Review of Ergon Energy 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
EDSD	Electricity Distribution and Service Delivery Review
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)
QME	Queensland Department of Mines and Energy
QCA	Queensland Competition Authority
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
UbiNet	A contiguous telecommunications backbone network being rolled out by Ergon Energy, known as the Ubiquitous Network or UbiNet

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 advised by AER

	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 Ergon Energy for the period 1 July 2010 to 30 June 2015 (the next regulatory control period).

Ergon Energy proposes to invest capital expenditure of $5,354m in its electricity system, $679m of capital expenditure in non-system assets and spend $1899m 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 system capital expenditure of $5,354m has not been found to be prudent and efficient. PB has recommended a reduction of $999m (19%) for a range of reasons as described below. PB’s advice is that a prudent and efficient expenditure in the next regulatory period would be $4,355m.
- The proposed non-system capital investment of $679m does not represent a prudent and efficient level of expenditure. PB recommends a reduction of $256m (37%) for a range of reasons as described below. PB’s advice is that a prudent and efficient expenditure in the next regulatory period would be $423m.
- The proposed operational and maintenance expenditure of $1898.5m has been found not to be prudent and efficient. PB recommends a reduction of $187.8m (10%) for a range of reasons as described below. PB’s advice is that a prudent and efficient expenditure in the next regulatory period would be $1,710.7m.
- An additional reduction of $20.4m is recommended relating to the service charge from ICT service provider SPARQ. The service charge is treated as an overhead and the recommendation results in a $17.1m reduction in capex and a $5.1m reduction in opex.

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

System capital expenditure

Ergon Energy proposes to invest capital expenditure of $5,354m on its electricity system over the next regulatory control period. PB has found $4,355m (90%) of the proposed expenditure to be prudent and efficient. PB’s key findings are as follows:

- Ergon Energy’s capital governance is generally consistent with good electricity industry practice.

- The options analysis included in Ergon Energy's business case documentation lacks robustness, generally does not consider non-network alternatives, and includes limited NPV analysis to demonstrate the efficiency of the selected option.
- The planning criteria used by Ergon Energy are aligned with good electricity industry practice, however demand forecast application is only partially demonstrated and non-network alternatives are not generally considered.
- Asset replacement policies and procedures are in line with good electricity industry practice, however asset replacement practices are not consistently implemented.
- Reliability and quality improvement planning follows many of the elements of good electricity industry practice.
- An adjustment in expenditure is recommended in the following categories for the reasons outlined:
  - A reduction of $526m to the Corporation Initiated Augmentation growth capex forecast as a result of deferring this expenditure for 18 months.
  - A reduction of $318m to the Customer Initiated Capital Works growth capex forecast as PB is of the view that the forecast has not been sufficiently substantiated.
  - A reduction of $119m to the asset replacement capex forecast as PB's view is that the volume forecasts underpinning the forecasts were not demonstrated to be prudent.
  - A reduction in reliability and quality improvement capex of $35.4m, as the increase above business-as-usual level for the Feeder Improvement Program has not been demonstrated to be prudent and efficient.

PB recommends that the system capex allowance for the next regulatory control period should be reduced by $998.7m (19%) from the levels proposed by Ergon Energy. 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
Ergon Energy Proposal	905.3	1,000.9	1,042.1	1,145.8	1,259.8	5,353.9
PB adjustment	(167.5)	(203.4)	(179.3)	(208.0)	(240.5)	(998.7)
PB recommendation	737.8	797.5	862.8	937.8	1,019.3	4,355.2

Non-system capital expenditure

Ergon Energy proposes to invest capital expenditure of $679m on non-system assets in the next regulatory control period, an average increase of 3.6% compared with expenditure in the current regulatory control period. PB has found this level of expenditure not to be prudent and efficient, and has recommended reductions as follows:

- Ergon proposes expenditure of $92.9m for ICT capex in the next regulatory control period, a reduction of 47.6% compared with the current regulatory control period. This is due to the establishment of SPARQ as their ICT service provider. PB recommends a reduction of $65.2m to the proposed expenditure to reflect removal of costs associated with the Change Program for which no information was provided to demonstrate prudence or efficiency. The expenditure recommended by PB relates to Ergon Energy's investment in end-use computing assets only.

- Ergon proposes to invest $386.8m on property in the next regulatory control period, an average increase of 74.4% compared with the current regulatory control period. PB recommends a reduction of $191m to the proposed expenditure which reflects a business-as-usual approach, taking into consideration likely increases due to forced maintenance as a consequence of not undertaking or deferring the proposed building program. In PB's view, the need and timing for the proposed building program is only partially demonstrated and, in general, alternatives have not been well considered.

- Ergon Energy proposes to invest $160.5m on fleet in the next regulatory control period, an average increase of 0.2% compared with the current regulatory control period. PB has concluded that Ergon Energy's proposed expenditure on motor vehicles is prudent and efficient. Therefore, PB recommends no adjustment in fleet expenditure for the next regulatory control period,

- The proposed capex for tools and equipment of $38.8m, representing a real decrease of 59% compared with expenditure in the current regulatory control period, is assessed by PB as being both prudent and efficient.

PB recommends that the non-system capex allowance for the next regulatory control period should be reduced by $256.0m from the levels proposed by Ergon Energy. 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
Ergon Energy proposal	180.9	199.0	135.1	82.2	81.8	679.0
PB Adjustment	(96.1)	(116.1)	(51.0)	1.2	6.0	(256.0)
PB Recommendation	84.8	82.9	84.1	83.4	87.8	423.0

Operational and maintenance expenditure

Ergon Energy proposes to spend $1,898.5m on operations and maintenance in the next regulatory control period, an average increase of 23% when compared to the current regulatory control period. PB has not found this level of proposed expenditure to be prudent and efficient, and has recommended reductions as follows:

- The proposed expenditure of $593.7m on preventive maintenance represents an average increase of 47% compared with the current regulatory control period. PB recommends a reduction in preventive maintenance opex of $15.35m based on the savings estimated to result from a change in the pole inspection cycle from 4-yearly to a 4.5-yearly. PB recommends an additional reduction in preventive maintenance opex of $2.9m based on reducing the number of visual inspections of customer services to account for the roll-out of a full inspection program in parallel.

- PB has found that the top-down forecasting approach for asset-based corrective maintenance is prudent and efficient. However PB recommends a $9m reduction from the proposed expenditure of $589.8m resulting from the recommended exclusion of a scope increase to allow for dismantling old replaced lines.

- The proposed expenditure of $205.7m on forced maintenance represents an average decrease of 2% compared with the current regulatory control period. PB has found the methodology for determining the base-line maintenance requirements is reasonable. However PB is of the view that Ergon Energy has not appropriately captured the benefits of its targeted asset replacement program in reducing its forecast of forced maintenance need in the final years of the next regulatory control period. PB therefore recommends a reduction in forced maintenance opex of $6.70m during the next regulatory control period.

- The proposed expenditure on vegetation management and corridors & sites is $549.1m . Clear evidence has been provided to PB of the need for a significant change in the approach to vegetation management, including a significant rural backlog and non-compliance with clearance standards. In PB's view the developing strategy is prudent and should deliver efficient cost outcomes in the long term. However, PB recommends a reduction of $48.48m in vegetation management and corridors and sites opex resulting from the removal of a 5% uplift in unit costs, removal of some scope increases where PB believes it is not sufficiently substantiated and a significantly reduced proposed expenditure associated with the volume of keys and locks for access gates.

- The proposed expenditure of $101.3m on customer service represents an average decrease of 32% compared with the expenditure in the current regulatory control period. Meter reading costs are proposed to increase by 39% to $60m in the next regulatory control period. PB recommends a reduction in meter reading and customer service opex of $79.56m during the next regulatory control period resulting from the removal of costs associated with Alternative Control Services activities that appear to have been inadvertently included in the Standard Control Service forecasts.

- Ergon Energy proposes to spend $213.7m on 'other' opex, an average increase of 91% when compared to the current regulatory control period. PB recommends a reduction in 'other' opex of $2.63m during the next regulatory control period resulting from removal of part of the forecast expenditure for program management associated with demand management initiatives.

PB's other key findings are as follows:

- Policies, documentation and modelling to support the asset management approach and the forecasting methodology is comprehensive, transparent and reflective of the needs of the business in the current environment.

- Except for the impact of network growth escalation, the opex forecasting approach adopted by Ergon Energy is reasonable and transparent, based on either a detailed bottom-up view of asset quantities or work volumes across key asset categories in all the material areas, or on a pragmatic top-down view - informed by historical experience - in the areas where a detailed bottom-up view is not practical.

- For network growth escalation, the opex forecasting approach used by Ergon Energy includes only a simplistic view of the impact on opex associated with the growth of the network, and does not suitably capture the actual capex program proposed, nor integrate the various strategies, including capex/opex trade-off, effectively.

- Asset maintenance and management practices are in a transitional stage. The current approach includes lagging indicators and fixed time-based inspections. The future approach will capture more condition based knowledge and be informed through leading indicators – reflective of a strategic increase in preventive maintenance requirements.

- Whilst asset performance of poles and lines is very good, there are a significant number of annual failures occurring for substation plant such as transformers, switchgear and instrument transformers.

- At a high-level, service delivery practices are reasonable and efficient, as is the estimating approach used to inform unit costs.

- In comparison[1] with a small sample of Australian DNSPs, Ergon Energy's opex forecasts appear relatively high from a top-down perspective using a composite size variable to normalise the businesses, and some reasons to explain this observation are indentified.

PB recommends that the opex allowance for the next regulatory control period should be reduced by $187.8m (10%) from the levels proposed by Ergon Energy. 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
Ergon Energy proposal	370.10	381.48	385.49	386.69	374.70	1,898.5
PB adjustment	(31.6)	(35.1)	(38.3)	(41.3)	(41.5)	(187.8)
PB recommendation	338.5	346.4	347.2	345.4	333.2	1,710.7

Overheads

PB has found the allocation of overheads is in accordance with the required cost allocation model.

PB has examined the service charge from ICT service provider SPARQ. PB considers that, with the exception of Data Centres, the proposed expenditure associated with the 'new capability' initiatives capitalised within SPARQ has not been shown to be prudent and efficient and, as such, PB recommends an ICT expenditure forecast aligned to historical levels. The recommendation results in a $15.7m reduction in capex and a $4.7m reduction in opex.

Table E4 Reduction in overheads due to SPARQ service charge

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Ergon Energy proposal	381.0	395.4	384.8	383.7	381.8	1,926.7
PB adjustment	(1.7)	(6.2)	(3.4)	(4.1)	(5.0)	(20.4)
PB recommendation	379.3	389.2	381.4	379.6	376.8	1,906.3

Cost escalation

PB has found the methodology used to calculate the capex cost escalators to be a detailed approach that is suitable for application to Ergon's forecast capex. PB has identified two problems with the workings of the cost escalation model. Correction of these issues results in a downward revision to forecast capex of $269.9m over the next regulatory control period. The annual and total adjustments are shown in Table E5.

[1] AER Opex Benchmarking 2001–02 to 2008–09

Table E5 Additional capex reduction due to revised cost escalation

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Ergon Energy proposal	1,086.2	1,199.9	1,177.3	1,228.0	1,341.5	6,032.9
PB adjustment	(73.5)	(72.7)	(55.67)	(41.3)	(26.7)	(269.9)
PB recommendation	1,012.7	1,127.2	1,121.6	1,186.7	1,314.8	5,763.0

Service delivery

PB's review of the contracting strategies and the material procurement practices used by Ergon Energy indicates that, in the view of PB, Ergon Energy should be able to deliver its proposed operating and capital programs of work during the next regulatory control period.

Service standards

PB notes that the reliability of supply targets proposed by Ergon Energy are required to meet the Minimum Service Standards (MSS) mandated by the *Electricity Industry Code*. PB notes that the current performance of Ergon Energy complies with the MSS up until 2007-08. PB has therefore assessed the expenditure proposed by Ergon Energy and determined that this expenditure is appropriate to maintain current service performance.

The values proposed by Ergon Energy for the service target performance incentive scheme are generally found to be appropriate, with the exceptions noted below.

PB's findings in relation to Ergon Energy's reliability of supply parameter are as follows:

- The quality of Ergon Energy's historical data is suitable for target setting.
- The targets for SAIDI and SAIFI should be set at Ergon Energy's internal business targets to reflect the likely future performance after taking account of the proposed capex and opex likely to impact on future service levels.

PB's findings in relation to Ergon Energy's customer service parameter are as follows:

- The quality of Ergon Energy's historical data is suitable for target setting.
- The target for the telephone answering parameter should be set at the average of historical performance less an allowance for the exclusion of telephone calls associated with major event days as described in clause 3.3(b) of the scheme.

In summary, PB recommends the values for the service performance parameters shown in Table E6 and the maximum revenue increment or decrement for the telephone answering parameter should be 0.2%.

Table E6 Recommended values for the service performance parameters

Parameter	Unit	Rate %	Targets 2010-11	2011-12	2012-13	2013-14	2014-15
SAIDI							
Urban	minute	0.023	129	128	127	127	126
Short rural	minute	0.020	296	291	287	283	279
Long rural	minute	0.004	699	687	675	664	652
SAIFI							
Urban	per interruption	1.764#	1.69	1.68	1.66	1.64	1.63
Short rural	per interruption	2.060#	3.06	3.02	2.98	2.94	2.91
Long rural	per interruption	0.601#	5.59	5.52	5.44	5.37	5.29
Customer service							
Telephone answering	%	-0.040	77.3	77.3	77.3	77.3	77.3

*Note: * Target to be determined based upon telephone answering data (2008-09 to 2010-11) when available.*

 # per 0.01 interruptions

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

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 both 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 Ergon Energy. The reviews of ETSA Utilities and ENERGEX are the subjects of separate reports by PB.

The Ergon Energy Regulatory Proposal[3] was submitted to the AER on 30 June 2009. PB was provided with a copy of the proposal on 3 July 2009. The AER is expected to make its Draft Determination by the end of November 2009 and its Final Determination by the end of April 2010.

1.2 Terms of reference

PB's terms of reference are detailed in Appendix A. The main objective of 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 Ergon Energy 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 involves a review of Ergon Energy's 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. Reviews of equity raising and superannuation costs are also outside of the scope of PB's engagement.

PB's final report to the AER on the Ergon Energy Regulatory Proposal was submitted end October 2009.

2 Please refer to Appendix B for a summary about PB and PB's relevant experience

3 Ergon Energy 2009, *Regulatory Proposal to the Australia Energy Regulator Distribution services for period 1 July 2010 to 30 June 2015*

4 Other than to the extent required to develop an independent recommendation on the prudence and efficiency of the expenditure proposed by Ergon Energy.

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. Section 4, 5 and 6 deal with the Ergon Energy system capex, non-system capex, and opex proposals respectively. Section 7 provides details of PB's review of Ergon Energy's deliverability proposals, and in Section 8 we provide our recommendations in respect of Ergon Energy's proposed Service Standards. Generic limitations of the report are provided in Section 9.

2. Review methodology

In this section of the report we describe the overarching methodology PB adopted in our review of the Ergon Energy expenditure proposal. It includes an outline of our approach to the review and details of aspects of the Ergon Energy proposal examined.

2.1 PB's phased approach

In undertaking the review of Ergon Energy, PB has adopted a phased approach. 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 key stages of the PB review are:

- a high level 'portfolio' review
- a more detailed, 'focused' review of key 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 recognises and allows for the need to undertake a high-level review of the entire regulatory submission *before* being able to determine which aspects warrant further review 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 robust independent advice on the prudence and efficiency of the Ergon Energy regulatory proposal.

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

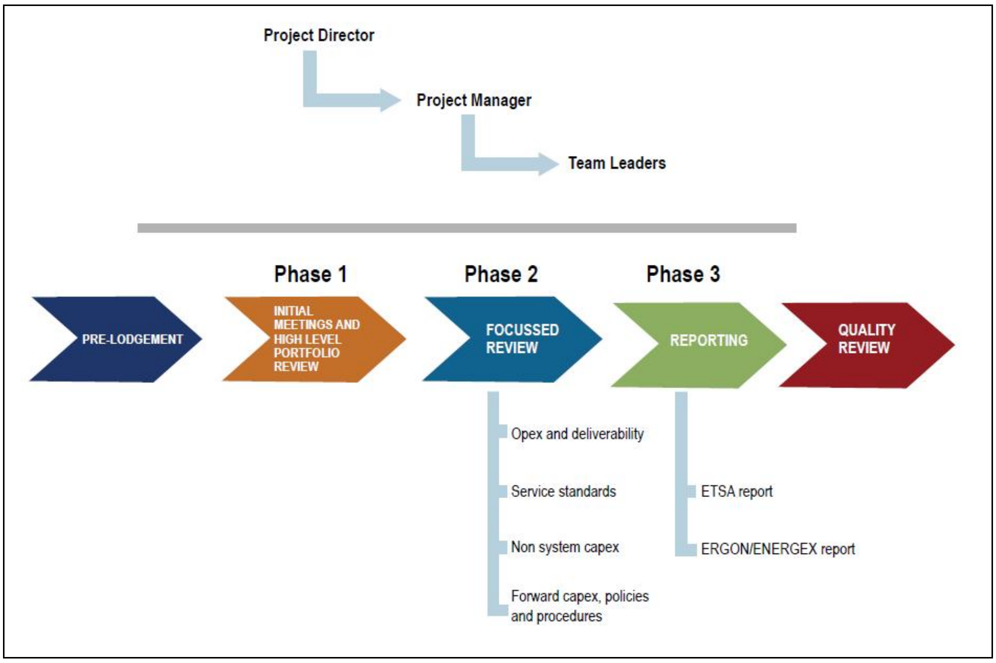

Figure 2.1 PB's approach to the review

The phased approach adopted by PB involved the following steps:

- a detailed desk-top review of the information provided in the Regulatory Proposal
- onsite meetings with Ergon Energy staff to discuss essential elements of the Regulatory Proposal (PB provided Ergon Energy 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 focused review stage
- formulation of detailed questions for Ergon Energy on its expenditure proposals
- consideration of Ergon Energy's responses
- a second on-site visit with Ergon Energy to discuss key issues and PB's preliminary views and findings on the expenditure proposals
- further questions and responses to establish a full understanding of specific expenditure items.

In meeting its primary objective of providing an independent view on the prudence and efficiency of the Ergon Energy 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 Ergon Energy 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 Ergon Energy about historical expenditures has therefore occurred. Further information about PB's review of the capex and opex proposed by Ergon Energy 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 Ergon Energy is acting efficiently in accordance with good electricity industry practice through a review of capital governance, policy and procedures, cost estimating practices, specific reviews of certain expenditures, and the deliverability of the proposed works program
- 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].

PB's review of Ergon Energy's forecast capex has specifically excluded the following matters from our scope of work:

- benchmarking of unit costs
- the level of forecast demand.

2.1.2 Opex review

PB's review of Ergon Energy's 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:
  - reviewing the opex by cost category in both the current and next regulatory control period, including trends and changes in each line item[6]
  - reviewing the variations between the opex in the final year of the current regulatory control period and opex in the first year of the next period (step changes in expenditures)
  - the reasonable application of escalation factors used to forecast expenditures
  - assessing the appropriateness of efficiency factors used to reflect the impact of economies of scale and scope
  - assessing the efficiency of labour and material costs used to forecast expenditures
  - 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:

[5] PB's review did not include assumptions made about the future demand for electricity.
[6] This included escalating historical nominal costs to real 2009-10 dollars and removing the impacts of labour and material escalation in the next regulatory control period to test the sensitivity of the real labour and material escalation built into the forecasts, and to provide more insight into the volumes of work in the next regulatory control period compared with historical levels.

- reviewing and understanding the business-as-usual approach to asset management processes and practices, 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 the Ergon Energy forecast opex has specifically excluded the following matters from our scope of work:

- self insurance arrangements and allowances ($20.1m included in the 'other opex' line item)
- costs of debt-raising ($18.8m included as an increased notional value of debt in the Post Tax Revenue Model (PTRM)
- costs of equity raising (unit transaction costs of 7.8% and 2% for Seasoned Equity Offering (SEO) and Dividend Reinvestment Plan (DRP), respectively, to be treated as opex)
- 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/Regulatory Asset Base (RAB), or opex/composite size ratios (to be undertaken by the AER)
- a high-level review of historical expenditure variations in the current regulatory control period compared with regulatory allowances (to be undertaken by the AER)
- a detailed review of the identified external factors and obligations (to be undertaken by 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.

2.1.3 Service standards

Ergon Energy 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.

Ergon Energy 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 Ergon Energy over the next regulatory control period. PB has assessed the STPIS values proposed by Ergon Energy 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 required by the STPIS, as well as the impact that the proposed 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 Ergon Energy 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 policies 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's investment approach. For this reason PB has undertaken a high-level review of Ergon Energy's capital governance framework as an integral element of assessing the prudence and efficiency of the proposed system capital investment for the next regulatory control period.

In our view, good practice in capital governance in the context of an asset manager involves both good practice in asset management principles as well as good practice in 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[7], IIMM[8], and TAM[9], as well a range of Australian and International Standards[10]. 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's 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's culture.

Further to this, PB expects sound capital governance to embody the principles of good practice in investment management as evidenced through prudent business management practices — specifically, formal delegations from the Board level through to the business's 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's risk management practices, quality practices, compliance practices, occupational health and safety (OH&S) practices, and environmental management practices, amongst others.

2.2.2 Policies and procedures

Ergon Energy 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 our assessment and recommendation PB has considered the extent to which we believe Ergon Energy's 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 our view on the Ergon Energy policies and procedures through a desk-top review of documentation, through discussions with Ergon Energy staff, and as an integral part of our 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.

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7 British Standards 2008, Publicly Available Standard 55 — Asset management. Specification for the optimized management of physical assets.

8 Association of Local Government Engineering NZ Inc. 2006, *International infrastructure management manual*.

9 NSW Treasury 2006, *Total asset management*.

10 For example, AS/NZS 4360 (risk management), AS/IEC 60300 (dependability management), ISO 9001 (quality management)

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 Ergon Energy 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 programs can have a significant impact on opex as well as on investment decision-making.

PB's review of the Ergon Energy work programs has been informed by the Regulatory Proposal and supporting documentation as well as through discussions with Ergon Energy 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 projects.

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 Ergon Energy to escalate forecast costs to account for increases in materials, labour and other factors above consumer price index (CPI), and to allocate overhead costs across expenditure categories.

3.1 Cost escalation

Ergon Energy has incorporated real-cost escalation factors into the forecasts for capex and opex in the proposal to the AER. Ergon Energy used a range of inputs and advice from consultants in order to establish appropriate cost escalation factors, as described in this section.

To determine appropriate cost escalators for capex, Ergon Energy engaged Sinclair Knight Merz (SKM) to prepare cost escalators for each of 27 expenditure asset classes. SKM arrived at annual real-cost escalators for each year of the next regulatory in period as presented Table 3.1.

