/manhole installation owing to current overcrowding; fault level control to facilitate improved access to cable vaults; and cable replacements.

PB notes ETSA Utilities' statement that the safety risks associated with the CBD assets have been managed to date by safety bans on live switching, and on restricting access to manholes containing energised HV cable joints. This has resulted in the majority of CBD maintenance work taking place at night due to the need for planned outages[233]. However, the only economic rationale provided for the proposed replacement is a statement that the current scenario results in higher operational costs and reduced staff effectiveness associated with carrying out maintenance work at night[234]. Furthermore, despite the reliance on risk-based justification for the replacements, no specific risk assessments to demonstrate the need were included in the CBD AMP, and limited assessment is provided in the related AMPs. For example, the underground cables AMP[235] identifies the additional CBD duct capacity and aged cable/joint replacements as a strategic project that results in a low residual risk being achieved from the initial medium risk assessment.

ETSA Utilities identifies that the ducts, cables and joints replacements (comprising 53% of the proposed program expenditure) are expensive[236], and cites the increased operating cost associated with the current arrangements as justification for the proposal. No attempt has been made to quantify the potential reduction in operating and maintenance costs that would be avoided by the program, or to assess the value of the risk reduction gained against the high cost of the proposed mitigation measures. In meetings with ETSA Utilities PB was advised that detailed economic assessments have not been made for this project, as the

232 ETSA Utilities, AMP 2.1.07 CBD, February 2009, p. 8.
233 ibid., p. 5.
234 ibid.
235 ETSA Utilities AMP3.1.09 Underground Cables, February 2009, p. 35.
236 ibid., p.36

need was clear and the asset risk is unacceptable in the long term[237]. PB requested that a risk assessment and costing be provided to support the proposed aged asset replacement line items. In response ETSA Utilities identified that the risk posed with the current mitigation measures in place is medium in all cases[238], and therefore the project is a ‘discretionary’ project under its capital budgeting procedures[239]. While PB accepts the criticality of the Adelaide CBD load, and as such it is prudent to address safety issues that restrict the ability to operate or maintain this network, ETSA Utilities has been unable to demonstrate the cost or timing efficiency of the proposed solutions.

Given the large number of individual asset replacement decisions covered by the CBD aged asset replacement program and ETSA Utilities’ reliance on its risk assessment-based capital budgeting procedures to ensure the efficient timing of projects for each annual budget, PB recommends that a high level adjustment be made to the CBD aged asset replacement program based on ETSA Utilities’ historically accepted risk level[240]. This will essentially adjust for the discretionary portion of the proposed capex.

ETSA Utilities has prepared its capex forecast for the regulatory submission on the basis of addressing any risks above a ‘medium’ or 6.0 score. However, ‘micro’ risk levels of 6.5 and 6.4 have been accepted in its annual budget in 2008 and 2009 respectively[241]. Furthermore, ETSA Utilities has advised that equivalent ‘micro’ risk levels have not been considered in preparing its Regulatory Proposal[242]. PB notes ETSA Utilities’ statements that:

> The risk bands indicate the residual risk if ETSA Utilities were not to undertake the proposed works program in the year planned.
>
> Deferral of projects from the year planned would generally further raise the risk level.

PB considers that if ETSA Utilities’ historically acceptable micro risk level of 6.4 was applied to the current projects included in the forecast, an annual deferral of 40% of the expenditure in the discretionary risk band (i.e. 6.0–7.0) would result. PB recommends an annual deferral of 40% of the total CBD safety-related expenditure. Table 4.35 shows PB’s recommended adjustments to the proposed safety related replacements program capex.

Table 4.35 PB’s recommended adjustment – CBD-related replacements

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	7.3	10.2	11.1	11.8	11.8	52.2
% of expenditure deferred 1 year	40%	40%	40%	40%	40%	
Deferred expenditure	(2.9)	(4.1)	(4.4)	(4.7)	(4.7)	
From Previous Year	-	2.9	4.1	4.4	4.7	
PB Total adjustment ($m)	(2.9)	(1.1)	(0.4)	(0.3)	(0.0)	(4.7)
PB recommendation	4.4	9.0	10.7	11.5	11.8	47.4

237 Meeting with ETSA Utilities 13 August 2009.

238 ETSA Utilities SI229 EM95 CBD Project Appendices.

239 ETSA Utilities Capital Budgeting Procedures , 2008, p. 13.

240 We note that the AER’s benchmarking analysis indentifies that ETSA Utilities’ capex with respect to its asset base is lower than other Australian DNSPs and therefore consider that ETSA Utilities’ capital budgeting process has historically been effective in ensuring the efficient timing of projects.

241 ETSA Utilities Response to question PB.ETS.EM.62.

242 ETSA Utilities Response to question PB.ETS.EM.63, p. 1.

PB conducted a high level review of the remainder of the proposed safety related capex, noting that it includes safety related asset replacements primarily associated with the condition of assets or to address compliance issues. These include the ongoing asbestos removal, rectification of unsafe buildings and inadequate line clearances and substation lighting upgrades. Also included is the replacement and consolidation of three older substations with a number of known condition related safety issues and a ten year plan to replace mobile communications equipment that is no longer supported.

PB recognises that the major components of the remaining safety related expenditure are primarily asset replacements with a clear condition driver and on this basis considers that the expenditure is prudent.

In the case of the unsafe substations, PB identified the double counting of age based transformer, fencing and circuit breaker replacements included in ETSA Utilities original proposal that accounted for $9.3m (2008 dollars) of the proposed base asset replacement capex estimate[243]. On the basis that these replacements have been removed through PB's recommended adjustments to the asset replacement capex, and that the proposed unsafe substations replacement program is supported by a detailed options analysis, economic assessment, and prudent condition based drivers, we recommend that the unsafe substations replacement project is retained in the safety related capex and no further adjustment is recommended.

From our high level review of the remainder of the safety related expenditure program, PB notes that the step change in safety related expenditure relates mainly to a large number of safety related asset replacements that may have historically been classified as asset replacement expenditure. Notwithstanding the classification of the expenditure, we conclude that the remaining safety related expenditure is prudent and efficient.

4.3.7 Review of security of supply projects

PB made a specific review of security of supply projects. As noted in Section 4.1.1, ETSA Utilities has forecast a twelve-fold increase in its security of supply expenditure from an expected level of $12.8m in the current regulatory control period to $170.4m over the next regulatory control period. This expenditure mainly relates to:

- the Kangaroo Island undersea cable duplication and 66 kV backbone upgrade
- the network security project involving the construction of a new network operations centre, replacement of the SCADA Master Station and providing new network switching capability.

This section outlines PB's specific review of the Kangaroo Island undersea cable duplication and 66 kV backbone upgrade projects, and network control project. The remaining security of supply expenditure includes an increase in substation land acquisition expenditure that is consistent with the increase in capacity expenditure associated with new lines and substation sites therefore PB has not conducted a specific review of the proposed substation land expenditure.

243 ETSA Utilities response to question PB.ETS.EM.79 & 80

Kangaroo Island

The Kangaroo Island undersea cable duplication and 66 kV backbone upgrade comprise $94.5m or 55% of the total security of supply expenditure proposed for the next regulatory control period.

The undersea cable duplication has been proposed as a security of supply measure to address the risk associated with the failure of the undersea cable that supplies the island from the mainland, while the 66 kV network is intended to provide additional sub-transmission capacity, and improve the supply reliability on the island.

Following our review of ETSA Utilities' documentation for this project, PB has a number of specific concerns:

- ESCoSA specifically states that ETSA Utilities is not obliged to meet an n-1 criterion for Kangaroo Island[244]. Therefore the requirement for the duplication of the second undersea cable is not necessary to meet ETSA Utilities' capacity planning obligations during the next regulatory control period.
- ESCoSA identifies that the 450-minute SAIDI reliability target is expected to be met by using the existing generation capacity on Kangaroo Island[245]. This is supported by significant improvements in ETSA Utilities' SAIDI performance since its installation in 2006[246], and ETSA Utilities has reported a 2008 calendar year performance of 261 SAIDI minutes[247].
- ESCoSA states the 450 minute SAIDI target was intended to have the same effect as an n-1 criterion, and that a generation solution was preferable on the basis it would address 'both the possibility of failure of the undersea cable as well as the ongoing reliability problems of the Island' [248].

  Furthermore, PB notes the planned $3.6m augmentation of the generation plant over the next regulatory control period will take place to ensure the entire Kangaroo Island peak demand can be met by the generation plant[249]. As noted by ESCoSA, this effectively provides the equivalent of an n-1 criterion, while avoiding the need to duplicate the cable and the radial network on the mainland.
- ETSA Utilities states the capacity driven, undersea cable augmentation is not required until 2016, and that the capacity driven, 66 kV sub-transmission augmentation is not required until 2025[250].

In addition to ETSA Utilities' Kingscote Power Station, the Kangaroo Island Development Board has identified that there is at least an additional 6.4 MVA of private generation on the island, which is approximately equivalent to the maximum demand of the island[251]. A significant proportion of this capacity has been installed to provide standby power to an

244 ESCoSA 2008, *South Australian Electricity Distribution Service Standards 2010–2015*, *Final Decision*, November 2008, p. 62.
245 ibid.
246 ibid.
247 ETSA Utilities, AMP 2.1.03 Kangaroo Island Sub-Transmission Electricity Supply, p. 23.
248 ESCoSA 2008, *South Australian Electricity Distribution Service Standards 2010–2015, Final Decision*, November 2008, p. 62.
249 ETSA Utilities, PB.ETS.EM.45.46.47.48.49 KI Responses, response to PB.ETS.EM.47, p. 5.
250 ETSA Utilities, AMP 2.1.03 Kangaroo Island Sub-Transmission Electricity Supply, p. 19.
251 Wessex Consult 2009, An *Investigation into the Utilisation of End user Generation on Kangaroo Island*, January 2009, p. 2.

individual site in the event of a network outage. Given the high degree of private standby and primary generation currently in place, and the ability of the existing ETSA Utilities' Kingscote Power Station to meet the island's peak demand, PB considers that the risk of failure to the undersea cable is well mitigated.

In the Kangaroo Island AMP, ETSA Utilities raises two additional issues. Firstly those customers with loads over 90 kVA are required to contribute to the cost of connection under the South Australian Electricity Supply Distribution Code. ETSA Utilities notes there are a number of potential customers with a total demand of 2.4 MVA who have enquired about connection but not proceeded on the basis of the augmentation cost when compared to a typical metropolitan connection[252]. With regard to this issue, ESCoSA states:

> The Kangaroo Island network is a very extensive network ….supporting a relatively small customer base. Inevitably, a new customer with a large peak demand may impose significant augmentation costs on the system. The Commission believes that augmentation charges for such a customer should be reflective of those costs.[253]

On this basis, the decision of customers not to proceed with connection owing to the high augmentation costs is consistent with the intent of providing a degree of cost reflectivity in connection pricing for new customers. Therefore the potential for new customers to incur high connection costs does not justify the need for the project.

The second issue ETSA Utilities highlighted is the high cost associated with supplying the island in the event of a prolonged outage of the submarine cable, which ETSA Utilities estimates to be $20.7m p.a.[254] [255]. While ETSA Utilities has derived an annual cost for supplying the island in the event of a 'worst case' 12 month outage, no attempt has been made to incorporate this cost into an economic analysis of the four options presented in the AMP. PB considers the cost of emergency supply should be used as a risk-weighted input to the options analysis to determine the highest NPV option.

ETSA Utilities presents four options for the long-term development of the Kangaroo Island network over a 30-year planning horizon. Two options are presented on the basis of a very high 7.0% annual load growth rate, similar to the Goolwa area, and two options are based on the historical growth rate of 3.3%[256]. Given that providing capacity for speculative high load growth scenarios is beyond ETSA Utilities' planning obligations, PB has only considered the options based on the historical load growth rate. These options comprise:

i) a capacity-driven scenario, where the cable is required in 2016, and the sub-transmission augmentation which is required in 2025

ii) a security of supply driven scenario where the cable is installed in 2012, with the sub-transmission augmentation following in 2014.

The scope, cost and timing of these options are summarised in Table 4.36.

252 ETSA Utilities, AMP 2.1.03 Kangaroo Island Sub-Transmission Electricity Supply, p. 10.
253 ETSA Utilities 2004, *Kangaroo Island Electricity Reliability Service Standards Draft Final Determination*, June 2004, p. 20.
254 ETSA Utilities, AMP 2.1.03 Kangaroo Island Sub-Transmission Electricity Supply, p. 12.
255 This cost includes fuel, maintenance, additional mobile generator sets to facilitate maintenance, additional fuel tanks and additional environmental control costs.
256 ETSA Utilities, AMP 2.1.03 Kangaroo Island Sub-Transmission Electricity Supply, p. 18.

Table 4.36 Kangaroo Island network development options ($m real 2008)

Expenditure category	Cost ($m)	Capacity driven	Security of supply driven
KI generation capacity	$3.6[a]	2010	2010
American River 33 kV voltage regulation	$1.5[a]	2012	2012
Undersea cable and associated 66 kV line works	$53.9	(2016)	2012
66 kV sub transmission augmentation	$32.4	(2025)	2014
Second undersea cable	$53.9m	(2034)	(2034)

[a] included as a separate project in capacity expenditure (Project No. 1058 & 1404 in ETSA Utilities spreadsheet SI13)

Source: ETSA Utilities AMP 2.1.03

ETSA Utilities has selected the security of supply driven option on the basis of mitigating the cost of supplying the island via generation in the event of a cable failure. PB notes that despite a fully costed long-term plan for each of the options, no economic analysis is presented to demonstrate the selected option is the highest NPV option.

Therefore, PB has undertaken an NPV analysis of the two options as proposed by ETSA Utilities[257]. We have also included the probability-weighted cost of the emergency supply solution based on the two known failures of the previous cable in its approximately 35-year service life (1987[258], 2001[259]). The probability-weighted cost of emergency supply has been applied annually for both options until the second cable has been installed. We have also included an assessment of the sensitivity of the result to changes in discount rate, actual emergency supply costs, and risk levels as summarised in Table 4.37.

Table 4.37 PB's recommended adjustment – security of supply

Scenario	Discount rate	NPV of costs over 30 years ($m)	Cost to supply ($m p.a.)	Likelihood of extended failure	Prob-weighted cost ($m p.a.)
0% Discount rate					
Capacity driven	0%	-154.7	20.7	6%	1.18
Security driven	0%	-161.5	20.7	6%	1.18
10% Discount rate					
Capacity driven	10%	-107.5	20.7	6%	1.18
Security driven	10%	-115.1	20.7	6%	1.18
100% Discount rate					
Capacity driven	100%	-15.0	20.7	6%	1.18
Security driven	100%	-23.0	20.7	6%	1.18
Emergency supply costs					
Capacity driven	10%	-126.3	76.6	6%	4.38

257 ibid., p. 19.
258 ibid., p. 11.
259 PB Associates 2004, *Kangaroo Island Reliability Performance Review*, June 2004, p. 23.

Scenario	Discount rate	NPV of costs over 30 years ($m)	Cost to supply ($m p.a.)	Likelihood of extended failure	Prob-weighted cost ($m p.a.)
Security driven	10%	-126.3	76.6	6%	4.38
Probability					
Capacity driven	10%	-126.3	20.7	21%	4.38
Security driven	10%	-126.3	20.7	21%	4.38

Source: PB analysis

PB notes that regardless of the discount rate chosen, the capacity-driven scenario is the highest NPV option over 30 years in all cases. Furthermore, the emergency supply costs during a failure would have to exceed $76.6m, or the likelihood of an extended failure needs be higher than 21% (1 in 5 year) probability for the security of supply driven solution to be preferred.

PB notes ETSA Utilities is not in breach of any mandatory security of supply requirement for Kangaroo Island under the current arrangements, and that ETSA Utilities' proposed security of supply driven solution is not the least cost option to meet the capacity needs of the island, Therefore, PB recommends that the proposed security of supply driven Kangaroo Island cable duplication project, and 66 kV sub-transmission network upgrade, is removed from ETSA Utilities' capex proposal and replaced by the capacity-driven option. This results in a $94.5m reduction in ETSA Utilities' total capex due to the deferral of the cable duplication project until 2016, and the deferral of the 66 kV sub-transmission network augmentation to 2025, where they are respectively forecast to be required for capacity reasons.

Table 4.38 shows PB's recommended adjustment for the proposed Kangaroo Island project capex.

Table 4.38 PB's recommended adjustment – Kangaroo Island base estimate ($m real June 2008)

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	-	27.0	43.2	16.2	-	86.3
PB adjustment ($m)	-	(27.0)	(43.2)	(16.2)	-	(86.3)
PB recommendation	-	-	-	-	-	-

Source: ETSA Utilities Spreadsheet CX001 and PB analysis

Table 4.39 outlines the total adjustment to the capex portfolio, as calculated by ETSA Utilities' capital accumulation spreadsheet [260] and roll-up model[261]. These figures are inclusive of real escalation and exclude the overheads implicit in ETSA Utilities' base capex forecasts. Therefore they are consistent with the figures contained in the Regulatory Proposal.

260 ETSA Utilities spreadsheet CX001 Summary Sheets version Opt10a (moderate), 1 June 2009.
261 ETSA Utilities Attachment E.1 SEM-Capex Model Ver 7.2.

Table 4.39 PB's recommended adjustment – Kangaroo Island inclusive of ETSA Utilities' real escalation

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	-	28.7	47.3	18.5	-	94.5
PB adjustment ($m)	-	(28.7)	(47.3)	(18.5)	-	(94.5)
PB recommendation	-	-	-	-	-	-

Source: ETSA Utilities Spreadsheets CX001, Capex SEM and PB analysis

4.3.8 Review of the network control project

PB made a specific review of the network control project, which comprises $50.1m or 29% of the total security of supply expenditure proposed for the next regulatory control period.

The project comprises building an additional network operations centre (NOC), providing additional remote switching capabilities in areas of high bushfire risk, as well as upgrading ETSA Utilities' SCADA master station and distribution management system (DMS) applications. The proposed expenditure is based on portions of the scope outlined in a report prepared by KEMA[262] for ETSA Utilities. PB has reviewed the supporting documentation, and made enquiries with ETSA Utilities. Following this review PB has a number of concerns regarding the proposed capex, specifically that:

- KEMA's estimates for labour are mainly associated with ETSA Utilities' operational labour, which is included in the proposed opex forecast[263].
- KEMA's estimates for the Disaster Recovery Control Centre (the existing NOC) are stated to include computer hardware, software, outside providers' services, WAN, and voice communication equipment[264]. However, ETSA Utilities has included approximately $3m to replicate IT, telecommunications and SCADA systems at an existing disaster recovery site before building the new NOC[265].
- KEMA's estimates for the new NOC are stated to include land costs; however, ETSA Utilities has advised that the NOC[266] will be constructed on land ETSA Utilities owns[267].

These issues are discussed further in the following sections. The provision of SCADA switching capability at high bush fire risk boundaries was demonstrated to be efficient on the basis of the potential loss of supply to approximately 94,000 customers who reside outside the high bushfire risk area boundary.

Operational staff costs

The KEMA report identifies ETSA Utilities' resourcing requirements of approximately 6 to 7 FTE engineering staff, 55 to 67 FTE operational staff, and 3 to 5 FTE project management staff over the 2011-2014 period to deliver the proposed program. PB notes that ETSA

262 KEMA, November 2008, Investigation and Recommendation Report into ETSA Utilities' SCADA/DMS Requirements 2009 to 2019.
263 ETSA Utilities response to question PB.ETS.EM.93
264 ibid., p. 11.
265 ETSA Utilities response to question PB.ETS.EM.92, p. 1.
266 KEMA, November 2008, Investigation and Recommendation Report into ETSA Utilities' SCADA/DMS Requirements 2009 to 2019, p. 10.
267 ETSA Utilities response to question PB.ETS.EM.90

Utilities has proposed completing only a proportion of the total scope outlined in the KEMA report during the next regulatory control period.

The bulk of the resourcing requirements relate to engineering and operational staff costs, such as field services officers, network controllers and network dispatchers, which are included in the opex forecast. In response to our enquiries, ETSA Utilities has identified that the staff costs associated with the network operations centre should be allocated in the forecast opex only[268]. On this basis, PB considers that including operational staff costs in the capex for the project effectively double counts staff costs included in the opex proposal. Therefore PB recommends these costs are removed from the forecast capex proposal.

Based on the minimum proportion of FTE engineering, operational and project management resources identified in the KEMA report, PB has calculated that approximately 80% relates to operational staff. This indicates that approximately 80% of the staff costs included in the KEMA report estimates are related to opex items. Therefore, PB recommends reducing the labour component of the network control projects by 80% to reflect the double counting of operating staff costs in the proposed capex. This results in a reduction of $6.9m (real 2008) to ETSA Utilities' base labour estimate for this project.

Disaster recovery IT expenditure

PB notes that $3.0m IT capex for the establishment of a disaster recovery facility at a third party site is outlined in the KPMG report[269]. The scope of this project involves the replication of the existing NOC capability, including the existing IT, communications and SCADA systems at a third party site in Kidman Park.

Whilst PB accepts the need to establish a disaster recovery site, we note that this project replicates the establishment of a secondary NOC and retrofit of the existing NOC as a disaster recovery control centre. The scope of the IT project includes the replication of a number of existing systems, such as the Citect SCADA system, which will be made redundant under the proposed Network Control Project within 2–3 years. We also note that the $3.0m IT capex project was intended to be implemented in six months[270], and was originally scheduled to occur in the second half of 2009[271] to mitigate against a repeat of the outage that affected the existing NOC on 2 April 2008[272]. The project has subsequently been deferred by one year, and is now scheduled to occur at the start of the next regulatory control period.

PB also notes that the establishment of the emergency backup NOC at Marleston was identified in the 1999 Citect SCADA system business case[273] and the absence of a secondary SCADA equipped backup NOC site has been acceptable to ETSA Utilities since this time. Therefore, the risk associated with the lack of a SCADA equipped disaster recovery site has not fundamentally changed over the current regulatory control period and, on this basis, when the site is established appears to be discretionary.

Despite these issues, PB considers the provision of a disaster recovery facility for the NOC is prudent and consistent with good electricity industry practice, and hence the interim solution provided by the IT project is also prudent as it is necessary to provide additional

268 ETSA Utilities response to question PB.ETS.EM.93
269 KPMG 2008, *Assessment of Disaster Recovery Options for NOC Operations*, July 2008, p. 11.
270 ibid., p. iii.
271 ETSA Utilities spreadsheet IT040, 41 NOC DR IT Infrastructure.
272 KPMG *Assessment of Disaster Recovery Options for NOC Operations*, July 2008, p. 4.
273 ETSA Utilities, Business Case NOC SCADA System Project, May 1999, p.5 (provided in response to question PB.ETS.EM.91).

capacity during emergency events before the NOC is completed in 2013. However, the IT project replicates much of the functionality the new NOC will deliver, and therefore provides a limited life of 2–3 years before the SCADA/DMS upgrades will make many of the systems obsolete. Given that ETSA Utilities has historically accepted the risk associated with the lack of a SCADA equipped disaster recovery control centre, and has planned NOC/SCADA upgrades to address these risks in the next regulatory control period, PB considers the additional $3m expenditure on the IT disaster recovery project arises from limited forward planning of the NOC capacity and redundancy requirements. Therefore, we conclude this is an inefficient cost and recommend that it is removed from ETSA Utilities' capex proposal.

Inclusion of land acquisition costs

The KEMA report states that the acquisition of land is included in the cost of the NOC construction estimate. PB notes the new NOC building would be constructed on a site ETSA Utilities owns, and therefore should not be included in ETSA Utilities' capex proposal[274]. ETSA Utilities has advised the NOC will occupy 720m^2 of an existing site and that the value of the land is considered to be $160k[275]. This estimate is broadly consistent with the average land costs advised by ETSA Utilities in other supporting documentation[276]. On this basis, and noting the relatively minor cost, PB accepts ETSA Utilities' estimate, and recommends a $160k reduction in its capex proposal for this project.

PB recommendation for network control project costs

Table 4.40 shows PB's recommended adjustments to ETSA Utilities' proposed capex for the network control project.

Table 4.40 PB's recommended adjustment – network control base estimate ($m real 2008)

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposed	7.0	11.0	13.3	9.1	5.6	46.0
Adjustment for operational staff costs	(1.7)	(1.5)	(1.2)	(1.3)	(1.2)	(6.9)
Adjustment for IT disaster recovery	(3.0)					(3.0)
Adjustment for land costs	(0.2)					(0.2)
PB recommendation	2.1	9.5	12.1	7.7	4.5	35.9

Source: ETSA Utilities Spreadsheets CX001, Capex SEM and PB analysis

Table 4.41 outlines the total adjustment to the capex portfolio, as calculated by ETSA Utilities' capital accumulation spreadsheet [277] and roll-up model[278]. These figures are inclusive of real escalation, and exclude the overheads that are implicit in ETSA Utilities' base capex forecasts. Therefore they are consistent with the figures contained in the Regulatory Proposal.

274 ETSA Utilities response to question PB.ETS.EM.90.
275 ibid.
276 ETSA Utilities spreadsheet CX067 Land Valuation.
277 ETSA Utilities spreadsheet CX001 Summary Sheets version Opt10a (moderate), 1 June 2009.
278 ETSA Utilities Attachment E.1 SEM-Capex Model Ver 7.2.

Table 4.41 PB's recommended adjustment – network control inclusive of ETSA Utilities' real escalation

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	7.3	11.8	14.5	10.1	6.4	50.1
PB Adjustment for operational staff costs	(1.8)	(1.7)	(1.4)	(1.6)	(1.4)	(7.9)
PB Adjustment for IT disaster recovery [a]	(3.3)					(3.3)
PB Adjustment for land costs [a]	(0.2)					(0.2)
PB recommendation	2.0	10.1	13.1	8.6	5.0	38.7

[a] escalated in proportion to the 8.8% total escalation in ETSA Utilities proposed costs from 2008 base estimate.

Source: ETSA Utilities Spreadsheets CX001, Capex SEM and PB analysis

4.3.9 PB assessment and findings

PB's has reviewed ETSA Utilities' non-demand driven capex proposal and made a number of key observations and findings.

PB's main observations are:

i) ETSA Utilities is proposing an overall real increase of 223% in non-demand driven capex.

ii) The major contributor to the increase is a 203% increase in replacement capex, accounting for $466.8m of the proposed $852.9m non-demand driven capex, a further $131.0m relates to safety driven capex, which is mainly asset replacement.

iii) ETSA Utilities has proposed a change in its asset management from fix-on-failure with the effective use of risk mitigation measures to more extensive condition monitoring.

iv) Asset replacement expenditure is determined by ETSA Utilities' revised approach to asset management that considers the outcome of its risk assessment process, the condition of assets and the age of assets.

v) The Kangaroo Island and Network Control security of supply projects account for $144.6m of the proposed expenditure and relate mainly to the duplication of existing assets to provide redundant capacity in the event of a failure.

PB main findings are:

i) ETSA Utilities was unable to demonstrate that the strategy underpinning the $467m asset replacement capex proposal is more efficient than its historical approach to asset management.

ii) The detailed assessment of risk within a project or program is simplistic and does not demonstrate efficient expenditure. In some cases the risk is arbitrarily related to asset age, which significantly overstates the level of replacement capex required.

iii) The cost-estimating process applied to derive the majority[279] of ETSA Utilities' asset replacement expenditure is based on reasonable, low level, unit cost build-up from the quantities identified in the AMPs, is transparently applied and appropriate for the purposes of forecasting ETSA Utilities' non-demand driven asset replacement expenditure.

iv) ETSA Utilities' proposed network asset replacement program incorporates a large number of age-based risk assessments and age-based models to forecast capex over the next regulatory control period. On this basis, PB has recommended adjustments totalling $119.4m arising from our specific reviews of ETSA Utilities' proposed network asset replacement forecast and a further general adjustment totalling $108.3m to reflect the existence of similar deficiencies that have been noted in a high level review of the remainder of the replacement portfolio.

v) ETSA Utilities has proposed onerous security fencing requirements that exceed normal industry practice and ETSA Utilities' obligations under the electricity regulations[280]. Furthermore, ETSA Utilities has proposed to apply these guidelines retrospectively to all metropolitan and a large number of non-metropolitan substations. PB has recommended a reduction of $13.5m to the safety-related replacement expenditure to reflect a revised scope.

vi) The risk threshold used to develop ETSA Utilities' capex proposal is lower than the level historically accepted in its annual budget. Because of all of the components of the CBD safety expenditure falling in ETSA Utilities' 'discretionary' risk band, PB has recommended an adjustment of $ 4.7m to reflect the higher risk threshold that has historically been accepted in ETSA Utilities' annual budget.

vii) ETSA Utilities was unable to demonstrate the security of supply driven need for the Kangaroo Island undersea cable. Therefore, PB has recommended deferring the cable until 2016 and deferring the 66 kV sub-transmission upgrade until 2025 in accordance with ETSA Utilities' forecast capacity requirements for the island. This results in a reduction of $94.5m to ETSA Utilities' proposed security of supply capex for the next regulatory control period.

viii) The network control project cost estimate includes a large proportion of operational labour covered by ETSA Utilities' normal opex and an allowance for the procurement of land that is not required. Furthermore, the relocation of the network operations centre to a new site in 2013 replicates the scope of the IT disaster recovery project to be completed in 2010. PB has recommended an adjustment of $3.3m to account for these additional costs and inefficiencies.

4.3.10 PB recommendations

Based on the findings of our review as discussed above, PB recommends the revised non-demand driven capex as set out in Table 4.42

279 PB notes that approximately $79.9m of unplanned asset replacement was forecast outside this process on the basis of an unreasonable extrapolation of historical trends. PB has recommended adjustments associated with this specific deficiency in our review of the network asset replacement program.

280 South Australia Electricity (General) Regulations 1997, Schedule 4- Requirements for substations.

Table 4.42 PB's recommended non demand driven capex adjustments

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	129.6	178.7	207.0	179.8	157.7	852.9
PB adjustments for asset replacement						
Table 4.15 Unplanned lines	(2.8)	(4.0)	(5.2)	(6.3)	(7.5)	(25.6)
Table 4.17 Circuit breakers	(5.8)	(7.9)	(8.8)	(7.7)	(6.5)	(36.7)
Table 4.19 Power transformers	(4.3)	(3.9)	(4.2)	(2.3)	(2.7)	(17.5)
Table 4.24 Poles	(4.0)	(4.2)	(4.4)	(4.6)	(4.7)	(22.0)
Table 4.27 Conductor	(2.5)	(3.4)	(4.3)	(3.9)	(3.5)	(17.7)
Table 4.29 General adjustment	(16.5)	(21.1)	(23.8)	(23.4)	(23.4)	(108.3)
PB adjustments for safety						
Table 4.34 Fencing and security	(2.5)	(2.1)	(2.3)	(3.2)	(3.3)	(13.5)
Table 4.35 CBD safety	(2.9)	(1.1)	(0.4)	(0.3)	(0.0)	(4.7)
PB adjustments for security of supply						
Table 4.39 Kangaroo Island	-	(28.7)	(47.3)	(18.5)	-	(94.5)
Table 4.41 Network control	(5.3)	(1.7)	(1.4)	(1.6)	(1.4)	(11.4)
PB adjustment for escalation						
Escalation	(5.1)	(5.9)	(6.3)	(6.5)	(6.1)	(29.9)
PB recommendation	77.9	94.6	98.6	101.6	98.6	471.2

4.4 Summary of findings and recommendations

This section presents a summary of PB's principal findings and recommendations relating to ETSA Utilities' system capex for the next regulatory control period. PB's recommended system capex is set out in Table 4.43

Major findings

ETSA Utilities has proposed a 126% real increase in gross system capex

ETSA Utilities has forecast that its gross system capex[281] for the next regulatory control period will be \$2,310m[282]. This represents a real increase of 126% over current period gross system capex of \$1,020m.

Capital governance is consistent with good electricity industry practice

ETSA Utilities has a well-developed documentation framework that demonstrates thorough capital governance practices. ETSA Utilities' capital investment and budgeting is audited annually, with no material issues noted in the February 2009 audit[283]. PB has concluded that ETSA Utilities' capital governance framework is generally in accordance with the principles of good asset management, and good electricity industry practice.

281 Gross capex is exclusive of customer contributions, while net capex is inclusive of customer contributions.
282 Excluding superannuation and equity raising costs.
283 KPMG 2009, *Internal Audit Report of Capital Investment and Budgeting*, February 2009.

Risk assessment practices do not support project prioritisation

The coarseness in the application of the risk assessment procedures at a project level does not support the consistent ranking of projects and analysis of alternative options in the medium term and this influences the identification of capital works priorities for the next regulatory control period.

Demand driven capex

Demand driven capex is proposed to increase by 93% in real terms

ETSA Utilities has forecast that its demand driven capex will be $1,457m over the next regulatory control period, which represents a 93% real increase over the current period demand driven capex of $647m. Of this total, proposed capacity expenditure totals $776m, which is a real increase of 266% from $212m in the current period, and customer connection expenditure totals $681m, which is a real increase of 25% from $544m in the current period.