Table 3.1 Real-cost escalators for capex

Expenditure type	2010-11	2011-12	2012-13	2013-14	2014-15
Overhead sub-transmission lines	1.023	1.027	1.020	1.021	1.027
U/G sub-transmission cables	1.011	1.018	1.013	1.010	1.017
Overhead distribution lines	1.014	1.027	1.024	1.022	1.028
U/G distribution cables	1.012	1.020	1.017	1.013	1.020
Distribution equipment	1.007	1.022	1.019	1.017	1.023
Substation bays	1.007	1.018	1.013	1.009	1.015
Substation establishment	1.019	1.013	0.995	0.985	0.996
Dist. substation switchgear	0.999	1.026	1.022	1.016	1.024
Zone transformers	1.002	1.047	1.039	1.029	1.041
Distribution transformers	1.009	1.030	1.025	1.020	1.028
Low-voltage services	1.004	1.037	1.036	1.037	1.046
Metering	1.007	1.015	1.014	1.013	1.016
Communications — pilot wires	1.000	1.000	1.000	1.000	1.000
Generation assets	1.009	1.032	1.025	1.018	1.026
Street lighting	1.013	1.018	1.014	1.013	1.017
Other equipment	1.000	1.000	1.000	1.000	1.000
Control centre — SCADA	1.000	1.000	1.000	1.000	1.000
Land & ease. — residential	1.098	1.094	1.094	1.098	1.103
Land & ease. — commercial	1.054	1.050	1.050	1.054	1.058
Land & ease. — rural	1.080	1.076	1.076	1.080	1.084

Expenditure type	2010-11	2011-12	2012-13	2013-14	2014-15
Land & ease. — other	1.049	1.045	1.045	1.049	1.053
Communications	1.000	1.000	1.000	1.000	1.000
IT systems	1.000	1.000	1.000	1.000	1.000
Office equipment & furniture	1.000	1.000	1.000	1.000	1.000
Motor vehicles	1.000	1.000	1.000	1.000	1.000
Plant & equipment	1.000	1.000	1.000	1.000	1.000
Buildings	1.019	1.013	0.995	0.985	0.996

Source: Ergon reference PL651c, SKM report Electricity industry labour, commodity and asset price cost indices — January 2009 update of escalators*, 14 January 2009.*

Ergon Energy has applied cost escalators to its opex forecasts across four broad categories: labour, materials, contractors and other. The four input cost escalators relevant to the opex forecast, together with the forecast CPI are outlined in Table 3.2.

Table 3.2 Real-cost escalators for opex

Real opex escalators	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Materials	1.0182	0.9236	1.0304	1.0117	1.0156	1.0107	1.0068
Contractors	1.0330	1.0230	1.0237	1.0195	1.0195	1.0195	1.0195
Labour	1.0330	1.0230	1.0237	1.0195	1.0195	1.0195	1.0195
Other	1.0093	1.0015	1.0074	1.0024	1.0024	1.0024	1.0024
CPI	1.0175	1.0275	1.0200	1.0250	1.0250	1.0250	1.0250

Source: PB analysis, Table 91 of Regulatory Proposal and SC Opex and Capex Model.xls, 'Data Input' tab

While it is not within PB's scope of work to review the value of the actual raw escalators Ergon Energy has incorporated into its expenditure forecasts, we are required to comment on the reasonableness and suitability of the methodology used. This review is detailed in the following sections on capex and opex cost escalation.

3.1.1 Capex cost escalation

The methodology and results of the SKM analysis with respect to escalators for capex were provided to PB for review in report PL651c[11]. The methodology involves the determination of raw input commodity and labour escalation forecasts and the application of weightings comprising two parts:

- weightings of input commodities and labour within individual assets
- weightings of asset building blocks within asset classes aligned with Ergon Energy's network.

This results in asset class escalators that align with Ergon Energy's breakdown of forecast capex. Ergon Energy then applies the resultant capex asset class escalators to their forecast capex in the spreadsheet model 'SC Opex and Capex Model.xls'.

11 Ergon Energy reference PL651c, SKM report *Electricity industry labour, commodity and asset price cost indices — January 2009 update of escalators*, 14 January 2009. PB notes that initial results were presented in report AR438 and results updated in report PL651.

PB assessment and findings

The methodology used to calculate the capex cost escalators (described above) results in escalation indices that are directly applicable to Ergon Energy's breakdown of forecast capex into asset classes. This methodology is therefore considered to be a detailed approach that is suitable for application to Ergon's forecast capex.

Ergon Energy is however unable to provide the weightings used by SKM to prepare the asset class escalators for capex due to protection of SKM's intellectual property[12]. Therefore, PB has not been able to review the specific value of the weightings. To assess the appropriateness of the resultant escalators, PB conducted an analysis using high-level estimates of typical weightings. Compared with the results of this high-level analysis, the results of the SKM applied weightings as used by Ergon Energy are considered efficient.

Ergon Energy applies the capex asset class escalators in the spreadsheet model 'SC Opex and Capex Model.xls'. The model works by performing the following steps and calculations:

1. Input values are real annual escalators for 2005-06 to 2014-15 for each asset category as per the SKM analysis

2. 'Cumulative' nominal escalators with a 2004-05 base are calculated by multiplying the above annual real escalators by the cumulative CPI index for each year since 2004-05

3. The cumulative nominal escalators above are re-based to 2007-08

4. These escalators are applied to expenditure forecasts in 2007-08 dollars for financial years 2008-09 to 2014-15 to arrive at expenditure forecasts in nominal dollars

5. The expenditure forecasts in nominal dollars are deflated back to 2009-10 dollars as required by the RIN by dividing through by the cumulative CPI index since 2009-10.

PB has identified two problems with the workings of this model:

- the calculation of cumulative nominal escalators in step 2 includes the cumulative effect of CPI but not of the escalators themselves

- the set of CPI values used to inflate 2007–08 real values to nominal in step 2 is different from the set used to deflate back to 2009–10 real values in step 5.

Correction of these issues results in a downward revision to forecast capex of $269.91m over the next regulatory control period. The annual and total adjustments are shown in Table 3.3. The impact of cost escalators on capex is not discussed further in this report

Table 3.3 Capex forecast adjusted for correct escalation

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposal	1,086.2	1,199.9	1,177.3	1,228.0	1,341.5	6,032.9
PB adjustment	(73.5)	(72.7)	(55.67)	(41.3)	(26.7)	(269.9)
PB recommendation	1,012.7	1,127.2	1,121.6	1,186.7	1,314.8	5,763.0

Source: PB analysis

12 Issue reference JH.01 24/08/09

The two issues discussed above also affect the table of nominal cumulative escalators presented in Ergon Energy's Regulatory Proposal in Table 90. The corrected values of the nominal cumulative escalators over the next regulatory period are given in Table 3.4.

Table 3.4 Corrected nominal cumulative cost escalators (2007–08 base year)

Expenditure type	2010–11	2011–12	2012–13	2013–14	2014–15
Overhead sub-transmission lines	0.994	1.046	1.093	1.143	1.203
U/G sub-transmission cables	1.046	1.091	1.131	1.170	1.220
Overhead distribution lines	1.031	1.085	1.139	1.192	1.256
U/G distribution cables	1.067	1.115	1.162	1.206	1.260
Distribution equipment	0.998	1.045	1.091	1.136	1.191
Substation bays	1.016	1.059	1.100	1.137	1.182
Substation establishment	1.102	1.144	1.167	1.178	1.202
Dist. substation switchgear	0.904	0.950	0.995	1.036	1.086
Zone transformers	0.824	0.884	0.941	0.992	1.058
Distribution transformers	0.972	1.025	1.076	1.124	1.184
Low-voltage services	0.881	0.936	0.993	1.055	1.131
Metering	1.046	1.087	1.130	1.172	1.220
Communications — pilot wires	1.071	1.097	1.124	1.152	1.180
Generation assets	0.960	1.015	1.066	1.112	1.169
Street lighting	1.076	1.122	1.166	1.209	1.260
Other equipment	1.071	1.097	1.124	1.152	1.180
Control centre — SCADA	1.071	1.097	1.124	1.152	1.180
Land & ease. — residential	1.406	1.576	1.767	1.988	2.246
Land & ease. — commercial	1.241	1.334	1.434	1.548	1.678
Land & ease. — rural	1.336	1.472	1.623	1.795	1.994
Land & ease. — other	1.224	1.309	1.401	1.506	1.624
Communications	1.071	1.097	1.124	1.152	1.180
IT systems	1.071	1.097	1.124	1.152	1.180
Office equipment & furniture	1.071	1.097	1.124	1.152	1.180
Motor vehicles	1.071	1.097	1.124	1.152	1.180
Plant & equipment	1.071	1.097	1.124	1.152	1.180
Buildings	1.102	1.144	1.167	1.178	1.202

3.1.2 Opex cost escalation

To determine appropriate values for the four opex cost escalators, Ergon Energy utilised a number of sources, including Ergon Energy's Union Collective Agreement 2008 (labour and contractors), independent advice provided by SKM[13] (materials), and Ergon Energy's internal review as part of its budgeting process (other).

13 AR509_SKM_Cover Letter Opex Materials Cost Esc_9Apr09.pdf

To reach a view on the appropriateness of the methodology, PB has relied to some extent on reviewing the audit processes and results of a third-party audit that was conducted for Ergon Energy in order to provide validation of the methodology employed[14].

The process undertaken by Ergon Energy to identify the opex percentage splits to which it would apply the four escalators primarily consisted of:

- utilising the annual 2007–08 budget forecasting process, which covered a four-year outlook period to 2012–13 and involved a bottom-up build from numerous responsibility-based cost centres as per the Ergon Energy chart of accounts manual[15]
- allocating expense elements in the four escalation categories in accordance with the items listed in Table 3.5.

Table 3.5 Impacts of real escalators used for opex 2008–09 to 2014–15.

Real opex escalators impacts	Element
Materials	Stores issues Stores oncost Stores consumables Stock write offs Stocktaking adjustments Freight on stock items Inventory pricing adjustments Returns pricing adjustments (system use) Returns offset (system use) External storage costs
Contractors	Contractors Consultants Labour hire Project resources JV contractor Consultants & contractors — non-deduction Portable long-service fees
Labour	Ordinary time costed Overtime costed Labour oncost costed
Other	Anything else

Source: EE Response to VP.92 (and VP.90 & VP.87) - Opex Percentage Splits, 26/08/09

The outcome of this process resulted in the percentage splits across the opex cost categories as shown in Table 3.6.

14 The modelling was reviewed by PwC as discussed in PL551c_Ergon Energy - AER2010 Financial Models AUP Report (Final) 220609.pdf

15 PL748c_EE_Chart of Accounts Manual_21Aug09.pdf

Table 3.6 Percentage allocation of opex 2008–09 to 2014–15.

Real opex escalators	Average split from 2008-09 to 2009-10				Average split from 2010-11 to 2013-14			
	Labour	Mat.	Contr.	Other	Labour	Mat.	Contr.	Other
Network operations	78	1	4	18	79	1	4	17
Preventive comms	100	-	-	-	100	-	-	-
Preventive lines1	7	-	93	-	7	-	93	-
Preventive meters	100	-	-	-	100	-	-	-
Preventive protection2	100	-	-	-	100	-	-	-
Preventive subs3	53	-	-	47	61	-	-	39
Preventive veg	-	-	100	-	-	-	100	-
Preventive inspection4	50	-	50	-	50	-	50	-
Preventive streetlights	-	-	100	-	-	-	100	-
Corrective comms	15	5	76	5	15	5	76	5
Corrective lines5	30	3	63	4	31	3	62	4
Corrective meters	4	1	94	1	4	1	94	1
Corrective protection2	15	5	76	5	15	5	76	5
Corrective subs3	52	3	42	3	52	3	42	3
Corrective veg	-	-	100	-	-	-	100	-
Corrective streetlights	15	5	75	5	15	5	75	4
Forced maintenance	55	27	4	15	55	28	4	14
Meter reading	100	-	-	-	100	-	-	-
Customer service	70	20	1	9	70	20	1	9
DMIA	-	-	-	100	-		-	100
Self-insurance	-	-	-	100	-	-	-	100
Training	100	-	-	-	100	-	-	-
GSL	-	-	-	100	-	-	-	100
DSM	71	1	14	15	19	-	-	81

Note 1: 'Preventive lines' is a rolled-up category inclusive of asset equipment classes {03, 04, 05, 06, 07, 08, 09, 10, 11, 13, 14} as per Table 6.7.

Note 2: 'Preventive' and 'corrective protection' are rolled-up categories inclusive of asset equipment classes {25, 26} as per Table 6.7.

Note 3: 'Preventive' and 'corrective subs' are rolled-up categories inclusive of asset equipment classes {17, 18, 19, 20, 21, 22, 23} as per Table 6.7.

Note 4: 'Preventive inspection' is a rolled-up category inclusive of asset equipment classes {02, 15} as per Table 6.7.

Note 5: 'Corrective lines' is a rolled-up category as per preventive line, plus {02, 15} as per Table 6.7

Source: PB analysis and PL561c_SCOpex Data Model.xls

PB assessment and findings

In reviewing the opex escalators, PB calculated the financial impact of the application of these real escalators on the opex forecast; the results are shown in Table 3.7.

Table 3.7 Impacts of real escalators used for opex

$m	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Materials	(0.50)	(0.31)	(0.07)	0.10	0.20	(0.58)
Contractors	12.75	16.44	19.87	22.54	23.54	95.14
Labour	11.72	14.68	17.45	20.64	23.55	88.04
Other	0.56	0.66	0.74	0.82	0.90	3.68
Total	24.53	31.47	37.99	44.10	48.19	186.28

Source: PB analysis

The percentage allocation data in Table 3.6 show that Ergon Energy is keeping the proportions within each category constant over the next regulatory control period in all but two categories: 'preventive subs', where there is a move of allocation from the 'other' category to the labour category, and 'DSM', where the bulk of the allocation has moved from 'labour' to 'other'.

In context of how the historical and forecast opex is apportioned into the four escalation categories, Figure 3.1 shows the year-on-year trend, indicating that Ergon Energy is not anticipating any significant variation in its approach over the next regulatory period.

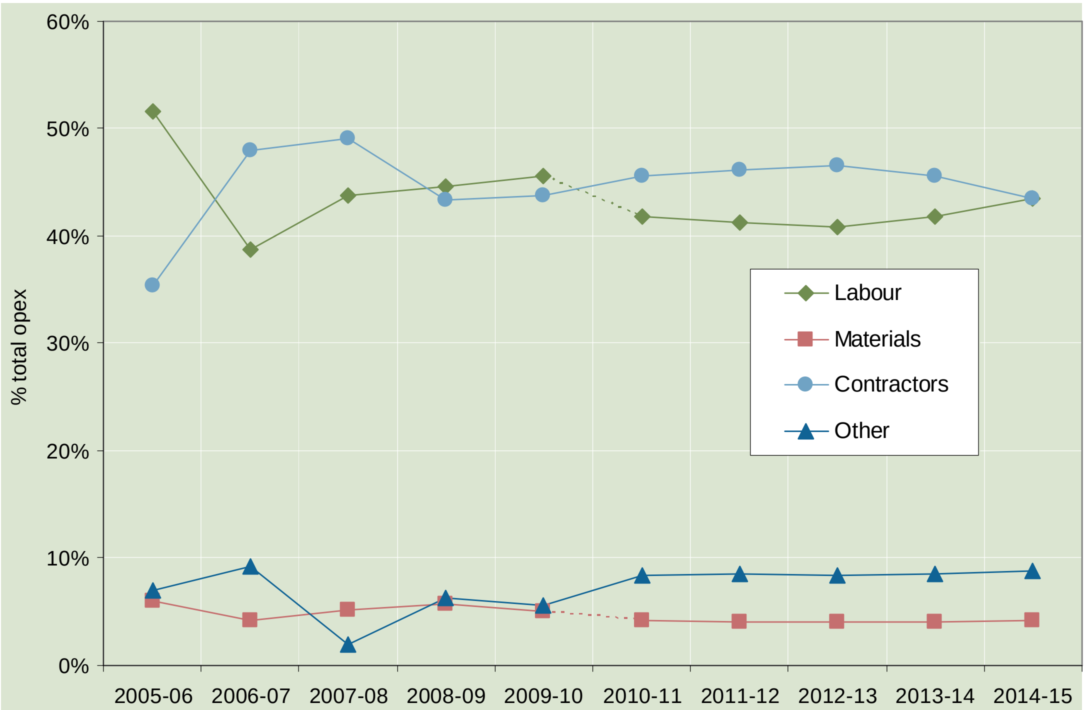

Figure 3.1 Historical and forecast split across escalation categories

Source: PB analysis

In assessing the opex escalators, PB has considered:

- the combination of the process that Ergon Energy undertook to arrive at its forecast splits of opex into each of the escalation categories (which is strongly informed by the annual business budgeting process)
- the reasonably constant % contribution to total opex identified within each of the four categories over the outlook period.

PB has formed the view that the methodology and application of the opex cost escalators through the various opex model spreadsheets (as independently reviewed by PwC) is reasonable and correct.

A more detailed discussion of the impact of input cost escalation on Ergon Energy's opex can be found in section 6.3.2 of this report.

3.2 Overhead allocations

'Overhead allocation' refers to the pool of costs, generally relating to management activities that are borne by the business but are not directly related to specific network activities. PB has reviewed the DNSP's overheads and has recommended adjustments based on this review. PB notes that overheads are applied to each of the expenditure categories and that any reductions made to these categories will require the overheads to be re-allocated across to remaining categories. The relationship between the overhead pool and the capital and operating expenditures was not considered part of PB's review. This section describes Ergon Energy's approach to allocating these costs across the network-specific capex and opex categories.

3.2.1 Proposed overhead expenditure

Ergon Energy's gross pool of overheads is equivalent to $1.93b over the five years of the next regulatory control period and this is allocated across capex and opex forecasts in accordance with the AER-approved Cost Allocation Method (CAM), which results in a 77% allocation of overheads to capex and 23% to opex. This value represents 24% of the summated capex and opex forecasts, or 27% of the opening Regulatory Asset Base (RAB), as shown in Figure 3.2.

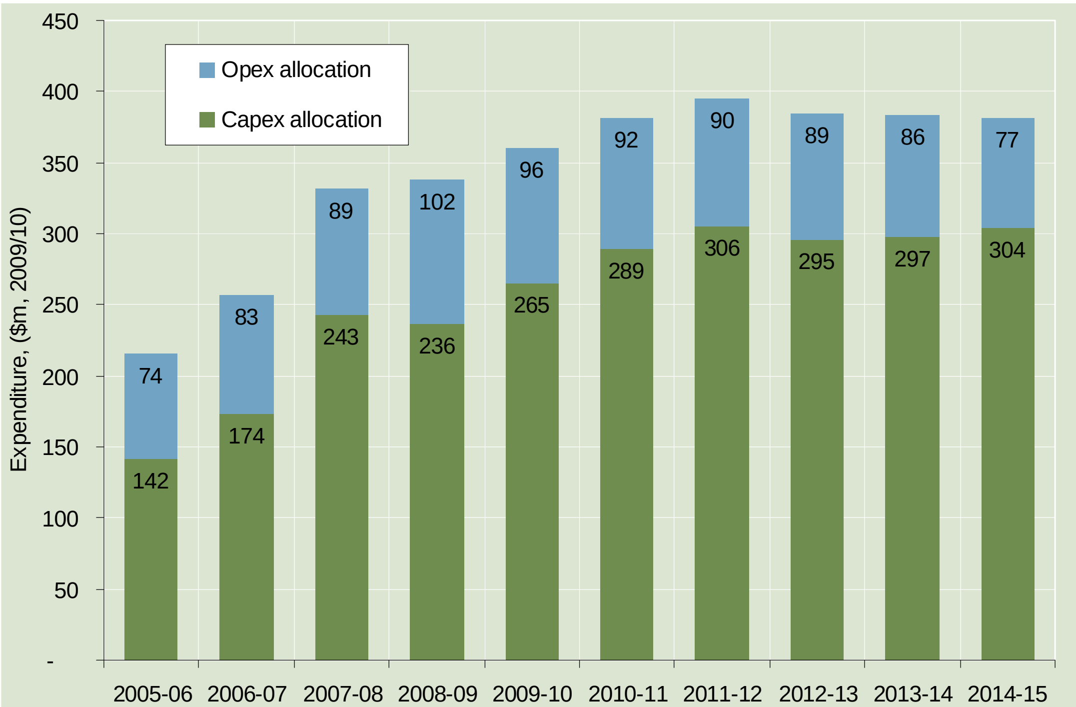

Figure 3.2 Ergon energy total overhead expenditure

Source: PB analysis andAR539c_RIN Submission Model.xls

The overhead expenditure for Ergon Energy includes the Service Level Agreement with the related party SPARQ Solutions[16], as well as other corporate function costs such as the Office of the CEO, Corporate Governance, Finance and Strategic Services, Employee and Shared Services, Customer and Stakeholder Engagement, Customer Services, Corporate Sustainability and Innovation, and Energy Services.

Ergon Energy has advised the proportion of total overheads that relate to each of these categories, and PB has used this information to produce the graphical illustration shown in Figure 3.3.

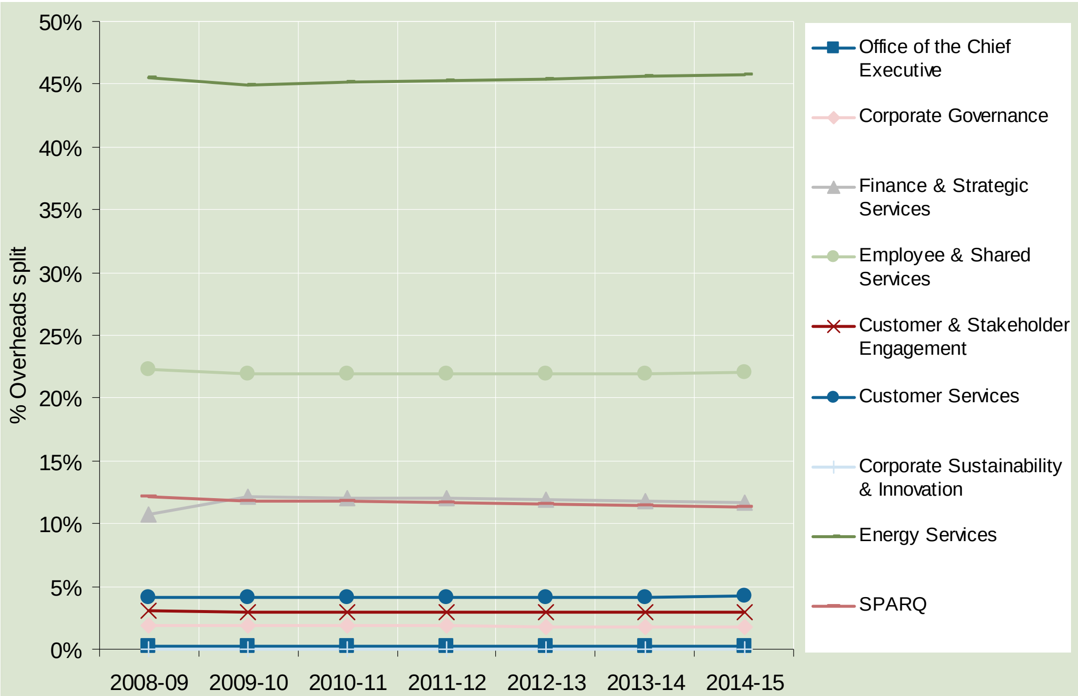

Figure 3.3 Ergon Energy overheads by corporate function

Source: PB analysis

3.2.2 Policies and procedures

PB has conducted a high-level review of the Cost Allocation method (CAM) employed by Ergon Energy.

As costs are incurred within Ergon Energy, they are directly attributed to account codes that are defined by responsibility centres, activities, product codes and expense elements in accordance with the business's Chart of Accounts. Ergon Energy can therefore directly map the contribution of each of its lines of business to Standard Control Services, Alternative Control Services or unregulated activities.

16 SPARQ Solutions is the jointly owned service provider to Energex and Ergon Energy, a related service provider under National Electricity Law. SPARQ provides information and communication technology (ICT) services to both businesses and recovers the costs of providing these services via a service charge to each business.

Ergon Energy has provided a detailed explanation in the Regulatory Proposal[17] of its lines of business and its unregulated activities (including its rationale for such activities which contribute around 3.4% to the business's revenue).

Ergon Energy has also provided a detailed explanation of its AER-approved CAM application[18], outlining a nine-step methodology to identify its gross pool of overheads and to then subsequently apportion these across its capex and opex forecasts.

Notwithstanding an error associated with Ergon Energy's inclusion of some alternative control service expenses in its bottom-up forecast of opex in the Customer Services regulatory category (as discussed in section 6.9), PB considers that Ergon Energy's application of the CAM and its treatment of unregulated activities has been appropriately and transparently described as part of its opex forecasting approach and should generally lead to the correct treatment of costs. This is further supported by the independent review undertaken by PwC[19], which explicitly includes a check as to whether the overhead pool had been correctly allocated in accordance with the method described in Ergon Energy's CAM document.