Planning criteria are aligned with good electricity industry practice

While ETSA Utilities' deterministic planning criteria are inherently conservative, as is their application, they are nonetheless typical of the broader industry practice. PB considers that ETSA Utilities' planning criteria are suitable for the purposes of forecasting its demand driven investment, and are appropriately applied through the planning process. Therefore, we have concluded that ETSA Utilities' planning criteria and their application to planning demand driven sub-transmission and zone substations is in accordance with good electricity industry practice

The demand forecast is consistently applied

ETSA Utilities consistently applies its medium growth, spatial demand forecast in identifying the efficient timing of capacity capex projects, and in doing so considers feeder transfers and the use of mobile substations in accordance with its planning criteria to determine the timing for the projects.

Options analysis is not formally documented

ETSA Utilities considers a reasonable range of options in its capacity planning decisions; however, limited formal documentation is prepared before the business case. Despite the absence of formal business case documentation until close to the approval for project expenditure, the options analysis for the reviewed network augmentation projects supported the proposed solution.

Non-network alternatives and demand management opportunities are considered and pursued

ETSA Utilities has evidenced the active development and implementation of demand management practices to proactively manage a reduction in expected peak demand through initiatives such as its direct load control trials of residential air conditioning. Non-network solutions have been selected for the Pinnaroo peak lopping power station project[284], and considered as options to alleviate other network constraints. ETSA Utilities evaluates the efficiency of proposed non-network solutions against the benefit of deferring network augmentation. Non-network solutions must be demonstrated to be more efficient than

284 ETSA Utilities, Attachment E.9 AMP1.1.01 Distribution System Planning Report 2010 to 2020, AMP.1.1.01, May 2009, p. 122.

network augmentation options to become the preferred solution. On this basis ETSA Utilities consideration of non-network solutions is consistent with good electricity industry practice.

The LV network capacity upgrade program is neither prudent nor efficient

The risk assessment for the LV network capacity upgrade program overstates the risk, and the underlying analysis does not support the full scope of the proposed program. Hence PB has concluded that the proposed LV network capacity upgrade program capex is not prudent or efficient, and has recommended a $102.1m reduction to the proposed capex.

Customer connection expenditure includes an unsupported contingency

In addition to the forecast of known major customer connections, ETSA Utilities has included an unsupported contingency allowance for 'unidentified projects' over the next regulatory control period. Therefore PB has concluded the proposed capex for major customer connections is not prudent or efficient, and has recommended a $31.0m reduction to the proposed capex.

Non-demand driven capex

Non-demand driven capex is proposed to increase by 223% in real terms

ETSA Utilities has forecast that its non demand driven capex will be $853m over the next regulatory control period, which represents a 223% increase over current period capex of $264m. This expenditure consists of:

- asset replacement totalling $467m, which is a real increase of 203% over current period expenditure of $154m
- safety expenditure totalling $131m, which is a real increase of 591% over current period expenditure of $19m
- security of supply expenditure totalling $170m, which is a real increase of 1,236% over current period expenditure of $13m
- other sundry remaining categories totalling $85m, which is a real increase of 8% over current period expenditure of $78m

The efficiency of ETSA Utilities' revised asset management approach has not been demonstrated

ETSA Utilities has proposed a change from a fix-on-failure approach with the effective use of risk mitigation measures, to a more extensive condition monitoring approach. PB found that the proposed asset replacement scope also included additional age and risk-based components are not supported by known asset condition or failure history. Therefore PB has concluded that ETSA Utilities was unable to demonstrate that the strategy underpinning the $467m asset replacement capex proposal is more efficient than its historical approach.

Asset replacement expenditure is not efficient

ETSA Utilities' proposed network asset replacement program incorporates a large number of age-based risk assessments, and age-based models, to forecast replacement capex over the next regulatory control period. ETSA Utilities' assessment of the risk, and the basis of its age-based replacement proposals could not be demonstrated to be efficient, and PB has recommended a $228m adjustment to the proposed capex.

Security and fencing program expenditure is not efficient

ETSA Utilities has proposed to retrospectively apply onerous substation security fencing requirements that exceed industry practice, and ETSA Utilities' obligations under the electricity regulations. The application of the ENA guidelines and the supporting site risk analysis does not support the scope proposed by ETSA Utilities for high security fencing, and accordingly PB recommends a reduction of $13.5 to the safety-related replacement capex.

CBD safety-related asset replacement expenditure is not efficient

The risk threshold used to develop ETSA Utilities' capex proposal is lower than the level historically accepted in ETSA Utilities' annual budget. The economic justification for adopting the lower risk threshold has not been demonstrated and the efficient timing of the individual asset replacements covered by this program has not been demonstrated. Under ETSA Utilities' risk assessment practices this expenditure falls into its 'discretionary' risk band, and accordingly PB has recommended an adjustment of $ 4.7m to reflect the higher risk threshold that has historically been accepted in ETSA Utilities' annual budget.

Kangaroo Island security of supply expenditure is not prudent

ETSA Utilities was unable to demonstrate the security of supply driven need for the Kangaroo Island undersea cable. PB has recommended that the cable is deferred until 2016, and the 66 kV sub-transmission upgrade is deferred until 2025 in accordance with ETSA Utilities' forecast capacity requirements for the island. This reduces ETSA Utilities' proposed security of supply capex for the next regulatory control period by $94.5m.

Network control security of supply expenditure includes double counted costs

The network control project cost estimate includes a large proportion of operational labour that is covered by ETSA Utilities' normal opex, and an allowance for the procurement of land that is not required. Furthermore, the relocation of the network operations centre to a new site in 2013 replicates the scope of the IT disaster recovery project to be completed in 2010. PB recommends an adjustment of $11.4m to account for these double counted costs and inefficiencies.

Recommendations

PB recommends that ETSA Utilities' proposed system capex allowance for the next regulatory control period should be adjusted as shown in Table 4.43 below. PB notes that ETSA Utilities' proposed system capex represents a real increase of 126% over system capex in the current period, while PB's recommended system capex represents a 68% real increase over current period system capex.

Table 4.43 PB's recommended system capex

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Capacity						
ETSA Utilities Proposal	146.6	194.4	147.6	144.6	142.6	775.7
PB adjustment[a]	(26.50)	(29.80)	(28.10)	(28.90)	(29.10)	(142.30)
PB recommendation	120.1	164.6	119.5	115.7	113.5	633.4
Customer Connection						
ETSA Utilities Proposal	130.6	139.1	127.6	141.0	143.0	681.3
PB adjustment[a]	(14.2)	(13.9)	(12.9)	(14.1)	(14.8)	(69.8)
PB recommendation	116.4	125.2	114.7	126.9	128.2	611.5
Asset Replacement						
ETSA Utilities Proposal	79.7	91.4	96.8	98.9	99.9	466.8
PB adjustment[a]	(38.6)	(47.3)	(53.5)	(51.2)	(51.4)	(242.0)
PB recommendation	41.1	44.2	43.3	47.7	48.6	224.8
Security of supply						
ETSA Utilities Proposal	15.5	45.9	65.3	33.8	9.9	170.4
PB adjustment[a]	(5.9)	(31.3)	(49.7)	(20.8)	(1.9)	(109.7)
PB recommendation	9.5	14.6	15.5	13.0	8.0	60.7
Reliability						
ETSA Utilities Proposal	4.9	5.0	5.0	5.1	5.2	25.2
PB adjustment[a]	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(1.5)
PB recommendation	4.6	4.7	4.7	4.8	4.9	23.7
Safety						
ETSA Utilities Proposal	18.4	24.6	27.9	29.9	30.2	131.0
PB adjustment[a]	(6.3)	(4.6)	(4.1)	(5.1)	(4.8)	(24.9)
PB recommendation	12.1	20.0	23.8	24.8	25.4	106.1
Environmental						
ETSA Utilities Proposal	2.7	3.2	3.3	3.3	3.4	15.9
PB adjustment[a]	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.9)
PB recommendation	2.6	3.0	3.1	3.1	3.2	15.0
Network other						
ETSA Utilities Proposal	8.4	8.6	8.7	8.9	9.0	43.6
PB adjustment[a]	(0.5)	(0.5)	(0.5)	(0.6)	(0.5)	(2.6)
PB recommendation	7.9	8.1	8.2	8.3	8.5	41.0
Total system capex						
ETSA Utilities Proposal	406.8	512.1	482.3	465.4	443.3	2309.9
PB adjustment[a]	(92.4)	(127.7)	(149.5)	(121.2)	(102.9)	(593.7)
PB recommendation	314.4	384.4	332.8	344.2	340.3	1716.2
Total adjustment (%)	(23)	(25)	(31)	(26)	(23)	(26)

[a] Inclusive of escalation adjustment outlined in section 3.1.1

Source: PB analysis.

5. Non-system capex review

This section presents PB's review of ETSA Utilities' proposed non-system capex for the next regulatory control period. A high level review is provided, including an analysis of trends in expenditures. This is followed by an overview of the relevant processes and procedures, and discussion on specific expenditure categories. A summary of PB's findings and recommendations concludes the section.

5.1 High level review

ETSA Utilities has submitted a proposed non-system capex of $363.7m for the next regulatory control period, as summarised in Table 5.1.

Table 5.1 Proposed non-network capex for the next regulatory control period

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Information systems	28.8	25.2	22.0	27.9	45.7	149.7
Plant and tools/ furniture and fittings	14.8	13.9	13.7	16.1	14.1	72.6
Office equipment	-	-	-	-	-	0
Vehicles – heavy fleet	6.8	6.4	7.7	20.5	9.5	50.8
Vehicles – light fleet	7.4	2.3	12.0	5.3	15.3	42.4
Buildings	9.1	11.1	11.2	8.2	4.2	43.7
Land	0.8	-	3.7	-	-	4.5
Total non system	67.7	58.9	70.3	78	88.8	363.7

Note: PB notes equity raising costs are excluded from the non-network capex total . Review of equity raising costs is not within PB's scope of works.

Source: ETSA Utilities RIN, Capex (2.2.1)

For analysis purposes, PB has reorganised the expenditure in two expenditure categories and combined another two categories to form the following four expenditure categories:

- information systems
- plant and tools
- property
- fleet.

PB discussed this approach with ETSA Utilities who advised that the plant and tools/fittings and furniture expenditure category in ETSA Utilities RIN consists of $37.5m for plant and tools and $35.1m for fittings and furniture[285]. PB and ETSA Utilities agreed that the furniture and fittings expenditure component was to be included with property expenditure to allow an equitable comparison of current and forecast expenditures, as discussed further below.

285 PB.ETS.CA.9 plant and tools mapping.pdf, PB.ETS.CA.22 Plant and tools allocation.pdf, SI314 CA.22 PropertyExpenditureCategories.xls, CX068 Building Services Capital Plan for 2009 Working includes Reset version 30_04_2009.xls

Table 5.2 summarises ETSA Utilities' proposed non-system capex expenditure for the next regulatory control period in the four expenditure categories. PB notes the following assumptions used in the generation of Table 5.2:

- plant and tools expenditure figures for each year of the next regulatory control period have been taken from Table 6.40 of the Regulatory Proposal[286].
- property expenditure for each year of the next regulatory control period is the sum of expenditure for buildings, land, and furniture and fittings. Furniture and fittings expenditure was derived by subtracting yearly plant and tools expenditure from the total plant and tools/furniture and fittings expenditure proposed by ETSA Utilities for each year of the next regulatory control period.

Table 5.2 Proposed non-system capex for the next regulatory control period, grouped by PB expenditure category

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Non-system capex						
Information systems	28.8	25.2	22.0	27.9	45.7	149.7
Plant and tools	7.8	7.2	6.9	8.3	7.3	37.5
Property	17.0	17.8	21.7	15.9	11.0	83.4
Fleet	14.2	8.7	19.7	25.9	24.7	93.2
Total non system	67.7	58.9	70.3	78	88.8	363.7

Source: ETSA Utilities proposal for the regulatory control period 2010-15

Figure 5.1 below provides a pie chart showing the breakdown of ETSA Utilities' proposed expenditure for land and buildings in the next regulatory control period.

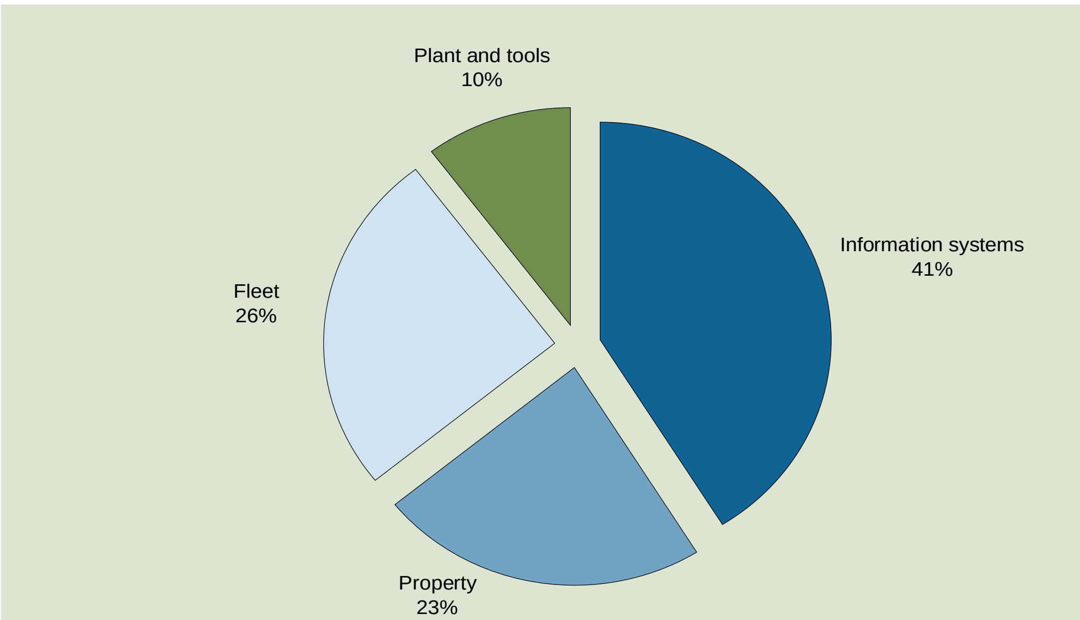

Figure 5.1 Forecast non-system capex by category, next regulatory control period

Source: PB Analysis

[286] ETSA Utilities Regulatory Proposal 2010-15, Table 6.40

PB reviewed historical variances between the ESCoSA allowance and ETSA Utilities' actual historical non-system capex. Figure 5.2 shows the actual non-system capex for the previous and current regulatory control period, the ESCoSA allowance for the current regulatory control period, and the forecast capex for the next regulatory control period.

ETSA Utilities' allowance for non-system capex set by the ESCoSA was $193.6 m for the current regulatory control period. ETSA Utilities invested a total of $182.7m on non-system capex in this period.

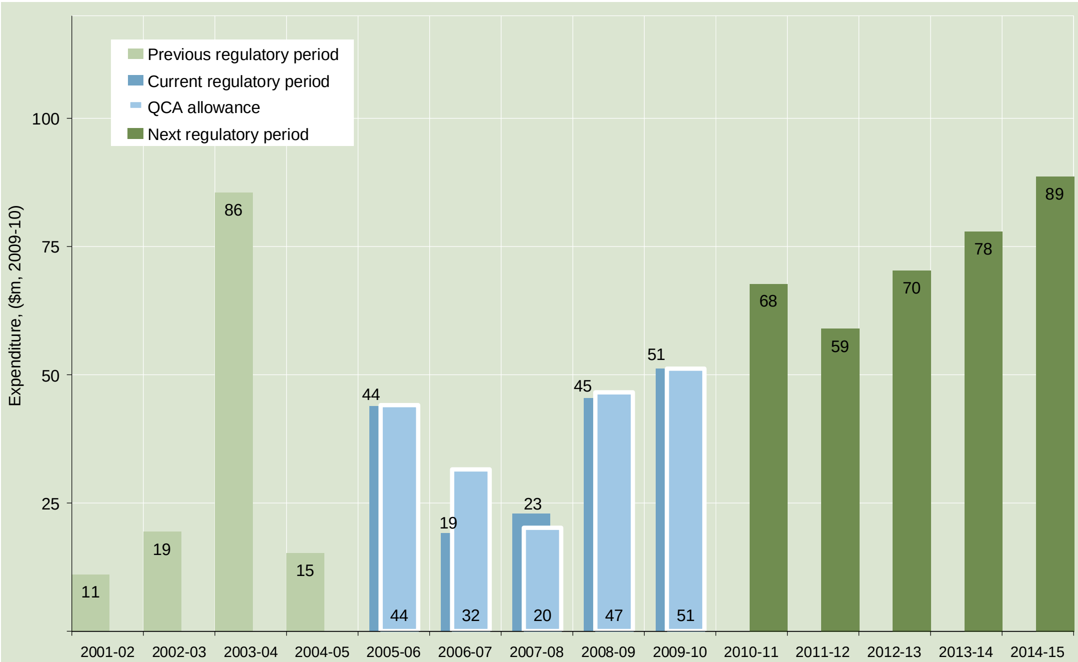

Figure 5.2 Comparison of total non-system capex

Source: ETSA Utilities Regulatory Proposal for 2010–2015

ETSA Utilities is requesting $363.8m for the next regulatory control period, an increase of 99% over actual expenditure in the current period. The trend in total non-system capex between 2001 and 2015 is illustrated in Figure 5.2.

Table 5.3 Change in non-system capex between the current and next regulatory control period by category

Regulatory category	Regulatory control period		Change (%)
	Current	Next	
Information systems	73.6	149.7	103
Plant and tools	33.7	37.5	11
Property	7.0	83.3	1090
Fleet	68.5	93.2	36
Total	182.7	363.8	99

Source: PB analysis.

It can be seen that the largest percentage increase in non-system capex for the next regulatory control period relates to property, where ETSA Utilities proposes to spend $83.3m, a 1090% increase from $7.0m in the current period.

Figure 5.3 Non-system capex by category from 2001 to 2015

Source: PB analysis.

5.2 Information systems

ETSA Utilities' expenditure category of information systems is a sub- category of non-system capex and does not include any further RIN sub categories of expenditure.

5.2.1 Proposed expenditure

Expenditure proposed for IT systems is $149.7m, a 103% increase from $73.6m in the current regulatory control period. In contrast to this, the proposed expenditure for the next regulatory control represents only a 15% increase compared with the previous regulatory control period, indicating there are some cyclic expenditures in this category.

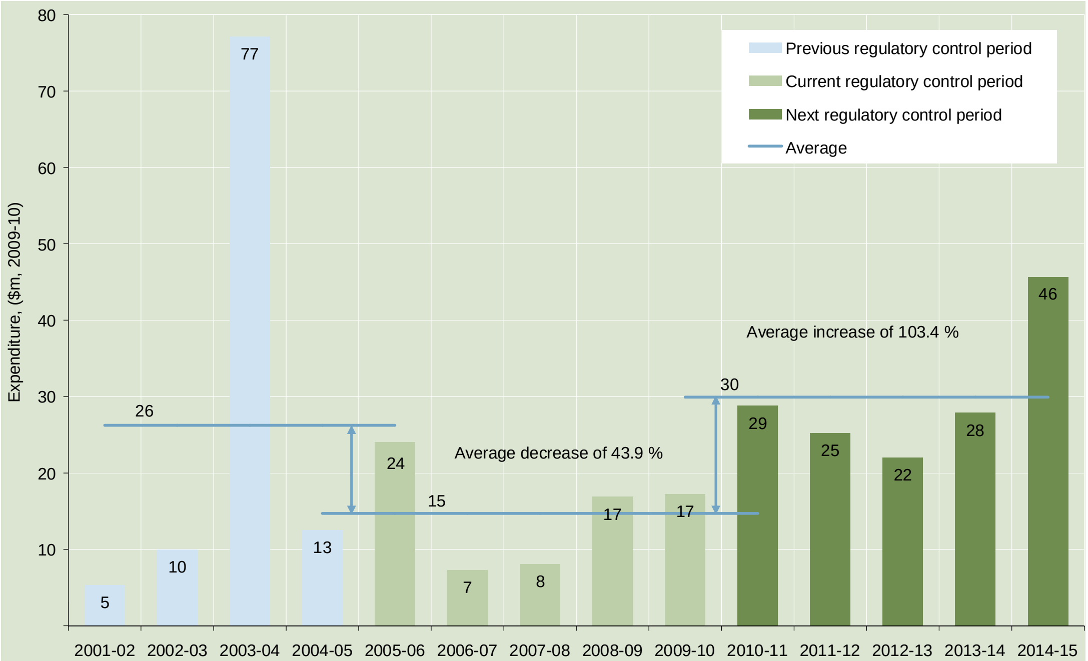

Figure 5.4 Capex for information systems

Source: PB analysis.

Figure 5.4 indicates that expenditure on information systems assets has increased between the current regulatory control period and that proposed for the next regulatory control period. It is noted that a significant proportion of expenditure in the previous period was due to the introduction of FRC in 2003. In the proposed period, the FRC system requires replacement and accounts for a significant proportion of expenditure[287] ($32m).

5.2.2 Drivers

The increase in non-network capex for information systems is driven mainly by an increase in[288]:

- uptake of IT systems by current staff
- FTEs in the proposed regulatory control period
- capability driven by business need[289].

ETSA Utilities has undergone significant employee growth in the current period and considers the expected uptake of IT systems by current staff as a significant driver for information systems growth in its own right.

5.2.3 Policy and procedures

ETSA Utilities' IT policy specifies an n-1 approach to applications and systems upgrades[290]. This entails keeping systems and applications at one version behind current versions. ETSA Utilities has established the ITCC (Information Technology Collaborative Committee) tasked

287 CX053 ETSA Utilities IT Strategy 2009-2015 v2.0 Approved.pdf.
288 CX053 ETSA Utilities IT Strategy 2009-2015 v2.0 Approved.pdf, p. 2, p. 6-19.
289 CX053 ETSA Utilities IT Strategy 2009-2015 v2.0 Approved.pdf, p. 29.
290 S129 PB.ETS.CA.6.-IT Principles v1.0.pdf.

with ensuring IT alignment with the business and ranking IT projects to provide greatest benefit to ETSA Utilities as a whole[291]. ETSA Utilities' IT department has documented underlying principles for sound IT investments[292].

5.2.4 PB assessment and findings

ETSA Utilities' IT strategy[293] divides the expenditure into two components:

- core systems and maintenance
- business driven initiatives

The core systems and maintenance component includes 'business as usual" expenditure – upgrades to existing systems. This component accounts for $90.9m[294] of the total information systems expenditure proposal. The major items are[295]:

- SAP and GIS
- infrastructure upgrades
- application and infrastructure enhancements
- IT peripherals
- major contracts (Microsoft, SAP, Citrix)
- expanding use of existing systems and new growth
- new and replacement of fleet technology.

The expanding use of existing systems and new contractor/employee growth account for $10.9m increased expenditure[296]. ETSA Utilities has examined the vendor roadmaps and have provided formal vendor costing estimates for upgrades planned for the next period[297]. ETSA Utilities procurement of IT related expenditures include options analysis. Specifically, decisions are based on examining existing vendor solutions versus current market options. This is evident in the recent acquisition of e-recruitment software where the business case favoured an alternative vendor over the incumbent (SAP)[298]. PB notes that ETSA Utilities has undergone a significant growth in the current regulatory period and the IT department has created IT strategies to manage new and existing priorities[299]. PB considers ETSA Utilities IT strategy appropriate for their business at this time.

PB considers the current period expenditure of $73.6m comparable with the proposed business-as-usual expenditure of $90.5m when taking into account expected growth within the currently employed staff and the projected growth.

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291 S133 PB.ETS.CA.7-ITCC.pdf.
292 S129 PB.ETS.CA.6.-IT Principles v1.0.pdf.
293 CX053 ETSA Utilities IT Strategy 2009-2015 v2.0 Approved.pdf.
294 CX053 ETSA Utilities IT Strategy 2009-2015 v2.0 Approved.pdf, p. 30.
295 ibid.
296 CX053 ETSA Utilities IT Strategy 2009-2015 v2.0 Approved.pdf.
297 IT001 SAP Product Roadmap.ppt, IT002 SAP_BIP and POA Roadmap 31 March 2008.pdf, IT003 ETSA Utilities Reset SAP License Pricing document.doc
298 PB.ETS.CA.7 IT business cases.pdf, SI34.PB.ETS.CA.7-eRecruitment.pdf
299 CX053 ETSA Utilities IT Strategy 2009-2015 v2.0 Approved.pdf, Discussions with ETSA Utilities 13 August 2009.

The component for business-driven initiatives includes those that increase the capability of IT, systems that require replacement and associated integration and upgrades in line with the needs of the operational side of the business. The major items are[300]:

- replacement: FRC systems
- capability: enterprise information and data management
- capability: enterprise project management
- capability: IT strategy and governance
- capability: asset and works management
- integration: streamlining business workflow
- upgrade: NOC disaster recovery.

The business-driven initiatives account for $63.3m of the total information systems expenditure proposal.

The FRC systems where ETSA Utilities is responsible for 33% of the expenditure are shared with Citipower and Powercor. The replacements for the FRC systems are required in the next regulatory control period because the IT platform support has been extended[301] as far as possible because of the discontinued vendor systems. This expenditure accounts for $32.3m[302] and has been estimated using historical costs[303]. PB considers ETSA Utilities' cost sharing with Citipower/Powercor an efficient way to establish the FRC systems[304].

ETSA Utilities is enhancing asset management capability by introducing condition-based asset monitoring[305] where IT requires new capability to support the business in this initiative[306].

ETSA Utilities established Project Management Office (PMO) capability in 2007[307] and this is built upon by introducing PRINCE2 project management capability[308] in line with industry practice. PB considers the introduction of PRINCE2 capability prudent to support the business driven initiatives.

ETSA Utilities is adding capability in information management, enterprise architecture and IT strategy and governance to support increasing use of information technology and maximising benefits from projects such as condition monitoring of assets[309].

PB considers ETSA Utilities' business-driven initiatives align with the corporate strategy. PB considers the timing of the initiatives is aligned with business-driven needs. PB considers ETSA Utilities' expenditure efficient where it has substantiated estimated costs using

300 CX053 ETSA Utilities IT Strategy 2009-2015 v2.0 Approved.pdf, p.31.
301 IT067 CHED Proposal to ETSA Utilities 200409 vfinal.1.pdf , Discussions with ETSA Utilities 13 August 2009.
302 The majority of this expenditure occurs in the last year of the proposed period, CX053 ETSA Utilities IT Strategy 2009-2015 v2.0 Approved.pdf, p. 46.
303 PB ETS CA 23 FRC expenditure.pdf.
304 IT067 CHED Proposal to ETSA Utilities 200409 vfinal.1.pdf.
305 ETSA Utilities Regulatory Proposal 2010-15.pdf, pp. 9, 12, 14, 16, 17, 19, 37, 38, 119, 131, 133, 138.
306 CX053 ETSA Utilities IT Strategy 2009-2015 v2.0 Approved.pdf, p. 39.
307 IT058 ETSA Utilities PMO, PM & BA Review Report Final.doc, p. 4.
308 IT059 Proposal for PRINCE2 Deployment at ETSA Utilities May 2009.pdf.
309 CX053 ETSA Utilities IT Strategy 2009-2015 v2.0 Approved.pdf.

external entities and take into account options outside existing vendor relationships. On this basis, PB considers ETSA Utilities' IT expenditure prudent and efficient.

5.2.5 PB recommendations

PB has reviewed ETSA Utilities' IT submission and has found it to be prudent and efficient. In carrying out our review, PB sought documentation demonstrating the proposed expenditure is efficient in meeting the demonstrated business needs, and that the expenditure was prudent given these needs.

PB notes that ETSA Utilities has split the expenditure in two parts:

- business as usual
- business-driven initiatives

PB recommends the business-driven initiatives are approved for this period as a one-off expenditure and should not be considered business as usual.

PB's recommendation for ETSA Utilities' expenditure on IT is summarised in Table 5.4.

Table 5.4 Recommended expenditure for ETSA Utilities information systems

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	28.8	25.2	22.0	27.9	45.7	149.7
PB adjustment	0.0	0.0	0.0	0.0	0.0	0.0
PB recommendation	28.8	25.2	22.0	27.9	45.7	149.7

5.3 Plant and tools

The plant and tools expenditure category discussed in this section comprises that part of the RIN sub-expenditure category 'plant and tools/fittings and furniture' that relates to plant and tools. The Plant and tools expenditure category includes $35.1m for office furniture and equipment that is associated with property[310]. The sum of $35.1m has thus been moved from plant and equipment and included in the property category for analysis. PB notes that furniture and fittings has not been included in the current period plant and tools category thus making an equitable comparison. Refer to section 5.1 for more information. The total proposed expenditure for plant and tools (excluding furniture and fittings) is $37.5m.

5.3.1 Proposed expenditure

The proposed expenditure for plant and tools in the next regulatory control period is higher $37.5m, an 11.5% increase from $32.1m in the current regulatory control period. The trend for the previous, current and next regulatory control periods is illustrated in Figure 5.5.

310 PB.ETS.CA.9 plant and tools mapping.pdf, PB.ETS.CA.22 Plant and tools allocation.pdf, SI314 CA.22 PropertyExpenditureCategories.xls, CX068 Building Services Capital Plan for 2009 Working includes Reset version 30_04_2009.xls

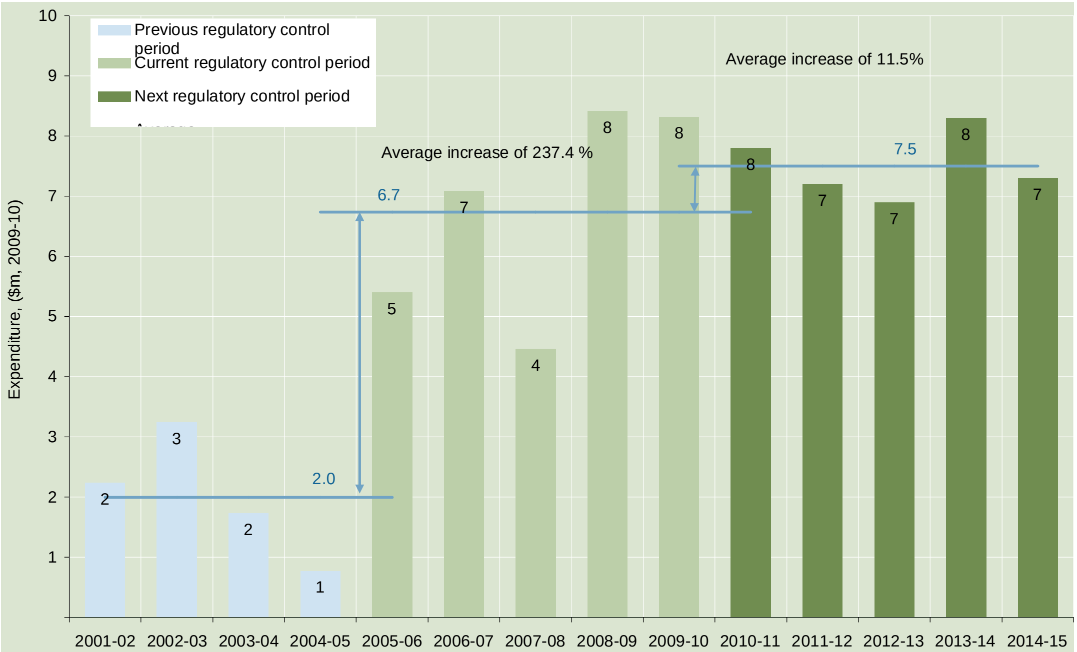

Figure 5.5 Capex for tools and equipment

Source: PB analysis

5.3.2 Drivers

ETSA Utilities states the proposed tools and equipment expenditure is based on a business-as-usual approach[311]. According to ETSA Utilities, the increase in expenditure for tools and equipment is driven by workforce growth. Plant and tool expenditure is increased to support:

- higher staff numbers
- a larger vehicle fleet.

5.3.3 Policies and procedures

ETSA Utilities does not have a plant and tools policy[312]; however, PB discussed the practices ETSA Utilities uses in relation to plant and tools. ETSA Utilities outlined the processes and procedures used in the current regulatory control period to determine projected tooling and equipment levels[313]. PB's high-level review indicated these processes and practices are likely to lead to expenditures that are prudent and efficient.

5.3.4 PB assessment and findings

PB notes that, as outlined in section 4.3.1, ETSA Utilities' forecast expenditure of $37.5m on tools and equipment represents an 11.5% increase relative to expenditure in the current regulatory control period. PB also notes that tools and equipment accounts for 10.3% of ETSA Utilities' total non-system capex program, and is thus a relatively small component of

311 Discussion with ETSA Utilities 5 August 2009.
312 PB.ETS.CA.28.pdf.
313 PB.ETS.CA.28.pdf.

the overall non-system capex program. For these reasons, PB only carried out a high-level review of ETSA Utilities' forecast expenditure on tools and equipment.

PB's high-level review involved a discussions with ETSA, which indicated that its staff numbers are set to significantly increase in the next regulatory control period. The proposed expenditure is in line with historical expenditure when taking this into account.

5.3.5 PB recommendations

PB recommends the proposed capex for tools and equipment be accepted with no changes, as set out in Table 5.5.

Table 5.5 Recommended expenditure for ETSA Utilities plant and tools

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	7.8	7.2	6.9	8.3	7.3	37.5
PB adjustment	0.0	0.0	0.0	0.0	0.0	0.0
PB recommendation	7.8	7.2	6.9	8.3	7.3	37.5

Source: ETSA Utilities RIN – Capex (2.2.1) & PB Analysis

5.4 Property

The property expenditure discussed in this section comprises the RIN sub-expenditure categories of:

- buildings
- land
- plant and tools/furniture and fittings (partial)
- office equipment.

Note that no expenditure is proposed for the office equipment category. However, the Plant and tools expenditure category includes $35.1m for office furniture and equipment that is associated with property[314]. The sum of $35.1m has thus been moved from plant and equipment and is included in this property category for analysis. PB notes that furniture and fittings was included in the buildings and office equipment category in the current period thus allowing for an equitable comparison. Refer to section 5.1 for more information.

5.4.1 Proposed expenditure

The proposed capex for property is $83.3m, a significant (1090%) increase from the $7.0m invested in the current regulatory control period. Figure 3 shows the proposed expenditure.

314 PB.ETS.CA.9 plant and tools mapping.pdf, PB.ETS.CA.22 Plant and tools allocation.pdf, SI314 CA.22 PropertyExpenditureCategories.xls, CX068 Building Services Capital Plan for 2009 Working includes Reset version 30_04_2009.xls

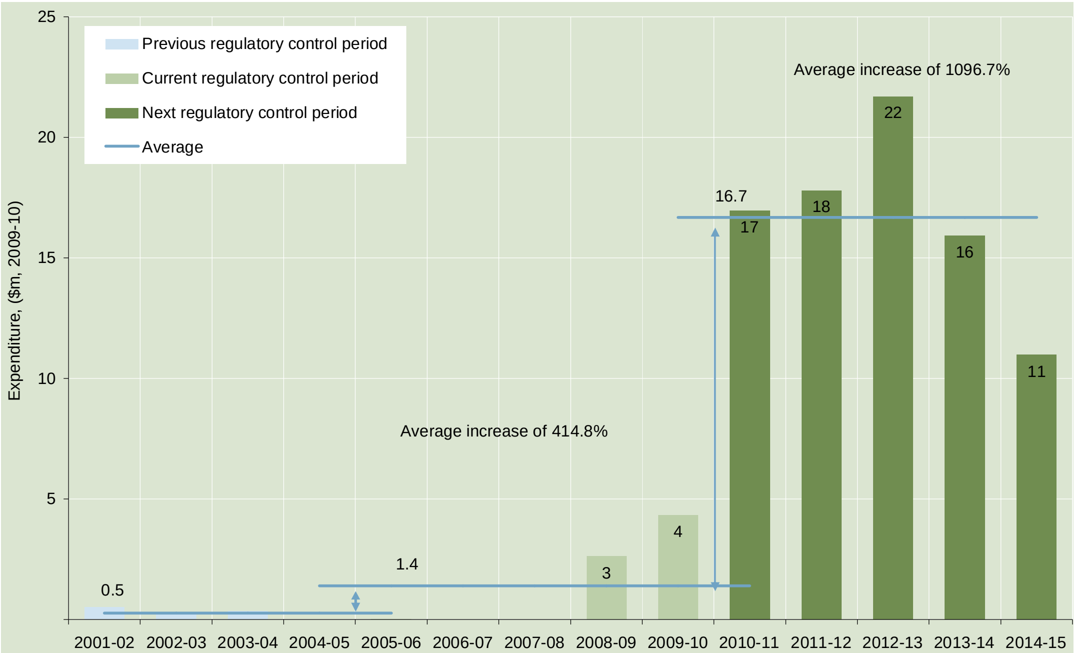

Figure 5.6 Proposed capex for property

Source: PB analysis

5.4.2 Drivers

ETSA Utilities states that the increase in property expenditure is driven by:

- employee growth resulting in a need for new buildings and upgrades
- aged building portfolio requiring the replacement of some facilities
- the construction of three new depots in response to changing demands, i.e. the need to relocate depots away from residential areas
- enhanced training facilities as a result of an increase in training initiative[315].

5.4.3 Policies and procedures

ETSA Utilities' property strategy[316] sets out a plan to expand, upgrade and replace existing facilities to meet operational needs, alleviate overcrowding and improve field response capability. ETSA Utilities' main considerations include[317]:

- maintain a consistent and equitable standard
- carry out ongoing reviews to identify and classify capital requirements
- consult with stakeholders on an ongoing basis to identify needs
- ensure buildings and lands are compliant with legislative requirements.

315 S130 PB ETS CA 10 property strategy.
316 S130 PB ETS CA 10 property strategy.
317 ibid.

ETSA Utilities' property program process[318] creates a preliminary capital plan using condition assessments for each site. The ETSA Utilities Real Estate[319] branch is consulted to ensure capital is not spent on sites considered surplus. Finally, stakeholders[320] are consulted to ensure that the proposed program meets with their expectations.

5.4.4 PB assessment and findings

ETSA Utilities' property plan details the proposed works required to replace, repair, repurpose and relocate on a site by site basis[321]. The plan consolidates several sites by grouping functions to achieve capacity requirements[322]. It offsets costs from revenue realised from sale of surplus land[323]. ETSA Utilities' property portfolio includes 10 depots dating from pre-1960 and housing 42% of the workforce[324]. In the next regulatory control period, ETSA Utilities proposes to upgrade older depots progressively at an average rate of one a year over the next 30 years[325] in conjunction with supporting the forecast employee growth.

ETSA Utilities' building services capital plan is shown in Table 5.6 below.

Table 5.6 Building services capital plan

nominal $m	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
All depots planned capital works	3.3	6.4	7.4	7.1	5.8	4.9	5.5	4.8	6.8	40.4
Asbestos remediation	0.3	0.4	0.8	0.6						2.1
Depot security upgrades	0.1	0.2	0.3	0.2	0.2	0.4				1.4
Facility works for growth	0.6	3.1	1.6	3.1	0.5	0.2	0.2			9.3
New depots			4.8		6.7					11.5
Rebuilt depots				2.5		3.6	3.6	3.6	3.6	17.0
Relocated depots		1.1	3.4		4.8					9.4
Revenue of land sales					(0.1)					
Land acquisition costs			0.7		3.2					3.9
Total proposed property program										
Land, buildings and office equipment	4.9	11.1	19.1	13.5	21.1	9.1	9.3	8.4	10.4	94.8

Source: CX068 Building Services Capital Plan for 2009 Working includes Reset version 30_04_2009.xls

318 ibid.
319 Department within ETSA Utilities.
320 Stakeholders include: DaNM, Field Services, CaMS and Services.
321 S130 PB ETS CA 10 property strategy.
322 S130 PB ETS CA 10 property strategy, e.g. office construction at Marleston North allows relocation of Angle Park Substation maintenance teams that in turns allows relocation of Keswick staff to cater for growth in Keswick.
323 PB ETS CA 13 Modelling sale of land.pdf.
324 S130 PB ETS CA 10 property strategy.
325 S130 PB ETS CA 10 property strategy, p. 5.

ETSA Utilities' employee growth has been planned for the period of 2009 to 2015 and allocated across the property portfolio[326] for this period. As a consequence, 12 properties will exceed current capacity by more than 10%. ETSA Utilities' total capacity for office staff will be exceeded by 23% and the capacity for field staff will be exceeded by 20%[327]. ETSA Utilities' depots planned capital works and security upgrades form the bulk of the proposal and are considered business as usual[328].

ETSA Utilities' proposed expenditure includes replacing four facilities over the next and following periods totalling approximately half of the expenditure in the next regulatory control period:

- Cleve
- Clare
- Nuriopta
- St Mary's Hut (ATCO office hut).

ETSA Utilities' proposed expenditure includes building new facilities in the period 2010-2013, to support growth of employees in population growth areas:

- Port Adelaide
- northern suburbs — close to Gawler and Seaford/Wilunga
- Roxby Downs
- relocation of premises in Holden Hill — current lease expires in 2010[329].

ETSA Utilities includes two relocations of existing depots at:

- Port Augusta — situated in CBD with no scope to expand as required
- Streaky Bay — shared site with the council and undergoing growth necessitating new sole tenant site[330].

The cost estimation follows ETSA Utilities' process for estimation, using condition assessments[331] as a basis for upgrades and repairs. The cost estimation for new/replacement facilities has been estimated using a generic depot design concept design for a large depot as a template and smaller depots have accordingly been reduced pro rata[332].

326 CX065 Depot numbers and capacity review.xls.
327 ibid.
328 S130 PB ETS CA 10 property strategy.
329 S130 PB ETS CA 10 property strategy, p. 5.
330 S130 PB ETS CA 10 property strategy.
331 SI51 Depot examples Clare_Nuri_PtAugusta_Barmera.pdf, SI49 Spotless_2005_Condition_Assessment_Nuri.pdf, SI48 Spotless_2005_Condition_Assessment_Clare.pdf, SI47 Spotless_2005_Condition_Assessment_Barmera.pdf, PB.ETS.CA.12 Condition assessments.pdf, SI50 Spotless_2005_Condition_Assessment_PtAug.pdf.
332 S130 PB ETS CA 10 property strategy, CX068 Building Services Capital Plan for 2009 Working includes Reset version 30_04_2009.xls - 08088-8584-ETSA Utilities Generic Depot Concept Estimate by FS.

ETSA Utilities' policy is to develop business cases with detailed options analysis in the year of or the year before the project starts[333]. Business cases have thus not been developed for the proposed new, relocated and replacement facilities[334]. PB notes the majority of new, replacement and relocation projects are relatively evenly distributed across 2011-12 to 2014-15 corresponding with the forecast employee growth[335].

PB considers that ETSA Utilities has demonstrated an appropriate staggering of projects to correspond with employee growth and notes the largest expenditure occurs in year 3 in the next period. PB considers that ETSA Utilities has demonstrated sufficient rigour in its cost estimation for existing facilities based on condition assessments. PB considers ETSA Utilities' generic depot design concept as sufficient on which to estimate new facilities. On this basis, PB considers ETSA Utilities' building program prudent and efficient.

5.4.5 PB recommendations

PB recommends no adjustment to the proposed expenditure program included in the Regulatory Proposal. PB's recommendation for ETSA Utilities' capex for land and building is set out in Table 5.7.

Table 5.7 Recommended capex for land and buildings

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	17.0	17.8	21.7	15.9	11.0	83.4
PB adjustment	0.0	0.0	0.0	0.0	0.0	0.0
PB recommendation	17.0	17.8	21.7	15.9	11.0	83.4

Source: PB Analysis

5.5 Fleet

The fleet expenditure discussed in this section comprises the RIN sub-expenditure categories of:

- vehicles – heavy fleet
- vehicles – light fleet.

5.5.1 Proposed expenditure

Proposed fleet expenditure has increased from $68.5m in the current regulatory control period to $93.2m in the next regulatory control period. This is an increase of 36.2% compared with the current regulatory control period. The trend in fleet expenditure between 2001 and 2015 is illustrated in Figure 5.7.

333 PB ETS CA 11 Property business cases (2).pdf.

334 S130 PB ETS CA 10 property strategy, CX068 Building Services Capital Plan for 2009 Working includes Reset version 30_04_2009.xls – First project requiring a business case is set to begin 2010-11 totalling $1.1m.

335 CX068 Building Services Capital Plan for 2009 Working includes Reset version 30_04_2009.xls, CX065 Depot numbers and capacity review.xls.

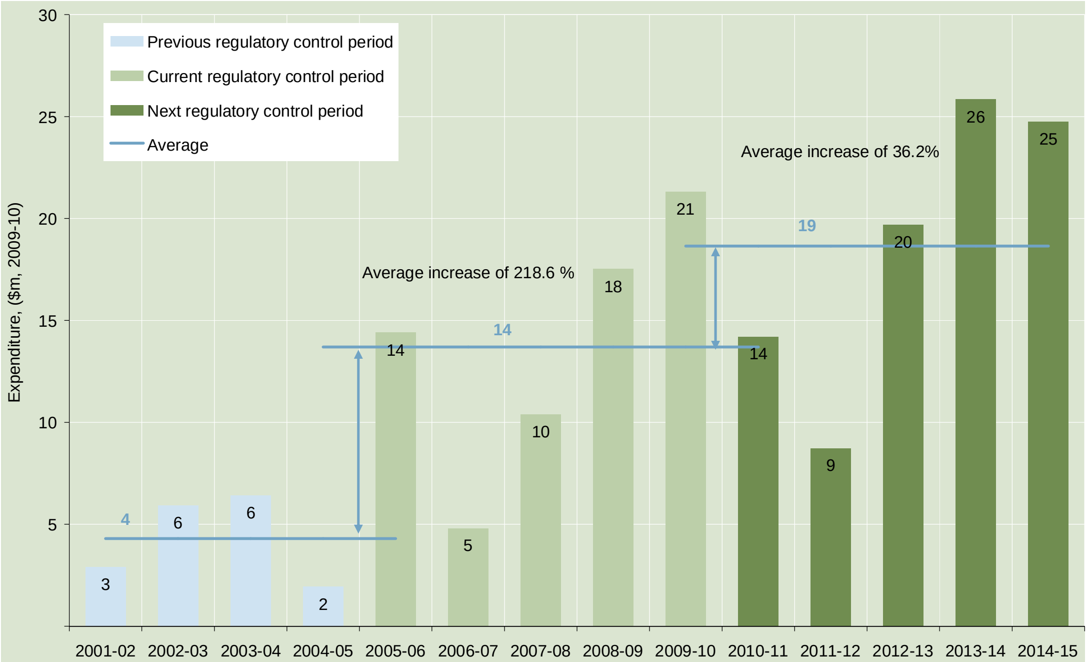

Figure 5.7 Capex for fleet

Source: PB analysis

5.5.2 Drivers

ETSA Utilities states the proposed fleet expenditure is based on business-as-usual practice, with the expenditure forecast for fleet derived from the replacement of existing vehicles, consistent with forecast staff requirements. The increase in fleet expenditure is driven by workforce growth and a significant portion of heavy vehicles requiring replacement in accordance with ETSA Utilities' replacement policy. For example, replacing elevating work platform vehicles in accordance with ETSA Utilities' 20-year replacement policy.

5.5.3 Policies and procedures

ETSA Utilities did not provide an overarching fleet management plan but stated an intention to develop such a plan, driven by the work plan and workforce plan in its 2009 Fleet Capital Budget[336]. ETSA Utilities did, however, state its fleet replacement policy in response to a question from PB[337] and provided earlier documentation for the policy in the 2009 Fleet Capital Budget report presented to its Executive Management Group (EMG)[338].

5.5.4 PB assessment and findings

PB expects that prudent fleet management would demonstrate that the size and range of fleet purchases was reasonable. PB's high-level analysis indicated the number of motor

336 ETSA Utilities 2009 Fleet Capital Budget, August 2008 EMG Workshop, p. 21.
337 PB.ETS.CA.15.pdf.
338 ETSA Utilities 2009 Fleet Capital Budget, August 2008 EMG Workshop.

vehicle forecast in the next regulatory control period[339] correlated with the forecast increase in ETSA Utilities' workforce[340].

PB expects that prudent fleet management would demonstrate the timing of motor vehicle expenditure was driven by a need in accordance with the company vehicle policy. ETSA Utilities' replacement policy is driven by age- and kilometre-based criteria, depending on vehicle type[341]. ETSA Utilities demonstrated that motor vehicles are replaced in accordance with this policy[342]. PB verified adherence to this policy through discussions with ETSA Utilities about the actual age of replacements for EWPs[343].

PB expects that efficient fleet management would demonstrate that fleet were acquired and sold in a cost-efficient manner. ETSA Utilities provided documentation indicating it had sought a range of market quotes for fleet purchases[344]. Discussions with ETSA Utilities indicated that an extension to its replacement policy for light vehicles, recommended in August 2008, had been implemented[345]. ETSA Utilities provided PB with NPV life-cycle comparisons on the costs of owning versus leasing light vehicles. These spreadsheets indicated ETSA Utilities had considered alternative costs for the purchase of vehicles[346].

PB's view is that the proposed fleet expenditure is prudent and efficient on the basis that ETSA Utilities has demonstrated market tested procurement, need and timing based vehicle replacement.

5.5.5 PB recommendations

PB recommends that the forecast capex for fleet be accepted as proposed, as shown in Table 5.8).

Table 5.8 Recommended expenditure for ETSA Utilities fleet

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ETSA Utilities proposal	14.2	8.7	19.7	25.9	24.7	93.2
PB adjustment	0.0	0.0	0.0	0.0	0.0	0.0
PB recommendation	14.2	8.7	19.7	25.9	24.7	93.2

Source: PB analysis

339 ETSA Utilities, S1300(updated CX0061) Reg Rest FleetReplacement 20090819a, Fleet Unit Requirements Sheet.
340 ETSA Utilities, S1300(updated CX0061) Reg Rest FleetReplacement 20090819a, Additional Fleet Sheet.
341 PB.ETS.CA.15.pdf.
342 ETSA Utilities, S1300(updated CX0061) Reg Rest FleetReplacement 20090819a, Light Fleet Sheet.
343 Discussion with ETSA Utilities 13 August 2009.
344 PB.ETS.CA.21.pdf.
345 Discussion with ETSA Utilities 13 August 2009.
346 ETSA Utilities, vehicle NPV cost comparison spreadsheet.

5.6 Summary of findings and recommendations

This section presents a summary of PB's principal findings and recommendations relating to ETSA Utilities' non-system capex for the next regulatory control period. PB's recommended non-system capex is set out in Table 5.9.

Information Systems

PB found that ETSA Utilities' business-driven initiatives in IT align with its corporate strategy, including the timing of activities. ETSA Utilities' has substantiated the estimated costs using external entities and has taken into account options outside existing vendor relationships. On this basis, PB considers ETSA Utilities' IT expenditure prudent and efficient.

Plant and tools

PB's high-level review of plant and tools found the proposed expenditure is in line with historical expenditure when taking into account forecast increases in staff numbers. On this basis, PB considers ETSA Utilities' plant and tools expenditure forecasts to be prudent and efficient

Property

PB considers that ETSA Utilities has demonstrated sufficient rigour in its cost estimation for existing facilities based on condition assessments. PB considers ETSA Utilities' generic depot design concept as sufficient on which to estimate new facilities. On this basis, PB considers expenditures associated with ETSA Utilities' building program are prudent and efficient.

Fleet

ETSA Utilities has demonstrated market tested procurement, need and timing based vehicle replacement. On this basis, PB considers that the proposed fleet expenditure is prudent and efficient.

Table 5.9 PB's recommended non-system capex

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Information systems						
ETSA Utilities proposal	28.8	25.2	22.0	27.9	45.7	149.7
PB adjustment	0.0	0.0	0.0	0.0	0.0	0.0
PB recommendation	28.8	25.2	22.0	27.9	45.7	149.7
Plant and tools						
ETSA Utilities proposal	7.8	7.2	6.9	8.3	7.3	37.5
PB adjustment	0.0	0.0	0.0	0.0	0.0	0.0
PB recommendation	7.8	7.2	6.9	8.3	7.3	37.5
Property						
ETSA Utilities proposal	17.0	17.8	21.7	15.9	11.0	83.4
PB adjustment	0.0	0.0	0.0	0.0	0.0	0.0
PB recommendation	17.0	17.8	21.7	15.9	11.0	83.4
Fleet						
ETSA Utilities proposal	14.2	8.7	19.7	25.9	24.7	93.2
PB adjustment	0.0	0.0	0.0	0.0	0.0	0.0
PB recommendation	14.2	8.7	19.7	25.9	24.7	93.2
PB adjustment for escalation						
Escalation	(4.8)	(4.2)	(4.8)	(5.2)	(5.7)	(24.7)
Total non-system capex						
ETSA Utilities proposal	67.7	58.9	70.3	78	88.8	363.7
PB adjustment	(4.8)	(4.2)	(4.8)	(5.2)	(5.7)	(24.7)
Total non system	62.9	54.7	65.5	72.8	83.1	339.0

6. Opex review

This section presents PB's review of ETSA Utilities proposed opex for the next regulatory control period. In carrying out its review, PB has provided technical advice about the efficiency and prudence of opex forecasts ETSA Utilities provided, and aims to provide input to assist the AER in its assessment of the opex objectives, criteria and factors set out in clause 6.5.6 of the NER.

6.1 Opex overview

ETSA Utilities has submitted an opex proposal of $1,131m for the next regulatory control period. During the current regulatory control period ETSA Utilities expects the total opex to be $733m, based on three years of actual expenditure and estimates for the last two years of the period. The proposed opex for the next regulatory control period therefore represents a 54% increase in real terms over the current regulatory control period.

The profile of the opex spend over the ten years is shown in Figure 6.1.

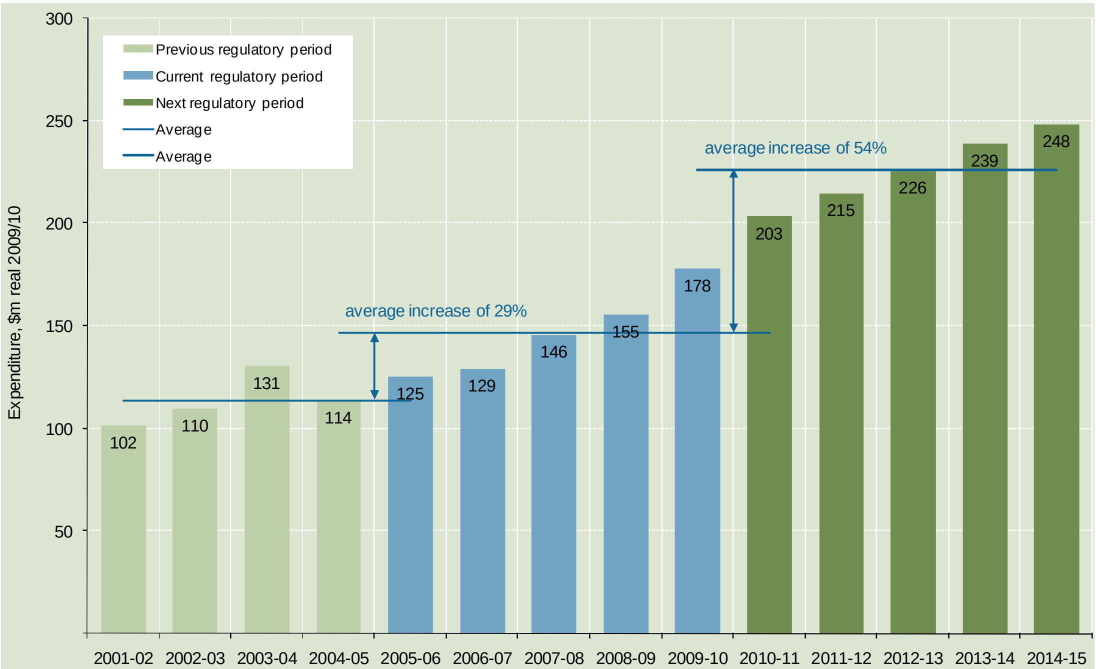

Figure 6.1 Opex over the 2001 to 2015 period

Source: PB analysis and RIN999 Final ETSA Utilities Pro Formas.xls, template 2.2.2

In accordance with ETSA Utilities' RIN submission pro-formas[347], its opex comprises five major cost categories and each of these major cost categories consist of a number of activities. The major cost categories include:

- network operating – related to those activities that enable the effective and efficient operation of the distribution network, including network access, network asset management, network telephony and regulatory compliance

347 Electricity Distribution Regulatory Information Notice Pro Forma statements, ETSA Utilities Section 2.2.2 EU opex

- network maintenance – related to planned or programmed maintenance carried out to reduce the probability of failure or performance degradation of a network asset; also includes vegetation management, emergency response, demand management and network insurance
- customer services – related to call centre activities, meter reading and regulated activities arising from the introduction of full retail competition (FRC)
- allocated costs – including the costs associated with the CEO, planning and audit, communications, regulation and company secretary, HR and training, property, information systems and risk management
- other operating costs – all other operating costs not captured above, including self insurance, superannuation and debt raising cost.

6.1.1 Opex in the current regulatory control period

ETSA Utilities has submitted to the AER that its total opex over the current five-year regulatory control period (2005-2010) will be $733.6m[348], in accordance with the main expense activities outlined in Table 6.1.

Table 6.1 Historical and estimated opex for the current regulatory control period

	2005-06	2006-07	2007-08	2008-09	2009-10	TOTAL
Network operating costs	17.65	19.85	19.80	22.47	24.34	104.12
Network maintenance	58.05	54.41	64.64	68.27	75.93	321.30
Customer services	21.08	19.96	21.35	21.86	22.15	106.40
Allocated costs	30.51	27.46	33.04	36.18	43.71	170.90
Other costs	-1.98	7.59	6.95	6.60	11.71	30.87
TOTAL	125.30	129.28	145.78	155.38	177.85	733.59

Source: PB analysis and RIN999 Final ETSA Utilities Pro Formas.xls, template 2.2.2

6.1.2 Forecast opex

ETSA Utilities opex in the next regulatory control period is estimated to be $1,131m, a breakdown of this expenditure by key expenditure category is provided in Table 6.2.

348 PB has escalated the historical opex figures from their nominal base to real 2009-10 in accordance with the inflation escalators approved by the AER

Table 6.2 ETSA Utilities forecast opex for the next regulatory control period

	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
Network operating costs	28.52	29.97	31.06	32.36	33.76	155.66
Network maintenance	83.52	87.66	93.01	99.00	103.86	467.06
Customer services	24.82	25.44	26.07	26.69	27.36	130.38
Allocated costs	49.93	54.32	57.54	62.15	63.89	287.83
Other costs	16.53	17.27	18.04	18.79	19.56	90.18
TOTAL	203.32	214.67	225.71	238.99	248.43	1,131.12

Source: PB analysis and RIN999 Final ETSA Utilities Pro Formas.xls, template 2.2.2

The percentage contribution of each cost category, and the real increase compared with the current regulatory control period are summarised in Table 6.3.

Table 6.3 Proposed opex for the next regulatory control period – proportions and increases

	% of total forecast opex	Average % real increase from current period
Network operations	14	49
Network maintenance	41	45
Customer services	12	23
Allocated costs	25	68
Other costs	8	201
TOTAL	100	54

Source: PB analysis and RIN999 Final ETSA Utilities Pro Formas.xls, template 2.2.2

The central observation from Table 6.3 is that ETSA Utilities is proposing a significant increase for each of its high-level regulatory cost categories. These matters are discussed further in section 6.4 to 6.7.

The profile of expenditure over the current and next regulatory control period varies in real terms in accordance with Figure 6.2.

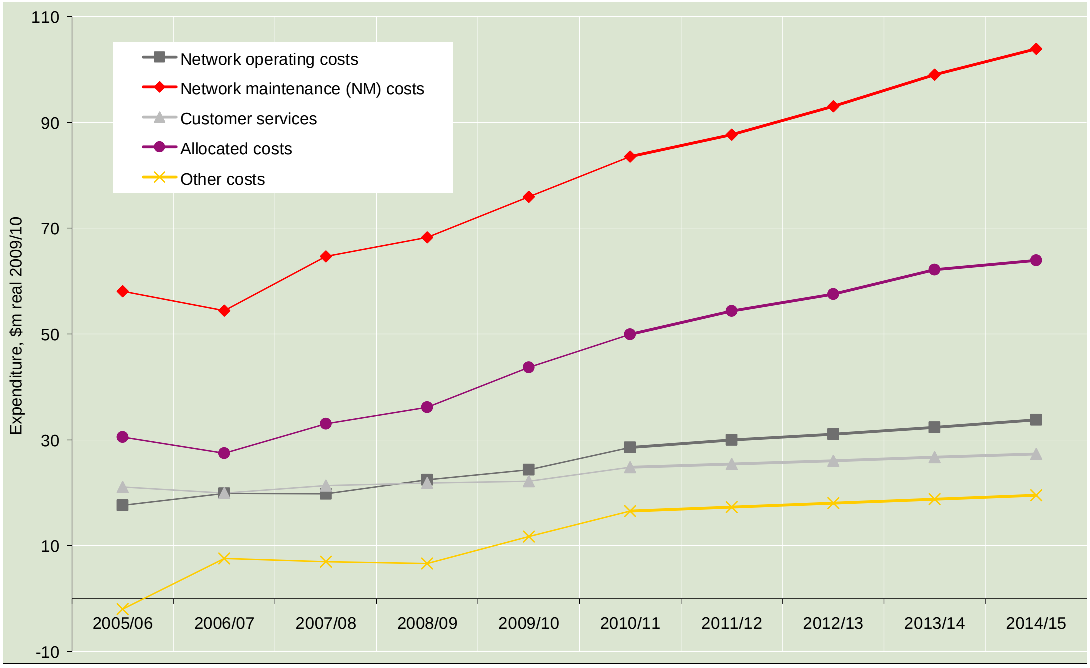

Figure 6.2 Proposed opex for the next regulatory control period - trends.

Source: PB analysis and RIN999 Final ETSA Utilities Pro Formas.xls, template 2.2.2

6.2 Operations and maintenance approach and strategy

ETSA Utilities operates under the principles and structures inherent in its Strategic Asset Management model which delineates the purposes, management focus and financial and operating relationships between:

- the Asset Owner (responsible for setting desired organisational and network outcomes)
- the Asset Manager (responsible for defining asset work programs to achieve these outcomes)
- the Asset Services providers (responsible for doing the work set out in the programs)
- Shared Service providers (responsible for providing cost effective support across all business functions)

This section aims to identify and discuss the approach ETSA Utilities adopts under this strategic model, and its business documentation relating to its asset management practices.

6.2.1 Key policies and documentation

Within ETSA Utilities asset management framework, there are a number of key policies and processes that directly inform and influence the forecast opex proposed by ETSA Utilities:

- BO08 2009-2013 Strategic Business Plan – represents the businesses view of its corporate objectives and strategic direction to 2013

- BO13 Asset Management Policy – defines responsibilities and requires ETSA Utilities to manage the network assets to satisfy customer service needs; to meet Licence and Regulatory obligations; to provide a safe environment for employees, contractors and the community; to deliver optimal returns to shareholders; to employ good electricity industry practice to manage the lifecycle of assets prudently and efficiently and to ensure long term sustainable performance and condition of the assets; and to prepare an asset management plan that is updated annually

- Customer Service Policy - to provide customers with services which are targeted to their needs and expectations and delivered in a way which reinforces their prime importance to the business

- Attachment E.7 Network Asset Management Plan (Manual 15) – the high level asset management plan that summarises the asset base, and details the document framework, key information systems, risk management, asset lifecycles, network performance, capacity planning, maintenance planning, network operations, financial planning, vested assets, safety and environmental plans and continuous improvements. It directly informs the wider library of detailed plans (x53) for selected asset classes

- OX031 AMP 3.0.01 CMLA Strategy 06.05.09 – outlines the businesses strategic asset management approach in regards to condition monitoring and life assessment methodology. Highlights historical, current and future approach, with a focus on need to capture asset information to allow business to move to a proactive and predictive asset maintenance approach rather then a reactive and responsive approach given the and declining performance condition anticipated as significant volumes of assets move into age-based risk areas. It provides detailed information in regards to expected technical lives across asset classes

- CX104 Poles AMP 3.1.05 – example of a detailed asset management plan for poles that systematically outlines asset populations within particular corrosion zones, including age profiles, condition, known problems, failures expected ages, spares and stock availability, maintenance and inspection strategies, risk, and disposal arrangements

- CX113 Substation Power Transformers AMP 3.2.01 - example of a detailed asset management plan for power transformers that systematically outlines asset populations within particular corrosion zones, including age profiles, condition, known problems, failures expected ages, spares and stock availability, maintenance and inspection strategies, risk, and disposal arrangements

- CX145 Line Clearance Rectification AMP 5.1.06 – example of a detailed asset management plan for vegetation management and maintaining safety and compliance clearances near operating assets, based on inspection cycles and bushfire risk areas

- CX101 – CX138 – a series of 37 further examples of detailed asset management plans for network assets, such as circuit breakers, metering, capacitor banks, overhead line components, etc

- OX028 2006 Maint Strategy SubTrans Assets 6_2 – specific maintenance strategy for overhead subtransmission lines including the inspection cycles and types of maintenance required

- OX037 NEM Metrology Procedure ref 2_6_8 – NEMMCO electricity metering code prescribing the testing and inspection requirements for meters

- DM04 Demand Management for Electricity Distribution Networks Guideline 12 – ESCoSA guideline that outlines the requirements of ETSA Utilities to meet its obligations to report and consult on its system constraints and demand management plans

- BO18 Procurement directive – outlines the principles through which ETSA Utilities seeks to maintain procurement practices that align with objectives of the strategic plan; provide value for money with an acceptable risk level; achieve ethical conduct with probity and accountability; establish positive relationships with suppliers; and demonstrate appropriate levels of control and performance. Includes clear role responsibilities and specific rules in regards to processes and delegated authority levels, etc

- BO25 Crisis and Emergency Management Manual and BO26 Crisis Mgmt Directive – outlines the system and processes to be used to manage any ETSA Utilities crisis or emergency situation , and the principles of the businesses response objectives

- BO30 2009 Environmental Management Plan – identifies clear and appropriate objectives, strategies, managerial controls and continuous improvement mechanisms for dealing with environmental issues associated with ETSA Utilities' business activities. Includes matter such as oil management, polychlorinated biphenyls (PCB's), asbestos, fuel management, contaminated land, electric and magnetic fields, etc

- BO28 Climate Change policy – to provide direction regarding the commitment to reduce the effects of operations and assets on climate change, and to manage the impacts of climate change on operations, including the need to factor in climate change impacts within asset augmentation, replacement and maintenance policies.