Except in the case of Customer Services regulatory category, as part of our review of the activities included as part of Ergon Energy's Standard Control Service opex projections, PB has found no reason to believe there are other unregulated activities or Alternative Control Services included.

3.2.3 PB assessment and findings

PB has implicitly reviewed the overheads for Ergon Energy as part of its detailed review of the forecast capex and opex allowances over the next regulatory control period. In addition to this review, PB has endeavoured to identify any material step changes in the total gross pool of overheads to be allocated. In accordance with Figure 3.3, PB has identified that there are no significant increases in the gross quantity of overheads during the outlook period, or variations within the line items that contribute to the pool. Given this finding, PB has identified no need for further detailed assessment, and coupled with our implicit review of the overheads as part of the capex and opex allowances (subject to the findings of the SPARQ ICT capex review in section 5.2) we have drawn the conclusion that the overhead costs are prudent and efficient. This is supported by the observation that they are informed through the businesses existing practices, and that if the real input cost escalation was backed out of the gross pool of overheads, there would be a decreasing trend in expenditure evident over the next regulatory control period.

Under the capex review of ICT in section 5.2, PB recommended a reduction in the SPARQ service charge relating to ICT expenditure capitalised by SPARQ. The recommendation is shown in Table 3.8.

17 Ergon Energy Regulatory Proposal, sections 4.7, 4.15.
18 Ergon Energy Regulatory Proposal, sections 34.1 and 34.2.
19 PwC, PL551c_Ergon Energy - AER2010 Financial Models AUP Report (Final) 220609.pdf

Table 3.8 Recommended capex for ICT expenditure – SPARQ

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Ergon Energy proposal	67.2	64.1	52.5	47.9	35.2	266.9
PB adjustment	(11.8)	(18.5)	(5.6)	(5.6)	(5.6)	(47.1)
PB recommendation	55.4	45.6	46.9	42.3	29.6	219.8
Change %	(17.6)	(28.9)	(10.7)	(11.7)	(15.9)	(17.6)

Source: PB analysis

To calculate the reduction in the service charge associated with the SPARQ capex, PB has used the 2008-09 SPARQ service charge as the base year cost and assumed the increase in the ICT overhead during the next regulatory control period is predominately driven by the SPARQ capex. PB has then applied a reduction to the increases in the SPARQ service charge that is proportional to the reduction recommended for the SPARQ ICT capex. The calculation is shown in Table 3.9.

Table 3.9 Recommended reduction in ICT overheads expenditure – SPARQ

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ICT overheads	70.9	82.6	92.7	95.7	92.7	434.6
ICT baseline (2008-09 year)	61.0	61.0	61.0	61.0	61.0	305.0
Increase in ICT ($m)	9.9	21.6	31.7	34.7	31.7	129.6
% reduction in SPARQ capex (see Table 3.8)	(17.6)	(28.9)	(10.7)	(11.7)	(15.9)	(17.6)
Proportional reduction in ICT overhead	(1.7)	(6.2)	(3.4)	(4.1)	(5.0)	(20.4)
PB recommended ICT overhead	69.2	76.4	89.3	91.6	87.7	414.2

Source: PB analysis and AR308c EE Joint ICT Finances_Sep08 baseline_V1.4_2Feb09.pdf

PB's recommends a reduction in overheads of $20.4m for Ergon Energy as shown in Table 3.10 due to the reduced ICT service charge.

Table 3.10 Recommended overheads for Ergon Energy

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Ergon Energy proposal	381.0	395.4	384.8	383.7	381.8	1,926.7
PB adjustment	(1.7)	(6.2)	(3.4)	(4.1)	(5.0)	(20.4)
PB recommendation	379.3	389.2	381.4	379.6	376.8	1,906.3

Source: PB analysis

3.2.4 Capitalisation policy

Ergon Energy's capitalisation policy[20] is incorporated in its two accounting policies 'Property, plant and equipment' and 'Intangible assets', which provide guidance in respect of:

- key criteria for recognition of an asset

20 AR284 and AR 285

- clarification of accounting treatment in respect of initial recognition as an asset and subsequent expenditure, including refurbishment costs.

The policy applies to all of Ergon Energy's business units and legal entities.

The policy indicates that the cost of an item of property, plant and equipment shall be recognised as an asset if:

- it is probable that a future economic benefit associated with the item will flow to Ergon Energy
- the cost of the item can be measured reliably.

At a project level, the type of costs that are capitalised include asset design, asset implementation, asset building, configuration, testing and commissioning; while, project planning, needs assessment, project scoping and budgeting, and post-implementation reviews are all expensed.

Two key documents associated with the capitalisation policy are the Defect Policy (AR318) and the Defect Classification Manual (AR078), in which:

- P1 defects are defined as conditions reported during inspection of an asset, which have either caused an asset failure in service, or present an imminent risk for failure, or present a risk to public safety
- P2 defects are defined as conditions that are expected to cause an asset failure that is not expected within the designated remediation timeframe
- PM defects are defined as asset conditions that are not expected to cause an asset failure but still vary from the defined asset standard because of age degradation or previous construction practices.

In regard to the detailed application of the policies concerning inspection-based asset requirements and defect policies, Ergon Energy provided in the following clarifications[21]:

- P1 line assets defects trigger a capital work order linked to the feeder.
- P2 line asset defects are coordinated into a package of work and capitalised.
- PM line asset defects are packaged together with P2 defects and are capitalised.
- The replacement of major items of plant that have failed in service (including distribution transformers, switchgear and cables) is capitalised.
- Suspect poles must be tested for level 2 serviceability within 13 weeks of inspection.
- Unserviceable poles must be replaced within 6 months.
- The replacement of major zone substation items of plant that have failed in service (including power transformers, instrument transformers and circuit breakers) is capitalised.
- Minor equipment failure on feeders or in zone substations is expensed.

21 Email — EE Response to AER-PB Q.VP.32 — Defect Policy & Capitalisation Policy Application, 31/07/09

Ergon Energy has stated that in the event that its capitalisation policy does change at any time prior to, or during, the next regulatory control period, Ergon Energy will, in accordance with clause 2.3.2 of the Efficiency Benefit Sharing Scheme (EBSS):

- adjust the forecast opex used to calculate the carryover amounts so that the forecast opex is consistent with the capitalisation changes
- provide the AER with a detailed description of any changes to the capitalisation policy, and a calculation of the impact of those changes on forecast and actual opex.

PB summary

As a result of several discussions PB had with Ergon Energy staff to clarify the documented policies, as well as our review of the type of activities that have been included in the opex forecasts, PB has formed the view that the capitalisation policy is reflective of typical industry practice in that it supports a reasonable and pragmatic approach to classifying business expenditures at a low level of asset detail. PB has not identified any material changes in Ergon Energy's approach to capitalisation, and considers it is applied throughout the organisation in consistent and accurate manner.

4. System capex review

This section presents PB's review of Ergon Energy's 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

Ergon Energy has submitted a proposed system capex of $5,353.9m for the next regulatory control period as summarised in Table 4.1. Ergon Energy's proposed system-related capex is 88.7% of the total proposed capex.

Table 4.1 Ergon Energy's proposed system capex

Category driver	2010–11	2011–12	2012–13	2013–14	2014–15	Total*
System capex						
Corporation initiated augmentation	267.8	339.4	401.3	463.6	518.9	1,991.0
Customer initiated capital works	336.1	355.0	315.6	328.7	359.6	1,695.0
Asset replacement	177.4	212.7	250.0	274.8	299.2	1,214.1
Reliability and quality improvement	18.3	20.9	24.5	28.3	30.4	122.4
Other system	105.6	72.9	50.8	50.4	51.7	331.4
Total system*	905.2	1,000.9	1,042.2	1,145.8	1,259.8	5,353.9

**Note: totals may not add due to rounding.*

Source: Ergon Energy Corporation Limited 2009, Regulatory proposal to the Australian Energy Regulator: distribution services for period 1 July 2010 to 30 June 2015*, Table 49, p. 192.*

In 2004, the Queensland Department of Mines and Energy (QME) made recommendations to Ergon Energy on security standards that should be adopted by the business based on the findings of the EDSD review[22]. The proposed expenditures reflect these recommendations.

4.1.1 Trends and comparative analysis

PB reviewed historical variances between Queensland Competition Authority (QCA) allowance and Ergon Energy's actual historical system capex[23].

Figure 4.1 shows the actual capex (system and non-system) for the current regulatory control period compared with the QCA allowance set in 2005 for the current regulatory control period. During the current regulatory control period Ergon Energy expects a total capex[24] overspend of $531.1m compared to the Queensland Competition Authority (QCA)[25]

22 Office of Energy, Department of Natural Resources, Mines and Energy July 2004, *Electricity distribution and service delivery for the 21st century*.

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

24 Combined system and non-system capex

25 Queensland Competition Authority (QCA) 2005, *Final determination, regulation of electricity distribution*, April 2005.

revenue allowance[26]. Ergon Energy states that this overspend was driven by the growth in customer-initiated capital works, rising costs, and one-off events such as Tropical Cyclone Larry[27].

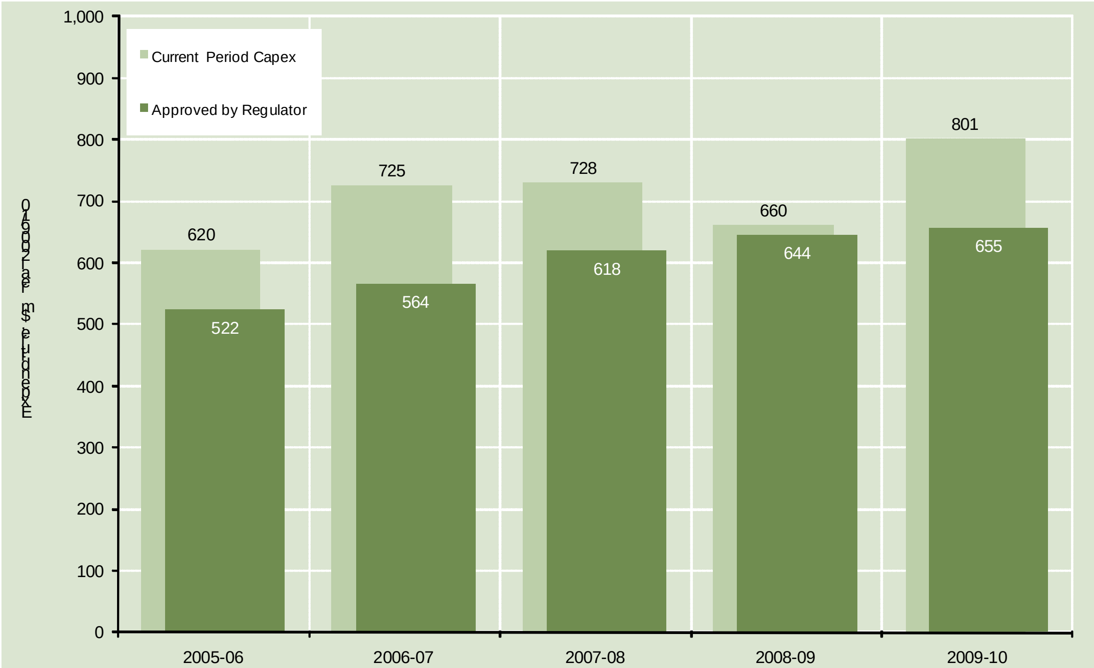

Figure 4.1 Current period overspend on QCA allowance

Source: Ergon Energy for regulatory control period 2010–11 to 2014–15, 1 July 2009 Table 64, page 252

In its review of Ergon Energy's historical expenditure, the AER noted that[28]:

> The overall significant overspend in total capex across the current period has been driven strongly by higher than anticipated levels of demand related and non-system expenditure, more than making up for underspends in asset replacement and reliability/quality improvements.

The principal drivers for the variance between the system capex in the current regulatory period, and Ergon Energy's system capex submission, have also been assessed to identify the underlying reasons for the significant change in the proposed level of expenditure.

Ergon Energy has forecast that its total system capex for the next regulatory control period will be $5,353.9m, which represents a real increase of 58.8% over the total system capex in the current regulatory control period of $3,372m. This trend in system capex is shown in Figure 4.2 [29].

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26 Ergon Energy Corporation Limited 2009, Regulatory proposal to the Australian Energy Regulator: distribution services for period 1 July 2010 to 30 June 2015, 1 July 2009, section 24.3.2.6, pp. 253–256.

27 Ergon Energy Corporation Limited 2009, Regulatory proposal to the Australian Energy Regulator: distribution services for period 1 July 2010 to 30 June 2015, 1 July 2009, section 24.3.2.6, pp. 253–256.

28 Australian Energy Regulator 2009, Queensland and South Australia electricity distribution determination 2010–15: review of historical capital expenditure, August 2009.

29 Note: PB has adjusted the historical nominal figures to real using the adjustment factors recommended by the AER.

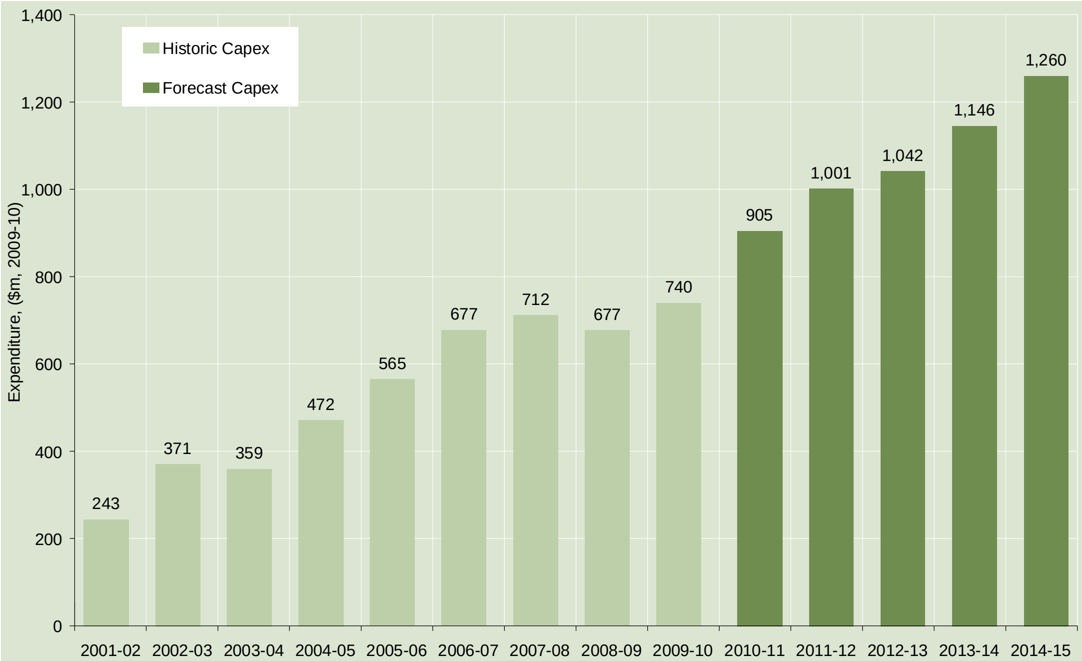

Figure 4.2 Total system capex

Source: PB analysis of Ergon Energy 2009, Electricity distribution regulatory information notice pro forma statements, Ergon Energy for regulatory control period 2010–11 to 2014–15, 1 July 2009.

The forecast capex for the next regulatory control period can be broken down by expenditure category as shown in Figure 4.3[26]. Under Ergon Energy's proposal, expenditure in all categories is forecast to increase significantly. Corporation-initiated augmentation (CIA) expenditure is the largest category, with total proposed expenditure of $1,991.0m, a real increase of 90% on the current regulatory control period.

Customer-initiated capital works (CICW) is the second largest category, with a total proposed expenditure of $1,695.0m, a real increase of 23% on the current period. Asset replacement capex is forecast to increase by a real 72% over the current regulatory control period to a total of $1,214m for the next regulatory control period. Reliability and quality of supply improvements will more than double to a total of $122.4m, a real increase of 131%, while 'other system' expenditure will rise to $331.4m, a real increase of 75%.

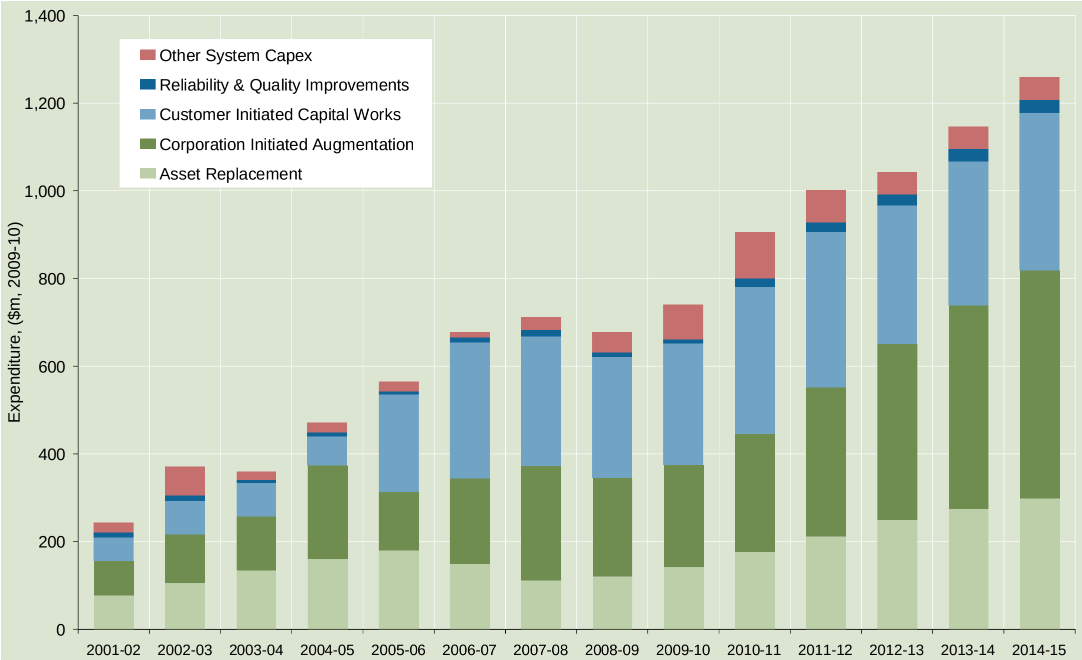

Figure 4.3 Forecast expenditure by capex category

Source: PB analysis of Ergon Energy 2009, Electricity distribution regulatory information notice pro forma statements, Ergon Energy for regulatory control period 2010–11 to 2014–15, 1 July 2009.

Figure 4.4 shows the main expenditure items in terms of asset type. The largest expenditure forecast for a single asset category during the next regulatory control period is $1,012.7m for overhead distribution lines, followed by expenditure on distribution transformers of $723.5m. With the exception of land and easements (system), metering and low-voltage services, Ergon Energy is proposing to more than double the level of expenditure on all asset categories. Although the asset categories are not broken down to this level of detail in Figure 4.4, the proposed expenditure on underground sub-transmission cables, distribution equipment and buildings (system) is forecast to more than treble in the next regulatory control period compared to the current regulatory control period.

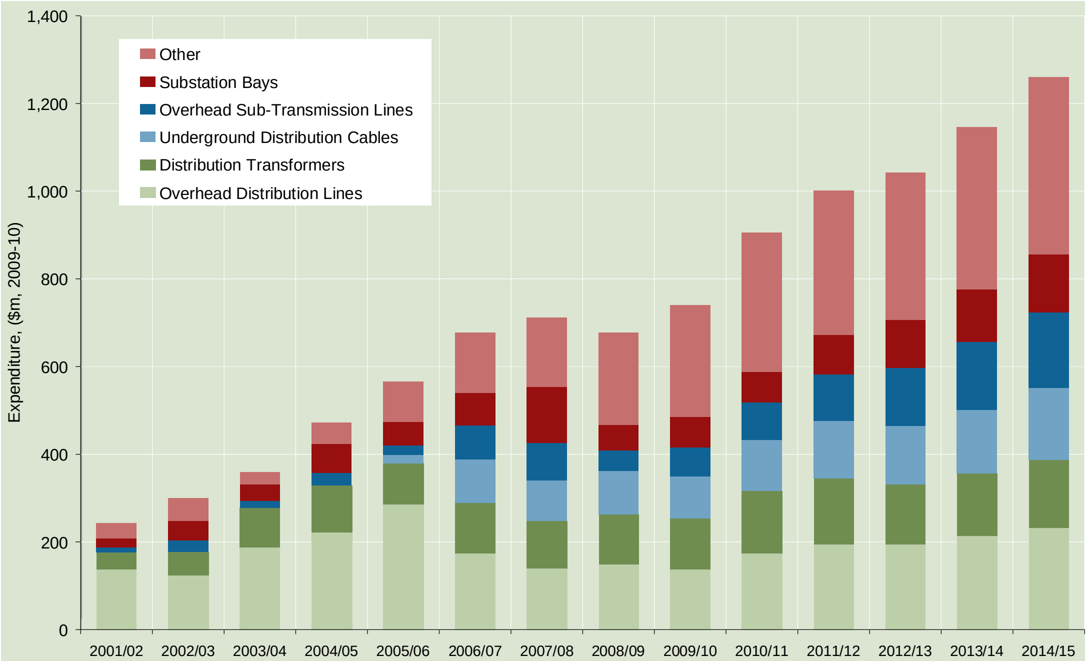

Figure 4.4 Expenditure by asset type

Source: *PB analysis of Ergon Energy 2009, Electricity distribution regulatory information notice pro forma statements, Ergon Energy for regulatory control period 2010–11 to 2014–15, 1 July 2009.*

The principal drivers for the increases proposed by Ergon Energy across the five major expenditure categories discussed in sections 4.2 to 4.5 of this report are summarised in Table 4.2.

Table 4.2 Drivers for the increase in proposed capex

Expenditure category	Average per annum increase compared to previous regulatory control period average expenditure	Principal drivers
Asset replacement	$102m	Improve reliability and public safety. A by-product is to replace failed assets and reduce average asset age to minimise future interruptions.
Corporation-initiated capex	$189m	Build additional network capacity and address forecast system constraints.
Customer-initiated capital works	$46m	Meet forecast levels of customer connections.
Reliability and quality improvement capex	$14m	Address reliability or quality of supply deficiencies.
Other capex	$58m	Specific individual project drivers

Source: *PB analysis, and Australian Energy Regulator 2009, Queensland and South Australia electricity distribution determination 2010–15: review of historical capital expenditure, section 4.4.*

Comparative benchmarking

The AER has conducted a comparative benchmarking study of Ergon Energy's historical and proposed capex in relation to other Australian DNSPs.[30] Ergon Energy was found to be best compared to Country Energy in NSW.

In forming its view on the prudency and efficiency of Ergon Energy's proposed capex for the 2010-2015 regulatory period, PB has taken into consideration the following conclusions from the AER's comparative benchmarking report.

Ergon Energy's actual / forecast capex / RAB ratios are reasonably closely aligned to their benchmark ratios with ratios trending down during the next regulatory control period.

4.1.2 Capital governance framework

Section 17 of Ergon Energy's regulatory submission[31], sets out an overview of the business's capital governance arrangements, and references a number of relevant supporting documents. Further details of Ergon Energy's investment approval process are provided in section 9 of Ergon Energy's asset management plan (AMP)[32], while an overview of the business's network planning and management is given in section 20 of the regulatory proposal[33]. PB also notes that a more complete list of the business's key capital governance documentation is provided in Table 38[34] and at the end of section 17[35] of Ergon Energy's Regulatory Proposal.

PB reviewed Ergon Energy's capital governance documentation identified in the business's regulatory proposal, and held discussions with relevant Ergon Energy staff, including the Chief Financial Officer. In addition to reviewing the regulatory proposal and supporting documentation, PB also reviewed a range of capital investment documentation such as business cases, AMPs and network planning documents. PB focused particularly on the business strategy and vision documentation, as well as the business's AMPs, programs, relevant policies, delegation arrangements, and the investment approvals process and supporting documentation, in order to assess their alignment with the principles of good capital governance as described in section 2.2.1.