These key policies and strategy documents inform the opex forecasts in accordance with Table 6.4.

Table 6.4 Policy document and expenditure mapping

Policy document	Network operations	Network maintenance	customer service	allocated costs
BO08 2009-2013 Strategic Business Plan	✓	✓	✓	✓
BO13 Asset Management policy	✓	✓	✓	✓
Customer Service Policy			✓	✓
Network Asset Management Plan (Manual 15)	✓	✓		
OX031 AMP 3.0.01 CMLA Strategy 06.05.09	✓	✓		
CX104 Poles AMP 3.1.05	✓	✓		
CX113 Substation Power Transformers AMP 3.2.01	✓	✓		
CX145 Line Clearance Rectification AMP 5.1.06	✓	✓		

Policy document	Network operations	Network maintenance	customer service	allocated costs
CX101 – CX138 (x37)	✓	✓		
OX028 2006 Maint Strategy SubTrans Assets 6_2	✓	✓		
OX037 NEM Metrology Procedure ref 2_6_8	✓	✓	✓	
DM04 Demand Management for Electricity Distribution Networks Guideline 12	✓	✓	✓	
BO18 Procurement directive	✓	✓	✓	✓
BO25 Crisis and Emergency Management Manual and BO26 Crisis Mgmt Directive	✓	✓	✓	✓
BO30 2009 Environmental Management Plan	✓	✓	✓	✓
BO28 Climate Change policy	✓	✓	✓	✓

Source: PB analysis

6.2.2 AM practices and performance

Prior to 2007, ETSA Utilities' approach to asset management was predominantly to adopt a "fix on failure" strategy for the majority of asset types, with a limited targeted replacement program for a small number of assets. Increasing asset failures, an asset age profile that predicted large numbers of assets would potentially need to be replaced, and reduced network performance were the key drivers of a change in strategy towards that of condition monitoring. This change would allow leading rather than lagging indicators of asset performance to be determined and allow predicative replacement, refurbishment and maintenance to be undertaken. The approach is detailed in ETSA Utilities Asset Management Plan AMP.3.0.01[349] which was submitted as part of PB's review process.

Figure 6.3 indicates ETSA Utilities historic, enhanced and future asset management approach across key asset categories.

349 Asset Management Plan AMP.3.0.01 2009 to 2020 Condition Monitoring And Life Assessment Methodology

Asset Type	Historical Approach	Enhancement	Future
Substations and transformer stations (general)	Routine inspection, routine maintenance, fix on failure	Improved information and condition assessment	Field knowledge management and data capture enabling predictive maintenance
Overhead conductors & support infrastructure	Inspections, fix on failure	Field computing devices, Aerial inspections	Predictive maintenance based on timely information and knowledge management
Underground cables	Fix on failure	Cable assessment and risk management	On-line and discrete monitoring and assessment. Predictive maintenance
Switchgear	Routine inspection, preventative maintenance	On condition maintenance based on improved knowledge	On-line monitoring (where justified). Predictive maintenance based on condition.
Power Transformers	Inspection, preventative maintenance, fix on failure, routine diagnostics (larger units)	On condition maintenance based on improved knowledge	Predictive maintenance based on condition. On-line condition devices (where economic), knowledge management
Instrument Transformers	Routine inspection	Routine testing and assessment	Predictive replacement, knowledge management on line systems (where justified by risk)
DC Systems	Routine maintenance and inspection	On condition maintenance based on improved knowledge	On line monitoring of asset condition. Predictive maintenance
Public Lighting	Fix on failure	Knowledge management	Optimised performance by improved knowledge management

Figure 6.3 Asset management approach for key asset categories

Source: CX100 CMLA Strategy AMP 3.0.01.pdf, p. 23

ETSA Utilities' asset maintenance practices are currently fundamentally associated with time-based inspections. There are no instances identified where the condition or performance of an asset dictates the maintenance requirements, however condition may inform capex replacement decisions. Even with poor-performing assets, the approach is to increase inspection timings rather than to optimise maintenance based on specific condition indicators or operations.

With specific reference to ETSA Utilities various detailed asset management plans, the following performance and practices are noted.

Asset management practices

ETSA Utilities stobie pole population in low corrosion zones (64%) is inspected on 10 year cycle, while those in the medium (31%) and high (5%) corrosion zones are inspected every 5 years. The intention is to catch the steel corrosion before it progresses too far so that they can be refurbished using welded plates rather then a full pole replacement.

For overhead conductor, periodic routine inspections (supplemented by additional inspections as determined by condition), plus thermographic photography, visual inspection of conductor and fittings, etc occur every five years in high and medium risk zones, and 10 years otherwise. A line patrol is undertaken prior to each summer period as well.

ETSA Utilities assets are inspected and cleared of vegetation at three yearly intervals in accordance with the relevant Electricity Act.

Distribution transformers are generally replaced on failure, unless replacement is identified through the annual inspection of all ground mounted units or the five yearly inspection of pad/pole mounted units.

The maintenance strategy for larger zone substation transformers comprises of periodic routine inspections, overhaul maintenance and condition monitoring, supplemented by additional specific inspections and checks as determined by the asset performance and condition. Routine inspections[350] occur every six months; overhaul maintenance[351] is every six years for units with on load tap changers or twelve years for units larger than 5MVA; transformers receive condition monitoring[352] every year if they are larger than 5MVA or more than 40 years old, or every three years otherwise; and all protective devices are maintained every six years.

The maintenance strategy for substation circuit breakers comprises periodic routine inspections every six months; overhaul maintenance every nine years for oil units (except for two classes where the cycle is halved where there are known issues) or every 18 years for SF6 circuit breakers; major inspections every 4.5 years; condition monitoring every 4.5 years; and mechanism checks every 9, 4.5 or 1.5 years depending on type. The planned inspections and maintenance can be supplemented with specific inspection and testing routines based on asset performance and condition.

Fix on failure (i.e. no maintenance) assets include: ground mounted distribution transformers, SF6 and vacuum ground level switchgear, metro area distribution cables, battery chargers, telephone networks.

ETSA Utilities combines its defect management rectification into coordinated and efficient programs work by area.

No quantified asset health indices are apparent to inform the relative performance or condition of assets.

350 Includes amongst other matters, OLTC readings, oil level check, bushing check, general tank, cooler check, etc performed while the unit is in service

351 Includes a detailed inspection, diagnostic testing and clean with the unit out of service

352 Includes oil samples and dissolved gas analysis

Asset performance

As an outcome of annual pole inspections, ETSA Utilities generally experiences a defect rate of around 1.0% for poles to be replaced, and 1.1% of poles to be refurbished by plating. This is based on a ten year cycle so around 72,300 inspections per annum.

For large transformers (greater than 20 MVA), ETSA Utilities has experience 5 major failures with four occurring since 2001, across two asset types in a population of 108. For medium transformers (less than 20 MVA but greater than 5MVA), ETSA Utilities has experience 6 major failures since 2000, across four asset types in a population of 213. For small transformers (less than 5MVA), ETSA Utilities has experience 13 major failures since 2000 out of a population of 345.

There have be six 66kV circuit breaker failures in a population of 382 since 2004, there has been one 33kV circuit breaker failure in a population of 237 since 2000, and there has been 17 11kV circuit breaker failures in a population of 977 since 2002.

PB summary

Having reviewed the considerable asset management documentation presented by ETSA Utilities, PB concludes that asset management practices appear to be comprehensive and reflective of the needs of ETSA Utilities in the current environment. The practices suitably recognise stakeholders, corporate objectives, service levels, asset condition and performance life cycle costing as key elements, and asset equipment plans provide a suitable (qualified) risk-based focus to action plans.

In particular, PB is of the view that the business is well aware of its current capabilities and its long-term goals, consistent with its long term corporate strategy. While the asset management practices are sound, they are fundamentally informed through an orthodox approach to preventive maintenance based on a fixed-time inspection cycle, followed by reactive and corrective defect repair and remediation. The majority of performance indicators are lagging, yet there is recognition of the strategic benefits of moving to the more proactive and contemporary practice of adopting an advanced condition-informed approach to asset maintenance and management where the use of quantified health/risk indices and a full Condition Based Risk Management (CBRM) is recognised to provide operational efficiencies. This is especially the case with the larger power transformers in substations. ETSA Utilities strategic intentions are evidenced by the well-presented long-term goals of the business in its Strategic Business Plan, its Asset Management Policy, its Network Asset Management Plan (Manual 15) and each of the Detailed Asset Management Plans submitted with the proposal. Specifically, the Strategic Business Plan indentifies key objectives as being the need to:

- implement our Asset Management Policy that includes an increased proactive Condition Monitoring approach to asset replacement that extends the life of our assets, by the ramping up of targeted asset refurbishment and replacement programs and by mitigating our risks by maintaining compliance with relevant regulations and codes
- improve key capabilities and develop skills that will support ongoing improvements in service and efficiency (eg quality systems, project management, contractor management)
- exploit benefits of sophisticated performance measurement and management to improve service and efficiency, and identify opportunities for ongoing improvement

ETSA Utilities documentation is thorough and comprehensive, and reflects somewhat limited, but sound knowledge of the performance and condition of assets and risks facing the business.

As a result of our discussions with ETSA Utilities asset managers, our review of the documentation presented including the numerous detailed asset management plans, and the written and verbal responses to our often-detailed and specific questions relating to network performance, condition monitoring and vegetation management, PB considers that the forecast opex expenditures are based on prudent and orthodox asset management principles, processes and procedures. The approach taken to system-wide time-based preventive maintenance cycles, coupled with clear drivers to capture asset performance knowledge using leading indicators, should provide a reasonable framework to move to a more efficient and advanced condition-based style of asset management in the future.

PB's views in this area are to a large extent consistent, as well as being informed by, the detailed independent reviews of ETSA Utilities asset management documentation undertaken by SKM[353] and Maunsell[354] over the last two years.

6.3 Forecasting methodology

Section 7.4 of ETSA Utilities Regulatory Proposal outlines the opex development process.

ETSA Utilities has developed a detailed and transparent integrated model to forecast its opex requirements over the next regulatory control period, including itemised allocated costs. The model consists of 22 directly attributed regulated services and 41 allocated costs (overheads). ETSA Utilities expenses all overheads in accordance with its AER-approved cost allocation method (CAM) and therefore none are allocated to capital works. Each of the directly attributed regulated services and the allocated costs are modelled on an individual worksheet within the model which aggregates these individual costs to develop annual opex forecasts for the next regulatory control period.

With the exception of vegetation management and demand management initiatives, the model essentially escalates base year data selected as 2008-09 for each of the 63 opex cost activities using a number of escalators and variations which ETSA Utilities considers were not included in the base year and which are added to the base costs. The escalations are grouped into two main categories, namely specific and general. The specific escalations relate to increases in expenditure resulting from growth in network assets, work volume, customers, employees or a combination of these escalators. In addition economies of scale are built into the specific growth escalator calculations General growth relates to the forecast real increases in labour, material and contractor costs.

Where variations are included in a specific opex cost activity ETSA Utilities has provided additional spreadsheets detailing what is included in the variations and how they were calculated.

The key inputs to the opex model are the base year expenditures across 63 separate opex cost activities, adjusted to remove one-off expenditures not part of business-as-usual expenditures; scope change variations where applicable; scale (specific) escalation related to specific drivers; and general input cost escalation, as shown in Figure 6.4.

353 Attachment E.12 SKM Asset Management Policy Review.pdf, April 2008
354 Attachment E.13 Maunsell AMP Review.pdf, November 2008

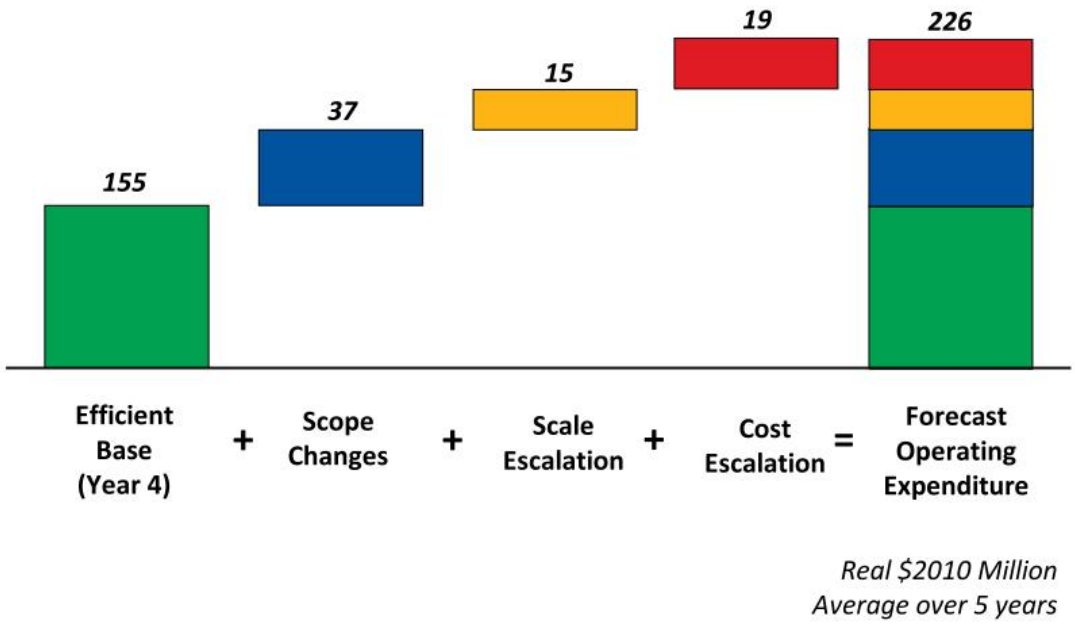

Figure 6.4 ETSA Utilities forecasting methodology over the next regulatory control period

Source: ETSA Utilities, Introductory presentation to PB-AER July20.pdf, p.24

An example directly extracted from ETSA Utilities opex model showing the level of detail provided for each of the 63 opex activities is shown in Figure 6.5, where the historical expenditure is shown, as is the baseline expenditure, the growing impact of scope variation, the growing impact of specific (scale) escalation, and finally the impact of all (general input cost) escalation.

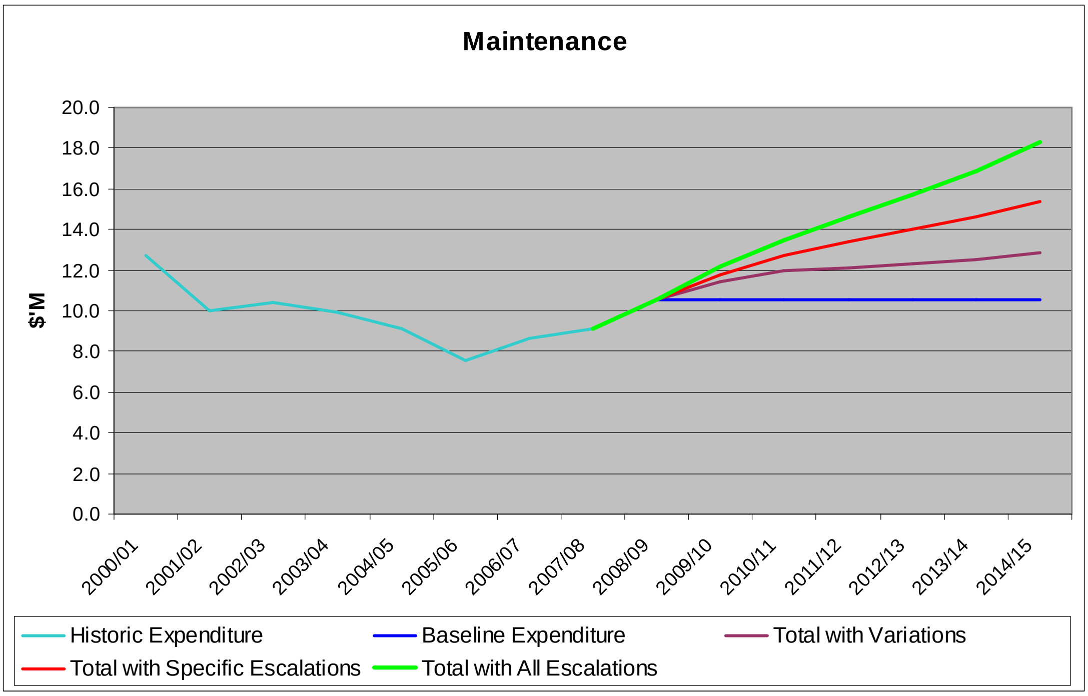

Figure 6.5 ETSA Utilities forecasting methodology over the 2010-2015 period

Source: ETSA Utilities, Attachment F.1 SEM-Opex Model Ver7.2-Read Only.xls, tab 'DA-13'

In the case of vegetation management (9.2% of entire opex forecast) and demand management initiatives (1.0% of entire opex forecast), ETSA Utilities undertook a detailed bottom-up forecast based on specific knowledge in these areas, and as outlined in various supporting documents.

All input costs to the ETSA Utilities opex model have used 2007-08 dollars as the reference, and these have subsequently been escalated by the ratio of CPI in December 2007 of 158.6 to that in June 2010 of 170.49, equivalent to 1.075.

6.3.1 Efficient base year

ETSA Utilities has selected 2008-09 as its base year as it considers this year is best-suited as it is the most recent year of actual performance, and audited regulatory accounts will be available before the AER is required to make a final determination. It also reflects the global economic conditions that are expected to prevail during the 2010–2015 regulatory control period and it aligns ETSA Utilities operating expenditure forecast with the operation of the Efficiency Carryover Mechanism (ECM) applying to ETSA Utilities in the current regulatory control period.

ETSA Utilities calculated its actual base year costs of $155m directly from its regulatory accounts for 2008-09, adjusted to comply with the approved cost allocation methodology for the 2005-2010 period, and with superannuation and self insurance adjusted to a cash basis.

In order to determine if the 2008-09 year is efficient, ETSA Utilities has also relied on the top-down benchmarking analysis it undertook in regards to its opex during the current regulatory control period. Whilst acknowledging the performance of an individual business is a difficult task[355], ETSA Utilities has adopted the methodology taken by Wilson Cook & Co in its draft review of the expenditure proposed by ACT and NSW DNSPs[356]. ETSA Utilities acknowledges that Wilson Cook used a slightly different benchmarking analysis for its final review[357], however notes that the different benchmarking approach adopted by Wilson Cook in its final report ‘produces results not materially different from those of the simple method used in the original analysis’[358].

The Wilson Cook approach uses a composite ‘size’ variable that combines common network variables for comparative purposes. The equation used to calculate the composite size variable is:

$$Size = C^{d}L^{e}D^{f}$$

where: C = number of customers; L = network length; D = maximum demand in MW; and d, e, and f are weights, with d = 0.5, e = 0.3, and f = 0.2.

In its analysis, reproduced as Figure 6.6, Wilson Cook & Co relied on publicly available data to develop a graph comparing various DNSPs total opex for 2007-08 against their respective composite size variables.

355 ETSA Utilities Regulatory Proposal, p. 146.
356 Wilson Cook & Co 2008, Review of Proposed Expenditure of ACT & NSW Electricity DNSPs Volume 1—Main Report Final, October 2008, p 18.
357 AER 2009, Final Decision: New South Wales Distribution Determination 2009–10 to 2013–14, 28 April 2009, p 175.
358 Wilson Cook & Co 2008, Review of Proposed Expenditure of ACT & NSW Electricity DNSPs Volume 1—Main Report Final, October 2008, p 19.

ETSA Utilities position on the graph has been re-plotted to reflect the correct amount of operating expenditure incurred during 2007-08 - an error also corrected by Wilson Cook & Co in its subsequent benchmarking analysis.

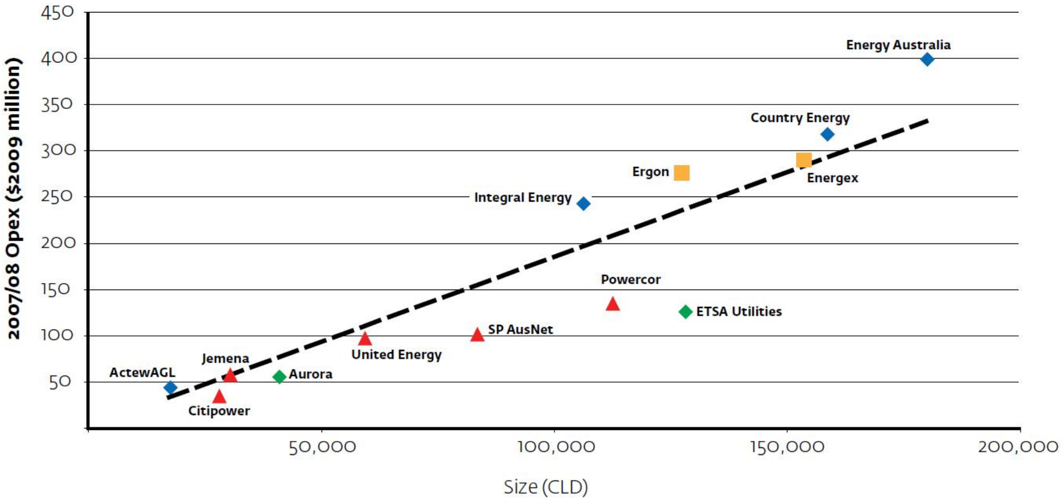

Figure 6.6 Wilson Cook analysis of the ACT and NSW DNSPs with ETSA Utilities forecast position plotted on the diagram

Source: ETSA Utilities Regulatory Proposal, p.146

6.3.2 Scope changes

Having defined a base year expenditure level, the next step in ETSA Utilities opex forecasting process involved indentifying specific scope changes affecting the businesses ability to maintain its levels of service, risk and compliance in the lead up during the next regulatory control period. This was achieved through an environmental scan process informed through long-term planning processes, a series of internal workshops, development of a list of potential issues, and finally selection and Executive approval.

The outcome of this process was a set of 34 separate and explicit opex variations as detailed in Table 6.5 and Table 6.6, which refer to the direct cost variations and the allocated cost variations, respectively and amount to an average annual increase over the next regulatory control period of $37m.

Table 6.5 Direct cost scope changes proposed for the next regulatory control period

Direct cost opex activity	Scope change	Five year total, $m
Asset strategy and planning	Additional labour resources to review condition monitoring data and develop/revise asset management strategies	0.5
	Resources to facilitate the establishment of a new workgroup responsible for capacity planning of LV assets	2.8
	Establishment of a dedicated substation asset management and condition monitoring team	2.9
Maintenance planning	Additional labour resources to analyse condition monitoring data and plan maintenance of powerline assets	0.9
Network telephony	Additional expenditure associated with the program of data link upgrades during the 2005 - 2010 control period	2.6
	Implementation of an intensified condition monitoring regime for Tel assets	2.3
Inspections	Change in the scope of ETSA Utilities' service contract with its aerial inspection services provider	6.8
	Resources to facilitate more frequent inspections of powerline assets as part of ETSA Utilities condition monitoring strategy	1.9
	Additional labour resources to facilitate more frequent and detailed asset inspections in high corrosion risk areas	8.8
	Resources to facilitate more detailed inspection of substation assets as part of ETSA Utilities condition monitoring strategy	3.7
Maintenance	Additional resources to facilitate delivery of a meter inspection and testing program that complies with new requirements	4.3
	Costs associated with non-network solutions (peak lopping generation)	0.7
	Additional operating expenditure associated with an increase in average asset age	4.7
Emergency response	Additional operating expenditure associated with an increase in average asset age	10.1
DMIF	Agreed allowance for DM activities in next period as per AER Framework & Approach.	3.0
Network insurance	Increase in insurance premiums as per AON forecast. Also includes BI insurance for loss of Q factor.	3.5
Retail contestability	Additional expenses associated with changes in the FRC systems supported by CHED Services	8.5
Total		68.1

Source: PB analysis and Attachment F.1 SEM-Opex Model Ver7.2-Read Only.xls

The five-year total increase due to direct cost scope increases is $68.1m prior to scale or general (input cost) escalation.

Table 6.6 Allocated cost scope changes proposed for the next regulatory control period

Allocated cost activity	Scope change	Five year total, $m
Regulation	Cost associated with undertaking revenue determination - embedded in base year	(3.7)
Finance - Adjustments	Variation to offset the impact of finance adjustments embedded in the base year	19.4
Training Centre	Resources to facilitate delivery of training services of the Davenport centre	2.2
Information Technology	SAP SUN Hardware support & maintenance extension - 2yrs	0.5
	Ongoing opex costs associated with supporting new capabilities delivered by the IT CAPEX program	19.2
Property – Offices and Depots	Increase in service contracts for depot related costs (ie fire, scheduled maintenance (electrical, AC, Security).	1.5
	Increase in land tax associated with new ETSA Utilities property acquisitions	3.4
	Increase in leasing fees due to lease of new Keswick office/carparking and Holden Hill properties	5.4
Property – DLC Land Tax	Increase in land tax based on Treasurer's instruction	10.7
Risk & Insurance – Shared Insurance Premiums	Change in insurance premiums per AON forecast. Also includes BI insurance for loss of Q factor.	1.4
Risk & Insurance – Support Costs	Change in insurance premiums per AON forecast. Also includes BI insurance for loss of Q factor.	5.5
Customer Relations, excluding Call Centre	Provides for focussed customer survey of 2 key aspects of ETSA Utilities' service delivery	0.8
	Additional labour resources to manage and operate the new outage notification system	0.3
Superannuation	Prescribed opex component of additional cash payments for superannuation.	13.0
Self Insurance	Standard Control Services opex component of additional costs for self insurance.	14.5
Debt Raising Costs	Debt raising costs calculated as opening RAB x 60% x 0.118%	12.3
	Cost of S&P Debt Raising Requirement	10.1
Total		116.7

Source: PB analysis and Attachment F.1 SEM-Opex Model Ver7.2-Read Only.xls

The five-year total increase due to allocated cost scope increases is $116.7m prior to scale or general (input cost) escalation.

PB notes that the material scope changes associated with superannuation, self insurance and debt raising costs are beyond our terms of reference, and will be accordingly assessed by the AER.

6.3.3 Scale (specific or growth) escalation

ETSA Utilities has adopted a similar approach to forecasting the scale escalation that will apply to its opex activities over the next regulatory control period compared with other businesses (in particular ElectraNet), in that it has selected key factors, developed top-down macro scale escalation factors, and applied these selectively to its activities giving due consideration to economies of scale and also inter-dependence.

The outcome of this process has amounted to an average annual increase over the next regulatory control period of $16.6m.

Four key factors have been designed and quantified using 2008-09 as the base year, including:

- Network growth - reflects growth in the size and number of assets within the distribution network
- Work volume - reflects changes in the volume of capital and maintenance work taking place on the network
- Workforce size –reflects changes in the numbers of staff and general workforce
- Customer growth –reflects specifically the growth in customer numbers.

Four opex activities have also had multi-factor escalators applied, which use a weighted combination of the four factors above.

Network growth escalators

The network growth escalators (year on year) are shown in Table 6.7. They have been determined by calculating the annual ratio of the capex associated with network extensions and upgrades[359] minus retirements[360] to the undepreciated Regulatory Asset Base (RAB)[361]. They have been applied to 27 of the 63 opex activities as per Figure 6.7 and Figure 6.8, including four multifactor escalators, increasing the forecast opex allowance by $46.9m over the five year period.

Table 6.7 Network growth escalators

Network growth (%)	Economy of scale	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Raw escalator	-	3.45%	3.15%	3.90%	3.30%	2.93%	2.60%
Direct charges	-	3.45%	3.15%	3.90%	3.30%	2.93%	2.60%
Maintenance	5%	3.27%	2.99%	3.70%	3.14%	2.78%	2.47%
Operations	75%	0.86%	0.79%	0.97%	0.83%	0.73%	0.65%
Asset management	90%	0.34%	0.32%	0.39%	0.33%	0.29%	0.26%
Corporate	90%	0.34%	0.32%	0.39%	0.33%	0.29%	0.26%

Source: ETSA Utilities, Attachment F.4 Derivation and application of scale escalators.xls

359 Defined as the capex categories: Reinforcement and upgrades (C-2), New customer connect (gross) (C-3), Underground residential subdivisions (C-6) and Network security (C-22)

360 Determined to be 12.5% of the Reinforcement and upgrades (C-2) capex and 1.6% of the New customer connect (gross) (C-3) capex.

361

Work volume escalators

The work volume escalators (year on year) are shown in Table 6.8. They have been determined by calculating the change in required trade-skilled labour (FTE's) needed to deliver the financial forecast of core, regulated work performed on the network, including both capex and opex. The base line financial forecast of work and required FTE's (2008-09) is $222.9m and 583, respectively .The work volume escalators have been applied to eight of the 63 opex activities as per Figure 6.7 and Figure 6.8, including three multifactor escalators, increasing the forecast opex allowance by $19.0m over the five year period.

Table 6.8 Work volume escalators

Work volume (%)	Economy of scale	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Raw escalator	-	145.6%	144.9%	165.9%	157.9%	156.6%	153.0%
Operations	75%	36.4%	36.2%	41.5%	39.5%	39.2%	38.3%
Corporate	90%	14.6%	14.5%	16.6%	15.8%	15.7%	15.3%

Source: ETSA Utilities, Attachment F.4 Derivation and application of scale escalators.xls

Customer growth escalators

The customer growth escalators (year on year) are shown in Table 6.9. They have been determined by direct reference to the forecast change in customers numbers, as informed by the independent services of the National Institute of Economics and Industry Research (NIEIR). The base line number of customers (2008-09) is 707,224. The customer growth escalators have been applied to nine of the 63 opex activities as per Figure 6.7 and Figure 6.8, increasing the forecast opex allowance by $6.1m over the five year period.

Table 6.9 Customer growth escalators

Customer growth (%)	Economy of scale	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Raw escalator	-	1.46%	1.39%	1.29%	1.08%	0.99%	1.04%
Operations	5%	1.38%	1.32%	1.22%	1.03%	0.94%	0.98%
Back-office	90%	0.15%	0.14%	0.13%	0.11%	0.10%	0.10%

Source: ETSA Utilities, Attachment F.4 Derivation and application of scale escalators.xls

Employee growth escalators

The employee growth escalators (year on year) are shown in Table 6.10. They have been determined by forecasting the change in the number of trade-skilled workers and apprentices based on required network needs, as well as the other employees across the wider business using a bottom up approach. The base line number of employees (2008-09) is 1,918. The customer growth escalators have been applied to 13 of the 63 opex activities as per Figure 6.7 and Figure 6.8, including one multifactor escalator, increasing the forecast opex allowance by $11.2m over the five year period.

In establishing its employee growth escalators, ETSA Utilities made the following key assumptions:

- it will not be able to recruit significant numbers of additional, fully qualified trade-skilled workers with respect to core electrical and powerline trades

- it must maintain a ratio of three fully qualified trades-people for every one apprentice
- attrition within trade ranks would remain at historical levels

Table 6.10 Employee growth escalators

Employee growth (%)	Economy of scale	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Raw escalator	-	7.25%	6.35%	3.41%	2.34%	2.23%	1.65%
Operations	5%	6.89%	6.03%	3.24%	2.23%	2.11%	1.57%
Back-office	90%	0.72%	0.63%	0.34%	0.23%	0.22%	0.16%

Source: ETSA Utilities, Attachment F.4 Derivation and application of scale escalators.xls

Multi-factor escalators

ETSA Utilities also identified that four of its opex categories were influence by more than one type of escalator. In this case it apportioned each escalator to arrive at a composite, or multi-factor escalator as shown in Table 6.11. These escalators have an impact of increasing the forecast opex allowance by $17.6m (included in impacts presented for each individual type of escalator in the previous figures).

Table 6.11 Multi-factor growth escalators

Multi-factor growth (%)	Economy of scale	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Network access monitoring and control	Network growth - ops 30%	0.26%	0.50%	0.79%	1.05%	1.28%	1.48%
	Work volume - ops 70%	25.48%	25.35%	29.03%	27.63%	27.40%	26.78%
	composite	25.74%	25.85%	29.82%	28.68%	28.68%	28.26%
Asset strategy and planning	Network growth - AM 40%	0.14%	0.26%	0.42%	0.55%	0.67%	0.78%
	Work volume - ops 60%	21.84%	21.73%	24.88%	23.68%	23.49%	22.95%
	composite	21.98%	21.99%	25.30%	24.24%	24.16%	23.73%
Maintenance of asset information	Network growth - AM 50%	0.17%	0.33%	0.53%	0.69%	0.84%	0.97%
	Work volume - ops 50%	18.20%	18.11%	20.73%	19.74%	19.57%	19.13%
	composite	18.37%	18.44%	21.26%	20.43%	20.42%	20.10%
Network telephony	Network growth - ops 90%	0.78%	1.49%	2.38%	3.15%	3.83%	4.44%
	Empl. growth - bk off. 10%	0.07%	0.14%	0.17%	0.19%	0.22%	0.23%
	composite	0.85%	1.63%	2.55%	3.34%	4.04%	4.67%

Source: ETSA Utilities, Attachment F.4 Derivation and application of scale escalators.xls

Application of scale escalators

The specific application of each of the scale growth escalators is presented in Figure 6.7 and Figure 6.8 for direct costs and allocated costs, respectively.

The scale escalators and their application have been reviewed in detail by SKM[362].

The five-year total increase over the next regulatory control period due to scale escalation increases is $82.9m prior to general (input cost) escalation.

362 Attachment F.2 SKM Review of Scale Escalators.pdf, 30 June 09

Expenditure Template	Service	Network Growth	Work Volume	Customer Growth	Employee Growth
DA-2	Network Access, Monitoring and Control	0.08	0.08		
DA-3	Customer Service			0.95	
DA-4	Standards Development and Maintenance	0.10			
DA-5	Asset Strategy and Planning	0.04	0.15		
DA-6	Maintenance Planning	0.25			
DA-7	Maintenance of Asset Information	0.05	0.05		
DA-8	Network Telephony	0.23			0.01
DA-10	Regulatory Compliance	0.10			
DA-11	Outage Management System	0.10			
DA-12	Inspections	0.95			
DA-13	Maintenance	0.95			
DA-14	Vegetation Management	0.95			
DA-15	Emergency Response	0.95			
DA-16	Meter Reading Charges			0.95	
DA-17	Call Centre Charges			0.95	
DA-18	Demand Management	0.10			
DA-20	Guaranteed Service Level Payments			0.95	
DA-21	Property – Substation Sites	0.95			
DA-23	Retail Contestability Charges			0.95	

Figure 6.7 ETSA Utilities application of scale escalators to direct cost activities

Source: ETSA Utilities, Attachment F.4 Derivation and application of scale escalators.xls

		Network Growth	Work Volume	Customer Growth	Employee Growth
A-1	CEO	0.10			
A-2	Strategic Planning	0.10			
A-3	Communications	0.10			
A-4	Audit Services	0.10			
A-5	eral Manager Regulation & Company Secretary	0.10			
A-6	Regulation	0.10			
A-7	CFO	0.10			
A-8	Accounts Receivable – Asset Damage	0.10			
A-9	Taxation – Specific Allocation	0.10			
A-10	Corporate Finance	0.10			
A-11	Operational Finance				0.10
A-12	Regulatory Finance	0.10			
A-13	Accounts Payable		0.10		
A-14	Payroll				0.10
A-15	Purchasing and Contracts		0.10		
A-17	General Manager Corporate Services				0.10
A-18	Employee Relations				0.95
A-19	Workforce Development				0.10
A-20	Training Centre				0.95
A-21	Apprentice Training				0.10
A-22	Training Centre Management				0.10
A-23	Information Technology				0.10
A-24	Property – Offices and Depots				0.10
A-25	Property – DLC Land Tax	0.25			
A-26	OHS		0.25		
A-27	Environment		0.10		
A-28	Printing				0.10
A-31	Legal Services		0.10		
A-32	General Manager Services			0.10	
A-33	Customer Relations, excluding Call Centre			0.10	
A-34	Business Improvement and Planning			0.10	
A-35	Works Coordination			0.95	
A-36	Employee Bonuses				0.95
A-39	Self-insurance	1.00			

Figure 6.8 ETSA Utilities application of scale escalators to allocated cost activities

Source: ETSA Utilities, Attachment F.4 Derivation and application of scale escalators.xls

6.3.4 General (input cost) escalation

The impact of the opex general input cost escalators is set out in Table 6.12.

Table 6.12 Impacts of real escalators used for opex

$m	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Labour	6.58	10.95	15.30	19.73	24.79	77.35
Materials	0.63	0.84	1.02	1.20	1.39	5.08
Services - construction	0.20	0.41	0.72	1.09	1.34	3.76
Services - general	0.53	0.86	1.35	2.09	2.74	7.57
TOTAL	7.94	13.06	18.39	24.11	30.26	93.76

Source: PB analysis

ETSA Utilities also engaged both SKM[363] and KPMG[364] to independently review the application of general input cost escalation within its model.

In order carry out a more targeted review of the proposed opex forecasts, PB also adjusted ETSA Utilities opex modelling spreadsheets to explicitly and dynamically show the impact of the real labour and material escalators that had been incorporated.

Primarily, this sensitivity analysis was used by PB to determine the base level of opex forecasts with the real cost escalators set to zero. This produced a version of the opex forecasts that were de-sensitised to cost escalation and showed more directly the need for opex as a result of the growth in asset volumes resulting from the corresponding capital works programs. Table 6.13 presents the contribution of real cost escalation to the total forecast system opex expenditures for the next regulatory control period.

Table 6.13 Base opex and the real annual cost escalation included in the forecast opex expenditures for the 2010-2015 regulatory control period

	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
Total opex (no escalation)	195.39	201.61	207.32	214.89	218.16	1,037.37
Real cost escalation	7.93	13.06	18.39	24.10	30.26	93.75
ETSA Utilities proposed opex	203.32	214.67	225.71	238.99	248.43	1,131.12

Source: PB analysis and Attachment F.1 SEM-Opex Model Ver7.2-Read Only.xls

This exercise indicated that the impact of the real cost escalation factored into opex forecasts for the next regulatory control period was $93.8m, or an uplift of 9% on the base opex. Sensitivity analysis indicates that real escalation contributes to the $93.8m increase in the proportions of labour: 82.5%, materials: 5.4%, contractors: 4.0% and 'other': 8.1%.

363 Attachment F.2 SKM Review of Scale Escalators.pdf
364 Attachment E.3 Pricing Submission Model Report 5853252_1.pdf

Figure 6.9 Base opex and the real annual cost escalation included in the forecast opex expenditures for the 2010-2015 regulatory control period

Source: PB analysis and Attachment F.1 SEM-Opex Model Ver7.2-Read Only.xls

Trends in each of the key cost categories after the removal of real escalation over the outlook period are shown in Table 6.14 and graphically in Figure 6.10.

Table 6.14 Historical and forecast system opex – after real escalation has been backed out of the forecasts.

	05-06	06-07	07-08	08-/09	09-10	10-11	11-12	12-13	13-14	14-15
Network operating costs	17.65	19.85	19.80	22.47	24.34	27.22	27.80	28.04	28.45	28.90
Network maintenance	58.05	54.41	64.64	68.27	75.93	80.25	82.31	85.42	88.93	91.04
Customer services	21.08	19.96	21.35	21.86	22.15	24.28	24.58	24.82	25.03	25.25
Allocated costs	30.51	27.46	33.04	36.18	43.71	47.76	50.71	52.44	55.52	55.68
Other costs	-1.98	7.59	6.95	6.60	11.71	15.88	16.21	16.59	16.95	17.29
Total system	125.30	129.28	145.78	155.38	177.85	195.39	201.61	207.32	214.89	218.16

Source: PB analysis and Attachment F.1 SEM-Opex Model Ver7.2-Read Only.xls

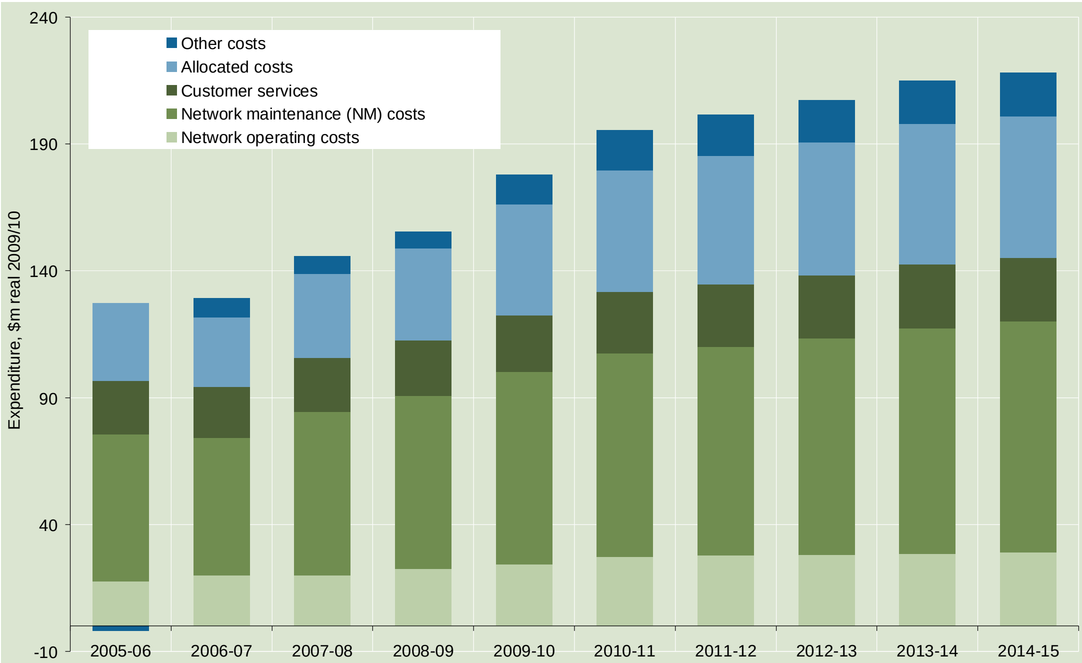

Figure 6.10 Historical and forecast system opex - real escalation removed from forecasts

Source: PB analysis and Attachment F.1 SEM-Opex Model Ver7.2-Read Only.xls

Table 6.15 presents the % increase in opex compared with the previous year for the period 2008-09 to 2014-15. Where the step change exceeds 10% in 2010-11, the value has been highlighted.

Table 6.15 Year-on-year step changes in opex forecasts – real escalation removed from forecasts for next regulatory control period

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Network operation	13%	8%	12%	2%	1%	1%	2%
Network maintenance	6%	11%	6%	3%	4%	4%	2%
Customer services	2%	1%	10%	1%	1%	1%	1%
Allocated costs	10%	21%	9%	6%	3%	6%	0%
Other costs	(5%)	78%	36%	2%	2%	2%	2%
Total	7%	14%	10%	3%	3%	4%	2%

Source: PB analysis and Attachment F.1 SEM-Opex Model Ver7.2-Read Only.xls

As evident from Table 6.15, step changes are expected to occur in each of the expenditure categories. In order to provide further insight into the drivers behind this, PB has undertaken the same analysis at the next level of expenditure resolution, as shown in Table 6.16. Once again, should the step change exceed 10% in 2010-11 compared with the previous year, the expenditure has been highlighted.

Table 6.16 Comparison of opex for the current regulatory control period to the forecast opex for the next regulatory control period excluding real cost escalation.

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Network operating costs										
Distribution licence fee	3.13	3.20	3.43	3.53	3.57	3.62	3.62	3.62	3.62	3.62
Network access, monitoring & control	3.28	3.33	3.77	5.00	5.06	6.46	6.71	6.70	6.78	6.84
Network asset management	2.19	2.52	2.59	2.88	3.51	4.82	4.91	4.92	4.96	4.99
Network asset systems & information	1.70	3.51	3.30	3.13	3.58	3.63	3.71	3.71	3.73	3.75
Network telephony	3.45	3.66	3.90	5.16	5.78	6.42	6.58	6.80	7.08	7.41
Regulatory compliance	1.98	1.90	1.84	2.20	2.24	2.27	2.28	2.29	2.29	2.30
Network maintenance costs										
Inspections	3.82	3.66	4.18	4.66	7.06	9.59	9.95	10.26	10.55	10.81
Maintenance & repair	7.54	8.62	9.09	11.06	12.50	13.66	14.40	15.04	15.72	16.56
Substation property maintenance	2.86	3.42	3.54	3.40	3.55	3.70	3.84	3.96	4.07	4.17
Vegetation management	13.11	9.20	16.10	15.93	20.33	20.79	19.90	20.13	20.79	19.90
Emergency response	19.19	19.35	23.86	24.92	26.51	28.15	29.66	31.22	32.83	34.51
Demand Management	0.86	3.44	2.32	3.90	1.39	0.64	0.64	0.65	0.65	0.65
Demand management innovation fund	0.00	0.00	0.00	0.00	0.00	0.60	0.60	0.60	0.60	0.60
GSL payments	2.03	0.49	0.85	0.81	0.83	0.85	0.86	0.87	0.88	0.88
Network insurance	2.33	1.49	1.59	1.90	2.10	2.27	2.45	2.70	2.86	2.95
Customer services										
Meter reading	3.65	3.15	3.17	3.41	3.49	3.58	3.63	3.66	3.70	3.74
Call centre	2.39	2.47	2.55	2.15	2.21	2.27	2.29	2.32	2.34	2.36
Full retail contestability	10.86	9.59	10.88	11.46	11.85	13.80	13.97	14.11	14.24	14.38
Other customer services	1.89	3.03	3.72	4.29	4.38	4.63	4.69	4.73	4.75	4.77
Allocated costs										
CEO, planning and audit	2.18	1.89	1.86	2.13	2.16	2.20	2.21	2.21	2.22	2.23
Communications	1.79	2.00	1.55	2.08	2.41	2.44	2.48	2.47	2.46	2.46
Regulation & company secretary	1.17	1.03	1.53	3.12	3.17	1.92	1.93	2.15	3.25	3.26
Finance	7.68	5.44	6.64	4.65	8.92	9.28	9.44	9.54	9.64	9.72
HR & training	1.08	1.39	4.09	6.37	7.12	7.58	7.74	7.86	7.98	8.07

	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Property	2.29	2.74	2.83	2.72	3.00	6.82	6.98	7.04	7.37	7.53
Information systems	5.10	6.25	7.89	6.63	7.20	8.54	10.48	11.27	12.39	12.05
Risk management	5.90	4.33	5.05	7.58	8.59	8.98	9.44	9.89	10.21	10.38
Other costs										
Superannuation	(0.59)	6.23	6.28	6.87	9.61	9.64	9.64	9.64	9.64	9.64
Self Insurance	(1.18)	0.70	0.33	(0.44)	1.75	2.13	2.30	2.46	2.62	2.78
Debt raising costs	-	-	-	-	-	4.10	4.27	4.49	4.69	4.87
Equity raising costs	-	-	-	-	-	-	-	-	-	-
TOTAL	125.30	129.28	145.78	155.38	177.85	195.39	201.61	207.32	214.89	218.16

Source: PB analysis and Attachment F.1 SEM-Opex Model Ver7.2-Read Only.xls

PB reviewed Table 6.16 which compares the current period opex converted to 2009-10$ to the next with the general escalators set to zero, and identified seven activities where there is a material step change in annual opex. Each of these activities is reviewed in detail in sections 6.4 to 6.7 of this report.

6.3.5 PB assessment and findings

The following sections provide PB views on the opex forecasting methodology undertaken by ETSA Utilities.

General forecasting methodology

In reviewing ETSA Utilities forecasting methodology, PB has found that the staged approach involving: the definition of a base-year of expenditure informed by historical experience; identification of scope changes that are likely to occur over the outlook period from a bottom-up perspective; escalation of selected opex activates by key factors at a macro level; and finally escalation of selected expenditures by cost category to account for the real escalation anticipated for general input costs has been logically constructed, soundly applied and generally appears well considered.

In particular, the integrated opex model outlining each of the 21 direct cost opex activities and the 41 allocated cost activities includes a high degree of transparency, with excellent labelling and cross-referencing. The model treats each activity in a systematic manner and appears refined and of a high professional standard and quality, consistent with the evidence provided by ETSA Utilities that many aspects have been independently reviewed by both SKM and KPMG. Furthermore, it is well supported by over 145 supporting documents that clearly identify the data and sources of key assumptions used by ETSA Utilities to inform its opex forecasts.

At a high level, PB considers the general approach and framework adopted by ETSA Utilities to its opex forecasting approach is reasonable and practical.

Efficient base year

In regards to the use of the 2008-09 base year, PB concludes that it considers the base year opex of $155m to be prudent and efficient for the purposes of informing the forecasts on the basis that:

- ETSA Utilities has presented a detailed level of resolution of the disaggregated (business-as-usual) regulatory account data used to inform it
- a simple review of changes in expenditure at an activity level from 2007-08 to 2008-09 (which summated to 4% growth in real terms), indicated that opex for 19 activities reduced, while it increased for 37activites, and in two activities it remained constant, suggesting that ETSA Utilities has taken a balanced and transparent approach in selecting the base year
- it is the latest data available, and audited results will be available to the AER at the time of its determination
- it appropriately accounts for the latest AER approved CAM and finance adjustments
- ETSA Utilities appears to have removed abnormalities where relevant, and incorporated increases where appropriate in the base year (such as increases for unusually low vegetation management, telecommunications, debt raising costs, self insurance, finance adjustments, and reductions for demand management and the regulatory proposal preparation)
- the top-down view on relative efficiency through comparative benchmarking using a composite size factor shows ETSA Utilities historical opex for 2007-08 to be relatively efficient (notwithstanding the limitations such a simple analysis inherently includes), and this finding can be reasonably extrapolated to 2008-09 (even though it is 7% higher than 2007-08) given that all the businesses benchmarked are likely to have experienced a similar (small) annual increase in opex
- the asset management practices for the existing asset base, as outlined in the various asset management plans, including the strategic objectives; performance and condition risks; and maintenance and inspection cycles as discussed in section 6.2 of this report are transparent and reasonable.

Scope changes

In regards to the various scope changes identified by ETSA Utilities, each of these are addressed in general as part of the PB's review of key expenditure categories in sections 6.4 to 6.7 of this report. PB considers the approach adopted by ETSA Utilities to identify the individual scope changes using environmental scans accounting for the influence of key drivers affecting the business, and as informed through internal workshops, is a reasonable and pragmatic process that should adequately inform the forecasts of new expenditure requirements. In particular, PB is satisfied the process was comprehensive and objective, as it excluded any speculative scope changes towards the end of the next regulatory control period, it was based on long-term planning processes, and it included numerous reviews culminating in formal Executive Management approval prior to inclusion in the Regulatory Proposal.

Scale escalation

In regards to the use of the four scale escalators applied by ETSA Utilities to accommodate growth in its opex activates over the next regulatory control period, PB is complimentary of ETSA Utilities for preparing a clear description of exactly how and why it had established and applied the escalators[365], and is generally satisfied that network size, work volume,

365 Specifically the document Attachment F.4 Derivation and application of scale escalators.xls.

workforce size and customer growth are each factors that will influence opex requirements. PB also notes that ETSA Utilities has used a reasonable level of discretion in selecting the activities to which each of the factors applies, and notwithstanding three specific matters reviewed in the following sections, PB generally concurs that each factor is applied to each activity in a reasonable manner based on our understanding of the nature of the activities and the intent of the factor, including the use of some multi-factor escalators. For example, PB considers it is reasonable to escalate inspections, maintenance, vegetation management and emergency response opex activities by network growth (assuming some degree of economies of scale given the significant baseline of existing opex in these areas). PB also considers the economy of scale assumptions that have been incorporated are reasonable and consistent with those used by similar businesses such as ElectraNet and PowerLink.

As a result of our critical review of the input references and methodology described in the relevant supporting reports, PB also notes and accepts as accurate the independent reviews undertaken by SKM and KPMG in regards to the application of the growth escalators and the following comments from these businesses that support the approach:

- KPMG - has not identified any significant mathematical inaccuracies and inconsistencies in the application of the unique formulae and calculations in the Opex Model[366]
- SKM - considers the principle followed by ETSA Utilities of applying Specific Escalators to base year opex costs, in order to account for the likely increase in the volume of individual future opex program work practices, to be a sound and reasonable methodology[367]
- SKM - examined the derivation of each of the four Growth Factors, and concluded that the methodology employed had followed a sound approach
- SKM - concluded that in assigning each of the Growth Drivers to the various individual Cost categories during the cost escalation calculations contained within the model, such applications were undertaken accurately, as intended
- SKM - based on its understanding of utility network Growth Drivers and their relationship to increases in Opex Costs, SKM concluded that ETSA Utilities' methodology of assigning "Growth Drivers" to the individual cost categories … was reasonable.

PB has identified four specific applications of the scale escalations that are discussed in the following sections:

- top-down versus bottom-up network growth scale escalation of opex activities
- top-down versus bottom-up scale escalation of network access, monitoring and control activities
- scale escalation of emergency response
- replacement capex/opex trade-off

366 Attachment E.3 Pricing Submission Model Report 5853252_1.pdf, p.6
367 Attachment F.2 SKM Review of Scale Escalators.pdf, p.2

Top-down versus bottom-up network growth scale escalation of opex activities

As part of our review of the application of the scale escalators, PB has noted that the cumulative outcome of the application of the network growth escalation is that it is approximately 21% over the period from 2008-09 to 2014-15. This equates to a 6 year average growth rate of approximately 3.22%, which appears relatively high in the context of the overall cumulative impact. Therefore PB requested ETSA Utilities to attempt to reconcile this macro informed growth level with details of actual and forecast growth for specific assets from a bottom-up perspective over the same period. These figures are presented in Table 6.17.

Table 6.17 Network growth for lines and distribution transformers from 2008-09 to 2013-14

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Lines (km)	88,489	91,800	94,570	97,443	100,021	102,806	105,571
Lines growth (year on year)	-	3.7%	3.0%	3.0%	2.6%	2.8%	2.7%
Distribution transformers	48,735	49,993	51,280	52,595	53,939	55,313	56,717
Distribution transformer growth (year on year)	-	2.6%	2.6%	2.6%	2.6%	2.5%	2.5%
Installed substation capacity	4,451	4,495	4,616	4,737	4,893	5,033	5,153
Installed substation capacity growth (year on year)	-	0.99%	2.69%	2.62%	3.29%	2.86%	2.38%
Average growth – bottom up	-	2.44%	2.76%	2.74%	2.83%	2.73%	2.54%
Network growth escalator used by ETSA Utilities	-	3.45%	3.15%	3.90%	3.30%	2.93%	2.60%

Source: ETSA Utilities, email response PB.ETS.VP.55 Network growth size.pdf

From the data in Table 6.17, PB has calculated the average year on year annual growth for lines to be 2.99%, for distribution transformers to be 2.56% and for substation capacity to be 2.47%. The average annual growth rate for all three indicators is 2.67%. PB considers that these three indicators are representative of the ETSA Utilities network asset growth over the period and hence has calculated the impact of substituting this bottom-up forecast of network growth to identify the impact. The bottom-up network growth escalators result in a compounding asset growth over the period 2008-09 to 2014-15 of 17%.

PB has adjusted the ETSA Utilities opex modelling with the network growth escalator set to the bottom-up forecast over the outlook period – a reduction in the average network growth down from 3.22% to 2.67%. The revised forecast opex based on this recommendation is reduced by $9.9m, as shown in Table 6.18.

Table 6.18 Recommended opex with network growth escalator set to 2.67%

	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
ETSA Utilities proposal	203.3	214.7	225.7	239.0	248.4	1131.1
PB adjustment	(0.8)	(1.6)	(2.1)	(2.5)	(2.8)	(9.9)
PB recommendation	202.5	213.0	223.6	236.5	245.6	1121.3

Source: PB analysis

PB recommends a downwards adjustment be applied to ETSA Utilities total forecast opex over the next regulatory control period of $9.9m to account for a network growth factor more reflective of the actual assets that will be installed.

Top-down versus bottom-up scale escalation of network access, monitoring and control activities

In reviewing the ETSA Utilities opex model it was observed that the network access, monitoring and control opex activity (worksheet DA-2), was forecast by escalating the base 2008-09 year expenditures by a multi-factor escalator in the context that it was based on a combination of two separate escalators, specifically the network growth escalator and the work volume escalator. PB noted that ETSA Utilities had set the ratio between the two escalators such that the major contributor to the combined escalation was work volume (70%).

PB considers that by its design, network access, monitoring and control capability tends to increase in discreet and significant step changes. This observation is based on the fact that an additional operating desk requires the employment of at least five additional operators, depending on the hours of operation, and in some cases additional support staff. Once the staff have been employed, the capacity of the control room to manage additional planned switching and unplanned system control increases significantly. PB therefore considers the costs of providing network access, monitoring and control are far more closely aligned to the FTEs directly employed in this activity rather than the growth in work volume or network growth.

PB requested ETSA Utilities to provided additional information identifying the bottom-up growth in FTEs employed in (or proposed to be employed in) this activity from 2008-09 to 2014-15. The information provided is shown in Figure 6.11.

Activity	Year						
	2008/09	2009/10	2010/11	2011/12	2012/13	20013/14	2014/15
Workload above base	*Base*	*46%*	*45%*	*66%*	*58%*	*57%*	*53%*
Network controllers (FTEs)	23	30	32	32	32	32	32
Facilities Systems (FTEs)	19	22	23	23	23	23	23
SCADA support ($)	$760K	$1,141K	$1,527K	$1,797K	$1,797K	$1,797K	$1,797K

Figure 6.11 Forecast of network asses, monitoring and control resources and costs.

Source: ETSA Utilities, email, PB.ETS.VP.61 NOC FTEs.pdf, 23/08/09

Based on the information provided in Figure 6.11, PB has calculated the growth in FTEs employed in the network access, monitoring and control activity. This information is shown in Table 6.19.

Table 6.19 Actual and forecast FTEs employed in the network access, monitoring and control activity from 2008-09 to 2014-15

FTEs	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Network controllers	23	30	32	32	32	32	32
Facilities systems	19	22	23	23	23	23	23
TOTAL	42	52	55	55	55	55	55
Percentage increase (year on year)	-	23.81%	5.77%	-	-	-	-

Source: PB analysis

PB adjusted the ETSA Utilities opex model to only apply the percentage growth relating to the network access, monitoring and control growth in FTEs from 2008-09 through to the end of the next control period. The revised network access, monitoring and control expenditures are shown in Table 6.20.

Table 6.20 Opex model adjustments network access, monitoring and control expenditure

Network access, monitoring and control	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
ETSA Utilities proposal	6.86	7.37	7.61	7.93	8.27	38.04
Adjustment – reduced NOC FTEs	(0.70)	(1.24)	(1.28)	(1.40)	(1.53)	(6.15)
Revised NOC opex forecast	6.16	6.13	6.33	6.53	6.74	31.89

Source: PB analysis

PB then assessed these adjusted forecasts for reasonableness based on the fact that the staffing levels during the next regulatory period will be 13 FTEs higher than the 2008/09 levels which form the basis for the baseline opex forecasts. Assuming the network access, monitoring and control costs per employee remain constant in real terms over the study period, the five year baseline network access, monitoring and control opex for the next regulatory period would be $31.15m. However this amount does not include general escalation which adds another $4.23m to the total network access, monitoring and control opex forecast making the PB revised forecast $35.38m. The PB recommended network access, monitoring and control opex forecast is $2.66m lower than the ETSA Utilities forecast. Therefore PB does not consider that the opex model adjustments produce reasonable network access, monitoring and control opex forecasts and hence revised network access, monitoring and control forecasts based on based on average FTE costs to predict future network access, monitoring and control forecasts. These revised forecasts are detailed in Table 6.21.

Table 6.21 Recommended network access, monitoring and control expenditure

Network access, monitoring and control	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
ETSA Utilities proposal	6.86	7.37	7.61	7.93	8.27	38.04
PB adjusted baseline opex forecasts	6.23	6.23	6.23	6.23	6.23	31.15
ETSA General escalation	0.37	0.62	0.84	1.07	1.33	4.23
PB adjustment	(0.26)	(0.52)	(0.54)	(0.63)	(0.71)	(2.66)
PB recommendation	6.60	6.85	7.07	7.30	7.56	35.38

Source: PB analysis

PB recommends the downwards adjustment in the total network access, monitoring and control opex activity of $2.66m over the five year regulatory control period based on a bottom-up forecast of staff required to undertake this activity. PB notes the recommended opex expenditure for this activity in 2010-11 is $6.60 which represents a 26.198% increase the 2009-10 expenditure. PB considers that this increase is adequate to compensate for the additional work associated with the proposed operational and capital works programs.

Scale escalation of emergency response opex

ETSA Utilities has applied the network growth scale escalation to the emergency response opex activity, assuming an economy of scale factor of 5%. The principle being that an increased number of network assets will be subject to increased unplanned failures associated with storms and external factors.

The concern PB has with this methodology is that emergency response not only includes responses to outages due to a variety of issues such as storms, animals contacting live assets and vegetation contacting mains, etc but also from asset failures. Therefore applying the network growth escalation assumes that all emergency response expenditures are related to external influences, which is clearly not the case.

PB requested ETSA Utilities to provided additional information identifying the major components of the historical emergency response expenditures by cause. This data was provided as shown in Table 6.22, and it indicates that equipment failures constituted 43% of the total emergency response expenditures.

Table 6.22 Breakdown of emergency response expenditures by cause for the 2008-09 year.

Cause	Expenditure	Percentage	Definition
Equipment Failure	$ 8,913,925	43%	Result of failed equipment
Third Party	$ 3,192,138	15%	Damage to equipment caused by a third party eg. car hit pole
Customer Fault	$ 2,628,584	13%	Loss of supply due to a fault in customer's installation
Weather	$ 2,190,895	11%	Lightning, wind, vegetation or wind-blown debris
No Cause Found	$ 1,446,679	7%	Unknown cause
Asset overload	$ 1,084,275	5%	Failure due to overload of assets
Environmental - animals	$ 469,512	2%	Possums, birds, white ants
ETSA Service Fuse	$ 424,850	2%	Blown service fuse
Other	$ 379,364	2%	Miscellaneous other causes
Total	$ 20,730,493	100%	

Source: ETSA Utilities, email, PB.ETS.VP.48 and 49 ER cost breakdown.pdf, 23/08/09

On this basis, PB recommends that the economy of scale factor to be applied to the network growth escalator for emergency response be reduced by 43% to account for the expectation that new assets are not likely to fail consistently and repeatedly in an unplanned manner[368] (i.e. reduced from 0.95 to 0.54), but are expected to be exposed to third party, external an environmental effects.

PB adjusted the ETSA Utilities opex model to this affect and the revised emergency response forecasts on this recommendation only is shown in Table 6.23[369].

Table 6.23 Recommended reduction in growth of emergency response expenditure

	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
ETSA Utilities proposal	29.8	32.4	35.1	37.9	41.0	176.20
PB adjustment	(0.75)	(1.26)	(1.75)	(2.23)	(2.70)	(8.69)
PB recommendation	29.05	31.14	33.35	35.67	38.3	167.51

Source: PB analysis

The PB recommended adjustment results in a total reduction in forecast emergency response opex of $8.69m or 4.9% over the five year regulatory control period.

Replacement capex/opex trade-off

Capex/opex trade-off refers to the effect that the level and type of capex undertaken by a business will have on the level and type of opex required to continue the operation and maintenance of the network assets. The ETSA Utilities proposal confirms that ETSA Utilities recognises a strong relationship between the asset replacement forecast and the preventive maintenance program, as discussed in section 7.9 of the Regulatory Proposal. ETSA Utilities considers that its opex requirements are expected to increase in accordance with the age-based escalators established by SKM, and discussed in detail in section 6.5.2 of this report. In section 6.5.2 of this report, PB outlines the basis for recommending that the age escalation is not suitable for application to ETSA Utilities' asset base, as even though the

368 Except in the case of run-in failures, which should be covered by manufacturer's warranty.
369 Determined by assuming the age escalation had already been removed.

framework employed by SKM and applied by ETSA Utilities for determining the asset age and opex relationships was generally sound, it was not appropriate primarily due to the lack of calibration of the opex/age curves with ETSA Utilities actual assets and asset management approach.

On the basis that, ETSA Utilities' asset replacement capex program focuses on assets that are in poor condition and therefore are most likely to fail in service, PB would expect that a well-targeted, prioritised and optimised asset replacement program will reduce preventive maintenance requirements because older assets are more likely to be in poor condition and to have been nominated for increased inspection and maintenance cycles. It is also reasonable to anticipate that the benefits of a well-targeted replacement program will mean fewer unplanned asset failures requiring both defects rectification and emergency response, and will result in improved reliability and public safety.

ETSA Utilities is projecting a significant increase in replacement capex areas across most asset classes such as conductors, poles, power transformers, and circuit breakers. On this basis, and in light of the removal of the age escalation applied to maintenance and repair and emergency response opex, PB recommends a trade-off be incorporated using a top-down financial ratio methodology.

Specifically, the method involves calculating the annual ratio of compounding recommended asset replacement expenditure to the current (undepreciated) replacement cost of the asset base, and then applying 20%[370] of this ratio to calculate the recommended adjustment in the network maintenance forecast opex.

In calculating the annual compounding asset replacement expenditure, PB has assumed that the asset replacement will be evenly distributed throughout the year. The undepreciated replacement cost of the ETSA Utilities asset base has been calculated by PB using the recommended network growth ratio of 2.77%, which implies a replacement cost of the ETSA Utilities assets of approximately $8b in 2008-09[371].

PB has calculated the compounding annual asset replacement expenditures, the percentage of these annual compounding spends to the corresponding assumed asset replacement base, and the resultant reduction in network maintenance and repair expenditures as shown in Table 6.24. The growth and replacement capex forecasts are based on PB's recommended allowances as per section 4 of this report.

370 The 20% factor accounts for reduced defect requirements with replaced assets, and effectively reflects the proportion of total maintenance that is typically experienced by network owners associated with rectifying defects compared with the amount associated with routine inspections and maintenance. This proportion has been identified as typical, based in PB's experience working with a number of network owners across Australia.

371 The recommended network growth ratio of 2.77% implies a current replacement cost of the ETSA Utilities assets of approximately $8b.

Table 6.24 PB opex/capex trade-off calculations.