Through our review and enquiries, PB found that Ergon Energy is developing an extensive and well-integrated documentation framework, and although we note that this framework is still being fully implemented, it demonstrates a thorough capital governance framework. This framework of capital governance links the corporate strategic documentation through policies, plans and procedures to Ergon Energy's day-to-day asset management operations.

PB's review of Ergon Energy's delegations structure and investment approvals process as evidenced by the business's policies, AMPs and business case documentation (etc.), also found that the business practices relating to capital investment management were generally sound, well documented and well evidenced. However, PB has concerns regarding the quality and robustness of the business options analysis as evidenced through examination of

30 AER Working paper on capex benchmarking 07/08/09
31 Ergon Energy Corporation Limited 2009, Regulatory proposal to the Australian Energy Regulator: distribution services for period 1 July 2010 to 30 June 2015, 1 July 2009, section 17, pp. 131–144.
32 Ergon Energy 2009, Asset management plan: 2009-10 – 2014/15 volume 2: asset management in practice, pp. 57–68.
33 Ergon Energy Corporation Limited 2009, Regulatory proposal to the Australian Energy Regulator: distribution services for period 1 July 2010 to 30 June 2015, 1 July 2009, pp. 150–158.
34 *Ibid*., pp. 138-142.
35 *Ibid*., p. 143.

Ergon Energy's business cases. This is discussed further in section 4.2.3 of this report. Notwithstanding these concerns, PB concludes that, overall, Ergon Energy's capital governance framework accords with the principles of good asset management, prudent business management, and good electricity industry practice in general.

4.1.3 PB assessment and findings

This section summarises the key observations and findings from the high-level review of Ergon Energy's capex proposal.

PB's key observations are:

i) Ergon Energy is proposing to increase total capex expenditure across all categories over the next regulatory control period. For system capex, the business is proposing a real increase of 58.8% over the total system capex in the current regulatory control period.

ii) Ergon Energy has an extensive and well-integrated documentation framework relating to capital governance. However, although we note that this framework is still being fully implemented, it demonstrates a thorough capital governance framework.

iii) The business case documentation did not demonstrate the expected level of quality and robustness due to the lack of robust consideration of alternative options and supporting economic analysis in the business options analysis. This is discussed further in section 4.2.3 of this report.

4.2 Growth capex

Growth capex is driven by increases in electricity demand and growth in new customer connections. Ergon Energy refers to capex driven by organic growth in electricity demand as corporation-initiated augmentation (CIA) expenditure, while capex related to new customer connections is referred to as customer-initiated capital works (CICW).

4.2.1 Proposed expenditure

Table 4.3 shows that the proposed capex on total system growth for the next regulatory control period is $3,686m. This expenditure is made up of CIA totalling $1,991m and CICW totalling $1,695m.

Table 4.3 Proposed growth capex ($m)

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
CIA	267.8	339.4	401.3	463.6	519.0	1,991.1
CICW	336.1	355.0	315.6	328.7	359.6	1,695.0
Total	603.9	694.4	716.9	792.3	878.6	3,686.1

Source: Ergon Energy Corporation Limited 2009, Regulatory proposal to the Australian Energy Regulator: distribution services for period 1 July 2010 to 30 June 2015, *Table 49, p. 192.*

Figure 4.5 shows the historical and forecast CIA capex and illustrates that the CIA capex is forecast to increase by 90% in real terms compared with the current regulatory control period expenditure of $1,046.1m.

Figure 4.5 Corporation-initiated augmentation

Source: PB analysis of Ergon Energy 2009, Electricity distribution regulatory information notice pro forma statements, Ergon Energy for regulatory control period 2010–11 to 2014–15, *1 July 2009.*

Figure 4.6 shows the historical and forecast CICW capex and illustrates that the CICW capex is forecast to increase by 23% in real terms over the current regulatory control period expenditure of $1,378.5m.

Figure 4.6 Customer-initiated capital works

Source: PB analysis of Ergon Energy 2009, Electricity distribution regulatory information notice pro forma statements, Ergon Energy for regulatory control period 2010–11 to 2014–15, *1 July 2009.*

4.2.2 Drivers

CIA expenditure is driven by the need to maintain compliance with reliability, security and quality of supply standards, while operating the system within its loading capabilities, under the forecast growth in demand. The forecast demand growth includes organic load growth and significant spot load developments. Ergon Energy states that the proposed CIA expenditure is based on ‘normal load forecasts’[36].

CICW expenditure is driven by Ergon Energy’s obligation to connect new customers to the network. Hence, CICW capex is driven by the growth in residential, rural, commercial and industrial customer connections across the network area.

PB’s view is that the key drivers of growth capex are changes in end-consumer technologies, local and regional demographics, local and regional development plans, and economic conditions. Higher growth capex will result when the above drivers result in changes such as increased penetration of appliances (both higher numbers and power usage), increases in customer numbers, and increases in business mining and industrial activity.

The development and reasonableness of Ergon Energy’s demand forecast is being reviewed by McLennan Magasanik Associates and is not within PB’s scope of works. However, PB is required to review the application of the forecast in the development of the CIA capex forecast. The review and analysis of this aspect is presented in section 4.2.3.

4.2.3 Policies and procedures

In this section PB considers the application of Ergon Energy’s key policies and procedures to the development of the CIA and CICW capex forecasts. The key aspects in the development of the CIA capex forecast are the application of Ergon Energy’s planning criteria, the development of recommended options to address constraints identified through the application of the planning criteria, and the application of the demand forecast (discussed in section 4.2.4). The key aspects in the development of the CICW capex forecast are the assessment of current costs of CICW and the forecast of new customer connections.

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 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 purely probabilistic methods, the long-standing application of deterministic approaches and their broad jurisdictional acceptance make them a central feature of contemporary electricity industry practice.

Within the industry, sub-transmission and zone substation deterministic planning criteria mostly involve the ‘N’, ‘N-1’, or ‘N-2’ principles (or variations thereof). These basic criteria are

36 Ergon Energy Corporation Limited 2009, Regulatory proposal to the Australian Energy Regulator: distribution services for period 1 July 2010 to 30 June 2015, section 23.3.2, p. 198.

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 etc.)[37].

Ergon Energy's planning criteria are described in detail in the Security Criteria Network Planning Targets NPD05, and Network Planning Criteria — Deliverable NP02[38]. The Network Security Criteria defines the amount of redundancy, if any, that should be available in the distribution network to continue to supply customers after failure of an item of plant. These criteria were developed following the 2004 EDSD review.

PB has reviewed Ergon Energy's planning criteria, and notes that the deterministic criteria are generally applied, with variations to account for the size and type of connected load, equipment cyclic ratings, restoration arrangements and times, as well as load transfer capability. A reliability-based planning approach involving the analysis of the risk of loss of supply is also applied where this is appropriate for the type of connected load and in the case of single transformer zone substations.

PB discussed the application of the planning criteria with Ergon Energy, and appraised this application through a review of selected planning reports and documents. PB reviewed business cases, Recommended Works reports, and Network Planning reports (refer section 4.2.6 for specific details). PB notes that some of the key deliverables of Ergon Energy's planning process are the Sub-transmission Network Augmentation Plans (SNAPs) and the Distribution Network Augmentation Plans (DNAPs). These documents are compilations of the results of the network planning process and form the basis of Ergon Energy's 10-year network augmentation plans. PB has also reviewed Ergon Energy's SNAPs and DNAPs.

PB has determined that Ergon Energy's planning criteria are in accord with good electricity industry practice and have been appropriately applied in developing the CIA capex forecast.

Options analysis

The application of planning criteria is central to identifying network constraints; options analysis follows in order to identify the appropriate response to the identified constraint.

PB anticipates that a prudent network planning process would require all practical options to be identified and assessed when determining the business's response to an identified constraint. Such options analysis would involve the application of net present value (NPV) analysis, risk assessment, consideration of the 'do nothing' case, as well as non-network (non-capex) alternatives. Options analysis is therefore a central plank in ensuring that proposed expenditure is the most efficient to meet the business's identified needs.

Ergon Energy's Network Planning Criteria NP02 requires that NPV analysis be used to assess and prioritise the viability of options[39]. NP02 also states that

> *'the application of the NPV methodology varies significantly across the region … and that … It is strongly recommended that the NPV methodology to apply throughout Ergon Energy be reviewed as a matter of urgency'*[40].

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 the Sinclair Knight Merz (SKM) report to the Australian Energy Market Commission (AEMC) entitled 'Advice on Development of a National Framework for Electricity Distribution Network Planning and Expansion'.

38 Ergon Energy 2003, ERGON ENERGY CORPORATION LTD security criteria network planning targets NPD05 12/04/05 and Ergon Energy deliverable NP02 – Network planning criteria version 2.03.

39 Ergon Energy 2003, Ergon Energy deliverable NP02 – Network planning criteria version 2.03, paragraph 3.7, pp. 12–13.

Ergon Energy has stated[41] that a review has been undertaken and completed in 2008 and non-network alternatives and improved NPV analysis was implemented in February 2009.

PB reviewed the overall quality of options analysis presented and found that the quality of the analysis varied considerably. In some cases the analysis involved identification of a limited range of options and failed to present NPV analysis that demonstrated the efficiency of the recommended option[42]. In other cases a reasonable range of practical options was identified and NPV analysis was undertaken along with sensitivity analysis that demonstrated the selection of the most efficient option[43]. Overall, most cases examined by PB did not consider non-network alternatives, and had only limited NPV analysis to demonstrate that the preferred option was most efficient.

Cost estimation

Ergon Energy uses two approaches to estimating the costs included in its capital expenditure forecasts[44]. For 'specified works' Ergon Energy uses the 'TaDS' estimating tool which is an internally developed database of unit rates. Material prices are obtained from a combination of Ergon Energy's supply system, period contract rates (where available), subject matter experts, suppliers and other third party organisations. Labour estimates are prepared for each skill type by subject matter experts within Ergon Energy

Ergon Energy's unit rates were independently reviewed in December 2008 and were found to be within a nominated tolerance range of +/- 15%. The reviewer concluded that the unit rates were 'reasonable and efficient cost estimates for the assets'[45].

For 'unspecified work' Ergon Energy applies a top-down approach using one or more of the following approaches:

- retaining the same dollar value of historic expenditure without escalation
- increasing historic expenditure using an appropriate escalator
- developing a baseline of historic expenditure and identifying scope changes for that baseline.
- maintaining a fixed pro-rata percentage of total expenditure program for each element of the program as in previous years
- where there are new programs of work, an initial estimate is prepared by subject matter experts, which can then be refined once actual results are available.

PB is of the opinion that the processes and procedures Ergon Energy uses are reflective of good electricity industry practice.

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40 *Ibid*., paragraph 4.2, p. 25.
41 Response to draft report dated 13 October 2009
42 For example, Ergon Energy 2009, Business case Point Vernon substation additional 4 x 11kV feeder bays.
43 For example, Ergon Energy 2007, Network planning & development report ND118 DCP18258 & CPMNN01474 Establish Broadlea 132/66 kV BSP & associated works.
44 Ergon Energy Corporation Limited 2009, Regulatory proposal to the Australian Energy Regulator: distribution services for period 1 July 2010 to 30 June 2015, 1 July 2009, section 32.2.1 p. 327.
45 Sinclair Knight Merz, Review of Estimates for AER Regulatory Proposal, 6 April 2009, p3.

4.2.4 Application of demand forecast

Ergon Energy's CIA capex proposal is based on the application of the demand forecast in conjunction with the planning and security criteria to determine the emerging need and timing of system capex.

As noted previously, McLennan Magasanik Associates is conducting a review of the development and reasonableness of Ergon Energy's demand forecast and these aspects of the forecast are not within PB's scope of work. This section provides PB's review of the application of the forecast in the development of the CIA capex proposal. The potential implications of McLennan Magasanik Associates' findings with regard to the proposed CIA capex are discussed in section 4.2.6.

Ergon Energy prepares demand forecasts annually for zone substations, feeders, and bulk supply points, and has utilised these forecasts in the development of the CIA capex proposal[46]. The capex proposal for the next regulatory control period is based on demand forecasts that were prepared in 2006–07. Revised demand forecasts were subsequently prepared in 2007–08 and 2008–09. Ergon Energy compared the revised demand forecasts with the 2006–07 forecast and considers the proposed 2006–07 forecast to be a conservative basis (i.e. low when compared to 2007-08 and 2008-09) for the business's proposed CIA capex[47].

Ergon Energy's regulatory submission and supporting documentation identifies that demand forecasts are applied within the network planning process when undertaking network studies[48]. Through these studies and the application of Ergon Energy's planning and security criteria, future network constraints are identified. Proposals to address these constraints are then developed under Ergon Energy's capital governance processes, and these proposals are used as the basis for Ergon Energy's CIA capex forecast. This process is clearly depicted in Figures 38 and 39 of Ergon Energy's regulatory proposal[49].

To test the application of the demand forecasts to the CIA capex forecast, PB examined a range of planning documents in order to evidence the use of the forecasts, and the linkage between these documents and the CIA capex proposal. PB reviewed a number of business cases, as well as the SNAPs and DNAPs. Each DNAP is accompanied by a spreadsheet that sets out the proposed program of works and supporting details.

The application of the demand forecasts is demonstrated in terms of specific works proposals (i.e. typically business cases). The SNAPs demonstrated a clear application of the demand forecast and its relationship to the proposed works; however for the DNAPs, the application of the demand forecasts was not evident in the documentation or the spreadsheets. Ergon Energy's forecasts have been applied through the planning process, as evidenced by the planning documentation (excepting the DNAPs.

PB also notes that the application of the forecast in the context of distribution network planning is summarised in Ergon Energy's regulatory proposal[50] as well as within its supporting documentation.

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46 Ergon Energy Corporation Limited 2009, Regulatory proposal to the Australian Energy Regulator: distribution services for period 1 July 2010 to 30 June 2015, section 21, pp. 159–183.

47 *Ibid.*, p. 160.

48 *Ibid.*, sections 20, 21 and 23.

49 *Ibid.*, pp. 199, 201.

50 *Ibid.*, section 23.3.3.2, pp.200–202.

4.2.5 Consideration of non-network alternatives

Ergon Energy's approach to non-network alternatives is described in its regulatory proposal[51]. The business follows a three-stage process to consider non-network alternatives. This process is undertaken in conjunction with existing capital works planning and investment approval processes in order to assess whether a suitable non-network alternative is more prudent than a more traditional network augmentation[52]. For augmentation projects greater than $10M, a public consultation is undertaken in accordance with the National Electricity Rules' Regulatory Test process.

Ergon Energy's current non-network alternatives program is focusing on conducting trials and pilot projects which are being undertaken during the 2008–09 to 2009–10 period, in order to develop the necessary skills and expertise before the commencement of the next regulatory control period[53].

During discussions, Ergon Energy stated that it is passionate about the development of non-network alternatives[54], and it was apparent to PB that Ergon Energy is actively investigating the use of non-network alternatives. Ergon Energy advised that the primary barrier to the business-as-usual incorporation of non-network alternatives was the current lack of experience in this area, and the consequent preference not to rely on techniques such as demand side management to address network constraints.

PB's review of documentation showed that currently non-network alternative are rarely recognised as potential options, and it is apparent that they are not considered within the network growth forecasts. However, PB notes that Ergon Energy is still in the trial and development stages of implementing non-network techniques to defer capital investment[55].

Good practice in non-network alternatives would mean the active development of demand management practices such as peak lopping, incentive schemes and energy efficiency programs to proactively manage a reduction in expected peak demand. Given the business's current stage of development, PB believes that Ergon Energy is broadly in line with good electricity industry practice.

4.2.6 Specific reviews

In examining Ergon Energy's CIA and CICW capex proposals, PB has undertaken three specific reviews:

Impact of the demand forecast

CIA capex

CICW capex.

51 Ergon Energy Corporation Limited 2009, Regulatory proposal to the Australian Energy Regulator: distribution services for period 1 July 2010 to 30 June 2015, section 30, pp. 313–320.
52 *Ibid.*, section (N) 6.1, p. 21.
53 *Ibid*.
54 Meeting between PB and Ergon Energy Chief Financial Officer, 15July 2009.
55 PB notes that Ergon Energy has sought an allowance of $5m over the next regulatory period through the AER's demand management incentive scheme for DNSPs in order to undertake initiatives in this area (Ergon Energy's regulatory proposal, section (N) 6.3).

Impact of the demand forecast

PB has considered the implications of MMA's findings with respect to the reasonableness of the demand forecasts underpinning the proposed CIA capex.

The relationship between Ergon Energy's demand forecasts and its CIA capex proposal is unclear and indirect in nature (see discussion in section 4.2.3). Therefore, to test the sensitivity of the CIA forecast to changes in the demand forecast, PB took a high-level approach with a focus on the component of the growth capex that is directly related to the forecast growth (i.e. excluding the proposed capex to address existing network constraints and therefore not directly related to demand forecasts).

Ergon Energy informed PB that 7.7% of the CIA expenditure during the next regulatory period is assigned to addressing existing security breaches and 55% is assigned to addressing forecast security breaches[56]. Ergon Energy further advised PB that the remaining 37.3% was targeted at specific issues[57]. PB has determined that, based on the information provided by Ergon Energy, the 37.3% of CIA expenditure can also be attributed to the demand forecasts. PB has therefore conducted the sensitivity analysis on the assumption that 92.3% of the CIA capex forecast is directly related to the demand growth forecast for the next regulatory period.

Based on MMA's findings[58], it is apparent the Ergon Energy's forecasts are considered to be an overestimate:

> *"MMA considers that the trend-line methodology applied by Ergon Energy is not realistic during times of significant change in key drivers, such as those due to the GFC, that the spot load methodology used is flawed as it allows double counting of spot loads and that the spot load forecasts and probabilities actually applied by Ergon Energy are likely to be over-optimistic in terms of both magnitude and timing"[59].*

MMA states that the difference between the Ergon Energy and MMA forecasts is approximately equivalent to one to two years of MD growth[60]. Consequently, in our analysis PB has considered the impact on the CIA capex forecast under the scenarios of a one-year and a two-year deferral of demand growth.

To approximate this relationship, PB utilised the data provided in the Regulatory Information Notice (RIN)[61] to determine the total MVA growth (for the summer maximum demand forecast) over the next regulatory period[62]. We then reduced this total growth by either one or two year's average annual MVA growth to create the two revised growth scenarios. These new growth forecasts were applied to 92.3% of the proposed CIA capex. The results of this analysis are shown in Table 4.4.

Ergon Energy's annual average growth in MVA over the next regulatory period is 2.9% (based on the RIN figures). Under our sensitivity analysis modelling, the one-year deferral model produces an average annual growth rate of 2.5%, while the two-year deferral

56 Ergon Energy email reply to questions AS.46, AS.109 and AS.112 29/08/09
57 Ergon Energy email reply to question AS.144 02/09/09
58 McLennan Magasanik Associates (MMA), Report to Australian Energy Regulator: Draft review of Ergon Energy's maximum demand forecast for the 2011 to 2015 price review, 25 September 2009
59 *Ibid.* p6
60 *Ibid*. p7
61 Ergon Energy 2009, Electricity distribution regulatory information notice pro forma statements, Ergon Energy for regulatory control period 2010–11 to 2014–15, 1 July 2009.
62 PB notes that Ergon Energy's demand is summer-peaking.

produces an average annual growth rate of 1.9%. This is broadly in line with the historical annual average growth of 2.2% across the 2001–02 to 2007–08 period.

Table 4.4 Sensitivity of CIA capex to demand forecast deferral

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Proposed CIA growth capex	267.8	339.4	401.3	463.6	519.0	1,991.1
CIA growth capex related to demand forecast	247.2	313.2	370.4	427.9	478.9	1,837.6
Reduction in CIA for 1-year deferral	71.3	70.1	62.9	70.1	64.6	339.0
Reduction in CIA for 2-year deferral	115.3	130.9	139.8	159.5	168.2	713.7

Source: PB analysis.

CIA capex proposal

In relation to the $1,991.0m CIA capex, which represents 37% of the total system capex proposal, PB has examined a range of planning documentation (e.g. business cases, Board papers). The review has focused on how well the need and timing of the proposed capex is demonstrated, as well as consideration of options and the selection of the most efficient option. The linkages between the planning documentation and business cases and Ergon Energy's CIA capex proposal have also been examined. PB has assessed the application of Ergon Energy's capital governance framework, policies and procedures, the application of planning criteria, and application of the demand forecasts. These issues are discussed in the preceding sections.

PB anticipates that, for large-value expenditure proposals, particularly in the early years of the next regulatory control period, robust business cases (or similar documentation) would be available to provide justification for the proposed expenditure. PB has requested business cases (or similar supporting documentation) for the top 10 augmentation projects by expenditure value, and Ergon Energy has provided a range of documentation for review.

PB has reviewed the documentation supplied, as well as a range of documents supplied with the regulatory proposal (e.g. SNAPs, DNAPs). In general, where business case documents (or similar) are available, they clearly addressed the need and timing for the proposed expenditure, leading PB to conclude that this proposed expenditure is prudent in this regard. However, as discussed in section 4.2.3. PB has found that in some instances[63] the options analysis is not robust and does not strongly support the business case - either because alternative options are not identified, or, where alternative options were identified, the cost of the option is not always fully developed. Ergon Energy has not been able to provide a business cases (or similar documentation) in a number of instances where, in PB's opinion, such documentation is necessary to demonstrate prudent and efficient expenditure.

The linkages between the planning documentation and Ergon Energy's CIA capex proposal, has been examined by reviewing the SNAPs and DNAPs, as well as the SC capex data model, which relates quantities of work forecast through the network planning process to the CIA capex forecast. PB was advised that, while the SC capex data model related to the CIA capex forecast, the work quantity forecasts were the results of inputs by various project planners, and that these quantities were derived from the SNAPs and DNAPs. PB has attempted to reconcile the information in the SNAPs and DNAPs with the quantities of work

63 PL616__EE__Belgian Gardens_Regulatory Test Final Report_9Feb07.pdf; PL562_EE_Townsville Central_Detailed Planning Report-RWR_Rev1_16Mar07.pdf; 614c_EE_ND102 Berserker Sub RWR_9Jun06.pdf; PL613c_EE_Belgain Gardens Sub Planning Rpt_10Aug06.pdf

input into the SC capex data model in order to examine the relationship between the forecasting documents (and hence the demand forecasts) and the CIA capex forecast. Despite our detailed examination of these models, examination of the documentation presented and discussions with Ergon Energy, PB has been unable to establish a clear relationship between the planning documentation and the quantities of work entered into the SC capex data model.

Since we have been unable to conclude that the proposed level of CIA capex expenditure is efficient, PB recommends that the CIA capex is deferred in line with the conclusions of the MMA report. As previously stated, the difference between the Ergon Energy and MMA forecasts is approximately equivalent to one to two years of maximum demand growth. PB therefore recommends that the CIA expenditure is deferred by 18 months. The reduction in CIA for 18 months deferral is the average of the one year and two year deferral results highlighted in Table 4.4. PB's recommended level of CIA is given in Table 4.5 below:

Table 4.5 PB recommended CIA capex

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Proposed CIA growth capex	267.8	339.4	401.3	463.6	519.0	1,991.1
PB recommended CIA capex	174.5	238.9	300.0	348.8	402.6	1,464.8

Source: PB analysis

PB was able to verify the derivation of the CIA capex proposal, as stated in the Ergon Energy regulatory proposal[64], from the inputs of the SC capex data model.

CICW capex proposal

This element of CICW capex relates only to SCS (and express excludes connection assets for new large customers – this is ACS). PB has reviewed the development of the $1,695.0m CICW capex proposal, which represents 32% of the total system capex proposal.

CICW capex relates to customer-initiated projects. Ergon Energy's annual report states that:

> Customer numbers have continued to grow by around 2% per annum over the past five years, with 2007/08 growth in the order of 2.5%. This growth has been driven mainly by development in the coastal centres of Hervey Bay, Mackay, Townsville and Cairns, as well as the Toowoomba region[65].

Section 23.4 of Ergon Energy's regulatory proposal provides a high-level outline of the CICW forecast. PB has reviewed Ergon Energy's regulatory submission and supporting documentation, and held discussions with relevant Ergon Energy staff. Ergon Energy also provided PB with the CICW forecasting model[66] and supporting documentation[67].

In its regulatory proposal[68] and in subsequent documentation[69], Ergon Energy outlines the methodology for preparing the CICW forecasts as follows:

64 Ergon Energy 2009, Electricity distribution regulatory information notice pro forma statements, Ergon Energy for regulatory control period 2010–11 to 2014–15, 1 July 2009.

65 Ergon Energy 2008, Annual Stakeholder Report 2007–08, p. 36.

66 CICW model named PL643c_EE_CICW Model_V8_12Aug09.xls.

67 Ergon Energy 2009, Forecasts customer-initiated capital works — standard control services, 11 June 2009.

68 *Ibid*.

- Extract the 2007–08 actual baseline expenditure from the relevant business systems.
- Apply an 18.9% escalation to the CICW price book[70], which Ergon Energy determined had not been fully updated to reflect current costs.
- Apply the National Institute of Economic and Industry Research (NIEIR) dwelling stock growth forecasts[71] to the historical baseline expenditure for small CICW connections, specifically subdivisions, domestic and rural, and commercial and industrial categories.
- Apply the NIEIR gross regional product forecasts to the historical baseline expenditure for larger CICW connections (i.e. larger commercial and industrial).

The overall CICW forecasting methodology is relatively transparent. However, PB raises the following concerns about the applicability of the various growth forecasts used in this methodology:

- The application of the NIEIR dwelling stock growth forecasts to forecast growth in future commercial and industrial connections is not appropriate.
- As Ergon Energy's most significant growth has occurred in specific regional centres (notably coastal), it is not clear that dwelling stock growth is a good predictor of rural customer connections.
- The gross regional product is not well correlated to large CICW connections, and is therefore not a good predictor of this class of customer connection.

Ergon Energy stated that it does believe there is a correlation between the CICW baseline expenditure, dwelling stock growth and gross regional product[72], but was unable to provide any evidence to substantiate its view (e.g. correlation analysis).

PB sought to independently test the CICW forecast and constructed a model based on the historical number of customer connections[73] and historical cost of customer connections[74]. The model averages the number of new customers over the last regulatory control period and increases this number by the expected annual growth[75].

PB applied a regression analysis to the historical cost of connection to account for any underlying trend in the costs. The resulting forecast is shown in Table 4.6.

69 Ergon Energy 2009, *Forecasts customer-initiated capital works – standard control services*, 11 June 2009, and the CICW model named PL643c_EE_CICW Model_V8_12Aug09.xls.

70 The CICW Price Book is a standard estimating tool used by Ergon Energy in estimating customer connection costs for the purposes of customer quotes and in determining capital contributions.

71 National Institute of Economic and Industrial Research 2008, Maximum demand forecasts for Ergon Energy connection points to 2018: coincident and non-coincident peaks for summer and winter by BSP.

72 Ergon Energy 2009, Forecasts customer-initiated capital works — standard control services, 11 June 2009, p. 39.

73 Ergon Energy; June 2009, AR462c_EE_CICW SCS Forecasts_V7_11Jun09.pdf, page 26, Table 2

74 Ergon Energy, July 2009, RIN Submission Model.xls.

75 Ergon Energy, July 2009, RIN Submission Model.xls. % increase in total customers as forecast by Ergon Energy and is equal to 1.6%

Table 4.6 PB simple CICW comparative forecast

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
CICW connections (number)	30,324	30,502	30,480	30,437	30,475	152,218
CICW capex	274.3	275.9	275.7	275.3	275.7	1,376.9
Ergon Energy CICW capex	336.1	355.0	315.6	328.7	359.6	1,695.0
Difference	(61.8)	(79.1)	(39.9)	(53.4)	(83.9)	(318.1)

Source: PB analysis

Ergon Energy is obligated to connect customers, as set out in section 23.4.6 of the regulatory proposal, and hence it is prudent for Ergon Energy to submit a CICW capex proposal. PB has concerns regarding Ergon Energy's CICW capex forecasting methodology and we are unable to conclude that the proposed expenditure is efficient. Consequently, PB recommends a reduction based on historical costs, as set out in Table 4.7.

Table 4.7 PB's recommended adjustment to CICW capex

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposal	336.1	355.0	315.6	328.7	359.6	1,695.0
PB adjustment	(61.8)	(79.1)	(39.8)	(53.4)	(84.0)	(318.1)
PB recommendation	274.3	275.9	275.8	275.3	275.6	1,376.9

Source: PB analysis

4.2.7 PB assessment and findings

PB has reviewed Ergon Energy's CIA and CICW proposals to assess their prudence and efficiency. The review considered the drivers of these categories of expenditure, the application of key policy and procedures, the application of the demand forecast and the sensitivity of the CIA capex forecast to the demand forecast. PB reviewed the consideration of non-network alternatives, and undertook a number of specific reviews.

Ergon Energy's planning criteria are fundamentally deterministic in nature and, while inherently conservative, are in accord with good industry practice. The criteria are appropriately applied and suitable for the purposes of developing the CIA capex forecast. PB was unable to identify any specific application of the reliability-based approach outlined in Ergon Energy's procedures, but we acknowledge that this may be a result of the sample of documents reviewed.

The quality, completeness and robustness of Ergon Energy's options analysis vary considerably. PB concurs with Ergon Energy's internal recommendation that the methodology be reviewed as a matter of urgency, but considers that the issue is broader than the application of NPV analysis alone. Ergon Energy's procedure is prudent in requiring options analysis to be conducted; however, the inconsistent and incomplete application of the process leads to results that do not clearly demonstrate efficient investment.

PB found that business case (or similar) documents, in general and where they were available, clearly addressed the need and timing for proposed expenditure, leading PB to conclude that expenditure was prudent in this regard. However, business case (or similar) documentation was not consistently available in some cases where it would be prudent to document and retain this information.

The prudent application of demand forecasts in the development of Ergon Energy's proposed capex investments is only partially demonstrated and evidenced by the business documentation.

In current practice Ergon Energy rarely recognises non-network alternatives as potential options when considering anticipated network constraints. However, Ergon Energy is currently developing its non-network alternative capability, and has pilot projects and trials in progress; this aligns broadly with good industry practice. Ergon Energy advised that the primary barrier to the business-as-usual incorporation of non-network alternatives was its current lack of experience in, and consequently its lack of confidence in relying on, non-network techniques to address network constraints. Pilot programs and trials should help overcome these problems.

In our examination of the sensitivity of the CIA capex forecast to changes in the demand forecast PB undertook a sensitivity analysis (see Table 4.4). This analysis demonstrates the impact of deferring demand growth on the CIA capex proposal.

The review of methodology for developing the CIA capex forecast found that the need and timing for the proposed expenditure was clearly demonstrated, and PB concluded that this expenditure was prudent in these regards. However, given the lack of NPV analysis to demonstrate selection of the most efficient option, the limited availability of business case documentation, and no clear reconciliation between the planning documentation and the CIA capex proposal, PB is unable to conclude that the CIA capex proposal is efficient. PB therefore recommends that the CIA capex is deferred by 18 months. This recommendation is in the middle of the expected range in the results of the MMA review.

Ergon Energy is obligated to connect customers, and hence it is prudent for Ergon Energy to submit a CICW capex proposal. However, as mentioned above, PB has concerns about the applicability of various growth forecasts used to inform the CICW forecast. Insufficient supporting data was available from Ergon Energy to justify the CICW forecasts, and PB is therefore unable to conclude the proposed CICW capex is efficient. PB independently modelled the CICW expenditure on a business-as-usual basis and produced an alternative (reduced) capex forecast for this category.

4.2.8 PB recommendations

Based on the findings of our review discussed above, PB recommends the revised CIA and CICW capex amounts as set out in Table 4.8.

Table 4.8 Recommended CIA and CICW capex

Expenditure category	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposal CIA	267.8	339.4	401.3	463.6	519.0	1,991.1
Ergon Energy proposal CICW	336.1	355.0	315.6	328.7	359.6	1,695.0
PB adjustment CIA	(93.3)	(100.5)	(101.4)	(114.8)	(116.4)	(526.4)
PB adjustment CICW	(61.8)	(79.1)	(39.8)	(53.4)	(84.0)	(318.1)
Ergon Energy proposal total	603.9	694.4	716.9	792.3	878.6	3,686.1
PB recommended total	448.8	514.8	575.7	624.1	678.2	2,841.6

Source: PB analysis

4.3 Asset replacement capex

This section of the report relates to capex that is required to maintain the performance of network assets by replacing existing assets.

4.3.1 Proposed expenditure

Ergon Energy's proposed expenditure on asset replacement capex over the next regulatory control period is $1,214.1m (see Table 4.9). Figure 4.7 shows that Ergon Energy is proposing a real increase in asset replacement capex of 72% compared with the expenditure in the current regulatory control period of $705m.

Table 4.9 Asset replacement capex forecast

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposal	177.4	212.7	250.0	274.8	299.2	1,214.1

Source: Ergon Energy Corporation Limited 2009, Regulatory proposal to the Australian Energy Regulator: distribution services for period 1 July 2010 to 30 June 2015, *Table 50.*

Figure 4.7 Asset replacement capital works forecast

Source: Ergon Energy Corporation Limited, 2009, 'Regulatory Proposal to the Australian Energy Regulator Distribution Services for Period 1 July 2010 to 30 June 2015', and PB analysis

4.3.2 Drivers

Ergon Energy states that there are two main drivers for asset replacement expenditure: defects and condition-based replacement[76]. The defect-related capex relates to assets that have failed or are expected to fail imminently. Ergon Energy considers that it does not have discretion in undertaking the defect-related asset replacement expenditure[77]. Condition-

76 Ergon Energy Corporation Limited 2009, Regulatory proposal to the Australian Energy Regulator: distribution services for period 1 July 2010 to 30 June 2015, section 23.2.

77 *Ibid*., section 23.2.2.1, p. 193.

based expenditure is driven by issues such as safety, environment, financial and customer outages, non-serviceability, obsolescence, replacement of whole assets rather than component parts, bulk replacements, unavailability of spare parts, asset life and premature aging[78].

PB expects that a prudent and efficient business following good electricity industry practice would have a sound understanding of the condition of its assets. The key driver for asset replacement from this perspective is the condition of the assets and the risk posed by that condition. Therefore, Ergon Energy has identified appropriate drivers for the proposed asset replacement expenditure.

4.3.3 Policies and procedures

An overview of Ergon Energy's asset replacement policies and procedures is provided in section 23.2 and Figure 36 of Ergon Energy's regulatory proposal. The key policy and procedural documents with respect to asset replacement are identified as:

- Asset Management Defect Policy
- Strategic Plan for Asset Renewal
- Network Defect Classification Manual.

The Asset Management Defect Policy sets out the purpose and objectives of defect management within the business. It also sets out classification, prioritisation and response time parameters to guide business decisions.

The Strategic Plan for Asset Renewal sets out the principles Ergon Energy applies when deciding to replace assets, and addresses Ergon Energy's current and future state of asset renewal management.

The Defect Classification Manual defines the defect classification and prioritisation requirements for recording defects during inspections. The manual consists of 15 parts and addresses 15 asset types.

Ergon Energy provided other examples of asset strategy documentation (e.g. Meter Asset Maintenance Strategy, Instrument Transformer Asset Maintenance Strategy). Ergon Energy's Asset Maintenance Strategy provides a comprehensive overview of the business drivers and reasons for the asset maintenance strategy, as well as the business regime required to support the strategy[79].

Ergon Energy has developed asset equipment plans (AEPs) which set out the management methodology for each of the company's 26 asset equipment types. The AEPs provide an overview of each asset class and outline a risk and safety assessment of the assets, including proposed actions and preventive maintenance programs.

PB anticipates that good asset management practice would align with the principles set out in such standards as PAS 55, IIMM, and TAM, as well a range of relevant Australian and International Standards. These principles involve a management framework of policy, strategy plans and procedures that guide all aspects of the business's asset management

[78] *Ibid.*, section 23.2.2.2, p. 194.
[79] Ergon Energy Corporation Limited 2009, Network maintenance asset management strategy, document asset maintenance strategy, version 0.8 final, April 2009, p. 5.

operations. PB expects 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.

PB has found that Ergon Energy has an extensive and well-integrated documentation framework, and although we note that this framework is still being fully implemented, it demonstrates a thorough framework for the management of asset replacement. However, PB has some concerns regarding the current level of implementation of Ergon Energy's replacement practices when considered from the perspective of the relevant standards and current good electricity industry practice. These concerns are discussed in section 4.3.4. Notwithstanding these concerns, PB concludes that, overall, Ergon Energy's key policies and procedures relating to the development of the asset replacement capex proposal accords with the principles of good asset management and of good electricity industry practice in general.

4.3.4 Specific reviews

PB has undertaken various reviews in order to test the prudence and efficiency of the $1,214.1m replacement capex proposal. The proposed replacement capex represents 23% of the total system capex proposal.

The development of Ergon Energy's replacement capex forecast is set out in section 23.2, and depicted in Figure 35, of the business's regulatory proposal[80]. The AEPs form a primary input to the replacement capex proposal. The actual replacement capex forecast is built up within Ergon Energy's NARMCOS[81] model, and the resulting capex forecast is then aggregated into the overall system capex forecast.

To assess the prudence and efficiency of Ergon Energy's asset replacement proposal, PB investigated how the proposed replacement capex forecast had been modelled, focusing particularly on how the business established the replacement volume forecasts. In order to test these forecasts, PB conducted a high-level review of the top 10 replacement capex expenditures and undertook detailed reviews of the top four replacement capex expenditures categories:

- pole tops replacement
- conductors and connectors replacement
- underground (UG) cables and joints replacement
- zone substation (ZS) transformers replacement.

Ergon Energy advised that the historical data provided in the NARMCOS model is not accurate and should not be relied upon. PB sought actual historical costs and volumes for the line items in the NARMCOS model, but the business was unable to provide this data. Consequently, PB's analysis focuses on the forecast volumes and the related documentation supporting these volume estimates.

80 Ergon Energy Corporation Limited 2009, Regulatory proposal to the Australian Energy Regulator: distribution services for period 1 July 2010 to 30 June 2015, section 23.2, pp 193–198.

81 Network Assets Replacement Maintenance Capital Expenditure Operating Expenditure Summary (NARMCOS).

Figure 4.8 shows the forecast growth for the top four replacement capex expenditures over the next regulatory control period, which represents 48% of the total proposed asset replacement capex. After an initial step change in 2010–11, expenditure on pole tops and UG cables and joints generally levels off over the period. However, expenditure on conductors and connectors, and ZS transformers, is forecast to grow by an average of 31% and 49% per annum respectively during the next regulatory control period.

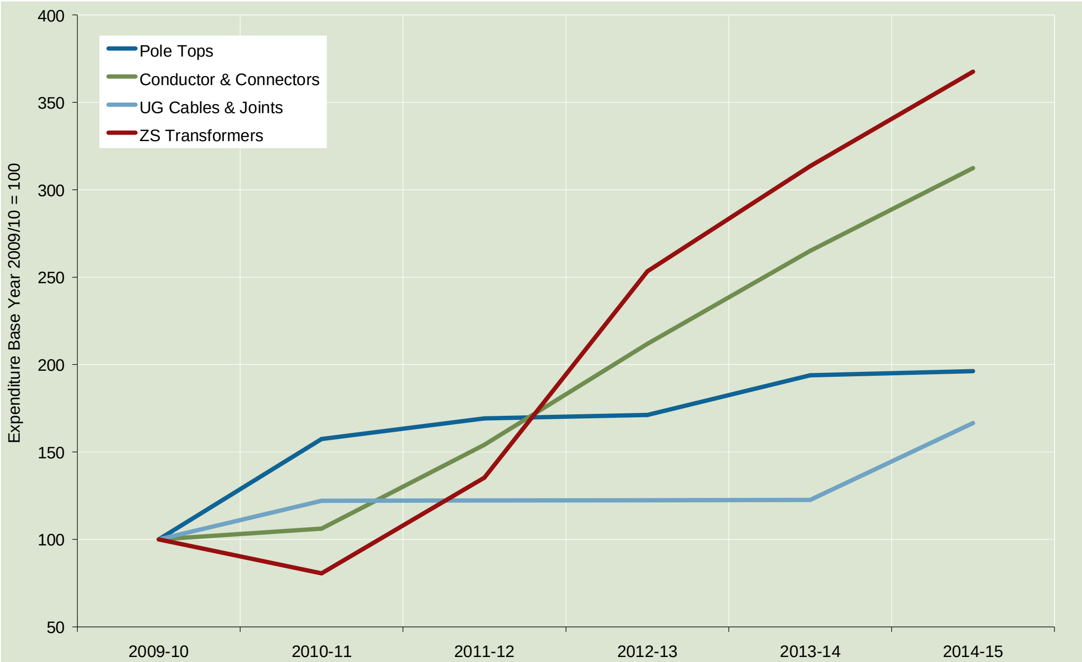

Figure 4.8 Growth in major asset replacement categories[82]

Source: PB analysis based on Ergon Energy's NARMCOS model

The following sections present the detailed reviews of the top four replacement categories.

Pole tops replacement

Ergon Energy's pole top replacement represents 10% of the total replacement capex proposal, and includes the replacement of over 43,000 pole tops in the next regulatory control period. After an initial step change in 2010–11, expenditure on pole top replacement generally levels off over the period

PB examined Ergon Energy's *Network asset equipment plan 03: pole top structures*, reviewed the NARMCOS model, and made enquiries with Ergon Energy to determine how the volume estimates were forecast, and how the prudence and efficiency of the proposed replacement volumes were established. The AEP states:

> Forecast failure rates are assumed to remain consistent with the current defect rates being experienced… Replacement rates are based on the current replacement rates identified in the FN program with some allowance for additional defects that a new inspection program is expected to find.[83]

PB made enquiries to establish what allowance had been made for additional defects identified by the new inspection program. Ergon Energy provided a spreadsheet showing analysis of the defect rates of pole tops resulting from the EWP inspection program in Far

82 This data excludes escalators and overheads as it is based on data taken from the NARMCOS model.
83 Ergon Energy 2009, Network asset equipment plan 03: pole top structures, 31/03/09, p. 8.

North Queensland[84]. The spreadsheet indicates that for this particular inspection program the pole top repair rates for 2006–07 were 7%, and the cross arm replacement rates were 20%. In PB's experience, this rate of failure is very high. We made further enquiries and were advised that:

> In particular the high risk distribution program is targeted at known high risk areas based on pole top age and known failure rates. Because this is a targeted program, the failure rate could in fact be higher than these levels but this will not be known until the program commences. It is also important to note that the High Risk Distribution Program is only targeting a very small quantity of inspections (45,133) compared to a population of pole tops of approximately 250,000 over 40 years of age.[85]

PB examined Ergon Energy's Asset Management Strategy Document[86], and noted its analysis, which states:

> There is no regulatory requirement for crossarm reliability, however also in response to pressure from the QLD Electrical Safety Office for improved safety performance Ergon Energy has developed a HV crossarm reliability index. This index can be seen in Figure 3 and is 99.9947% as of January 2006 (Note: this excludes LV ARM Failures). This is based on DEE (Dangerous Electrical Event) failure data only and the estimated HV crossarm population. The only industry benchmarking currently available to Ergon Energy is a study completed by a Swedish University entitled 'Distribution System Component Failure Rates and Repair Times – An Overview'. This study concluded that for 'Overhead Lines (Including insulator, x-arm failures, connectors and attachment)' of which most of the above Ergon Energy table is included, the industry average failure rate was 0.93/(100km,yr) and the Industry Maximum was 1.81/(100km,yr) … Ergon Energy compares favourably with a failure rate of 0.670/(100km,yr).'

Figure 4.9 is a reproduction of the Figure 3 referred to in the above quotation, and was taken directly from the strategy document. The figure indicates that Ergon Energy's cross arm reliability, while marginally reducing, is well above the benchmark selected. Furthermore, PB concurs with Ergon Energy's conclusion that it compares favourably with the benchmark.

84 Ergon Energy email response to questions AS.75 and AS.76 21/08/09.
85 Ergon Energy response to questions AS.102, AS.115 and AS.125 21/08/09.
86 Ergon Energy Corporation Limited 2009, Network maintenance asset management strategy document: asset maintenance strategy: Version 0.8 final, April 2009.

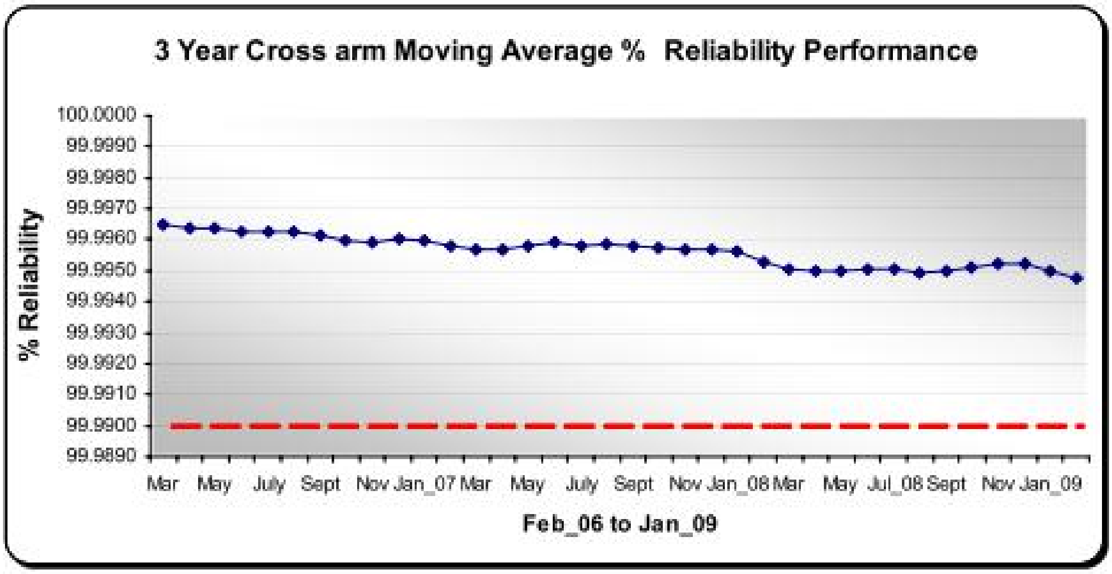

Figure 4.9 Ergon Energy HV cross arm asset reliability performance

Source: Ergon Energy's Asset Management Strategy Document, p. 10.

PB has a number of concerns regarding the information provided by Ergon Energy to support its volume forecast for pole top replacements, particularly in the context of the proposed 72% real increase over the current period for total replacement capex. Ergon Energy AEP states that forecast failure rates are assumed to remain consistent with current defect rates, as are the replacement rates, but with some allowance for new inspection programs. However, the defect rates for these new programs appear to be based on the findings of one relatively limited study, and confined to a specific geographic area. While Ergon Energy has indicated that it is uncertain about this failure rate, it has also stated that it applied to only a relatively small proportion of poles. Moreover, Ergon Energy's analysis of the overall performance of its cross arms, when compared to a benchmark that includes insulators, cross arm failures, connectors and attachments, is that it compares favourably.

Ergon Energy has confirmed[87] that this category of replacement expenditure is a new category and therefore no historical volumes. We cannot assess whether the proposed volume estimates are consistent with the AEP-stated position that rates should be consistent with current defect rates and replacement rates, but with some allowance for new inspection programs.