	2010-11	2011-12	2012-13	2013-14	2014-15
Network growth capex ($m)	138.50	238.10	225.20	287.40	252.86
UndepreciatedNetwork Replacement Cost ($m)	8377	8633	8949	9210	9477
Annual forecast asset replacement expenditure ($m)	56.60	66.60	70.00	76.50	78.90
Compounding asset replacement expenditure ($m)[1]	28.30	89.90	158.20	231.45	309.15
Percentage of annual asset replacement to undepreciated RAB	0.33%	1.00%	1.72%	2.44%	3.17%
95% of network maintenance (DA-13 only) ($m)	13.74	14.94	16.05	17.25	18.70
Recommended reduction in maintenance and repair ($m)	(0.01)	(0.03)	(0.06)	(0.08)	(0.12)

Note 1 – assuming the asset replacement capex is evenly spent throughout the year.

Source: PB analysis

The resulting reduction in network maintenance recommended by PB as a result of a top-down estimate of the capex/opex trade-off is $0.30m, as shown in Table 6.25.

Table 6.25 Recommended reduction in network maintenance to account for the asset replacement capex trade-off

Network maintenance	2010–11	2011–12	2012–13	2013–14	2014–15	TOTAL
Proposal	83.52	87.66	93.01	99.00	103.86	467.06
Difference — capex/opex trade-off	(0.01)	(0.03)	(0.06)	(0.08)	(0.12)	(0.30)
PB recommendation	83.51	87.63	92.95	98.92	103.74	466.76

Source: PB analysis

General (input cost) escalation

PB's review of the real labour, material and services escalation was confined to assessing the methodology used by ETSA Utilities to apply the escalation and not the reasonableness of the quantity of the escalators used. This aspect of the review will be carried out by the AER. To check the methodology ETSA Utilities used to escalate the base opex, PB ran the model several times changing the model inputs and checked the outputs each time for reasonableness. The model functioned correctly and was integrated in manner such that the impact of each escalator was clearly traceable and evident – affectively each escalator was applied at an activity level, which was each explicitly disaggregated into the cost categories. Given that the expenditure in each cost category over the next regulatory control period was either directly informed through historical experience from the regulatory accounts as part of the development of the base year, or through a detailed bottom-up forecast, PB considers the application of the real input cost escalators is applied accurately in accordance with their intended design.

As a result of the reviews conducted by PB on the ETSA Utilities opex model, PB believes that the model produces reasonable and accurate results in relation to the application of the real labour, material and services escalators. This finding is also supported by the independent reviews undertaken by SKM and KPMG, and their findings.

6.4 Network operations

Network operations opex is related to those activities which enable the effective and efficient operation of the distribution network including network access, network asset management, network telephony and regulatory compliance.

6.4.1 Proposed expenditure

The proposed expenditure for network operating costs as presented in the ETSA Utilities proposal is shown in Table 6.26. PB has included a second version of the forecast with the real cost escalation factors removed in order to determine the extent of any growth or step changes forecast for the network operations cost category.

Table 6.26 Proposed network operations opex for the 2010-2015 regulatory control period

Network operations	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
Distribution licence fee	3.62	3.62	3.62	3.62	3.62	18.09
Network access, monitoring and control	6.86	7.37	7.61	7.93	8.27	38.04
Network asset management	5.13	5.41	5.61	5.82	6.06	28.03
Network asset systems and information	3.84	4.05	4.18	4.33	4.48	20.88
Network telephony	6.65	7.00	7.44	7.96	8.52	37.57
Regulatory compliance	2.42	2.52	2.61	2.70	2.81	13.06
ETSA Utilities proposal	28.52	29.97	31.06	32.36	33.76	155.66
ETSA Utilities proposal – no escalation	27.22	27.80	28.04	28.45	28.90	140.41

Source: PB analysis and RIN999 Final ETSA Utilities Pro Formas.xls, template 2.2.2

6.4.2 PB assessment and findings

PB has reviewed the forecasting methodology as it relates to network operations and concluded that the process is reasonable and transparent, noting PB's previous recommendations in section 6.3.5 regarding adjustments to the proposed network growth escalation factors. This section examines the justification for scope changes.

The proposed scope changes in the network operations opex activities are shown in Table 6.27.

Table 6.27 Network operations direct cost scope changes proposed for the next regulatory control period.

Direct cost opex activity	Variation ID	Scope change	Five year total, $m
Asset strategy and planning	1	Additional labour resources to review condition monitoring data and develop/revise asset management strategies	0.5
	2	Resources to facilitate the establishment of a new workgroup responsible for capacity planning of LV assets	2.8
	3	Establishment of a dedicated substation asset management and condition monitoring team	2.9
Maintenance planning	4	Additional labour resources to analyse condition monitoring data and plan maintenance of powerline assets	0.9
Network telephony	5	Additional expenditure associated with the program of data link upgrades during the 2005 - 2010 control period	2.6
	6	Implementation of an intensified condition monitoring regime for Tel assets	2.3
Total			12.0

Source: PB analysis and Attachment F.1 SEM-Opex Model Ver7.2-Read Only.xls

Variation 1[372] is related to increasing the number of FTEs from 1.3 to 2.0 per annum to manage the increased management of asset condition related data such as the increased volume of defect data, reviewing and cataloguing records and photo's, analysing data reports, etc. PB considers this activity is prudent and efficient and will assist in realising the longer term benefits of opex and capex efficiency associated with improved CBRM.

Variation 2[373] is associated with establishing a team of 4 FTE's focussed on developing a LV planning function to improve capacity management of street transformers and LV mains. Whilst PB found that the risk assessment used as the primary basis for proposing significant capex increases on the LV network overstates the risk to ETSA Utilities, and does not support the full scope of the proposed program[374], PB does concur that a more proactive approach to LV planning is prudent in that it will assist to mitigate the impacts of severe heat-waves and the likelihood and consequences of unplanned failures. Establishing the planning function will ensure the recommended allowance for the LV upgrade work is best optimised and prioritised, and provide further targeted insight into any strategy required going forward. As a result of PB's recommendation to reduce LV planning capex program be from $124 to $32m, the LV planning opex work will be slightly diminished, however the reinstated opex allowance of $0.8m for the QoS LV planning and monitoring function will offset any reduction[375]. Therefore PB considers the full opex allowance for Variation 2 is prudent and efficient.

Variation 3[376] is associated with establishing a team of 5 FTE's focussed on fully incorporating condition and performance monitoring of substation assets (transformers, primary plant, switchgear and earth grids), including the establishment of appropriate performance measures and goals, data analysis and risk management, maintaining

372 Reference to OX014 and OX015

373 Reference to OX016 and OX017

374 Section 4.2.6, capex review of LV network upgrade program

375 For the avoidance of doubt, PB has included the costs removed from capex for the QoS LV planning and monitoring function, refer to the adjustment made in Table 4.6.

376 Reference to OX034

maintenance strategies and updating standards. PB considers this activity is prudent and efficient and is important in supporting the longer term benefits of opex and capex efficiency associated with ETSA Utilities move to a strategic CBRM approach, and it will allow ETSA Utilities to optimise the asset replacement capex proposed by PB.

Variation 4[377] is related to increasing the number of FTEs from 2.4 to 3.7 per annum to manage the increased management of asset condition data related to powerlines, including investigation into powerline and cable failures and the annual review of asset management plans. PB considers this activity is prudent and efficient and will assist in realising the longer term benefits of opex and capex efficiency associated with improved CBRM.

Variations 5 and 6[378] are related to network telephony and the need to upgrade telecommunications data links between sites and implement an increased condition monitoring regime for telecommunication assets. ETSA Utilities has staff and IT systems located in 27 depots and office sites throughout South Australia. These sites are connected by a data network made up of both ETSA Utilities and third party owned telecommunications carrier services. PB has reviewed the bandwidth currently available to these sites and the proposed upgrades and considers the upgrades to be if anything overdue given the very low capacity to transfer data between operational sites. The additional opex included in the forecast network telephony is associated with the provision of the additional bandwidth to ETSA Utilities depots and offices and PB considers the additional opex to be prudent and efficient.

6.4.3 PB recommendations

PB considers ETSA Utilities proposed network operations opex is prudent and efficient and recommends no further adjustment to the proposed opex as a result of our review of the proposed scope changes in this category. This accounts for PB's review of the justification of scope changes, and is in accordance with PB's review of the forecasting methodology, including the development of the base-year expenditure, and the application of general escalation. PB has made adjustments to the proposed allowance (as described in section 6.3.5 and Table 6.20) in regards to the application of growth escalators.

Table 6.28 Recommended network operations opex for the 2010-2015 regulatory control period

Network operations	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
ETSA Utilities proposal	28.52	29.97	31.06	32.36	33.76	155.66
PB adjustment – reduced scale escalation	-	-	-	-	-	-
PB recommendation	28.52	29.97	31.06	32.36	33.76	155.66

Source: PB analysis

377 Reference to OX018 and OX019
378 Reference to OX106, OX107 and OX110

6.5 Network maintenance

Network maintenance opex is related to planned or programmed maintenance carried out to reduce the probability of failure or performance degradation of a network asset. It also includes vegetation management, emergency response, demand management and network insurance, and it makes up the majority (41%) of the total opex forecast.

6.5.1 Proposed expenditure

PB has reviewed the forecasting methodology as it relates to network maintenance and concluded that the process is reasonable and transparent and notwithstanding PB's findings in section 6.3.5, the escalation factors have been applied appropriately. This section examines the justification for scope changes.

Table 6.29 Proposed network maintenance opex for the 2010-2015 regulatory control period

Network maintenance	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
Inspections	10.02	10.65	11.25	11.84	12.45	56.21
Maintenance & repair	14.47	15.72	16.90	18.15	19.68	84.93
Substation property maintenance	3.79	4.01	4.24	4.48	4.67	21.19
Vegetation management	21.02	20.26	20.66	21.58	20.90	104.43
Emergency response	29.84	32.41	35.06	37.87	40.96	176.14
Demand Management	0.68	0.70	0.72	0.74	0.77	3.61
Demand Management Innovation Fund	0.60	0.60	0.60	0.60	0.60	3.00
Guaranteed Service Level Payments	0.85	0.86	0.87	0.88	0.88	4.33
Network insurance	2.27	2.45	2.70	2.86	2.95	13.23
ETSA Utilities proposal	83.52	87.66	93.01	99.00	103.86	467.06
ETSA Utilities proposal – no escalation	80.25	82.31	85.42	88.93	91.04	427.95

Source: PB analysis and RIN999 Final ETSA Utilities Pro Formas.xls, template 2.2.2

6.5.2 PB assessment and findings

PB has reviewed the forecasting methodology as it relates to network maintenance and concluded that the process is reasonable and transparent and escalation factors have been applied appropriately. This section examines the justification for scope changes.

The proposed scope changes in network maintenance opex activities are shown in Table 6.30.

Table 6.30 Network maintenance direct cost scope changes proposed for the next regulatory control period.

Direct cost opex activity	Variation ID	Scope change	Five year total, $m
Inspections	1	Change in the scope of ETSA Utilities' service contract with its aerial inspection services provider	6.8
	2	Resources to facilitate more frequent inspections of powerline assets as part of ETSA Utilities condition monitoring strategy	1.9
	3	Additional labour resources to facilitate more frequent and detailed asset inspections in high corrosion risk areas	8.8
	4	Resources to facilitate more detailed inspection of substation assets as part of ETSA Utilities condition monitoring strategy	3.7
Maintenance and repair	5	Additional resources to facilitate delivery of a meter inspection and testing program that complies with new requirements	4.3
	6	Costs associated with non-network solutions (peak lopping generation)	0.7
	7	Additional operating expenditure associated with an increase in average asset age	4.7
Emergency response	8	Additional operating expenditure associated with an increase in average asset age	10.1
DMIF	9	Agreed allowance for DM activities in next period as per AER Framework & Approach.	3.0
Network insurance	10	Increase in insurance premiums as per AON forecast. Also includes BI insurance for loss of Q factor.	3.5
Total			47.5

Source: PB analysis and Attachment F.1 SEM-Opex Model Ver7.2-Read Only.xls

Inspection variations

The inspection related variations (1 to 4) summate to $21.7m over the next regulatory control period. In section 6.3 of this report PB referenced ETSA Utilities change in asset management approach (commenced in 2009/10) from generally only replacing an asset after failure, to a condition monitoring and life assessment (CM&LA) methodology. Typically, any move towards a condition based approach to maintenance is accompanied by increased inspections in order to determine asset condition.

The variations proposed by ETSA Utilities include new inspections, as well as increased inspection frequency where issues have been identified in high corrosion areas.

PB has reviewed the spreadsheets that form the basis for the variations[379] and identified that the additional inspections proposed by ETSA Utilities include sound level testing at zone substations, additional thermo-graphic imaging, 66kV transformer bushing tests, zone substation earthing mat resistivity testing and gas insulated 66kV switchgear tests.

379 OX029 Inspections and tasks in high corrosion risk areas and OX033 Intensified CM for power lines bottom-up forecast

In addition to additional testing, ETSA Utilities proposes to increase inspection cycles in high corrosion areas for distribution lines. 'Stobie' poles[380] have a very long life in areas where the soil is non-corrosive, and ETSA Utilities has adopted a 10 year inspection cycle. In areas where the soil is corrosive the poles can experience severe rusting on the steel channels and therefore ETSA Utilities has commenced a trial 5 year inspection cycle in these areas. ETSA Utilities provided advice during our discussions indicating that the 5 year cycle in high corrosion areas was effective in identifying poles that could be reinforced prior to failure and hence these additional inspections were cost effective because they reduced the number of unplanned failures.

ETSA Utilities is proposing a change in approach to aerial inspections[381]. Historically, an ETSA Utilities employee was used as a spotter in the aircraft or helicopter to identify either asset defect or line faults, as ETSA Utilities uses aerial inspections for both purposes. ETSA Utilities has indefinitely suspended internal staff from participating in these inspections for health and safety reasons and intends to engage operators with either additional technology or specially trained personnel to provide these services in the future. Technology has advanced to the extent that clear digital images shoeing defects or faults can be taken without the need for aircraft to be in such close proximity to the assets. ETSA Utilities considers this approach to be far safer than the current method. PB agrees with this approach and also concurs that aerial inspections are more cost effective and efficient than ground patrols. ETSA Utilities has included additional opex to compensate for these changes and PB considers that the additional $6.8m (including real cost escalation) over the five year control period is reasonable.

PB's review has concluded that the proposed additional inspections and the reduction in inspection cycle times in high corrosion areas are prudent given ETSA Utilities asset performance and therefore recommend that the additional inspection opex be included in the forecast opex for the next regulatory period. PB considers this increased inspection activity is prudent and efficient and is important in supporting the longer term benefits of opex and capex efficiency associated with ETSA Utilities move to a strategic CBRM approach, and it will allow ETSA Utilities to optimise the allocation of asset replacement capex in the next regulatory control period.

Maintenance and repair variations

The maintenance and repair related variations (5 and 6) include additional opex associated with new meter testing requirements[382] and a need for additional mobile generator opex[383].

The National Electricity Market (NEM) Metrology Procedure[384], prepared in accordance with clause 11.5.4 of the NER, was issued by the National Electricity Market Management Company (NEMMCO) on 9 November 2006, with an effective date of 1 January 2007. Prior to release of this procedure, ETSA Utilities carried out its metrology testing and maintenance in accordance with the Electricity Metering Code issued by ESCoSA[385]. NEMMCO's new metrology procedure requires ETSA to make significant changes to its metrology testing and maintenance procedures; and the changes are to be approved by NEMMCO. Clause 2.6.8 of the Metrology Procedure requires meter sampling of Type 6 metering installations at least once every five years. This requirement represents a considerable change when compared

380 'Stobie' poles are concrete and steel based poles unique to South Australia.
381 OX023 Explanatory Paper - Aerial Inspections.pdf
382 OX041 New Metering Compliance Requirements Tasks
383 OX045 Mobile Generators- Bottom-up forecast
384 NEMMCO, *National Electricity Market Metrology Procedure*, Version 1.00
385 ESCoSA, Electricity Metering Code, last varied 1 July 2005.

with clause 3.15.3 of the Code issued by ESCoSA, which previously required that metering installations be sampled only once every ten years.

PB notes that this is a statutory requirement and therefore considers the need is prudent. PB has reviewed the costing spreadsheet[386] presented by ETSA Utilities, which forecasts based on a detailed bottom-up approach with references to 2008 unit costs for maintenance across activity types. Given the 2008 unit costs are transparent and have been informed by historical experience, PB concludes that the proposed costs are efficient.

ETSA Utilities uses mobile generation for both the provision of emergency power resulting from planned maintenance or equipment failure and for peak lopping support at electrically isolated locations such as Kangaroo Island, Meningie and Pinnaroo. The opex costs included in the mobile generation variation include generator lease costs, fuel, and inspections and service costs. ETSA Utilities has extensive experience utilising mobile generation for HV support and peak lopping support for locations such as Kangaroo Island.

PB has reviewed the detailed spreadsheet[387] used to develop the bottom up forecast and considers the $0.7m (including real cost escalation) total additional forecast opex for mobile generation prudent and efficient. The number of mobile generators will increase from 1 in 2008 to 8 in 2012 and beyond, providing a high degree of flexibility for improved reliability in remote areas.

Asset age escalation

Variation 7 and 8 have relate to asset age escalation. ETSA Utilities has applied a scope change in the form of an annual cumulative escalation factor to the base year maintenance costs and the base year emergency response opex in accordance with a recommendation by SKM[388], as per Table 6.31.

Table 6.31 SKM proposed age escalators to apply to maintenance and repair and emergency response opex

age escalator	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Weighted average opex escalation due to asset age - annual	1.87%	1.72%	1.40%	1.66%	1.81%	1.97%
Weighted average opex escalation due to asset age - cumulative	1.87%	3.62%	5.07%	6.82%	8.75%	10.89%

Source: Attachment F.3 SKM Analysis of Asset Age Impacts.pdf, p.17

SKM was engaged by ETSA Utilities to model the impact of its proposed capex program over the next regulatory period on the average age of the distribution network. The results of this study indicate that the weighted average age of the total distribution network varies over the outlook period from 36.2 years in 2009 to 38.9 years (+7%) in 2015. This view was heavily informed by the 'overhead' asset class, which comprised 75% of the total replacement cost and itself varied from 39.4 years to 44.3 years (+12%) over the same period. This relatively significant increase in average age is expected to reflect in increased opex requirements.

386 OX041 New Metering Compliance Requirement Tasks.xls
387 OX045 Mobile Generators - Bottom-up forecast.xls
388 Attachment F.3 SKM Analysis of Asset Age Impacts.pdf

The process undertaken by SKM to calculate the increase in opex costs included the following steps:

- Establishing age versus opex characteristics for each asset class based on an exponential relationship between the cost of maintaining a brand new asset compared with an aged/poor condition version, where SKM mapped ETSA Utilities asset classes to its database of opex cost curves. These cost curves were based on previously obtained data for the Powercor network in Victoria (on the basis that ETSA Utilities could not disaggregate its historical opex by asset class due to limitations in its information systems, and that the Powercor network most resembled ETSA Utilities in the context of being a combination of both urban and rural networks).

- Establishing asset age profiles before and after the proposed capex programs to identify the change in age profile, assuming that replacement capex replaced the oldest assets as a priority.

- Multiplying the age versus opex curves by the adjusted age profiles to directly work out the annual increase in opex by asset class, and then summating this

Whilst PB concurs with the principle that an aging asset base will generally require additional maintenance when the average asset age is approaching the end of its expected service life, we have a number of reservations about the wide-ranging application of the escalators as prepared by SKM and applied by ETSA Utilities. These include the following matters:

- in PB's view, age versus opex characteristics can vary significantly within an asset class and across asset classes subject to an individual businesses strategy and approach to asset management, maintenance and defect policy

- the accuracy of the model is fundamentally dependent on a calibrated age versus opex characteristic, yet the asset management practices or opex costs for ETSA Utilities and Powercor have not been reconciled, or aligned to ensure the age versus opex curves are appropriate

- the inspection, maintenance and repair practices of ETSA Utilities for stobie poles is materially different compared with round wooden or concrete poles used by Powercor, and this is a material factor as the overhead asset class strongly informs the opex increases as this asset class comprises 75% of the network by value and it is exhibits the greatest increase in weighted average age (+12%)

- ETSA Utilities has proposed a variation to increase inspection cycles in high-corrosion zones to every five years instead of every 10 years

- ETSA Utilities strategy is to move to an asset management and maintenance approach that relies significantly on condition-based indicators, which will have the impact of lessening the opex/age relationship

- The average increase in weighted average age for overheads assets moving from 36 years to 44 years is not likely to be a significant factor in increasing opex needs as these asset are far from the end of their standard lives, ETSA Utilities has assigned aset lives of:

  - poles – 100 , 75 and 50 years in low, medium and high corrosion zones, respectively (where 95% of the population is located in the medium or low corrosion zones)

   - conductors – 70 , 56 and 45 years in low, medium and high corrosion zones, respectively (where 96% of the population is located in the medium or low corrosion zones)
   - overhead line components – 56 years, with no systematic deterioration of porcelain and glass insulators until over 50 years of age, and mean life of 100 years[389]

- the assessment carried out by SKM in no way suggests the asset failure rate will increase in proportion to the increasing average age as there is no direct age versus failure rate characteristic included, necessitating a direct increase in emergency response opex

- ETSA Utilities has applied the age escalation to the entire emergency response opex activity, which not only includes responses to outages resulting from asset failures but also responses to outages due to a variety of other issues such as storms, animals contacting live assets and vegetation contacting mains. Applying the asset age escalation assumes that all emergency response expenditures are related to asset failure, which is clearly not the case, and ETSA Utilities has advised that in 2008-09 only 43% of the entire emergency response opex related to plant failures[390].

Given these matters, notably the lack of calibration of the SKM age versus opex characteristics to ETSA Utilities existing asset base and classes, PB is of the view that the proposed increases in opex due to increasing asset age have not been substantiated and therefore are not prudent and efficient scope changes. PB recommends the asset age escalation be removed from the maintenance and repair and emergency response opex forecasts in accordance with Table 6.32.

Table 6.32 Recommended maintenance and repair and emergency response expenditure opex.

	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
ETSA Utilities proposal - total	44.31	48.13	51.96	56.02	60.64	261.06
ETSA Utilities proposal - emergency response	29.84	32.41	35.06	37.87	40.96	176.14
PB adjustment - emergency response	(1.08)	(1.66)	(2.46)	(3.45)	(4.68)	(13.33)
ETSA Utilities proposal – maintenance and repair	14.47	15.72	16.90	18.15	19.68	84.92
PB adjustment – maintenance and repair	(0.48)	(0.76)	(1.14)	(1.61)	(2.21)	(6.20)
PB recommendation – total	42.75	45.71	48.36	50.96	53.75	241.53

Source: PB analysis

Vegetation management

ETSA Utilities has forecast its vegetation management from a bottom-up perspective, which PB believes is reasonable in the context it is the second largest opex activity over the next regulatory period (9.2%).

389 CX105 Overhead Line Components AMP 3.1.06.pdf, p.23

390 ETSA Utilities, email response PB.ETS.VP.48 and 49 ER cost breakdown.pdf

ETSA Utilities has had a legislated obligation to manage vegetation in the vicinity of its assets within prescriptive clearance zones[391], since 2000. ETSA has balanced the risk posed by vegetation close to its assets with the visual amenity provided by the tree-scape as part of significant an ongoing consultation with local councils.

However, during the current regulatory period, ETSA Utilities determined the risk posed by non-compliance was too high and proposed to deliver a complaint program over the next regulatory control period. This led to considerable resistance from local councils, culminating in legal action in the South Australian Supreme Court, which was subsequently withdrawn. ETSA Utilities thereafter made a submission to the state government seeking and amendment to the Regulations when they expire in September 2009. In the interim, ETSA Utilities has proposed a fully complaint vegetation management program as part of its forecast opex allowance, and will seek a negative change pass-through should any material change to the Regulations occur.

PB considers the need for the increased vegetation management allowance is reasonable and prudent given the current non-compliance and potential safety issues. Our review of the bottom-up cost estimate identified that a 5% contingency allowance has been included as part of the external costs. PB considers the inclusion of such a contingency is not prudent or efficient as the scope of work is not specified. On this basis, PB recommends the contingency allowance is removed from the vegetation management allowance in accordance with Table 6.33[392].

Table 6.33 Recommended vegetation management opex for the 2010-2015 regulatory control period

Vegetation management	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
ETSA Utilities proposal	21.02	20.26	20.66	21.58	20.90	104.42
PB adjustment – reduced vegetation contingency	(0.96)	(0.92)	(0.94)	(0.98)	(0.95)	(4.77)
PB recommendation	20.06	19.34	19.72	20.6	19.95	99.65

Source: PB analysis

Network insurance

PB has reviewed the AON insurance premium forecast report informing the scope change to opex required for network insurance[393]. The report clearly outlines the methodology applied, including the following considerations:

- detailed outline of the base year insurance premiums for 2008-09
- ETSA Utilities forecasts of business trends, including asset values, revenue and employee numbers
- wider insurance industry trends
- aligning ETSA Utilities relationship to the wider insurance industry trends
- forecasting future insurance costs, without taking into account possible extreme events.

391 Electricity (Principles of Vegetation Clearance) Regulations 1996
392 This adjustment has been quantified independently from PB's other adjustments.
393 Attachment F.8 AON Insurance Premium Forecast.pdf

In view of the transparent approach adopted by AON and given the nature of the insurance classes included in ETSA Utilities 2008-09 insurance costs and the potential impact of bushfire and environmental factors outlined, PB is satisfied the increased opex requirements are prudent and efficient. PB also notes that ETSA Utilities has ensured that only the appropriate proportion of the insurance premium relevant to Standard Control Services is include in the forecast opex allowance, as per the AER approved CAM.

Demand management

During the current regulatory control period, ESCoSA made specific provision for ETSA Utilities to commit approximately $20m over the five year period to trial a number of demand management initiatives, with the aim of reducing peak-driven network investment.

The range of initiatives trailed has included:

- power factor improvements in business and manufacturing premises
- trials of Voluntary Load Curtailment (VLC) programmes for large customers
- direct Load Control (DLC) of residential equipment such as air-conditioners
- use of standby generation
- the use of incentives for customers to reduce demand at times of peak demand.

On the basis of the investigations completed by ETSA Utilities thus far, a number of non-network solutions have been incorporated into ETSA Utilities' projected capital and operating expenditure programs. Examples include the use of customer standby generation capacity in the North Adelaide area to defer network augmentation, and construction of a small power station at Pinaroo to defer a connection point project.

The opex allowance incorporated by ETSA Utilities into its direct cost forecasts (in addition to the DM incentive scheme) is simply an allowance for the creation of 6 FTE positions to run the DM program. PB considers this approach to be prudent and the costs proposed are efficient given the bottom-up nature of the forecast, therefore PB recommends the total allowance for DM be included by the AER.

It is noted that ETSA Utilities has proposed a modification to the AER's proposed Demand Management Incentive Scheme (part B) as discussed in chapter 9 of its Regulatory Proposal.

6.5.3 PB recommendations

PB recommends a reduction in network maintenance opex of $24.3m during the next regulatory control period. The adjustment would result from a reduction in the asset age escalation applied to the maintenance and repair and the emergency response activities, and the removal of a contingency allowance included in the bottom-up forecast for vegetation management.

Table 6.34 Recommended network maintenance opex for the 2010-2015 regulatory control period

Network maintenance	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
ETSA Utilities proposal	83.52	87.66	93.01	99.00	103.86	467.06
PB adjustment - emergency response	(1.08)	(1.66)	(2.46)	(3.45)	(4.68)	(13.33)
PB adjustment – maintenance and repair	(0.48)	(0.76)	(1.14)	(1.61)	(2.21)	(6.20)
PB adjustment – reduced vegetation contingency	(0.96)	(0.92)	(0.94)	(0.98)	(0.95)	(4.77)
PB recommendation	81.00	84.32	88.47	92.96	96.02	442.76

Source: PB analysis

6.6 Customer services

Customer services opex is related to call centre activities, meter reading and regulated activities arising from the introduction of full retail competition (FRC).

6.6.1 Proposed expenditure

The proposed expenditure for customer services opex as presented in the ETSA Utilities proposal is shown in Table 6.35. PB has included a second version of the forecast with the real cost escalation factors removed in order to determine whether any growth or step changes apart from real cost escalation are forecast for the customer service category.

Table 6.35 Proposed customer services opex for the 2010-2015 regulatory control period

Customers services	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
Meter reading	3.62	3.68	3.75	3.82	3.90	18.76
Call centre	2.29	2.33	2.37	2.41	2.46	11.86
Full retail contestability	14.05	14.38	14.71	15.05	15.43	73.62
Other customer services	4.86	5.06	5.24	5.40	5.58	26.15
ETSA Utilities proposal	24.82	25.44	26.07	26.69	27.36	130.38
ETSA Utilities proposal – no escalation	24.28	24.58	24.82	25.03	25.25	123.96

Source: PB analysis and RIN999 Final ETSA Utilities Pro Formas.xls, template 2.2.2

6.6.2 PB assessment and findings

PB has reviewed the forecasting methodology as it relates to customer services and concluded that the process is reasonable and transparent and escalation factors have been applied appropriately. This section examines the justification for scope changes.

One scope change in customer service opex is proposed, as shown in Table 6.36.

Table 6.36 Network maintenance direct cost scope changes proposed for the next regulatory control period.

Direct cost opex activity	Variation ID	Scope change	Five year total, $m
Retail contestability	1	Additional expenses associated with changes in the FRC systems supported by CHED Services	8.5

Source: PB analysis and Attachment F.1 SEM-Opex Model Ver7.2-Read Only.xls

PB has reviewed the significant step change in customer service opex over the next regulatory control period related to the full retail contestability activity.

ETSA Utilities has entered into commercial contracts with CHED Services, a related party that has part ownership of ETSA Utilities. These contracts relate to provision of call centre services, FRC services and FRC systems support services. The current contracts with CHED Services for call centre and FRC services cover the period 2008 to 2010, whereas the current contract for FRC systems support services expires on 31 December 2009.

Before these contracts were established, KPMG was engaged to determine whether the draft contracts with CHED Services and the proposed prices reflected commercial terms. As a result of this review, new contracts were negotiated, with amendments reflecting the advice of KPMG - as detailed in its reports concerning call centre services[394] and FRC services[395].

With respect to the provision of FRC services and FRC systems support services, KPMG determined that the margins in the current contracts both fall within the range considered reflective of arm's length terms[396]. With respect to the provision of call centre services, KPMG determined that the call centre costs per customer are lower than all the comparison benchmarks, and that costs per call were in the lower half of the peer benchmarks.

As a participant in the NEM, ETSA Utilities is required to interact with NEMMCO and other market participants through the use of information systems. In particular, the introduction of full retail competition (FRC) has obliged ETSA Utilities to implement IT systems to enable the transfer of customers between registered retailers in the NEM. The NEM systems implemented by ETSA Utilities are very similar to those implemented by Citipower and Powercor— Victorian DNSPs that are related through ownership to ETSA Utilities. At the time that these systems were implemented, ETSA Utilities entered into commercial arrangements with Powercor for the implementation, maintenance and support of these systems. The provision of these services has since transferred to CHED Services, and the contractual arrangements with CHED Services have been reviewed by KPMG. In its report, provided as Attachment F.12 to the Regulatory Proposal, KPMG found that they are reflective of commercial terms and ETSA Utilities believes that consumers have benefited from these arrangements through lower costs, which have been made possible through shared IT infrastructure, software licensing and IT system support personnel.

Starting in 2009, the State Government of Victoria has approved the widespread implementation of advanced interval metering. Owing to the substantial change in functionality of the FRC systems required by the advanced interval metering rollout, CHED

394 KPMG, Analysis of call centre outsourcing contract performance benchmarks, 20 November 2008, provided as Attachment F.13 to this Proposal

395 KPMG, Examination of commercial terms in FRC and IT services outsourcing contracts with CHED services, 10 April 2008, provided as Attachment F.12 to this Proposal

396 ETSA Utilities Proposal, section 7.6.7 (FRC Systems Support) where a proposal by CHED Services to increase its service fee is addressed in detail.

Services has been required to completely revamp its systems, and because of this has proposed a significant increase in the support and maintenance fees ETSA Utilities pays.

In light of the proposal CHED Services has put forward, ETSA Utilities engaged the services of SMS Consulting Group Ltd (SMS), consultants with extensive knowledge and experience of the FRC systems involved, to review CHED Services' proposal. SMS were also commissioned to review alternative options available to ETSA Utilities, and to recommend the most prudent and efficient option. In its report[397], SMS advised that, despite the proposed cost increase, the solution offered by CHED Services remains the most cost-effective, with significant savings of approximately 13% beyond those of developing and maintaining stand-alone systems, the next-cheapest option[398].

PB has reviewed the two KPMG reports relating to call centre outsourcing contract performance benchmarks and examination of commercial terms in FRC and IT services outsourcing and also the SMS Management & Technology, ETSA Utilities Strategic Scenarios Assessment, 25 February 2009. The reviews indicated to PB that although the margins achieved by CHED Services appear to be at the high end compared to the margins detailed in the KPMG report, the synergies ETSA achieved in outsourcing these services results in lower costs than providing the services in-house on a stand-alone basis. Accordingly, PB considers the opex included in the forecasts for the next regulatory period for these services to be reasonable and the option selected in relation to the ongoing provision of FRC services to be the most cost-effective.