PB has attempted to assess the basis of Ergon Energy's volume estimates based on the limited information provided by the business. We concluded that it is prudent for Ergon Energy to propose expenditure to replace pole tops that are in poor condition. However, PB has been unable to clearly determine the basis of the pole top volume forecasts, and therefore cannot conclude that the proposed pole top replacement expenditure is efficient.

Replacement of conductors and connectors

Ergon Energy's replacement of conductors and connectors represents 24% of the total replacement capex proposal. Expenditure on this replacement category is forecast to grow at 31% per annum on average over the next regulatory control period.

87 Ergon Energy 2009, response to draft report, comment A31.

PB has examined Ergon Energy's *Network asset equipment plan 04: conductors & connectors*, reviewed the NARMCOS model, and made enquiries with the business to determine how the volume estimates and the prudence and efficiency of the proposed replacement volumes were established.

The conductors and connectors AEP sets out a number of existing capital programs, as well as proposed new programs and proposed changes to existing programs[88]. PB attempted to reconcile the view presented by the AEP with that presented in the NARMCOS model, but was able to create only a partial reconciliation. The history presented in the NARMCOS model is incomplete, and Ergon Energy has advised that the historical figures in the NARMCOS model are not to be relied upon. Consequently, PB is unable to reconcile this information in order to establish the basis of the volume forecasts for conductors and connectors.

PB has also made a number of enquiries in relation to the basis of the volume forecasts. In particular, in relation to the proposed 66 kV line rebuilds, Ergon Energy advised that:

> *The forecast quantities for 66kV line rebuilds in NARMCOS are not based on defect or failure rates. Rather, it is a generic provision to provide for the replacement of an average of approximately 1% of total 66kV line length per annum. This provision is considered conservative considering the life of a 66KV sub-transmission line is approximately 50 years. Detailed analysis to determine priorities for replacement is yet to be completed.*[89]

In relation to the proposed 110/132 kV line rebuilds, Ergon Energy advised that:

> *The forecast quantities for 110/132kV line rebuilds in NARMCOS are not based on defect or failure rates. Rather, it is a generic provision to provide for the replacement of an average of approximately 0.7% of total 110/132kV line length per annum. This provision is considered conservative considering the life of a 110/132KV sub-transmission line is approximately 50 years. Detailed analysis to determine priorities for replacement is yet to be completed*[90].

The information provided makes it apparent that the volume forecasts are estimated provisions based on a view of the asset age, which contradicts Ergon Energy's stated position of undertaking asset replacement on a defect and condition basis.

PB also made enquiries with regards to the proposed copper, steel and ACSR replacement programs. Ergon Energy stated that:

> *Ergon Energy's network has large quantities of 3/2.75 steel and 3/4/2.5 ACSR in its 3 phase systems. An analysis of outage data has shown that these conductors along with 7/.064 copper are responsible for the majority of conductor failures. This program will target the replacement of these conductors. Our reporting capability for replacement of conductor other than copper is limited at this stage…The proposed expenditure in the next regulatory control period allows for this program to be ramped up over the period and hence the reason for the increasing quantity of conductor to be replaced as the period progresses'*[91].

This advice is not consistent with the AEP-recommended action to:

> *Identify a process to determine the condition of copper wire and develop a copper Wire Rebuild Program for high voltage. Implement an improved field outage summary sheet for field crews*

88 Ergon Energy 2009, Network asset equipment plan 04 conductor & connectors, 06/04/09, pp. 10–12.
89 Ergon Energy email response to question AS.77 21/08/09
90 Ergon Energy email response to question AS.77 21/08/09
91 Ergon Energy email response to question AS 78 25/08/09

> *associated system cause codes to improve information available on location of LV conductor failures*.[92]

While it is prudent for Ergon Energy to propose expenditure to replace and refurbish conductor and connector assets, such expenditure should be clearly justified on the basis of defect history and condition analysis, consistent with Ergon Energy's stated approach. Ergon Energy has been unable to provide information that sufficiently explains how the proposed expenditure, or indeed ramping up replacement expenditure, is prudent or efficient. It appears that many of the volume estimates are age-based provisions that are not directly related to defect history or condition assessment. Based on our review of the information provided and our enquiries to Ergon Energy, PB cannot conclude that the proposed conductors and connectors capex is prudent or efficient.

Underground cables and joints replacement

Ergon Energy's proposed underground cables and joints replacement capex represents 7% of the total replacement capex proposal. After an initial step change in 2010–11, expenditure on underground cables and joints replacement generally levels off over the next regulatory control period.

PB has examined Ergon Energy's *Network asset equipment plan 05: underground cables & joints*, reviewed the NARMCOS model, and made enquiries with the business in order to determine how volume estimates were produced, and how the business established that the proposed replacement volume is prudent and efficient.

While growth in the replacement expenditure in this asset category is modest compared to the other three asset categories selected for review, PB questioned Ergon Energy on how levels of historical expenditure were related to the future forecast expenditure. Ergon Energy responded as follows:

> All historical figures in NARMCOS are to be ignored. The future quantity for failed-in-service cable is a best estimated by the subject matter experts (SME) in the area. An allowance has been made in the next regulatory control period and this has been divided equally over the years in the period. These are considered modest amounts. Defects are identified during inspection programs. The number of defects is based on a percentage of the population and the growth in defects therefore reflects the population growth. Where failures are sporadic, an allowance has been made and these have generally been spread evenly over the period. Again the SME's best estimate has been used for future replacement estimates and these have been spread evenly over the regulatory control period. It is difficult to predict the failure of these cables as no condition monitoring is available for these cables so an allowance has been made[93].

PB also noted the information provided in the AEP, and in particular the following extracts:

> Defect Management - Underground Pillars identified during inspection programs are packaged and replaced. Allowances based on projected defect rates are made.
>
> Refurbishment — A successful trial of one supplier's cable rejuvenation system has been concluded and a trial of a new market entrant's technique is ongoing and targeted in wet tropical areas to treat an identified XLPE cable for 'water treeing'. A portion of the traditional cable replacement budget has been separated as a provision for cable refurbishment to encourage the uptake of this option which is relatively new to the business. Experience to date in the Ergon

92 Ergon Energy 2009, Network asset equipment plan 04: conductors & connectors, 03/04/09, p. 5.
93 Ergon Energy email response to questions AS.80, 81, 82, 105 & 106 21/08/09.

> Energy's silicon injection trials are that refurbishment may be possible in 50% of the instances of water tree degradation.
>
> Replacement — Cables that fail in service are assessed as to their suitability for repair or replacement. An allowance based on historical amounts is allowed for the replacement of failed in service cable for those occasions where a significant length of cable is involved. Allowances are made for age / condition replacement of various cable types covering LV, HV, submarine, sub-transmission and older style paper lead. Quantities have been forecast from knowledge and experience with the various denominations in recent years. Some small allowances are made for other cable asset issues including targeted cast terminations and replacement of poor thermal backfill around some cables.
>
> Recommended Changes for 2009-10 onwards — There are no recommended changes to the capital programs. [94]

It is clear from these extracts that Ergon Energy has to some degree used historical defect rates when estimating the volume forecasts for underground cables and joints. While PB considers this an appropriate approach, Ergon Energy has been unable to provide its calculations to substantiate its methodology or to show the extent to which it has applied this approach. PB also notes that the discussion in relation to refurbishment strongly indicates good electricity industry practice in this area, and in our view Ergon Energy should be encouraged to continue its investigations into these practices.

PB has noted Ergon Energy's allowance for age-based replacement, as well as its stated practice of assessing cables that fail in service as to their suitability for repair or replacement. While Ergon Energy's age-based replacement is not in line with good industry replacement practices, assessing failed cables for repair or replacement is good practice.

We also note that the AEP recommends no changes for 2009–10 onwards — that is, a business-as-usual approach.

Management of this asset category shows evidence of some good electricity industry practices. The basis of the volume estimates appears to be a mixture of historical defect rate analysis, age-based replacement and expert judgement. However, PB was not able to clearly establish how Ergon Energy determined the forecast replacement volume estimates.

From the information provided, it appears no major new expenditure is proposed for replacing this category of asset, and PB notes the AEP proposes a business-as-usual approach. Consequently, even though Ergon Energy has not been able to provide historical data, PB is satisfied that, for this asset category, the proposed expenditure represents a business-as-usual level of expenditure. PB concludes that it is prudent for Ergon Energy to propose expenditure on this category and because PB's analysis has not revealed any reason or factors to indicate that base (unescalated) forecasts should significantly differ from current period expenditures, PB concludes that this expenditure is also efficient.

Zone substation transformer replacement

Ergon Energy's zone substation transformer replacement capex represents 7% of the total replacement capex proposal. This expenditure is forecast to increase by an average of 49% per annum over the next regulatory control period.

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[94] Ergon Energy 2009, Network asset equipment plan 05: underground cables & joints, 06/04/09, p. 5.

PB has examined Ergon Energy's *Network asset equipment plan 17: zone substation transformers* (AEP), reviewed the NARMCOS model, and made enquiries of Ergon Energy in order to establish how it has established the volume estimates, and that the proposed replacement volume is prudent and efficient.

Based on the NARMCOS models data, 94% of the proposed transformer replacement capex is related to three proposed expenditures:

- general replacements — 43%
- purchase of strategic spares — 31%
- transformer dry-out — 21%.

In relation to general replacements, the AEP recognises a range of techniques for analysing transformer condition; Ergon Energy's transformer management decision making is informed by this analysis. The AEP states condition-based analysis techniques are used in conjunction with financial analysis; it also states that:

> For the purposes of calculating the replacement year for transformer type assets, a range of techniques are used for determining the condition of the asset and estimating its expected remaining engineering life. Ergon Energy's transformer condition analysis uses end of life predictions and extrapolations to determine an expected replacement year, and a small number of transformers are replaced on this basis[95].

Not only are the stated transformer management practices generally in accord with good electricity industry practice, but the AEP states that this approach results in a small number of units being replaced. Examination of the NARMCOS model shows that 35 transformers, or 5.5% of the current population, are proposed to be replaced during the next regulatory period. PB sought information from Ergon Energy to substantiate the apparent increase on replacement expenditure, and received the following response:

> Ergon Energy is proposing to commence a program to replace high risk transformers at the end of their life prior to failure. The step change in 2012 allows for the lead time to complete the analysis to target the highest risk transformers, initiate this program and procure transformers before replacement can commence. The first transformer deliveries and replacements are planned to commence in 2011-12 with an ongoing program established and running through 2012-13 and beyond. Ergon Energy also points out that the 'step-change' is only from 2 to 6.[96]

Ergon Energy also stated that 'To date no business cases have been produced because initiated projects for transformer replacement based only on condition have been deferred due to funding constraints'.[97]

In relation to the purchase of strategic spares, the AEP notes that the volume forecast is based on the current rate of failure, which averages 5 per year and represents approximately 0.8% of the current transformer population. This failure rate is considerably higher than PB would anticipate for this class of asset, so we sought more information regarding failure rates to identify the reasons for the high numbers of failures being experienced. Based on the limited information provided, the high failure rates appear to be related to moisture problems, although PB has been unable to clearly establish the underlying causes. PB also notes that the NARMCOS model forecast reflects this failure rate on average.

95 Ergon Energy 2009, Network asset equipment plan 17: zone substation transformers, p. 13.
96 Ergon Energy response to questions AS.83 and 84 25/08/09.
97 Ergon Energy email response to question AS.37 30/07/09.

Ergon Energy's transformer dry-out program is briefly discussed in the transformer AEP, which proposes to:

> Develop a new program which allows for the on-site dry out of transformers which will significantly reduce down-time, costs and resources.[98]

The AEP also states that:

> Extensive oil sampling accompanied with comprehensive analysis of condition of transformers in Ergon Energy has determined a rate of 20 on-site oil dry-outs and 18 workshop style dry-outs are required per year over the next 10 years as a rate which will recover the population to a manageable level. Prioritised lists of these transformers to be dried out are published in Ergon Energy and used to inform asset management decisions. [99]

In relation to recommended changes for 2009–10 onwards, the AEP concludes that:

> Ergon Energy is proposing to introduce Onsite Transformer Dry-outs commencing in 2010-11 as an alternative to the current workshop program. This is due to a range of factors including workshop capacity, transport costs and the risk of damage when transporting large power transformers hundreds and in some cases thousands of kilometres on Queensland roads[100].

The NARMCOS model conflicts with the details in the AEP in relation to volumes and the apparent costs of the dry-out program. While the AEP proposes 20 on-site oil dry-outs and 18 workshop style dry-outs per annum over the next 10 years, the NARMCOS model proposes only an average of 8 on-site dry-outs and 7 workshop dry-outs per annum over the next regulatory control period. In response to PB's enquires regarding the proposed dry-out volumes, Ergon Energy stated that:

> While the number of transformers identified for replacement is consistent with the submission, the number of transformers identified for workshop/onsite dry-out and for dry-out using sieves and Trojans is considerably more than the numbers forecast in the submission. The dry-out program will therefore be prioritised based on risk.[101]

PB also has concerns regarding the cost forecasts Ergon Energy has used with regard to on-site power transformer dry-outs contained in the NARMCOS model, particularly in light of the AEP's statement that on-site dry-out of transformers will significantly reduce costs and resources. The NARMCOS model estimates the unit cost for on-site dry-out to be $200,000, while its estimated unit cost for a workshop dry-out is $120,000. PB concurs with the view expressed in the AEP that a significant saving in costs and resources should be achieved through the adoption of on-site power transformer dry-outs. When PB sought clarification of these costs, Ergon Energy stated:

> the additional onsite labour cost, additional accommodation costs and the additional costs of site establishment are estimated to make the on-site dry-outs more expensive than workshop dry-outs … Currently, no on-site dry-outs have been undertaken, so we do not have any actual costs for this work'.102

98 Ergon Energy 2009, Network asset equipment plan 17: zone substation transformers, p. 7.
99 Ergon Energy 2009, Network asset equipment plan 17: zone substation transformers, p. 13.
100 *Ibid*., p. 13.
101 Ergon Energy email response to question AS.117 25/08/09.
102 Ergon Energy email response to question AS.85 25/08/09.

PB sought further clarification as to why Ergon Energy was pursuing an on-site dry-out program, given the considerably higher unit costs being proposed. In response, Ergon Energy stated:

> Sufficient spare transformers will not be available to enable the required number of transformers to be processed to be taken out of service and returned to the workshops for dryout. The cost of purchasing additional transformers will exceed the additional costs of the onsite dryouts. Therefore a combination of onsite and workshop dryouts are proposed to enable a larger number of transformers to be processed over the next regulatory period to reduce the risk of failure, and remove derating factors applied on the significant number of wet transformers in Ergon Energy's network.[103]

Ergon Energy also provided PB with a number of condition assessment reports relating to the transformer dry-out program. Based on this information and the stated historically high transformer failure rates, we agree with Ergon Energy's view that there appears to be a significant 'wet transformer' problem that needs to be addressed. While the need for remediation may be apparent, it is not at all clear to us that the proposed costs of addressing this problem are efficient, and as the cost of the proposed program is in excess of $12.8m (nominal), PB would expect that Ergon Energy would have a robust business case to support this proposal.

PB has concerns regarding the volume forecast for the general replacement of transformers as no information has been provided to substantiate Ergon Energy's forecast. While the purchase of strategic spares is based on historical failure rates, PB notes that these rates are much higher than general industry trends, which is most likely indicative of an underlying asset management problem. Similarly, PB is concerned that the proposed transformer dry-out program volumes may be too low given the apparent state of the transformer population and its high failure rate. The unit costs associated with the transformer dry-out program are also of concern, and no information has been provided to clearly demonstrate that the dry-out program is efficient or effective. Consequently, PB cannot conclude that the proposed transformer replacement capex is prudent or efficient.

Other review issues

Because of the lack of information to substantiate Ergon Energy's replacement capex proposals in those categories selected for detailed review, PB sought information in relation to other asset replacement expenditure categories. In particular, PB wanted to examine the business risk associated with the asset replacement programs — that is, to analyse the risk currently faced by the business, and the change in this risk due to the proposed replacement capex expenditure. In response to our enquiries, Ergon Energy stated, 'There has been no specific business documentation prepared setting out the proposed change in risk other than the details contained in the AEPs. Rather the change in risk is considered in the development of project business cases'.[104]

4.3.5 PB assessment and findings

PB reviewed Ergon Energy's asset replacement capex proposal in order to assess its prudence and efficiency. PB considered the drivers for this category of expenditure and the application of key policy and procedures, and undertook specific reviews to determine the basis of Ergon Energy's replacement capex forecasts.

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103 Ergon Energy email response to question AS.117 25/08/09

104 Ergon Energy response to question AS.56 04/08/09

PB found that Ergon Energy has an extensive and well-integrated documentation framework. Although still being fully implemented, it demonstrates a thorough framework for the management of asset replacement. PB's conclusion is that Ergon Energy's key policies and procedures relating to the development of the asset replacement capex proposal generally accord with the principles of good asset management and good electricity industry practice.

PB believes that where the replacement rate for particular assets is increasing over time, a condition-based replacement approach can curb the rate of increase better than an age-based approach. PB believes that good electricity industry practice is to use a condition-based replacement approach. PB is concerned that Ergon Energy, although it purports to use a condition-based approach to asset replacement, still utilises, in many instances, an age-based approach.

PB has concerns regarding the current level of implementation of Ergon Energy's replacement practices when considered from the perspective of the relevant standards and current good electricity industry practice. We noted that Ergon Energy partially utilises an age-based approach in determining its replacement capex forecasts. Additionally, we have seen little evidence that risk analysis has been uniformly applied to the development of replacement capex, or that risk assessment is being routinely applied in asset replacement decisions. It is apparent that Ergon Energy's replacement capex proposal has limited reliance on asset condition data or asset condition models based on asset population data. PB has formed the view that Ergon Energy is only partially following condition-based asset renewal practices. Our view seems to accord with Ergon Energy's *Strategic plan for asset renewal*, which concludes its review by noting that:

Currently, there are seven significant issues affecting the asset renewal process[105]:

1. Adoption and understanding the concept of refurbishment

2. Quality and availability of asset data (both asset data and condition information)

3. Application of risk analysis to asset renewal decisions is not yet universal or mature

4. Difficulty co-ordinating asset renewal works with other stakeholders/drivers

5. Relativity of renewal works priority against other business priorities

6. Funding and resource constraints due to large load growth, N-1 security requirements and high costs of work

7. The lack of a recognised maintenance and renewal methodologies (eg. FMECA, RCM and/or CBRM).

PB generally concurs with the findings of Ergon Energy's *Strategic plan for asset renewal*, and we note the plan's proposed actions to move the business towards good electricity industry practice. In our view, Ergon Energy should be strongly encouraged to continue to develop its asset replacement and refurbishment capabilities, as proposed in Ergon Energy's *Strategic plan for asset renewal*.

PB undertook specific reviews of the four largest replacement expenditure items in order to examine how the proposed replacement capex forecast had been determined. With the exception of the underground cables and joints replacement capex, which seems to be

105 Ergon Energy 2009, *Strategic plan for asset renewal*, 3 April 2009, pp. 25 – AR451.

forecast on a business-as-usual approach, PB found that the basis of the replacement volume forecasts could not be clearly demonstrated or substantiated. Consequently, PB has concluded that the basis for the proposed real increase of 72% over current period expenditure has not been demonstrated, and we cannot conclude that the proposed replacement capex is prudent or efficient. Hence, PB recommends a business-as-usual level of funding as explained below.

PB notes that during the current regulatory period replacement capex expenditure has shifted downwards from its historical growth rate. The AER noted that this reduction 'largely reflected delays in expenditure to undertake higher priority capex in demand related areas'[106]. In order to establish a business-as-usual level of growth PB ignored the current regulatory period expenditure profile. Instead we calculated the historic growth rate during the most recent years of replacement capex increases for which data is available (2001/02 to 2005/06). This growth rate was then applied to the replacement capex in the last year of the current regulatory period to establish a business-as-usual forecast for the next regulatory period. This modelling results in an asset replacement budget requirement of $1,095.3m, representing a total reduction of $119m (or 9.8%) on the proposed asset replacement capex of $1,214.1m.

4.3.6 PB recommendations

Based on the findings of our review, PB recommends the revised replacement capex amounts as set out in Table 4.10.

Table 4.10 Recommended adjustment to asset replacement capex

Expenditure category	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposal	177.4	212.7	250.0	274.8	299.2	1,214.1
PB adjustment	(9.8)	(19.3)	(31.0)	(30.0)	(28.7)	(118.8)
PB recommendation	167.6	193.4	219.0	244.8	270.5	1,095.3

Source: PB analysis

4.4 Reliability and quality improvement expenditure

This section of the report relates to expenditure that is targeted at addressing reliability and quality-of-supply issues across the distribution network.

4.4.1 Proposed expenditure

Ergon Energy has proposed system capex for reliability and quality improvement over the next regulatory control period of $122.4m. The proposed expenditure is shown in Table 4.11; historical expenditure in this category is charted in Figure 4.10. The comparison chart shows that the proposed expenditure represents a real increase of 131% ($69.4m) over the reliability and quality of supply expenditure in the current regulatory control period.

106 Australian Energy Regulator, 2009 Queensland and South Australia Electricity Distribution Determination 2010-15, Review of Historic Capital Expenditure, July 2009, p7

Table 4.11 Reliability and quality improvement capex forecast

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposal	18.3	20.9	24.5	28.3	30.4	122.4

Source: Ergon Energy Corporation Limited 2009, Regulatory proposal to the Australian Energy Regulator: distribution services for period 1 July 2010 to 30 June 2015, *1 July 2009, Table 53.*

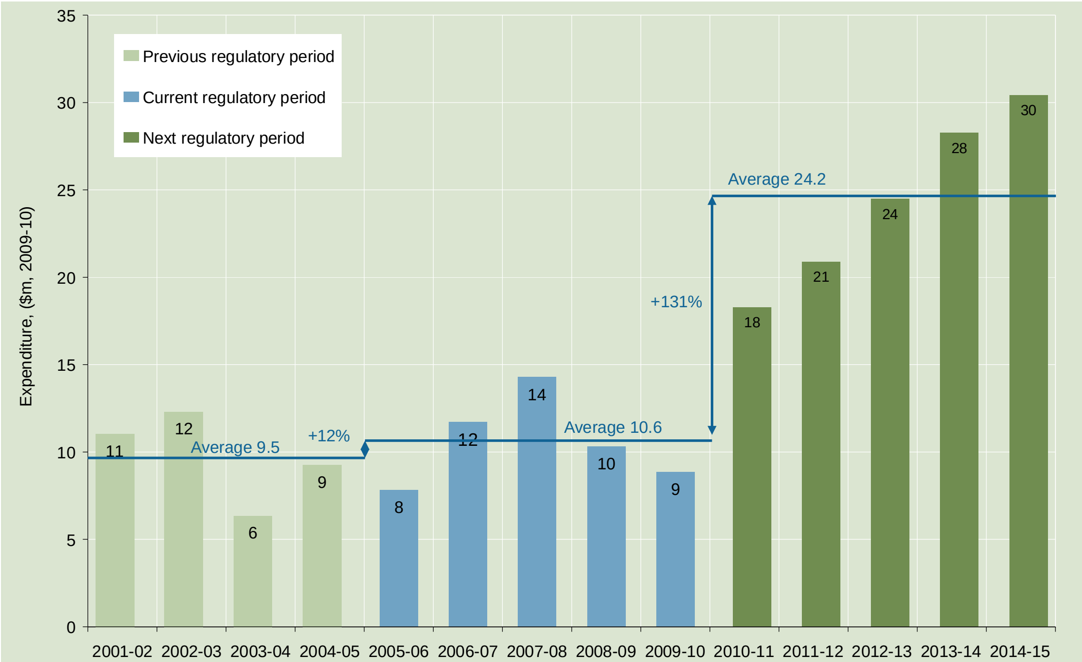

Figure 4.10 Reliability and quality improvement capex forecast

Source: PB analysis and Ergon Energy 2009, *Electricity distribution regulatory information notice pro forma statements, Ergon Energy for regulatory control period 2010–11 to 2014-15*, 1 July 2009

The proposed expenditure on reliability and quality improvement is relatively small, representing only 2% of the total proposed system capex, but it is the category with the largest real increase in proposed expenditure.

4.4.2 Drivers

Ergon Energy notes in its regulatory proposal that this capex is driven by the need to meet external and internal service standards, and hence to meet the minimum service standards mandated by the Queensland *Electricity Industry Code*.

Reliability and quality of supply are also affected by asset condition; hence, asset replacement capex as well as growth-related capex (CIA capex in particular) will influence reliability and quality performance measures.

4.4.3 Policies and procedures

PB has conducted a high-level review of the policies and procedures which Ergon Energy applies to meet its reliability and quality of supply standards. Reliability and quality of supply are influenced by the level of growth and replacement capex; therefore, the related policies and procedures, as outlined in sections 4.2 and 4.3, are also relevant to this expenditure category.

An overview of Ergon Energy's policies and plans relevant to its management of reliability and quality of supply and the development of the related capex proposal is provided in section 23.5 and Figure 41 of Ergon Energy's regulatory proposal. The key documents identified by Ergon Energy are:

- Network performance standard[107]
- Network performance strategy[108].

Other relevant documents identified include the *Annual network performance report*, *SCADA acceleration strategy*, *Feeder improvement program*, and the *Power quality strategic program*.

Ergon Energy's *Network performance standard* details the minimum reliability and power quality standard to be provided by Ergon Energy's distribution network, while the *Network performance strategy 2010–15* outlines key initiatives established by the business to meet the network performance standards.

It is generally considered good practice to identify the worst-performing network assets through a rigorous analysis of the business's network performance data, and then to target the specific causes and worst performance instances. While such an approach is prudent and efficient if undertaken rigorously, the timing and ranking for addressing such issues, as well as the opex and capex required, are also important for this analysis. Good practice could be demonstrated through economic assessment and risk analysis of the efficient level of expenditure and provide for the revision of this analysis on an ongoing basis. This approach should be based on clearly defined and documented performance standards, and supported by policies, standards, strategies and robust data, as well as specific plans and procedures.

The Ergon Energy documents outlined above indicate that the business has identified and analysed the worst-performing elements of the network. Specific strategies and plans have been developed to address the identified issues, and Ergon Energy has highlighted the following strategies to secure network performance improvements:

- network performance reporting and data quality assurance
- network performance monitoring
- network remote control strategy
- system configuration strategy
- voltage regulation and power quality improvement
- network investigative initiatives
- feeder improvement programs
- network technology roadmap and research initiatives.

Ergon Energy states that a process of project ranking is undertaken to develop a program of works that forms the basis of the budget planning process[109]. Ergon Energy expects to

107 Ergon Energy Corporation Ltd 2007, *Network performance standard*.
108 Ergon Energy Corporation Ltd 2009, *Network performance strategy 2010–15*.

improve network reliability performance and customer service through improved fault isolation times and restoration times, particularly for the worst-performing distribution feeders.

Ergon Energy has adopted many of the elements of good electricity industry practice, as outlined above, and documentation reviewed provides evidence of this. While the level of rigour, particularly in relation to the economic analysis and risk analysis, is less than PB would expect in a fully developed application of these approaches, these aspects are present and are being applied. PB encourages Ergon Energy to continue to develop its capabilities in this area.

PB has concluded that Ergon Energy's policies and procedures as they relate to the management of reliability and quality of supply improvement are generally in accord with good electricity industry practice.

4.4.4 Specific reviews

In relation to the $122.4m reliability and quality improvement capex, PB sought to examine a range of planning documentation (e.g. business cases, board papers). Specifically, PB wanted to examine the demonstration of the need and timing of the proposed capex, as well as the consideration of options and the selection of the most efficient option.

PB expects that robust business cases (or similar documentation) would be available to provide justification for the proposed expenditure. We have examined the information contained in the SC Capex Data Model for the individual expenditure items under this category. The SC Capex Data Model is used as an input to the regulatory proposal, and applies unit costs to the forecast number of assets that Ergon Energy proposes to build. The output of this model feeds into the headline figures given in Table 4.11.

To undertake this review, PB requested the supporting documentation for the two largest reliability and quality improvement capex items in the SC Capex Data Model. These expenditure items and their relative proportion of the reliability and quality improvement capex are:

- Feeder Improvement Program[110] (33% of reliability and quality capex)
- SCADA installation (28% of reliability and quality capex).

Feeder improvement program

Ergon Energy's *feeder improvement program* is intended to identify the worst-performing feeders based on a rolling average of SAIDI for three financial years, and to prioritise the improvement of poor performing feeders that have a relatively high number of customers, as well as of poor performing radial feeders that are relatively long. The program documentation explains:

> *The red feeders are further analysed to identify the top 50 worst performing feeders which approximately equal to 5% of the total distribution feeders. 10 Urban, 30 Short Rural and 10 Long*

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109 Ergon Energy Corporation Limited 2009, Regulatory proposal to the Australian Energy Regulator: distribution services for period 1 July 2010 to 30 June 2015, section 23.5.3, p. 210.

110 Ergon Energy, 2009 PL560C SC Capex data model.xls. The 'feeder improvement program' is listed as 'miscellaneous work – red feeders' in the spreadsheet.

Rural feeders have been included in the worst performer's list for detailed analysis to identify the performance improvement opportunities. Out of the top 50 worst performing feeders, Ergon Energy intends to target 42.5 feeders (8.5 feeders per annum) in the feeder improvement program during the next regulatory period. A higher number of Short Rural feeders have been considered compared to other feeder categories since they form the highest proportion of the distribution feeder network and cover the largest customer base as well. The Feeder Improvement Program will target the worst performing feeders (red feeders) and other poor performing feeders (Amber and yellow feeders) with the highest number of customers. [111]

The process adopted by Ergon Energy demonstrates a targeted approach by identifying the 50 worst-performing feeders throughout the next regulatory control period. However, the document does not demonstrate why the top 50 worst performing feeders is the prudent number to target. The document also notes that:

Out of the top 50 worst performing feeders, Ergon Energy intends to target 42.5 feeders (8.5 feeders per annum with an estimated CAPEX of approximately $653K/feeder excluding the overheads) in the feeder improvement program during the next regulatory period.[112]

The basis for the proposed cost per feeder, and the scope of work associated with this cost are not considered by the document in reaching the recommendation to proceed with the proposed program. The *Feeder improvement program* document also states:

Besides the CAPEX specific to the feeder improvement program, the red feeders would also be targeted by the other non-performance specific program of works. The reactive approach for the red distribution feeder performance improvement should adopt the least cost options from the following:

Network Operation Improvement (Short term benefits)

Prioritisation of Preventive Maintenance

Augmentation and Refurbishment through CAPEX [113].

The document also notes:

The red feeders will also be targeted by the accelerated SCADA extension strategy to increase the remote control availability.[114]

The Feeder improvement program documentation contains a summary of the performance but does not include any detailed analysis of the causes of the poor performance of the identified worst-performing feeders. Nor does the document consider how the Feeder improvement program will integrate with the Network operation improvements, preventive maintenance, augmentation and refurbishment capex, or the SCADA acceleration strategy. While the Feeder improvement program documentation recognises that benefits will be achieved from all these initiatives, it does not address the potential overlap in the proposed expenditures.

PB's concerns in relation to the proposed expenditure are:

- The individual benefits of each feeder improvement are not recognised or the timeframe over which they should be addressed is not listed.

111 Ergon Energy 2009, *Feeder improvement program*, 01/04/09, page 15 – AR341
112 *Ibid*., p. 17.
113 *Ibid*., pp. 17–18.
114 *Ibid*.

- The causes of poor performance are not recognised, and it is therefore unclear how the proposed expenditure will address the performance issues and how the proposed cost has been determined.
- Other capex and opex expenditures are identified that will also target the same performance problem, and this has not been taken into account in the development of the *Feeder improvement program* capex proposal.

On the basis of the information presented, it appears that the proposed *Feeder improvement program* capex would be best described as a provision for feeder improvement works rather than a program of specific projects.

Due to the lack of supporting information, PB cannot conclude that the proposed *Feeder improvement program* capex is prudent or efficient.

SCADA installation

Ergon Energy's *SCADA acceleration strategy* states that:

> Ergon Energy's historical reliability performance analysis demonstrates a gradually improving trend over the past six years for frequency of outages (SAIFI). Ergon Energy considers this largely attributable to the benefits of improved asset management practices. However, the SAIDI improvement trends for all feeder categories imply that Ergon Energy needs to put more focus on improving the SAIDI performance by addressing the outage duration[115].

The *SCADA acceleration strategy* includes a cost–benefit analysis (both to Ergon Energy and its customers) of the proposed accelerated SCADA deployment. This analysis demonstrates a positive NPV for this project, and shows that Ergon Energy's savings (excluding overheads) are estimated to be $55.5m, while total cost savings by customers are estimated to be $213.3m over the 15-year life of the project[116].

Ergon Energy also stated that 'The cost benefit analysis in the SCADA Acceleration Strategy, is completely based on the estimated customer minutes savings for the three feeder categories (Urban, Short Rural and Long Rural) due to the deployment of full SCADA to Zone Substations'. The cost–benefit analysis demonstrates modest savings in operating costs for Ergon Energy, with these savings accruing only as the strategy is fully implemented. However, significant benefits are expected to accrue to customers based on the Value of Customer Reliability (VCR) figures in the AER's STPIS Scheme[117].

PB has reviewed the documentation provided for the proposed SCADA acceleration strategy and is satisfied that it demonstrates the prudence and efficiency of the proposed expenditure.

4.4.5 PB assessment and findings

PB's review of Ergon Energy's reliability and quality improvement capex proposal has considered the relevant performance standards, the application of key policy and procedures, and has included two specific reviews in order to establish the prudence and efficiency of the forecast capex.

115 Ergon Energy Corporation Limited 2009, *SCADA acceleration strategy*.
116 PB notes that the *SCADA acceleration strategy* document does not specify the cost base to which these figures relate.
117 Ergon Energy response to question AS.133 20/08/09.

Ergon Energy has established prudent strategies to identify the worst-performing parts of the network and to prioritise expenditure on those areas. Ergon Energy's policies and procedures as they relate to the management of reliability and quality of supply improvement are generally in accord with good electricity industry practice.

Review of the two largest expenditure items in this category concluded that while PB accepts that it is prudent to forecast targeted expenditure in order to achieve reliability and quality standards, Ergon Energy's documentation does not clearly demonstrate this. The *Feeder improvement program* documentation did not demonstrate the prudence or efficiency of the proposed expenditure. The *SCADA acceleration strategy* documents did provide appropriate analysis and evidence. PB concluded that the *Feeder improvement program*, which represents 33% of this capex category, is not specifically targeted expenditure, but appears to be a provision to address feeder performance. While this is strictly not an issue of prudence or efficiency, it is of concern due to the potential for the proposed capex to duplicate other capex and opex that are identified to target the same performance problems.

Due to the concerns outlined, as well as the limited application of economic analysis to support this forecast expenditure, PB is unable to conclude that the reliability and quality capex proposal is prudent and efficient.

4.4.6 PB recommendations

PB recommends that expenditure for reliability and quality of supply be maintained at current period levels into the next regulatory control period, with the addition of an allowance for the proposed *SCADA acceleration strategy*. PB has not undertaken a review of the prudence and efficiency of historical costs, however, PB's analysis has not revealed any reason or factors to indicate that reliability and quality improvement capex forecasts should significantly differ from current period expenditure (with the exception of an increase in expenditure for SCADA acceleration). The recommended reduction in capex for reliability and quality improvement is $35.4m in total over the next regulatory period.

Capex in the current regulatory control period averages $10.6m per annum and the proposed SCADA acceleration strategy is forecast to cost approximately $34m over five years. The recommended capex for reliability and quality improvement is set out in Table 4.12. This recommendation is derived by sculpting the $34m for SCADA over the five years of the next regulatory control period based on Ergon Energy's proposed expenditure growth profile and adding an allowance of $10.6m per year for the remaining reliability and quality improvement capex.

Table 4.12 Recommended capex for reliability and quality improvement

Expenditure category	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposal	18.3	20.9	24.5	28.3	30.4	122.4
PB adjustment	(2.6)	(4.5)	(7.1)	(9.8)	(11.4)	(35.4)
PB recommendation	15.7	16.4	17.4	18.5	19.0	87.0

Source: PB analysis

4.5 Other capex

'Other' capex contains a broad range of expenditures. Ergon Energy has presented the 'Other' capex in five broad categories including communications, protection, Single Wire Earth Return (SWER), undergrounding, and other programs that comprise low-voltage fuse retrofits, low-voltage spreaders, substation security, oil containment bundling and alternate substation AC supplies.

4.5.1 Proposed expenditure

Ergon Energy is proposing to spend $331.4m in the next regulatory period on other capex. The proposed expenditure is shown in Table 4.13. Figure 4.11 illustrates that this represents a real increase of 75% of expenditure in this category over expenditure in the current regulatory control period of $188.9m.

Table 4.13 'Other system' capex forecast

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposal	105.6	72.9	50.8	50.4	51.7	331.4

Source: Ergon Energy regulatory proposal Table 54

Figure 4.11 'Other system' capex forecast
Source: Ergon Energy regulatory proposal RIN submission and PB analysis

4.5.2 Specific reviews

As other capex contains a broad range of expenditures driven by a range of issues, PB has focused on specific reviews in order to examine the prudence and efficiency of the proposed expenditure. Ergon Energy's proposed other capex is divided into the following five subcategories of expenditure:

- communications
- protection
- Single Wire Earth Return (SWER)
- undergrounding
- other programs that comprise low-voltage fuse retrofits, low-voltage spreaders, substation security, oil containment bundling and alternate substation AC supplies.

The SC Capex Data Model indicates that 58% of expenditure in this category relates to communications and undergrounding. The largest elements are the UbiNet project and the CARE program. The other line items of expenditure represent 42% and are all relatively small expenditures ranging from less than $50,000 annually to $2.4m annually (excluding overheads and escalators). PB has taken a high level review of the proposed capex expenditure and has examined in detail those expenditure categories which constitute a high proportion of overall expenditure. Consequently PB has concentrated its review on the largest expenditure items — UbiNet and the Cyclone Area Reliability Enhancement (CARE) program. If UbiNet were excluded from the expenditure proposal, the proposed 'other capex' category would reduce to virtually a business-as-usual approach.

Communications

The proposed expenditure on communications represents 38% of the proposed total 'other system' capex, and relates to the proposed UbiNet project.

Ergon Energy has begun the first stage of rolling out a contiguous telecommunications backbone network, known as the Ubiquitous Network, or UbiNet, throughout its distribution area. Ergon Energy states that 'UbiNet will satisfy a range of its telecommunications requirements including SCADA, network monitoring and control, fixed and mobile staff communications, and if required, connectivity to customer meters'. UbiNet stage 1 involves investing in the core telecommunications backbone network across the Ergon Energy distribution area[118], and is being implemented between 2008–09 and 2011–12. No further stages of UbiNet have been included in the regulatory proposal expenditure forecasts.

PB has reviewed the UbiNet business case, the business case review undertaken by Queensland Treasury Corporation[119], and the business case review undertaken by independent consultants for Ergon Energy[120].

The business case for UbiNet is limited in that it only considers two options — business-as-usual and establishing UbiNet. Queensland Treasury Corporation's (QTC's) financial model

118 Ergon Energy 2009, Regulatory proposal to the Australian Energy Regulator: distribution services for period 1 July 2010 to 30 June 2015, section 23.6.2.1 p. 212.

119 Queensland Treasury Corporation 2008, UbiNet Project – financial model and high level business case review, May 2008.

120 Evans & Peck 2008, *UbiNet – review of business case*, November 2008.

and high-level business case review identified that a relatively large number of the project's operating and capex costs are based on internally sourced estimates rather than estimates sourced from expert third parties. QTC recommended that Ergon Energy seek formal pricing in relation to internally sourced expenditure assumptions. QTC concluded that the benefit of the UbiNet project was $8.63m on a net present cost of $132.69m. In QTC's opinion, this benefit was not significant. Furthermore, QTC noted that a 10% increase in Ubinet's capital costs or a 10% decrease in the costs associated with business-as-usual would make it more beneficial to pursue a business-as-usual approach.

Ergon Energy engaged Evans & Peck to undertake an independent review of the UbiNet business case and assess whether the estimated costs presented in the business case align with telecommunication industry expectations for a network of this size. Evans & Peck confirmed that the estimated capital costs were reasonable for a project of this size and geographic spread.

PB concurs with the view of the QTC that the business case for UbiNet is marginal, and any change in the estimated costs or business costs would make this expenditure inefficient. However, PB acknowledges that based on current cost estimates Ergon Energy's business case demonstrates that UbiNet is an economically justified investment and therefore the proposed expenditure can be considered prudent and efficient. Ergon Energy will need to manage the costs, risks and benefits of this project closely to ensure that the value on which the business case is based is achieved.

Undergrounding

Ergon Energy's other undergrounding expenditure represents 20% of the proposed total 'other system' capex.

Ergon Energy's strategy with regard to undergrounding lines is that it will install overhead lines except in urban residential developments (subdivisions)[121] where local government requires undergrounding[122]. This capex refers to specific undergrounding relating to the Cyclone Area Reliability Enhancement (CARE) program, which represents most of the proposed undergrounding cost proposal, and the Toowoomba Trees program.

The CARE program involves the progressive undergrounding of critical high-voltage infrastructure in cyclone-prone areas[123]. CARE expenditure is $6.5m per annum, excluding overheads and escalators. While the CARE expenditure is not mandatory, it has the support of local government and communities, and aims to limit the impact of cyclones on the community and Ergon Energy's distribution network. The options analysis for the CARE program does not include any assessment of the benefits of the expenditure. The justification for the CARE expenditure would be strengthened with the addition of such analysis. Given the relative size of the expenditure, and the likely community and network benefits, PB accepts that this expenditure is prudent.

PB has examined Ergon Energy's *Underground cabling strategy*[124], and notes the value analysis presented in the document. In particular, the document states:

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121 Capex associated with undergrounding residential estates is included in the CICW capex proposal. Reference should be made to section 4.2.6 for further details of this category of expenditure.

122 *Ibid*., section 23.6.3.4, p. 217.

123 Ergon Energy 2008, *Paper number 0012-5-6 Powerlines Undergrounding Project AR247c* and email dated 22/12/08 from the Assistant Business Secretary confirming resolution by the Board for the program.

124 Ergon Energy 2009, Underground cabling strategy, 31 March 2009, p. 31.

> *The key issue with CARE, today, is whether the benefits being derived from projects remains the same as that achieved initially, or, whether the returns are diminishing. This issue is being exacerbated by the escalating cost of UG projects.*
>
> *As stated above the initial focus of CARE was aimed at establishing secure underground connections to essential services such as hospitals, assembly points, nursing hospices, water and sewerage pumps, etc. and the majority of these installations within the allocated area have now been addressed. ….*
>
> *A separate analysis of CARE projects has demonstrated conclusively that the value of projects based on the original priority assigned/ cost basis (CARE Value Index) is declining*.

The recommended strategy recognises that one class of work — the undergrounding of HV backbone lines — has been the primary focus and that not all aspects of the original CARE program have been achieved. The recommendation highlights several areas that need further attention, and stresses that:

> *A review should be instigated to develop the criteria for the second stage of CARE projects to ensure that the remaining funds achieve the optimum cost/value return*.[125]

PB generally concurs with this view. The analysis in the *Underground cabling strategy* demonstrates the prudent management of the program; however, the value achieved from the proposed expenditure is diminishing, and both the value, effectiveness and efficiency are likely to have changed since the inception of the program and should be reviewed.

With regard to the efficiency of the proposed expenditure for the CARE program (as well as the Toowoomba Trees program noted above), PB notes the conclusion of the *Underground cabling strategy*:

> *Other underground applications in established overhead areas are shown to be unjustifiable, purely on a cost only basis and their use would need to be justified by the value of other network benefits that offset the significant cost differential or by funding by customers from the improved aesthetic values*. [126]

PB concurs with this view, and concludes that through our review of the CARE program documentation we have not been able to establish the efficiency of the proposed expenditure. However, we note that the proposed expenditure is generally in accordance with a business-as-usual proposal.

4.5.3 PB assessment and findings

PB has reviewed Ergon Energy's 'other system' capex by conducting a specific review of the two largest expenditures, which together represent 58% of the expenditure in this category.

Based on our review, PB observed that the UbiNet business case is marginal and that this investment would need to be carefully managed to ensure the value of the investment is achieved. However the current business case does demonstrate that UbiNet is an economically justified investment, and therefore the proposed expenditure is accepted as prudent and efficient.

125 Ibid, p. 33.
126 Ibid, p. 4.

For the undergrounding expenditure, which is predominantly the CARE program, Ergon Energy has identified that the value of this program is declining, and recognises a need to revisit the CARE program strategy. PB has concluded that the care program is prudent, and the proposed expenditure appears to represent a business-as-usual approach.

PB notes that the real increase of 75% in the 'other capex' category over the current period is almost completely attributable to the one-off UbiNet project, which we conclude is prudent and efficient. The balance of the expenditure in this category (once UbiNet is removed) is generally in accord with historical levels of expenditure, and appears to represent a business-as-usual approach. PB recommends no specific changes to the proposed expenditure.

4.5.4 PB recommendations

PB recommends no specific changes to the proposed 'other capex', as set out in Table 4.14.

Table 4.14 Recommended capex for 'other system' capex

Expenditure category	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposal	105.6	72.9	50.8	50.4	51.7	331.4
PB adjustment	0.0	0.0	0.0	0.0	0.0	0.0
PB recommendation	105.6	72.9	50.8	50.4	51.7	331.4

Source: PB analysis

4.6 Summary of findings and recommendations

This section presents a summary of PB's key findings and recommendations relating to Ergon Energy's proposed system capex for the next regulatory control period.

Key findings

Ergon Energy proposes to spend $5,353.9m on system capex in the next regulatory control period, an average increase of 59% compared with the current regulatory control period.

An increase in expenditures is proposed across all regulatory categories. The largest increases (in dollar terms) relate to asset replacement capex and customer initiated capex, where Ergon Energy proposes to increase expenditure by $509.1m and $944.9m respectively.

PB reviewed Ergon Energy's capital governance and in general found it consistent with good electricity industry practice, however the options analysis included in business cases lacked robustness. Overall, most options analysis cases examined by PB did not consider non-network alternatives, and had only limited NPV analysis to demonstrate that the preferred option was most efficient.

Growth Capex

Ergon Energy proposes to spend $3,685.9m on growth capex (CIA and CICW) in the next regulatory control period, an average increase of 52% compared with the current regulatory control period.

The planning criteria Ergon Energy has used are aligned with good industry practice, however demand forecast application is only partially demonstrated and non-network alternatives are not generally considered.

The need and timing for the CIA capex was clearly demonstrated and is therefore considered to be prudent, however the lack of NPV analysis to demonstrate selection of the most efficient option has meant PB is unable to conclude that CIA capex is efficient. PB recommends a reduction of $526.3m over the next regulatory period based on an 18 month deferral of the CIA program.

The CICW capex forecast is not sufficiently substantiated and PB recommends a reduction of $318m for the next regulatory control period.

Replacement Capex

Ergon Energy proposes to spend $1,214.1m on replacement capex in the next regulatory control period, an average increase of 72% compared with the current regulatory control period.

Asset replacement policies and procedures are in line with good electricity industry practice, however asset replacement practices are not consistently implemented.

The volume forecasts underpinning the replacement capex forecast were not demonstrated to be prudent and PB recommends an amount equivalent to business-as usual- for asset replacement which results in a reduction of $119m for the next regulatory control period.

Reliability and quality improvement expenditure

Ergon Energy proposes to spend $122.4m on reliability and quality improvement expenditure in the next regulatory control period, an average increase of 131% compared with the current regulatory control period.

Reliability and quality improvement planning follows many of the elements of good electricity industry practice.