6.6.3 PB recommendations

PB considers the forecast opex for customer services is prudent and efficient and has not recommended any adjustment.

Table 6.37 Recommended customer services opex for the 2010-2015 regulatory control period

Customer services	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
ETSA Utilities proposal	24.82	25.44	26.07	26.69	27.36	130.38
PB adjustment – reduced scale escalation	-	-	-	-	-	-
PB recommendation	24.82	25.44	26.07	26.69	27.36	130.38

Source: PB analysis

6.7 Allocated costs

Allocated costs are all shared business overheads, including the costs associated with the CEO, planning and audit, communications, regulation and company secretary, HR and training, property, information systems and risk management.

397 ETSA Utilities proposal Attachment F11, SMS Strategic Scenarios Assessment v3,

398 SMS Management & Technology, ETSA Utilities Strategic Scenarios Assessment, 25 February 2009, p 6.

6.7.1 Proposed expenditure

The proposed expenditure for allocated costs as presented in the ETSA Utilities proposal is shown in Table 6.38. PB has included a second version of the forecast with the real cost escalation factors backed out in order to determine whether any growth or step changes apart from real cost escalation are forecast for the allocated cost category.

Table 6.38 Proposed allocated costs for the 2010-2015 regulatory control period

Allocated costs	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
CEO, planning and audit	2.29	2.36	2.42	2.49	2.56	12.13
Communications	2.51	2.59	2.61	2.64	2.67	13.02
Regulation and company secretary	2.06	2.15	2.49	3.71	3.82	14.22
Finance	9.85	10.38	10.84	11.29	11.76	54.12
HR and training	8.02	8.47	8.86	9.25	9.64	44.24
Property	6.92	7.17	7.36	7.86	8.12	37.44
Information systems	8.97	11.24	12.38	13.85	13.88	60.32
Risk management	9.30	9.95	10.58	11.07	11.43	52.33
ETSA Utilities proposal	49.93	54.32	57.54	62.15	63.89	287.83
ETSA Utilities proposal – no escalation	47.76	50.71	52.44	55.52	55.68	262.11

Source: PB analysis and RIN999 Final ETSA Utilities Pro Formas.xls, template 2.2.2

6.7.2 PB assessment and findings

PB has reviewed the forecasting methodology as it relates to allocated costs and concluded that the process is reasonable and transparent and escalation factors have been applied appropriately. This section examines the justification for scope changes.

The proposed scope changes in allocated cost activities are shown in Table 6.39.

Table 6.39 Allocated cost scope changes proposed for the next regulatory control period

Allocated cost activity	Scope change	Five year total, $m
Regulation	Cost associated with undertaking revenue determination - embedded in base year	(3.7)
Finance - Adjustments	Variation to offset the impact of finance adjustments embedded in the base year	19.4
Training Centre	Resources to facilitate delivery of training services of the Davenport centre	2.2
Information Technology	SAP SUN Hardware support & maintenance extension - 2yrs	0.5
	Ongoing opex costs associated with supporting new capabilities delivered by the IT CAPEX program	19.2
Property – Offices and	Increase in service contracts for depot related costs (ie fire, scheduled maintenance (electrical, AC, Security).	1.5

Allocated cost activity	Scope change	Five year total, $m
Depots	Increase in land tax associated with new ETSA Utilities property acquisitions	3.4
	Increase in leasing fees due to lease of new Keswick office/carparking and Holden Hill properties	5.4
Property – DLC Land Tax	Increase in land tax based on Treasurer's instruction	10.7
Risk & Insurance – Shared Insurance Premiums	Change in insurance premiums per AON forecast. Also includes BI insurance for loss of Q factor.	1.4
Risk & Insurance – Support Costs	Change in insurance premiums per AON forecast. Also includes BI insurance for loss of Q factor.	5.5
Customer Relations, excluding Call Centre	Provides for focussed customer survey of 2 key aspects of ETSA Utilities' service delivery	0.8
	Additional labour resources to manage and operate the new outage notification system	0.3

Source: PB analysis and Attachment F.1 SEM-Opex Model Ver7.2-Read Only.xls

PB has reviewed the insurance premium increases as part of section 6.5.2.

PB considers the reduction to account for the cyclic nature of the revenue determination is reasonable and informed though actual costs incurred.

PB considers the increased opex allowance for running the Davenport training centre is prudent and reasonable given it will support: the recruitment of staff; the initial purchase of materials needed for the delivery of training services; and contract developments with external service providers.

PB considers the variations proposed to offset the impact of finance adjustments embedded in the base year are reasonable as they account for one-off adjustments related to the removal of superannuation provisions for proposed legislative and operational changes to the defined benefit scheme, which have not eventuated, and an adjustment to the long service leave provision in line with actuarial advice.

PB also considers the allowances to undertake focussed customer surveys, plus the initiatives to improve customer outage notifications during emergencies are also prudent and reasonable.

PB has reviewed two significant step changes in the allocated costs over the next regulatory control period in detail: that related to property; and that related to information systems.

Property

The South Australian State Government has imposed a change in ETSA Utilities land tax obligations confirmed to commence at 1 July 2010[399], following expiry of ESCoSA's Electricity Distribution Price Determination for the current regulatory period. ETSA Utilities has received formal notice from the State Government of the amount of this additional land

399 Letter from Kevin Foley, South Australian Treasurer, to Lew Owens dated 28March 2008.

tax liability and has used this to calculate the proposed change in opex for the next regulatory control period.

ETSA Utilities has included $2.1m for additional land tax in each year of the next regulatory period and this accounts for the majority of the step change. The remaining additional expenditure has been included to account for the additional two depots and the relocation and expansion of other depots included in ETSA Utilities capital works programs.

The opex related to relocation and expansion is dependent based on a bottom up estimate which PB considers is reasonable.

PB concludes that the forecast property related opex is prudent and efficient.

Information systems

ETSA Utilities has forecast its IT opex by escalating the base year opex and also adding in annual variations. Each of these variations is detailed in specific spreadsheets which were provided with the proposal. In total, 14 spreadsheets were included detailing the additional opex relating to specific IT programs.

Information Technology expenditure is forecast to increase from a 2008/09 value of $16.9m per annum to an average of $29.9m (including real cost escalation) per annum in the next regulatory control period. At an average increase of $13.0 million per annum, the IT expenditure increase makes up 4.5% of ETSA Utilities total forecast increase in capital expenditure. The main drivers for the expenditure increase are:

- increases in base opex costs (75% of increase) associated with support of the existing suite of applications; and
- new applications and systems (25% of increase) associated with extending the existing suite of applications to industry standards.

The factors that influence the base IT opex are additional staff, an increased organisation wide reliance on IT based information and systems, increased reliance on mobile computing, an increasing number of operating sites to support, an increased level of required software upgrades and equipment renewals and major systems renewals.

Additional costs will also be incurred to support the new Network Operations Centre. Independent consultants KEMA were engaged to review and provide recommendations for the development, upgrade or expansion of the Network Operations Centre (NOC) and, in particular, the Supervisory Control and Data Acquisition (SCADA) system. KEMA's recommendations[400] have been accepted by ETSA Utilities and associated expenditure is proposed in its Regulatory Proposal. This includes: the replacement of the outdated SCADA software; development of a new network operations centre (NOC); conversion of the existing NOC into a backup centre; and installation of SCADA switches on feeders located in high bushfire areas in order to limit interruptions when during bushfires.

KEMA stated in its report *"At present, ETSA Utilities SCADA system and SCADA field components lack the capability to be a platform for network and operational automation. The level of SCADA monitoring and control is lower than the industry standard practice. Operational processes are highly manual. Operational staff are not equipped with advanced software tools to assist them to operate the distribution networks".* PB is aware that the

400 ETSA Proposal Attachment E14 KEMA Review

existing NOC is extremely small compared to industry standards, and concurs with the KEMA observation that the SCADA software needs updating in order to improve functionality and reach within the network

PB has reviewed each spreadsheet associated with the IT variations but notes that OX064[401] summarises all IT variations, and the three most significant projects are the full NOC disaster recovery, enterprise project management and substation drawing management. PB interviewed the IT staff responsible for developing these estimates and is satisfied that they reflect reasonable opex costs for the proposed works.

6.7.3 PB recommendations

PB considers the forecast allowance for allocated costs is prudent and efficient and has not recommended any adjustment to the proposed opex.

Table 6.40 Recommended allocated costs for the 2010-2015 regulatory control period

Allocated costs	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
ETSA Utilities proposal	49.93	54.32	57.54	62.15	63.89	287.83
PB adjustment – reduced scale escalation	-	-	-	-	-	-
PB recommendation	49.93	54.32	57.54	62.15	63.89	287.83

Source: PB analysis

6.8 Inter-business benchmarking

The AER provided PB with a high level opex ratio analysis, based on a number of key assumptions. These assumptions give rise to limitations in the application and interpretation of the results, specifically, the AER study has not normalised for factors such as:

- differences in accounting/capitalisation policies
- network/age/condition profiles or other unique network operating characteristics

Not withstanding these limitations, PB considers there are two studies within the AER analysis provided that are reflective indicators of distribution operational efficiency as they include customer numbers and line length, which may each be influential distribution cost drivers. The benchmarks include the *simple ratio of opex/km versus line length* refer to Figure 6.13 and the normalised study of *opex/km versus customer/line length* refer to Figure 6.12. In reference to section 4.1.1, PB considers these top-down benchmarks are informative, given that they present some relative indications of opex levels as a function of two key drivers, in the context that opex trends tend to be more stable compared with capex forecasts (that can be influenced by large and expensive projects that are needed to satisfy locational specific constraints).

401 ETSA/OX064 IT Price Reset Investment 2010-2015

These studies are contained in the internal AER analysis provided to assist PB [402] which compares the QLD and SA distributors forecast opex expenditures for the next regulatory control period against an efficiency frontier calculated using ACT, NSW, QLD and SA distributors 2007-08 financial year actual opex expenditures and network statistics. PB prefers the use of actual (rather than regulatory approved 2007-08 financial year expenditures) as they are representative of the opex costs incurred by the distributors. In addition it is observed by the correlation factors that these two benchmarks exhibit the most significant statistical relationship. For the simple ratio of *opex/km versus line length* the R squared is 0.7599 and for the normalised study of *opex/km versus customer/line length* the R squared is 0.9269.

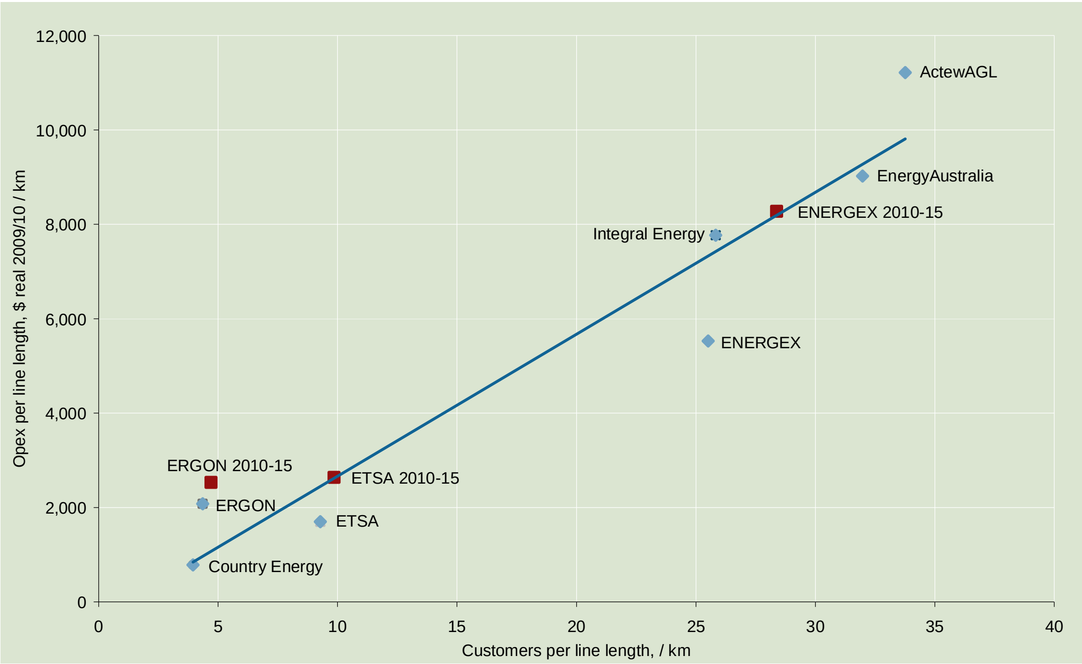

Figure 6.12 Normalised analysis of opex per km plotted against customers per line length.

Source: AER benchmarking study

402 AER Opex Benchmarking 2001-02 to 2008-09

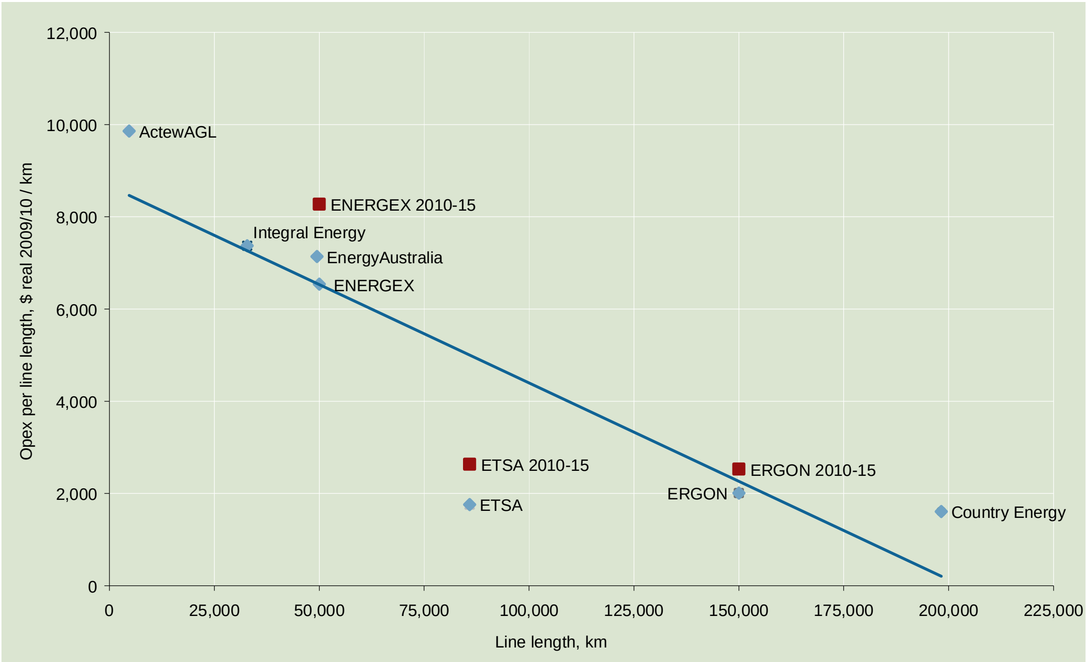

Figure 6.13 Simple ratio analysis of opex per km plotted against line length in km.

Source: AER benchmarking study

The simple ratio analysis of opex per km plotted against line length indicates ETSA Utilities' forecast opex to be the most efficient relative to other low customer density distributors, and positioned well below the efficiency frontier. The normalised analysis of opex per km plotted against customers per line length indicates that ETSA Utilities forecast opex in on the efficiency frontier.

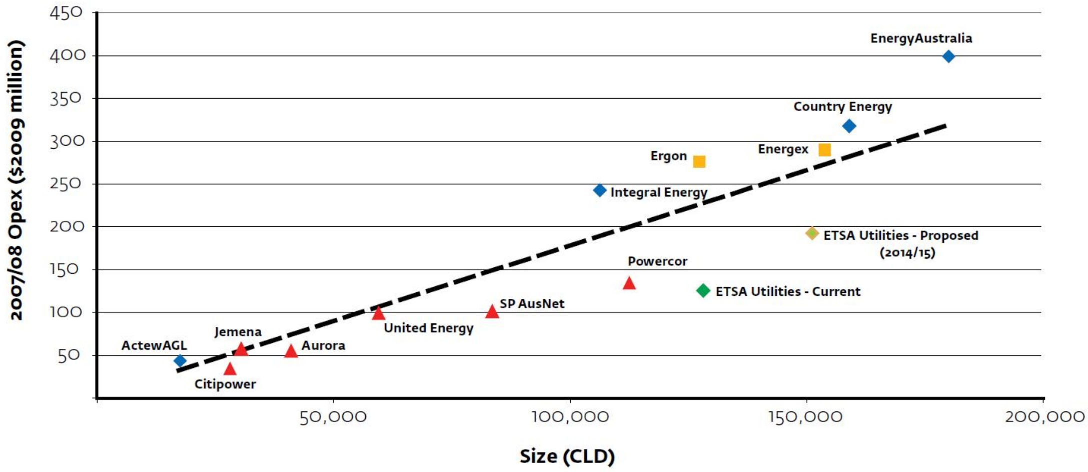

Figure 6.14 Wilson Cook analysis of the ACT and NSW DNSPs with ETSA Utilities forecast position plotted on the diagram

Source: ETSA Utilities Regulatory Proposal, p.146

Figure 6.14 shows a diagram of the Wilson Cook[403] analysis of the ACT and NSW distributors relative efficiency based on a size metric. ETSA Utilities has plotted its forecast position in 2014-15 on the diagram. PB notes that whilst ETSA Utilities is moving closer to the relative efficiency frontier during the next regulatory control period it is still positioned well below the efficiency frontier.

Some of the reasons ETSA Utilities would differ from other business within the peer groups include:

- all overheads are expensed
- almost exclusive use of concrete and steel ‘stobie’ poll design has fundamental differences as an key asset class within a distribution network compared with round wood poles used elsewhere
- a genuine mix of CBD, urban and rural type networks

PB summary

PB considers that the Wilson Cook benchmarks and the AER benchmarking studies in combination indicate that ETSA Utilities opex forecasts are relatively efficient from a top-down inter-business comparative perspective using reasonable normalising variables such as network size and customer numbers.

6.9 Summary of findings and recommendations

This section presents a summary of PB’s key findings and recommendations relating to ETSA Utilities forecast opex for the next regulatory control period.

Key findings

ETSA Utilities proposes to spend $1,131.1m on opex in the next regulatory control period inclusive of all allocated costs (overheads), an average increase of 54% compared with the current regulatory control period.

Network maintenance, including inspections, maintenance and repair, vegetation management and emergency response, accounts for $467m, or 41% of the entire forecast.

Allocated costs account for $288m, or 25% of the entire forecast.

Policies, documentation and modelling to support the asset management approach and the forecasting methodology are comprehensive, transparent and reflective of the needs of the business in the current environment.

Asset maintenance and management practices are in a transitional stage – moving from a lagging indicator and fixed time-based inspection approach, to a future state capturing more condition based knowledge and informed through leading indicators – reflective of an increase in strategic preventive maintenance requirements.

403 Wilson Cook & Co, Review of Proposed Expenditure of ACT & NSW Electricity DNSPs Volume 1—Main Report, Final, October 2008, p 26.

The staged opex forecasting approach adopted by ETSA Utilities accounting for: definition of a base year in 2008-09; inclusion of scope changes; macro scale escalation based on key drivers such as network asset growth and customer numbers; and finally general escalation for real input cost escalation; has been logically constructed, soundly applied and generally appears well considered.

The integrated opex model outlining each of the 21 direct cost opex activities and the 41 allocated cost activities includes a high degree of transparency, with excellent labelling and cross-referencing, and it appears well refined and of a high quality.

PB concludes that the base year opex of $155m for 2008-09 is prudent and efficient for the purposes of informing the forecasts.

ETSA Utilities has provided a clear description of how and why it had established and applied scale escalators, and PB is generally satisfied that network size, work volume, workforce size and customer growth are each factors that will influence opex requirements. PB also considers that ETSA Utilities has used a reasonable level of discretion in selecting the activities to which each of the factors apply, and seeking independent advice on its approach.

However, in regards to the application of scale escalation, PB recommends four adjustments:

- a reduction of $9.9m to account for a network growth factor more reflective of the actual assets that will be installed from a bottom-up perspective
- a reduction in the total network access, monitoring and control opex activity of $2.66m based on a bottom-up forecast of staff required to undertake this activity
- a reduction in the total emergency response opex activity of $8.7m to reduce the growth escalation, on the basis that new assets are not likely to fail consistently and repeatedly in an unplanned manner
- a reduction of $0.3m to account for the asset replacement capex / opex trade-off.

PB believes that ETSA Utilities model produces reasonable and accurate results in relation to the application of the real labour, material and services input cost escalators. This finding is also supported by the independent reviews undertaken by SKM and KPMG.

In comparison with Australian peers, ETSA Utilities' opex forecasts appear relatively low from a top-down perspective using a composite size variable to normalise the businesses.

Network operating costs

ETSA Utilities proposes to spend $156m on network operating costs, an increase of 49% compared with the current regulatory control period.

PB assessed ETSA Utilities' proposed expenditure as prudent and efficient, including scope changes based on the forecasting methodology and the bottom-up substantiation of the changes, which are focussed on a strategic decision to move to a condition based asset management strategy.

Network maintenance

ETSA Utilities proposes to spend $467m on network maintenance in the next regulatory control period, an average increase of 45% compared with the current regulatory control period.

PB has concluded that the proposed additional inspections and the reduction in inspection cycle times in high corrosion areas is prudent given ETSA Utilities asset performance and therefore recommend that the additional inspection opex be included in the next regulatory period

In regards to the additional opex associated with new meter testing requirements, PB considers this scope change is prudent and efficient in that it is required for statutory requirements.

In regards to the additional opex associated with increased mobile generator opex, PB considers this scope change is prudent and efficient in that it has been established based on a detailed bottom-up forecast and provides for a high degree of flexibility for improved reliability in remote areas.

PB is of the view that the proposed increases in network maintenance opex due to increasing asset age have not been substantiated and therefore are not prudent and efficient scope changes, primarily due to the lack of calibration of the SKM age versus opex characteristics to ETSA Utilities existing asset base and classes. A reduction of $19.5m is made to remove the escalation.

PB considers the need for the increased vegetation management allowance is reasonable and prudent given the current non-compliance and potential safety issues, however we recommend the 5% contingency allowance included is removed. A reduction of $4.8m is made to remove the contingency.

PB is satisfied the increased network insurance scope changes are prudent and efficient given the transparent approach adopted by AON in developing the forecasts and given the nature of the insurance classes included in ETSA Utilities 2008/09 insurance costs and the potential impact of bushfire and environmental factors outlined.

Customer services

ETSA Utilities proposes to spend $130m on customer services in the next regulatory control period, an average increase of 23% compared with the current regulatory control period.

PB assessed ETSA Utilities' proposed expenditure as prudent and efficient, based on the forecasting methodology, including a scope change attributed to a demonstrated cost effective increase in the provision of IT systems for FRC by CHED Services.

Allocated costs

ETSA Utilities proposes to spend $288m on allocated costs (overheads) in the next regulatory control period, an average increase of 68% compared with the current regulatory control period.

PB assessed ETSA Utilities' proposed expenditure as prudent and efficient, based on the forecasting methodology, including a series of scope changes, in particular attributed to a government imposed increase in property land tax, and a demonstrated cost effective increase in opex associated with the provision of new IT systems.

PB's recommendations

PB recommends that the forecast opex allowance for the next regulatory control period should be adjusted from the levels proposed by ETSA Utilities. PB's proposed adjustments are shown in Table 6.41.

Table 6.41 Recommended opex for the next regulatory control period.

	2010-11	2011-12	2012-13	2013-14	2014-15	TOTAL
Network operating costs	28.52	29.97	31.06	32.36	33.76	155.66
Network maintenance	83.52	87.66	93.01	99.00	103.86	467.06
Customer services	24.82	25.44	26.07	26.69	27.36	130.38
Allocated costs	49.93	54.32	57.54	62.15	63.89	287.83
Other costs	16.53	17.27	18.04	18.79	19.56	90.18
TOTAL - proposed	203.32	214.67	225.71	238.99	248.43	1,131.12
Adjustment 1 - reduced network growth escalator	(0.8)	(1.6)	(2.1)	(2.5)	(2.8)	(9.9)
Adjustment 2 - reduced NOC FTEs	(0.26)	(0.52)	(0.54)	(0.63)	(0.71)	(2.66)
Adjustment 3 – growth in emergency response	(0.75)	(1.26)	(1.75)	(2.23)	(2.70)	(8.69)
Adjustment 4 –opex capex trade-off	(0.01)	(0.03)	(0.06)	(0.08)	(0.12)	(0.30)
Adjustment 5 – asset age removed from emergency response	(1.08)	(1.66)	(2.46)	(3.45)	(4.68)	(13.33)
Adjustment 6 - asset age removed from maintenance and repair	(0.48)	(0.76)	(1.14)	(1.61)	(2.21)	(6.20)
Adjustment 7 - reduced vegetation contingency	(0.96)	(0.92)	(0.94)	(0.98)	(0.95)	(4.77)
TOTAL Adjustments	(4.34)	(6.75)	(8.99)	(11.48)	(14.17)	(45.85)
TOTAL Adjustments %						(4.05%)
TOTAL - PB recommended	198.98	207.92	216.72	227.51	234.26	1,085.27

Source: PB analysis

7. Service standards

ETSA Utilities proposes to maintain its level of reliability of supply service performance to meet the standards set by ESCoSA in its Final Decision on the South Australian Electricity Distribution Service Standards 2010-2015[404]. In section 4.3, PB has assessed that the proposed expenditure to achieve these levels of performance is prudent and efficient. No other change in service performance is proposed.

In the remainder of this section, PB examines the Service Target Performance Incentive Scheme (STPIS) established by the AER in June 2008 and revised in May 2009. The scheme has an objective to assist in the setting of efficient capex and opex allowances by balancing the incentive to reduce actual expenditure with the need to maintain and improve reliability for customers. This objective is met by establishing appropriate parameters to be included in the scheme and by setting appropriate values for targets and other attributes of the scheme.

The parameters forming the STPIS were fixed before ETSA Utilities was required to submit its Regulatory Proposal. In this section, we review ETSA Utilities' proposed values for the established parameters, including the recommendation of appropriate targets.

7.1 Framework and approach paper

In its Framework and Approach paper, the AER set out the likely approach to the application of the STPIS. The agreed matters in relation to this paper as stated in ETSA Utilities' Regulatory Proposal are as follows:

- the parameters to be included in the scheme are unplanned SAIDI and unplanned SAIFI (for CBD, urban, short rural and long rural feeder categories) and telephone answering
- parameters definitions are in accordance with the STPIS
- the overall revenue at risk is 3% and the revenue at risk for the customer service parameter (telephone answering) is 0.5%
- incentive rates are in accordance with the STPIS
- the events excluded from the customer service parameter are in accordance with the STPIS requirements.[405] [406]

7.2 PB assessment and findings on reliability of supply parameter

PB makes the following observations and findings regarding the reliability of supply parameter.

404 ETSA Utilities 2009, *Regulatory Proposal 2010–2015*, section 10.3.2.
405 ibid.,section 10.2.
406 AER 2008, *Final Framework and Approach, ETSA Utilities 2010–15*, section 4.6.

7.2.1 Suitability of data

From 1 July 2005, ETSA Utilities altered its method of recording reliability data in conjunction with the introduction of a new outage management system (OMS). The OMS adopts a different method of identifying the number of customers affected by a HV network outage, which was previously done using a manual estimation process. The new system also records outages on the LV network, previously omitted from the reliability data. ETSA Utilities demonstrated the reliability parameters based on the new OMS should be consistent with the requirements of the STPIS.

Given that OMS data is only available for the last four years, PB examined the previous data to see if it could be transformed to be consistent with the OMS data and hence used to inform target setting. ETSA Utilities demonstrated the previous data can produce reliability data that is either higher or lower than the OMS data, depending on the number of customers assumed to be affected by a network outage. PB confirms that no consistent translation is possible and that data before 1 July 2005 should not be used.

The parameters SAIDI and SAIFI based on OMS data have been audited for ESCoSA by Ernst and Young for the 3-month period to March 2009. Unplanned SAIDI was assessed as A2 (robust process[407] and an accuracy of ±5%) and unplanned SAIFI as A1 (robust process and an accuracy of ±1%).

The parameter definitions for urban and short rural feeders used to produce the reliability data as set out in the Regulatory Proposal are slightly different to the STPIS definitions in that any feeder that supplies an urban area is classified as urban. This is consistent with current reporting arrangements to ESCoSA. ETSA Utilities provided reliability data using the STPIS definitions and confirms that future reporting will be in accordance with the STPIS definitions.

The OMS data includes a data field that identifies the cause of the outage event. ETSA Utilities showed that outage cause codes identify the events that meet the exclusion criteria set out in clause 3.3(a) of the STPIS. These codes are used to filter the OMS data when calculating reliability performance under the scheme. The approach to excluding events under clause 3.3(b) of the scheme is discussed in the next section below.

Hence, PB concludes that the quality of ETSA Utilities' data forms a suitable base for the setting of performance targets.

7.2.2 Exclusions from the data

STPIS Clause 3.3(b) allows events that exceed the major event day boundary to be excluded from the calculation of the revenue increment or decrement under the scheme. It describes a methodology of calculating the major event day threshold based on the natural log of the reliability data.

ETSA Utilities maintains that the natural log transformation of its reliability data does not produce a normally distributed dataset. It proposes to use the Box-Cox transformation to normalise its reliability data as opposed to the natural log method set out in appendix D of the STPIS.

407 All data is based on sound information systems and records and on documented policies, practices and procedures that are consistent with the Commission's Electricity Industry Guideline No. 1 and fully understood and followed by staff.

PB has examined the reliability data and confirms that the log transformation does not produce a normalised dataset. Based on the shape of the resulting distribution, PB confirms that the Box-Cox transformation provides a more accurate normalisation of the available data[408].

Table 7.1 Comparison of data transformation types

Transformation type	Skew	Kurtosis
Natural log	-0.352	0.801
Box-Cox	0.016	0.495

Source: PB analysis

Based on the 4-years of data to 30 June 2009, the boundary is calculated to be 4.369. Applying this boundary would exclude an average of 5.0 events per year compared to 1.2 events per year if the log transformation was adopted. In PB's experience, the number of events typically excluded by the major event day threshold is 3 to 5 (based on limited information on NSW and Queensland networks). For the ETSA Utilities network, the number of events excluded by the Box-Cox transformation appears at the high end of that typically found. This may be due to the limited data available (4 years).

PB is of the view that the outcome of applying the Box-Cox transformation is likely to be more consistent with the application of the scheme to other DNSPs. It maintains the focus of the scheme on non-major event days, which would not occur if the natural log transformation was used. Hence PB recommends that the alternative transformation proposed by ETSA Utilities be adopted when calculating the major event day boundary.

7.2.3 Targets

In its Regulatory Proposal, ETSA Utilities proposes to set targets for the reliability parameters based on four years of data to 2008-09. The fourth year of this data was subsequently provided to PB on 13 August 2009 together with a calculation of the proposed targets[409].

The STPIS requires that targets be based on the previous five years of reliability performance. To determine whether four years of data is sufficient to set targets, PB requested information about the external factors that drive reliability performance (weather) and historical variability about the average. Summarised in Table 7.2, this information shows the data set contains both severe and light weather impact years. PB also examined ETSA Utilities' reliability data based on the older manual process for the eight year period to 2007-08. This assessment confirmed that the variability in reliability that can be seen in the 4-year period to 2008-09 is consistent with the variability in the longer term data. PB concludes that the four years of performance data is sufficient to inform the setting of targets.

408 Skewness characterizes the degree of asymmetry of a distribution around its mean. Positive skewness indicates a distribution with an asymmetric tail extending toward more positive values. Negative skewness indicates a distribution with an asymmetric tail extending toward more negative values. Kurtosis characterizes the relative peakedness or flatness of a distribution compared with the normal distribution. Positive kurtosis indicates a relatively peaked distribution. Negative kurtosis indicates a relatively flat distribution.

409 ETSA Utilities, 2009, PB.ETS.AP11-18 STPIS, and spreadsheet '*SI120 EU_to_AER_OMS Daily SAIDI and SAIFI_Jul09_amended_25_Sep_09.xls*.

Table 7.2 Historical service performance for reliability (including excludable events)

	2005-06	2006-07	2007-08	2008-09
Unplanned SAIDI	200	197	136	164
Unplanned SAIFI	1.91	1.82	1.40	1.53
ETSA Utilities assessment of weather impacts	severe	severe	light	average

Source: ETSA Utilities Sept 2009, spreadsheet "SI120 EU_to_AER_OMS Daily SAIDI and SAIFI_Jul09_amended_25_Sep_09.xls'

PB notes that ETSA Utilities was subject to an incentive scheme for reliability in the current regulatory period and did not seek an expenditure allowance to improve reliability performance[410]. ETSA Utilities again has not proposed expenditure to improve its level of reliability performance. Hence, PB is satisfied that ETSA Utilities will not receive any benefit under the STPIS for improving service performance where this service performance has otherwise been funded through either the capex or opex allowances.

PB recommends that the targets be set at the average of the 4-years of data to June 2009 as proposed by ETSA Utilities. Table 7.3 shows the historical data and average performance for each of the parameters.

Table 7.3 Average of historical service performance for reliability (excluding major event days)

	2005-06	2006-07	2007-08	2008-09	Ave
SAIDI					
CBD	27.5	24.2	23.6	33.0	27.1
Urban	128.4	106.0	92.4	90.7	104.4
Short rural	170.1	214.7	159.7	191.4	184.0
Long rural	260.1	309.5	265.3	245.8	270.2
SAIFI					
CBD	0.250	0.315	0.236	0.251	0.263
Urban	1.530	1.362	1.173	1.102	1.292
Short rural	1.912	1.794	1.457	1.782	1.736
Long rural	2.046	2.353	2.063	1.981	2.111

Source: ETSA Utilities Sept 2009, spreadsheet "SI120 EU_to_AER_OMS Daily SAIDI and SAIFI_Jul09_amended_25_Sep_09.xls'

7.3 PB assessment and findings on customer service parameter

PB makes the following observations and findings regarding the customer service parameter.

410 ETSA Utilities Expenditure Submission 2005/06 – 2009/10, p. 81

7.3.1 Parameter definitions

ETSA Utilities reports on a telephone answering parameter to ESCoSA that differs from the STPIS parameter in the way abandoned calls are reported. ETSA Utilities has proposed this same parameter be used in the STPIS.

The definition for this parameter varies from the STPIS definition only in the way abandoned calls are reported. ETSA Utilities has confirmed that data using the STPIS definition can be produced. Given that the AER has an objective of national consistency in regulation, and given that there is no reason why data in the required format cannot be produced, PB considers the revised definition should not be adopted for used in the STPIS.

7.3.2 Suitability of data

Data for the telephone answering parameter is taken directly from the telephone system. This data is then modified to remove days that meet the exclusion criteria.

The telephone answering data was last audited for ESCoSA by Deloitte for the 2006 performance year. The auditor found 'no significant data errors affecting the accuracy of the calculation of the percentage of telephone calls answered within 30 seconds of 87.4%'.[411]. PB notes the different treatment of abandoned calls would not affect this finding.

PB concludes that the quality of telephone answering data is suitable upon which to base performance targets.

7.3.3 Targets

Data that is consistent with the STPIS definition was provided for the four years to 2008-09 and is reproduced as Table 7.4. PB recommends that the targets be set at the average of the four year performance, 88.7%, as proposed by ETSA Utilities.

Table 7.4 Average of historical service performance for telephone answering (excluding major event days)

	2005-06	2006-07	2007-08	2008-09	Ave
Telephone answering	89.2%	88.6%	87.7%	89.2%	88.7%

Source: ETSA Utilities August 2009, spreadsheet 'EU_to_AER_STPIS_Incentive_rate_Jul09_v1.xls'

PB notes that ETSA Utilities was subject to an incentive scheme for telephone answering in the current regulatory period and did not seek an expenditure allowance to improve performance. ETSA Utilities again has not proposed expenditure to improve its level of call centre performance. Hence, PB is satisfied that ETSA will not receive any benefit under the STPIS for improving service performance where this service performance has otherwise been funded through either the capex or opex allowances.

411 Deloitte 2007, *Regulatory Compliance Audits for the Electricity Sector ETSA Utilities – 2006 Service Incentive Scheme – Final Report*, p. 2.

7.4 PB assessment and findings on the modified s-bank operation

The s-bank provision in the STPIS allows ETSA Utilities to delay the application of a revenue increment or decrement for one year. ETSA Utilities provides an example based on its historical reliability performance that illustrates that these provisions will not always reduce price volatility to customers. ETSA Utilities proposes that the s-bank be modified to permit a maximum of 5% of revenue to be retained in the bank and that no time limits apply.

Table 7.5 Illustration of s-bank operation

Scenario	Revenue change (%)			
	Year 1	Year 2	Year 3	Range
1. Base case - no banking applied				
s-factor	(2.2)	(1.6)	3.8	
banked	0	0	0	
revenue change	(2.2)	0.6	5.4	7.6
2. Current s-bank – banking 1st and 2nd years				
s-factor	(2.2)	(1.6)	3.8	
banked	-2.2	(1.6)	0	
revenue change	0	(2.2)	4.4	6.6
3. Current s-bank – banking 1st year only				
s-factor	(2.2)	(1.6)	3.8	
banked	(2.2)	0	0	
revenue change	0	(3.8)	7.6	11.4
4. ETSA Utilities proposed s-bank				
s-factor	(2.2)	(1.6)	3.8	
banked	(2.2)	(3.8)	0	
revenue change	0	0	0	0
5. Current s-bank – banking 1st, 2nd and (2.2% only) 3rd year				
s-factor	(2.2)	(1.6)	3.8	
banked	(2.2)	(1.6)	2.2	
revenue change	0	(2.2)	2.2	4.4

Source: ETSA Utilities Regulatory Proposal and PB analysis

Note: the values are calculated in accordance with appendix C of the STPIS: s-factor (equation 4A), banked (equation 3), and revenue change (equation 2).

PB has considered the base case of no amount placed into the s-bank and the three examples provided by ETSA Utilities. It has also considered other potential scenarios in the application of the s-bank. Table 7.5 shows the five scenarios considered. PB notes that:

- In scenario 2, the current s-bank provisions reduce the volatility in pricing to customers over the base case, but do not entirely remove the variation in pricing.

- In scenario 3, not banking the revenue decrement in the second year results in an increase in volatility in pricing, illustrating that incorrect use of the s-bank can have undesirable outcomes.
- In scenario 4, the proposed modification removed the volatility in pricing entirely.
- In scenario 5, PB has retained 2.2% of revenue in the s-bank in the third year, demonstrating that the volatility in pricing can be further reduced by banking only a part of a revenue increment or decrement.

The examples show that proper application of the current s-bank can reduce volatility in pricing, but is unlikely to remove all variation in pricing for no underlying change in service performance.

The modified s-bank has the characteristic of delaying the application of any revenue increment or decrement for an indefinite period, up to a limit of 5% of revenue. Hence, the incentive to control variations about the average will be diminished. The delay will also decouple changes in performance from the application of the revenue increment or decrement, weakening the incentive properties of the scheme. In PB's view, these characteristics do not meet the objectives for the scheme as set out in clause 1.5 of the STPIS, in particular to provide an incentive to maintain and improve service performance as set out in clause 6.6.2(a) of the NER.

PB recommends that the modifications to the s-bank operation proposed by ETSA Utilities not be applied.

7.5 Revenue at risk

While the AER's framework and approach paper indicated that the overall revenue at risk should be 3% and ETSA Utilities' Regulatory Proposal confirms this, PB notes that this relates to the version of the STPIS that was current at the time. The current STPIS allows revenue at risk of 5%.

PB is not aware of any matters that would limit the revenue at risk to 3% and recommends that the current STPIS limit of 5% be applied.

Should the AER decide, however, to maintain the limit at 3%, PB considers the value of the telephone answering parameter in the scheme should be maintained at about 10% of the total incentive (i.e. 0.5% divided by 5%). For an overall cap of 3%, this equates to a cap on the telephone answering parameter of 0.3%.

7.6 PB recommendation

This section summarises PB's findings and recommendations in relation to service standards.

PB's findings in relation to ETSA Utilities' reliability of supply parameters are as follows:

- The quality of ETSA Utilities' data is suitable for target setting.

- The four years of performance data available is sufficient to inform the setting of targets, which should be set at the average of the four years to June 2009.

- The Box-Cox transformation provides a more accurate normalisation of the available OMS data and should be adopted when calculating the major event day boundary for ETSA Utilities.

PB's findings in relation to ETSA Utilities' customer service parameter are as follows:

- The revised definition based on a different treatment of abandoned calls should not be accepted.

- The quality of ETSA Utilities' data is suitable for target setting.

- The targets should be set at the average of the four-year performance to 2008-09, 88.7%

PB also recommends that the proposed modified s-bank operation should not be applied as this would weaken the incentive properties of the scheme and hence is not consistent with the objectives for the scheme.

In summary, PB recommends the values for the service performance parameters shown in Table 7.6.

Table 7.6 Recommended performance incentive scheme

Parameter	Unit	Rate	Targets				
		%	2010-11	2011-12	2012-13	2013-14	2014-15
SAIDI							
CBD	minute	0.0087	27.1	27.1	27.1	27.1	27.1
Urban	minute	0.0486	104.4	104.4	104.4	104.4	104.4
Short rural	minute	0.0089	184.0	184.0	184.0	184.0	184.0
Long rural	minute	0.0109	270.2	270.2	270.2	270.2	270.2
SAIFI							
CBD	per interruption	0.7962#	0.263	0.263	0.263	0.263	0.263
Urban	per interruption	4.0465#	1.292	1.292	1.292	1.292	1.292
Short rural	per interruption	1.0228#	1.736	1.736	1.736	1.736	1.736
Long rural	per interruption	1.5151#	2.111	2.111	2.111	2.111	2.111
Customer service							
Telephone answering	percentage	-0.0400	88.7	88.7	88.7	88.7	88.7

Note: # per 0.01 interruptions

Incentive rates for SAIDI and SAFI parameters are calculated using ETSA's proposed average energy consumption.

Source: PB Analysis

8. Generic limitations of this report

8.1 Scope of services and reliance of data

This report has been prepared in accordance with the scope of work/services set out in the contract, or as otherwise agreed, between PB and the client. In preparing this report, PB has relied upon data, surveys, analyses, designs, plans and other information provided by the client and other individuals and organisations, most of which are referred to in the report (the data). Except as otherwise stated in the report, PB has not verified the accuracy or completeness of the data. To the extent that the statements, opinions, facts, information, conclusions and/or recommendations in this report (conclusions) are based in whole or part on the data, those conclusions are contingent upon the accuracy and completeness of the data. PB will not be liable in relation to incorrect conclusions should any data, information or condition be incorrect or have been concealed, withheld, misrepresented or otherwise not fully disclosed to PB.

8.2 Study for benefit of client

This report has been prepared for the exclusive benefit of the client and no other party. PB assumes no responsibility and will not be liable to any other person or organisation for or in relation to any matter dealt with in this report, or for any loss or damage suffered by any other person or organisation arising from matters dealt with or conclusions expressed in this report (including without limitation matters arising from any negligent act or omission of PB or for any loss or damage suffered by any other party relying upon the matters dealt with or conclusions expressed in this report). Other parties should not rely upon the report or the accuracy or completeness of any conclusions and should make their own inquiries and obtain independent advice in relation to such matters.

8.3 Other limitations

To the best of PB's knowledge, the facts and matters described in this report reasonably represent the conditions at the time of printing of the report. However, the passage of time, the manifestation of latent conditions or the impact of future events (including a change in applicable law) may have resulted in a variation to the conditions.

PB will not be liable to update or revise the report to take into account any events or emergent circumstances or facts occurring or becoming apparent after the date of the report.

Appendix A

PB Terms of Reference

A. PB Terms of Reference

In this section we set out PB's proposed terms of reference for the review of regulatory submissions made to the AER by ETSA Utilities, Ergon Energy and Energex.

A.1 Introduction

The Australian Energy Regulator (AER), in accordance with its responsibilities under the National Electricity Rules (NER), is to conduct an assessment of the appropriate revenue determination to be applied to direct control services provided by DNSPs in South Australia and Queensland for the period 1 July 2010 to 30 June 2015. Previous regulatory arrangements for ETSA Utilities, Ergon Energy and Energex were established by the Essential Services Commission of South Australia (ESCOSA) and the Queensland Competition Authority (QCA). Relevant documents for these determinations, including submissions, consultancies and the final determination, are available at www.escosa.sa.gov.au and www.qca.org.au.

As part of the AER's assessment, an appropriately qualified consultant is required to review the DNSPs' past and forecast capital expenditure (capex), operational expenditure (opex), associated policies and procedures, and service standards proposals. Consultants interested in providing these services may submit a separate quotation for one or each of the determinations or a single quotation covering both determinations.

The AER is required to establish that the capex and opex forecasts of the electricity distribution businesses comply with the requirements of the National Electricity Law (NEL) and the National Electricity Rules (NER), particularly chapter 6 of the NER[412]. The consultant would be primarily concerned with providing technical advice regarding the efficiency and prudence of capex and opex forecasts provided by the distributors. The AER takes into consideration its consultant's views in making its assessments under the NER.

The AER's determinations are subject to merits review by the Australian Competition Tribunal and judicial review in the Federal Court. The consultant's analysis and reports must be produced at a standard that is commensurate with this context.

A.2 Services required

The services required for the primary engineering assessment and cost review covered by these terms of reference are described below. Within its report, the consultant must have regard to the opex and capex objectives, criteria and factors set out in clauses 6.5.6 and 6.5.7 of the NER. The consultant is to undertake an assessment of the DNSP's regulatory proposal to enable the AER to interpret and apply the NER. For example, the opex and capex factors include items such as:

- benchmarking the level of expenditure that would be incurred by an efficient DNSP[413];
- substitution possibilities between opex and capex; and
- the provision for efficient non-network alternatives such as demand management.

412 Clause 6.5.6 of the NER relates to opex and clause 6.5.7 of the NER relating to capex. Clause 6.5.6(a) sets out the opex objectives, clause 6.5.6(c) sets out the opex criteria and clause 6.5.6(e) sets out the opex factors. This structure is mirrored in clause 6.5.7 with respect to capex.

413 This benchmarking was subsequently removed from PB's terms of reference

The consultant will be required to provide an explanation for its decisions in regards to its assessment of the relevant considerations required for the AER to apply the capex objectives, criteria and factors set out in clauses 6.5.6 and 6.5.7 of the NER.

The AER requires a thorough assessment, including the provision of a high standard of detailed information in order to for it to evaluate the NER requirements. The AER expects that the consultant's assessments will be based on more than past experience and that the consultant will substantiate and justify its conclusions with references to data and information sources. For example, where the consultant uses sample testing, the samples must be statistically significant, the source of comparable unit costs must be given and the range of efficient costs justified.

The AER expects that the consultant will have adequate resources to undertake the review in the time required and will be familiar with the AER's previous determinations in regards to Chapter 6 of the NER.

A.2.1 General pre-lodgement work

The consultant will be required to assist the AER with a variety of pre-lodgement tasks. Such tasks may include, for example, development of independent forecasts of unit costs in advance of regulatory proposals (see section 2.6 of this document). It would also involve attending preliminary meetings held with the DNSPs and the AER during May 2009.

A.2.2 High-level review of opex and capex during current regulatory period

The consultant will undertake a review of the actual and forecast capital and operating expenditures that have occurred or are forecast to occur over the current regulatory period and compare them with the expenditure levels forecast at the time of the last determination. The review should examine material variances between forecasts and actuals and explain the drivers for the differences and whether the drivers are expected to persist for the next regulatory period. This review will assist the AER in assessing clauses 6.5.7(e)(5) and 6.5.6(e)(5) respectively of the NER.

The purpose of this review is not to assess whether the expenditures in the current regulatory period are prudent but to establish the context in which the expenditure forecasts have been made and provide an indication of areas of the forecast expenditures that require more detailed analysis. In undertaking this review the consultant should assess historic capex and opex separately for each DNSP.

Using its findings from its review of forecast and actual expenditures in the current regulatory period, the consultant should examine and explain material expenditure variances between the current regulatory period and the next regulatory period. This review should examine and explain the reasons for any significant variances.

The consultant will also need to demonstrate that the opex base year for the DNSPs opex forecast is an appropriate year to forecast from.

A.2.3 Review of identified external factors and obligations of the DNSPs

The DNSPs have been asked to submit a list of external factors as part of their regulatory proposals. These external factors will include legislative and regulatory obligations such as licence conditions and any other requirements that are expected to affect the level of services to be provided by the DNSPs and to influence the level and types of expenditure required to be undertaken by the DNSPs.

The consultant shall assess the list of external factors and obligations for completeness and to ensure a full understanding of the operational and cost implications of the obligations on the DNSPs. This will include a separate analysis of new obligations that have operational and cost implications in the next regulatory control period. The consultant shall also identify any obligations that it considers material and that have been omitted.

A.2.4 Forecast demand and cost escalators

External factors such as those affecting the future demand for electricity and the future cost of labour and materials will have a significant influence on the DNSPs' expenditure forecasts.

The AER intends to engage a separate consultant to review the DNSPs' demand forecasts. The AER requires the consultant to verify the effect of any revised maximum demand forecasts that are developed as a consequence of the recommendations of the demand consultant under section 2.7 and the primary consultant's assessment under section 2.6 of this document.

The AER anticipates that the DNSPs will propose their own cost escalators on labour and materials for the next regulatory period. The AER intends to engage a separate consultant to undertake an independent review of labour costs over the next regulatory period. The AER will undertake its own assessment of material cost escalators over the next regulatory period. As such the primary (engineering) consultant will not be required to provide a view in relation to labour and material cost escalators proposed by the DNSPs. However, the consultant will be required to understand how the DNSP's escalators have been applied and verify that the calculations are correct.

The consultant will also be required to take into account the AER's views on forecasts of cost escalators, where identified, when formulating its advice on the capex and opex programs.

A.2.5 Review of policies and procedures

The DNSPs have been asked to specify the policies and procedures by which their operational and investment decisions are made. Such policies are expected to relate to, for example, augmentation, replacement, opex, cost allocation, capitalisation and demand management. The consultant shall undertake a detailed review of these policies and procedures. This work is to include a review of network performance targets and associated forecasts, augmentation models and opex and replacement models.

The consultant shall report on its review of these policies and procedures, noting, where relevant, any policies and procedures that it considers unreasonable or inappropriate having regard to good electricity industry practice and clauses 6.5.6(c) and 6.5.7(c) of the NER. Should the consultant find any such policies or procedures, it is to specify alternative policies or procedures and substantiate why they are reasonable and appropriate with reference to clauses 6.5.6 and 6.5.7 of the NER.

A.2.6 Review of unit costs

The DNSPs have been asked to provide information on the unit costs used in developing their expenditure proposals for the next regulatory period. It is anticipated that a variety of unit costs will be identified relating to the various components of augmentation and replacement capex and for opex.

The consultant shall develop its own independent forecasts of unit costs in advance of the regulatory proposals of the DNSPs being received. These independent unit costs are to be developed, based on historical expenditure by similar DNSPs and, where possible, by reference to such industry benchmarks as the consultant considers relevant. It is intended that the independent unit costs will be used to inform the further stages of the consultant's review and the analysis of the unit costs of new assets proposed by the DNSPs. If considered appropriate, the consultant's unit costs may be used to develop alternative unit costs.

Following receipt of the DNSPs' regulatory proposals, the consultant shall review and analyse the unit costs presented by the DNSPs. Following this review, the consultant should identify the unit costs reviewed and indicate whether they reasonably reflect a realistic expectation having regard to clauses 6.5.6(c)(3) and 6.5.7(c)(3) of the NER. Where the unit costs do not represent a realistic expectation, the consultant will be required to recommend substitute unit costs to the AER and identify the impact on the proposed forecast.

A.2.7 Review of capex and opex, and impact of demand forecasts

The consultant is to test the magnitude of the capex and opex forecasts submitted by the DNSPs by examining whether the application of the submitted policies and procedures (see section 2.5 above) and unit costs (see section 2.6 above) to the DNSPs' networks for the next regulatory period.

The consultant is also to review the expenditure projections for consistency with the demand forecasts accepted by the AER.

For these purposes, the DNSPs will be asked to provide details of their forecast augmentation, replacement, opex and non-network expenditure programs as part of its regulatory proposals. This information is to include a list of all major projects and programs above a specified threshold.[414]

The consultant shall review the application of the DNSPs' policies and procedures (and, where relevant, shall check for consistency with the demand forecasts) with regard to:

- the major projects and programs identified in each of the regulatory proposals;
- areas of expenditure where there is a substantial deviation, upwards or downwards, from expenditure in the current period and/or agreed to in the previous determination (the preliminary high-level review of expenditure during the current regulatory period may also highlight areas for testing the application of relevant policies and procedures); and
- a representative sample of projects and programs to be agreed with the AER. In recommending the sample, the consultant shall include forecast expenditure on a range of assets, time, magnitude and location for the DNSPs, sufficient to demonstrate consistency of application of the DNSPs' stated policies.

The focus of the assessment is identifying whether there are any systemic flaws in the DNSPs' practices. The consultant is to identify the projects and programs reviewed in its report and present well-reasoned and substantiated conclusions as to whether the relevant policies, procedures and unit costs have been applied appropriately.

[414] The draft RIN for South Australian and Queensland DNSPs specified that a project or program would be considered material if cumulative expenditure on it exceeded 2% of the annual revenue requirement in the final year of the current regulatory control period.

Should the consultant identify relevant policies and procedures and unit costs that it considers have not been applied appropriately, it shall identify the problem and recommend appropriate adjustments where considered necessary to correct the situation. In such an instance, in consultation with the AER, the consultant may be required to investigate whether the application problems are systemic in nature. If found to be the case, this would likely involve the assessment of additional projects and programs of a similar nature. Again, well-reasoned and substantiated recommendations must be made, including the recommendation of appropriate adjustments to the opex and capex allowances resulting from amendments to the relevant policies, procedures and unit costs where considered necessary.

The consultant is required to comment on the deliverability of the DNSP’s proposed capex program, having regard to capex delivered in the current regulatory period and the DNSP’s capex delivery framework and policies for the next regulatory control period. It is expected that the consultant will substantiate the factors considered in the consultant’s conclusions on deliverability.

Clauses 6.5.6(e)(10) and 6.5.7(e)(10) of the NER require the AER to have regard to the extent the DNSPs have considered, and made provision for, efficient non-network alternatives. The consultant is required to assess whether the businesses are actively considering demand management and what may be some of the obstacles to the take up of demand management by the DNSPs.

There are a number of specific cost areas where the AER requires the consultant to review and provide a detailed assessment, in particular:

- Information Technology (IT) expenditure and other non-system costs.
- Where services are provided by a related party without competitive tendering, the basis of determining opex charges will need to be assessed (for example, IT services for Energex and Ergon);
- The efficiency of the overheads proposed and their allocation to capex and opex; and
- In relation to self insurance, a review of insurance costs to ensure that these are excluded from expenditure proposals.

The consultant shall also make such other recommendations to the AER as the consultant considers necessary to ensure that the expenditure levels are prudent and efficient.

A.2.8 Cost pass-through

Clause 6.6.1 of the Rules concerns cost pass-through. Unlike the transmission regulatory framework, contingent projects are not included in the regulatory framework for electricity distribution. However, the AER is given discretion to nominate ‘additional’ pass-through events in the determination.[415] This discretion allows the AER to include large uncertain distribution capex projects as pass-through events.

The consultant will be required to examine any pass-through events identified by the AER. For example, such an assessment may include analysis on whether the costs attributable to the pass-through event have already been included in forecast capex (and if not, whether

[415] See the definition of pass-through event in chapter 10 of the NER. ‘Additional’ refers to items not within the four categories of pass-through events listed in the glossary.

these costs should be included) and the likelihood of the pass-through event occurring in the next regulatory period.

A.2.9 Service standards

DNSPs will be subject to a Service Target Performance Incentive Scheme (STPIS), including a reliability of supply component and a customer service component. The consultant shall recommend appropriate reliability of supply and customer service performance targets to be applied to each DNSP over the next regulatory period.

The consultant must assess the STPIS values proposed by the DNSPs against both the principles outlined in the AER's STPIS and clause 6.6.2 of the NER.

In determining the future performance targets, the consultant must have regard to the DNSPs past performance, as outlined in the STPIS, as well as the impact that the capex and opex programs allowed for in the determination may have on its performance.

A.2.10 Potential further in-depth review as directed by the AER

The AER may direct the consultant to undertake further assessments of specific aspects of the regulatory proposals of the DNSPs. The extent and scope of this work is unknown and, potentially, this work may not be required. Accordingly, should the AER require further in-depth reviews to be undertaken by the consultant, the work will form a separate item under the contract (with separate terms of reference), to be charged at the agreed hourly rates up to a cap of $40,000.

A.2.11 Review of submissions from interested parties

The consultant may be required to review and provide advice on matters raised in submissions from interested parties prior to the AER's draft determination.

A.3 Liaison with DNSPs and the AER

Without affecting the independence of the review, the consultant is expected to liaise closely with the DNSPs, and related parties if required, during the course of the review. This liaison is expected to include meetings with the DNSPs at their respective offices with AER staff in attendance and, if required, preparation of written requests for additional information and documentation.

The consultant shall also liaise closely with AER staff and provide regular updates on:

- progress towards achieving deliverables;
- any impediments that have arisen to achieving those deliverables; and
- any significant issues that have been identified.

The consultant will also be required to liaise with the AER's secondary engineering consultant. This consultant will be engaged by the AER to review specific issues and provide the AER with a report critiquing the primary consultant's draft report.

A.4 Pre-determination conferences

The consultant shall attend all pre-determination conferences (public forums) held by the AER during the review process. The AER's general practice is to hold two public forums to receive representations from interested parties, one after the proposal has been received and another after it has released its draft decision.

A.5 Project deliverables – South Australian and Queensland determinations

To comply with the NER, the AER is required to publish its final determination two months before the commencement of the DNSPs' next regulatory control period, viz. by 30 April 2010. The consultant is to note that the timeframe in the NER does not allow for flexibility in the dates and that there are no 'stop the clock' provisions. The consultant is therefore required to meet the timeframe specified in the terms of reference to ensure compliance with the requirements of the NER.

The DNSPs are to submit their regulatory proposals by 31 May 2009. Given the timing requirements set out in the NER, the AER must release its draft determination by late November 2009 and thus the consultant will be required to meet the following deadlines:

- preliminary meetings with the AER and DNSPs during May 2009 and other pre-lodgement work as defined in clause 2.1 above;
- meetings as required with the DNSPs following the submission of its proposal;
- provision of a preliminary report by 24 July 2009, setting out the key issues and directions that the consultant is considering in its assessment;
- provision of draft written reports by the close of business 28 August 2009.
- presentation to the AER Board of the findings of draft reports;
- attendance at the public forums held to discuss the draft determination; and
- provision of final written reports on its findings by close of business 25 September 2009.

In addition to its draft and final reports, the consultant must provide supporting spreadsheets and analysis relied upon in its report to ensure the AER can meet the requirements set out in clause 6.12.2 of the NER.

The consultant must be available for follow-up questions from the AER as well as responding to any issues raised in submissions on the draft determination and any revised proposal submitted by the DNSPs under clause 6.10.3 of the NER. Should the AER require further advice from the consultant following the publication of its draft determination, the work will form a separate item under the contract, to be charged at the agreed hourly rates up to a cap of $40,000.

A.6 Penalties

The provision of project deliverables in accordance with these Terms of Reference are critical to the successful completion of the project. Given the importance of the delivery of the consultant's draft and final reports the AER intends to include in the consultancy contract a penalty of 0.5 per cent per day of the total contract value where a critical project deliverable (as indicated in section 5 above) is not provided at the specified time. Penalties imposed under the contract will be capped at a maximum of 15 per cent of the total contract value.

A.7 Merits and judicial review

The regulatory determinations made by the AER under the NEL are subject to merits review by the Australian Competition Tribunal and judicial review in the Federal Court. Accordingly, the consultant's final report must be written to a professional standard with well-reasoned analysis and recommendations. The consultant's report will be published alongside the AER's determinations as part of the public consultation process.

Any work required as a result of a merits review would be the subject of a separate contract.

Appendix B

About PB

B.1 About PB

Parsons Brinckerhoff ("PB") is one of the world's oldest continuously operating consulting engineering firms, and one of the world's leading planning, environmental, engineering, and program and project management firms. PB is an employee owned company with over 12,000 professional and technical staff operating from 250 offices in 50 countries. This enables us to provide leading edge consultancy services from the latest standards and trends in Europe, North America and the Asia Pacific region to the benefit of our clients.

PB operates in all major cities of Australia. Using the combined capabilities of PB we are able to provide the comprehensive services required for specialised and informed advice on utilities and associated matters anywhere in Australia.

The PB strategic and management consulting group has a leading role in the provision of strategic management services in the utility, infrastructure and energy sectors, focusing on areas of industry and regulatory reform, energy economics, strategic planning, project finance, valuations, and advice on mergers and acquisitions.

The group builds on the experience PB has gained internationally as advisors to governments and utilities on the unbundling and restructuring of electricity supply undertakings around the world, and knowledge of the market structures within which privatised electricity utilities, generators, network operators and suppliers trade. This has included review and advice on various aspects of the electricity supply industry in England, Wales and Scotland since privatisation in 1990. The experience has been built on and extended into other countries, including New Zealand, Ireland, Poland, Portugal, Argentina, Venezuela, the Dominican Republic, United Arab Emirates and the Philippines.

The PB team consists of senior engineering, economic and financial professionals. In addition, we have access to an enormous network of professionals interstate and around the world.

PB can deliver a dedicated project team to the AER, each having relevant and recent experience, in order to ensure its objectives are met with high quality outcomes and within the required timeframes.

We remain acutely aware that the needs and drivers of utility regulators are different from the needs of utility managers, governments and shareholders. From this perspective, PB has an extensive history of delivering reports and outcomes that are of direct value and use to utility regulators. We note a significant potential for failure is to consider the review as an engineering study. Although PB will draw on a significant level of engineering resources, we recognise that an engineering report will not meet the needs of this study. The project team for this project has significant regulatory experience and will ensure that the project outcomes are aligned with the regulatory needs of the AER.

The team has a detailed knowledge of distribution (and transmission) networks – both in Australia and overseas. It also has extensive experience in working with economic regulators in reviewing optimal capital and operating expenditure requirements of monopoly utility businesses – particularly in gas and electricity where regulation is often more evolved. Team members have also worked directly for regulated electricity network businesses. PB believes that this experience provides a sound base for assisting the AER in undertaking this regulatory review the South Australia and Queensland DNSPs' revenue proposals for the period 1 July 2010 to 30 June 2015.

B.2 Summary of relevant experience

In this section we provide a summary of the PB experience which is relevant to this assignment. More detailed information on PB international and local experience is available on request.

The strategic and management consulting group of PB focuses on regulatory advice for the international electricity, gas and water utility industries, and has done so for an extended period of time, as reflected in the following referenced projects.

The teamwork which operates among the different disciplines and skill centres in the company provides an excellent mechanism for the cross-fertilisation of both individual and company experience. The approach has been successfully used to leverage off previous experience that PB has gained as a firm globally, and applied to provide solutions to the challenges facing regulators and electric utilities in an increasingly dynamic marketplace.

PB has considerable experience in the many aspects of utility industry reform, privatisation, regulation and restructuring. The company has advised on a number of wide-ranging privatisation, restructuring and regulation issues, beginning with its appointment in 1987 as technical advisor to the UK Government on privatisation of the electricity supply industry in England and Wales, and also under separate contract in Scotland. This experience has since been built on and extended to other countries including Australia, New Zealand, Argentina, Portugal, Italy, Ireland, Chile, Venezuela, Philippines, and India.

PB has advised the AER on similar revenue proposals, most recently TransGrid's 2009-10 to 2013-14 revenue proposal.

PB has been involved in numerous projects directly related to the AER's request for proposal for the South Australia and Queensland DNSPs, these include the following:

- Review of the TransGrid (transmission) revenue reset submission for the Australian Energy Regulator (AER), 2008/09
- Provision of strategic regulatory advice to the management team at Country Energy as part of the company's preparations for the 2009 distribution price determination
- Provision of technical and commercial advice to the management team at Integral Energy as part of the company's preparations for the 2009 distribution price determination
- Review of the SP AusNet and VENCorp (transmission) revenue reset submissions for the Australian Energy Regulator (AER), April 2007
- Strategic commercial, technical and regulatory advice to TransEnd as part of its preparation for the 2009/10 – 2013/14 regulatory review, 2008
- Provision of expert advice to Western Power in the preparation of its Access Arrangement proposal to the Economic Regulation Authority (ERA), 2008
- Provision of expert regulatory advice to the senior management team as part of the company's preparations for the 2008 distribution price determination – engaged by Aurora Energy (Tasmania), Australia, September 2006
- Powerlink (QLD) Revenue Reset for the Australian Energy Regulator (2006)

- Price reviews for three distribution businesses for the Philippines Energy Regulatory Commission (2006)
- Development of the Technical Rules for the South West Interconnected Network in WA (2006)
- Regulatory submission reports for Western Power (2008 and 2005)
- Review of the TransGrid forward transmission capex for ACCC (2005)
- Review of the Energy Australia forward transmission capex for ACCC (2004)
- DirectLink Regulatory Test Review undertaken for the ACCC (2004)
- distribution price review of ETSA undertaken for ESCoSA (2004)
- reliability incentive review for IPART (2004)
- MurrayLink Regulatory Test Review undertaken for the ACCC (2003)
- SPI PowerNet and VENCorp transmission review for the ACCC (2002)
- distribution price review of Aurora Energy undertaken for OTTER (2002)
- review of NSW distribution and retail competition costs for IPART (2001)
- distribution price reviews of Ergon & Energex for the QCA (2001)
- PowerLink Transmission Review undertaken for the ACCC (2000)
- distribution price reviews of all 5 Victorian DNSPs for the ESC (2000)
- TransGrid transmission review undertaken for the ACCC (1998).

Specifically, all of the key team members for this review have directly participated in work for the AER as part of the recent TransGrid transmission revenue review, or have been associated with providing advice on service target performance incentive schemes.