The Feeder Improvement Program is not demonstrably efficient.

The SCADA acceleration strategy is demonstrated to be prudent and efficient.

PB recommends a reduction in reliability and quality improvement capex of $35.4m, the recommendation is based on maintaining the current level of capex in this category with an additional allowance for the SCADA acceleration strategy which Ergon Energy demonstrated to be prudent and efficient.

Other Capex

Ergon Energy proposes to spend $331.4m on other system capex in the next regulatory control period, an average increase of 75% compared with the current regulatory control period.

The majority of the forecast for other system capex represents a business-as-usual approach which PB accepts as prudent and efficient.

The 75% real increase in other capex relates to Communications capex for the UbiNet project. The Ubinet project is demonstrated to be prudent and efficient via the business case analysis.

No changes are recommended to other system capex.

PB recommendations

PB recommends that the system capex allowance for the next regulatory control period should be adjusted from the levels proposed by Ergon Energy. PB's proposed adjustments are shown in Table 4.15.

Table 4.15 Recommended system capex for Ergon Energy

Expenditure category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Corporation Initiated Augmentation						
Ergon Energy Proposal	267.8	339.4	401.3	463.6	518.9	1,991.0
PB adjustment	(93.3)	(100.5)	(101.4)	(114.8)	(116.4)	(526.4)
PB recommendation	174.5	238.9	299.9	348.8	402.5	1,464.6
Customer Initiated Capital Works						
Ergon Energy Proposal	336.1	355.0	315.6	328.7	359.6	1,695.0
PB adjustment	(61.8)	(79.1)	(39.8)	(53.4)	(84.0)	(318.1)
PB recommendation	274.3	275.9	275.8	275.3	275.6	1,376.9
Asset Replacement						
Ergon Energy Proposal	177.4	212.7	250.0	274.8	299.2	1,214.1
PB adjustment	(9.8)	(19.3)	(31.0)	(30.0)	(28.7)	(118.8)
PB recommendation	167.6	193.4	219.0	244.8	270.5	1,095.3
Reliability and Quality Improvement						
Ergon Energy Proposal	18.3	20.9	24.5	28.3	30.4	122.4
PB adjustment	(2.6)	(4.5)	(7.1)	(9.8)	(11.4)	(35.4)
PB recommendation	15.7	16.4	17.4	18.5	19.0	87.0
Other System						
Ergon Energy Proposal	105.6	72.9	50.8	50.4	51.7	331.4
PB adjustment	0.0	0.0	0.0	0.0	0.0	0.0
PB recommendation	105.6	72.9	50.8	50.4	51.7	331.4
Total system capex						
Ergon Energy Proposal	905.3	1,000.9	1,042.1	1,145.8	1,259.8	5,353.9
PB adjustment	(167.5)	(203.4)	(179.3)	(208.0)	(240.5)	(998.7)
PB recommendation	737.8	797.5	862.8	937.8	1,019.3	4,355.2
Total adjustment (%)	(18.5)	(20.3)	(17.2)	(18.2)	(19.1)	(18.7)

Source: PB analysis.

5. Non-system capex review

This section presents PB's review of Ergon Energy's 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

Ergon Energy has submitted a proposed non-system capex of $679.1m for the next regulatory control period. PB divided Ergon Energy's non-system capex into the following four expenditure categories for analysis:

- end use computing assets
- property
- fleet
- tools and equipment.

The total non-system capex proposed by Ergon Energy, together with the breakdown by expenditure category, are summarised by year in Table 5.1.

Table 5.1 Ergon Energy–proposed non-network capex for the next regulatory control period

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Non-system capex						
End-use computing assets	20.3	18.9	18.2	17.1	18.4	92.9
Buildings	121.7	141.3	76.7	22.3	19.8	381.8
Office equipment and furniture	0.5	0.5	0.5	0.5	0.5	2.5
Land and easements	0.0	0.4	0.0	2.1	0.0	2.5
Fleet	30.9	30.3	32.0	32.3	35.0	160.5
Tools and equipment	7.5	7.6	7.8	7.9	8.0	38.8
Total non-system	180.9	199.0	135.2	82.2	81.7	679.0

Source: Ergon Energy, July 2009 RIN submission model.xls

In this report PB discusses Ergon Energy's information and communication technology (ICT) function, which includes Ergon Energy's end-use computing assets as set out in Table 5.1 and those functions provided by SPARQ Solutions127. This arrangement is examined in section 5.2.4. Table 5.2 outlines the total non-system capex and SPARQ ICT expenditure for the next regulatory control period.

127 SPARQ Solutions is the jointly owned service provider to ENERGEX and Ergon Energy, a related service provider under the National Electricity Law. SPARQ provides ICT services to both businesses and recovers the costs of providing these services by a service charge to each business.

Table 5.2 Ergon Energy–proposed non-network capex for the next regulatory control period by category

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Total non system – Ergon Energy proposal	180.9	199.0	135.2	82.3	81.7	679.1
SPARQ ICT expenditure	67.2	64.1	52.5	47.9	35.2	266.9
Total non-system – including SPARQ ICT capex	248.1	263.1	187.7	130.2	116.9	946.0

Source: Ergon Energy, July 2009 RIN submission model.xls

Figure 5.1 provides a pie chart showing the breakdown of Ergon Energy's proposed expenditure for non-system capex in the next regulatory control period. PB notes that Figure 5.1 includes ICT expenditure for SPARQ together with the end use computing forecast from the Ergon Energy proposal.

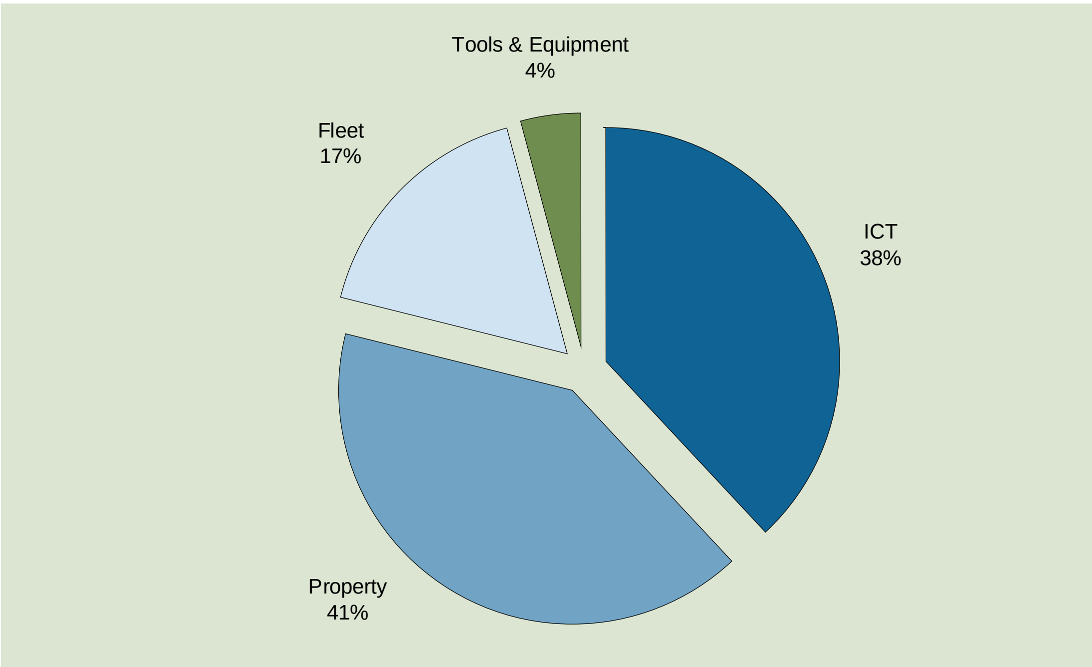

Figure 5.1 Breakdown of Ergon Energy non-system capex (including SPARQ ICT) forecast for next regulatory control period

Source: Ergon Energy, July 2009 RIN submission model.xls

PB reviewed historical variances between the Queensland Competition Authority (QCA) allowance and Ergon Energy's actual historical non-system capex. Figure 5.2 shows the actual non-system capex[128] for the previous and current regulatory control period compared with the QCA allowance, and the forecast capex for the next regulatory control period.

128 Ergon Energy, July 2009 Regulatory proposal to the Australian Energy Regulator, distribution services for period 1 July 2010 to 30 June 2015.

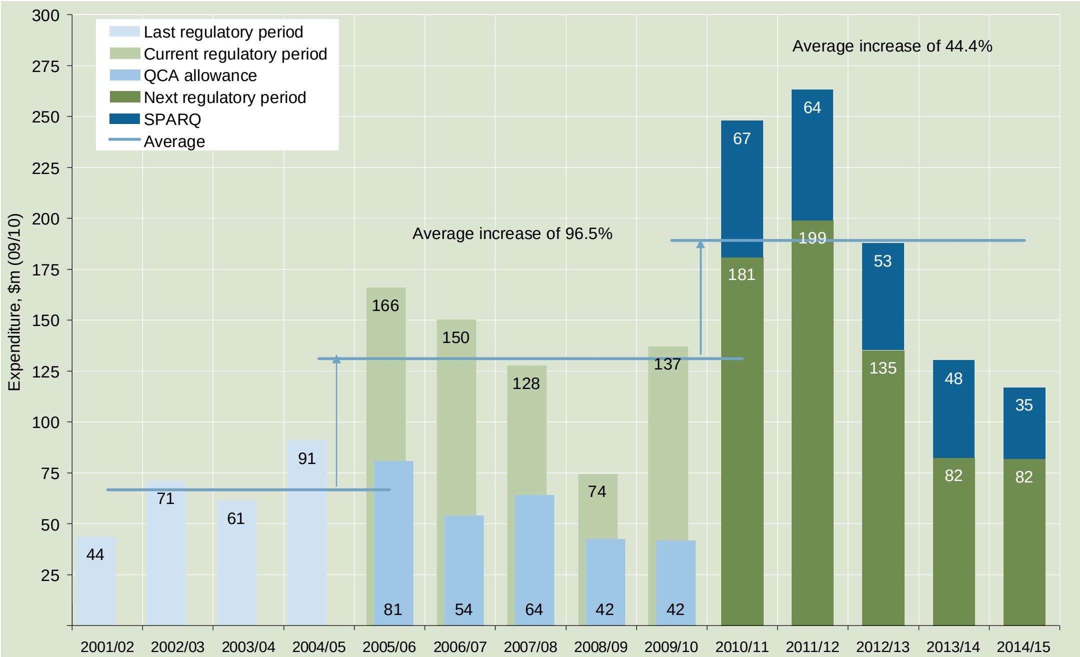

Figure 5.2 Comparison of total non-system capex

Source: Ergon Energy, July 2009 RIN submission model.xls

Ergon Energy's allowance for non-system capex set by the QCA was $282.9m for the current regulatory control period. The actual level of non-system capex for Ergon Energy during this period was $655.1m.

Forecast non-system capex expenditure

Ergon Energy has proposed non-system capex of $679.1.7m for the next regulatory control period, an increase of 3.6% over actual expenditure in the current regulatory control period. The trend in total non-system capex between 2001 and 2015 is illustrated in Figure 5.2.

Table 5.3 Comparison of current and proposed non-system capex and non-system capex (including SPARQ ICT)

Regulatory category	Expenditure ($m)		Change (%)
	Current	Proposed	
Total Non-System Capex	655.2	679.1	3.6
Total Non-System Capex (including SPARQ ICT)	655.2	946.0	44.4

Source: PB analysis

Figure 5.3 shows that the largest increase in the next regulatory control period relates to ICT with an increase in the combined non-system capex for Ergon Energy and SPARQ of 103%, from $177.3m in the current regulatory period to $359.7m in the next regulatory control period. There is also a significant increase in the proposed expenditure for property. Ergon Energy proposes to spend $386.8m on property in the next regulatory control period, a 74.4% increase from the $221.8m capex in the current regulatory control period.

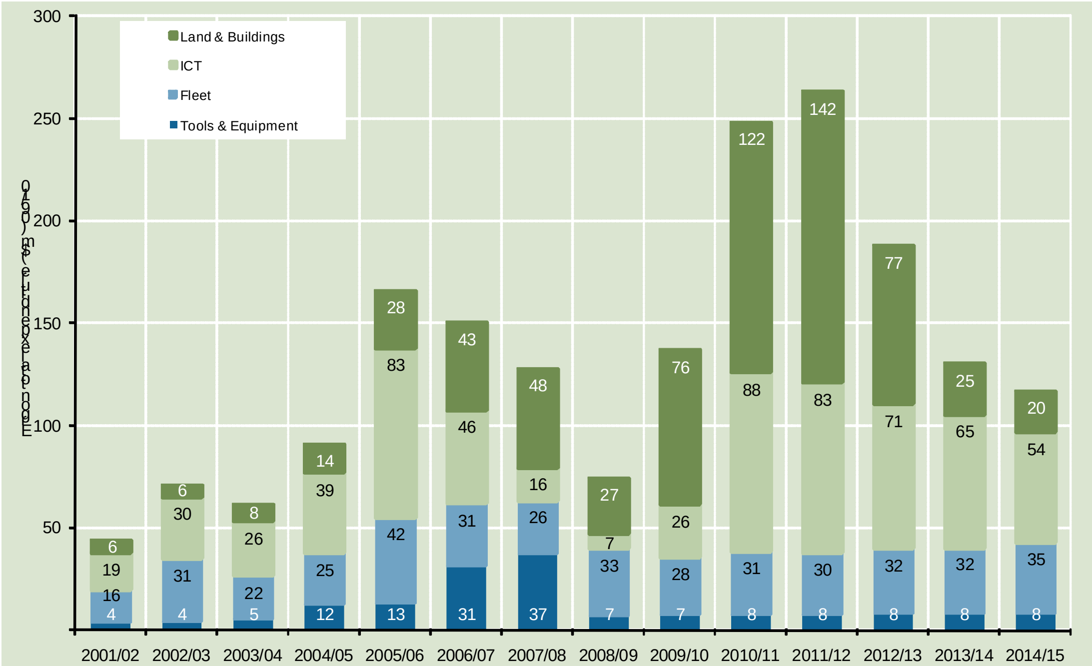

Figure 5.3 Non-system capex (including SPARQ ICT) by category from 2001 to 2015

Source: Ergon Energy, July 2009 RIN submission model.xls

5.2 Information and communication technology (ICT) capex

The majority of Ergon Energy's ICT function is delivered by SPARQ Solutions, an ICT service provider established on 1 July 2004, and jointly owned by Energex and Ergon Energy. Under this arrangement, the provision of ICT services by SPARQ is covered by a service charge to each business. The impact of this is that the capex that would otherwise be incurred by Ergon Energy is capitalised by SPARQ, and amortised into SPARQ's service charge. This service charge is then recognised by Ergon Energy as an overhead and is allocated across the capex and opex as described in section 3.2.

In order to establish the underlying prudence and efficiency of the proposed forecast ICT expenditure (herein referred to as total ICT capex), PB has taken into account the ICT capex proposed by both Ergon Energy and SPARQ (as it relates to Ergon Energy[129]) and considered this as if they were the one proposal. The conclusions of this section as they relate to Ergon Energy's proposed ICT capex are then taken into account in our overall non-system capex recommendations. Similarly, the conclusions of this section as they relate to SPARQ's proposed ICT capex are taken into account in the overhead allocations section of this report (refer section 3.2).

5.2.1 Proposed expenditure

The total ICT capex proposed is $359.8m over the next regulatory control period. Of this amount, $92.9m will be capitalised by Ergon Energy (as submitted in the Regulatory Information Notice (RIN)), and the remaining $266.8m will be capitalised by SPARQ (see Table 5.4).

129 PB notes that not all of SPARQ's proposed capex relates to Ergon Energy, and has only considered that portion that related to Ergon Energy.

Table 5.4 Summary of total ICT expenditure – Ergon Energy and SPARQ

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Ergon Energy ICT expenditure	20.3	18.9	18.2	17.1	18.4	92.9
SPARQ ICT expenditure	57.1	54.1	42.1	34.5	29.9	217.7
Total ICT capex	77.4	73.0	60.3	51.6	48.3	310.6

Note: Ergon Energy's ICT expenditure is inclusive of 'Change Program' and overhead costs. SPARQ ICT expenditure was provided in 2008–09 dollars and escalated by a factor of 1.026 by PB to derive 2009–10 values.

Source: Ergon Energy ICT expenditure sourced from RIN submission. SPARQ ICT expenditure sourced from Ergon PL 706c_EE_Joint ICT AER Initiative List.xls

Figure 5.4 shows the forecast expenditure for total ICT capex for Ergon Energy and SPARQ, along with the historical actual expenditure. PB notes that the expenditure figures from 2008–09 to 2014–15 have been sourced directly from Ergon Energy's joint ICT capital forecast program, and include the ICT capex of both SPARQ and Ergon Energy as outlined above[130]. However, as these figures were provided in 2008–09 dollars, PB has escalated them to reflect real 2009–10 dollars. Figures for the remaining historical years (2001–02 to 2007–08) have been sourced from the RIN.

Figure 5.4 Ergon Energy and SPARQ – total proposed ICT capex

Source: PB analysis of Ergon Energy capital program from RIN

As shown in Figure 5.4, Ergon Energy estimates that its average annual expenditure on ICT will crease from $44.6m in the current regulatory control period to $43.6m in the next regulatory control period, a drop of approximately 2.4%. This compares to a change from $27.8m in the previous regulatory control period to $44.6m in the current regulatory control period, an even higher growth of 60.2%.

In reviewing the trend of the Ergon Energy component of ICT capex specifically (see Figure 5.5), it can be seen that there is a clear reduction in expenditure from the current to the next

130 Ergon Energy August 2009, Ergon PL 706c_EE_Joint ICT AER Initiative List.xls

regulatory control period. That is, Ergon Energy estimates that its average annual expenditure on ICT will decrease from $35.5m to $18.6m, a significant reduction of 47.6%. This compares to a change from $27.8m to $35.5m from the previous to current regulatory control period, a real increase of 27.4%.

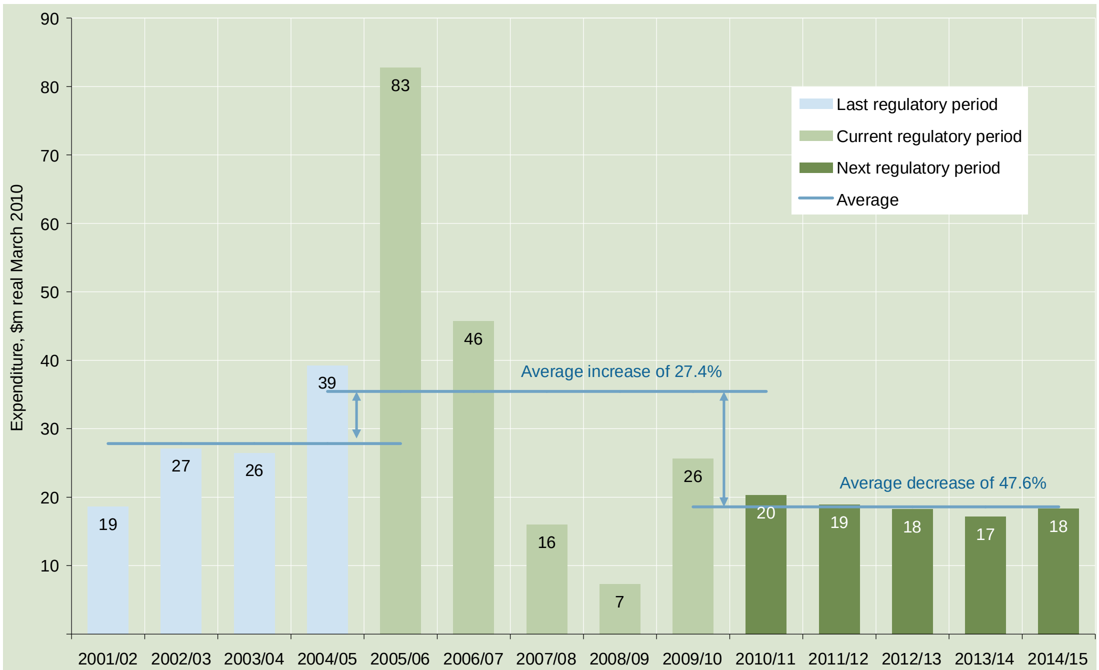

Figure 5.5 Ergon Energy — proposed ICT capex

Source: PB analysis of Ergon Energy capital program from RIN

Ergon Energy's ICT capex is made up of items which Ergon Energy, rather than SPARQ, will continue to purchase in the next regulatory control period, including end use computing assets such as desktop and laptop personal computers and smaller ICT devices. In contrast, SPARQ's ICT capex is made up of 10 investment streams, including governance, risk and compliance (GRC), knowledge management (KM), market systems, customer servicing, energy management, workforce automation (WFA), enterprise resource planning (ERP), network model, planning and design, network operations, and infrastructure and communications.

Of the ten investment streams, infrastructure and communications (24%), followed by enterprise resource planning (14%) and network model, planning and design (14%) are forecast to be the top three investment streams for the next regulatory control period .

5.2.2 Drivers

The drivers for total ICT capex are set out in the Joint ICT Investment Plan[131] (the Plan) for the years 2010 to 2015. Within this Plan, it is stated that as a general rule, SPARQ will 'upgrade' existing applications on behalf of the businesses on a three-yearly basis. According to the Plan, this is driven by the need to maintain existing applications in the face of:

- discontinuation of older versions of software

131 Joint ICT Plan – September 2008 baseline (version 1.2, 19 January 2009)

- business changes
- technology changes.

The Plan also states that IT initiatives associated with replacement, retirement or consolidation of existing applications would be undertaken within a six-to-nine-year cycle. According to the Plan, this is driven by:

- the need to increase functional capabilities and performance
- business changes
- technology changes
- the need to improve efficiencies through consolidation of systems.

5.2.3 Policies and procedures

Ergon Energy's Joint ICT Investment Plan sets out a blueprint to upgrade or replace existing ICT assets to meet operational needs, as well as to enhance and develop new capabilities. The operational role of the Plan is to guide ICT investment decision making for the near to medium term and is a direct input into the annual Consolidated Program of Work (CPoW) planning process which determines respective ICT operating budgets for Ergon Energy.

5.2.4 PB assessment and findings

After receiving the documentation provided as part of the Regulatory Proposal, PB requested further information from Ergon Energy and SPARQ to support the Ergon Energy application, including information outlining historical actuals, current forecast and AER forecast numbers for the 10 investment streams within the Plan; business cases supporting major projects that would provide investment analysis; and other material, including Board papers and information that would illustrate the prudence and efficiency of the ICT program.

In response to the information request, Ergon Energy and SPARQ provided the following new information.

- spreadsheet outlining the bottom-up build of the ICT capex forecast, listing a breakdown of all ICT projects for each of the 10 investment streams
- Joint ICT Plan roadmap development approach and strategic blueprint outlining the framework used to translate business objectives into IT solutions
- other specific documentation outlining the strategic plans and roadmap for selected projects and/or investment streams, such as Infrastructure and Telecommunications, as well as the Distribution Management System (DMS)
- a small sample of business cases, investment short forms, and other supporting documentation, including Ergon Energy's Investment Review Committee Charter setting out high-level guidelines describing the need for business cases.

In particular, Ergon Energy has indicated as part of its submission that there are at least four new areas of capability in the next regulatory control period where an allowance is being sought above the steady state (business-as-usual) expenditure[132]. Subsequent information provided by Ergon Energy for new capabilities in 2008–09 dollars, and escalated to 2009–10 dollars by PB, indicate the following proposed expenditures[133]:

- DMS at a cost of $22.8m ($26m in regulatory proposal)
- field force automation (FFA) at a cost of $19.1m ($18m in regulatory proposal)
- data centre reconfiguration at a cost of $4.9m ($5.4m in regulatory proposal)
- new ICT infrastructure technologies at a cost of $5.1m ($6m in regulatory proposal).

Table 5.5 illustrates the corresponding breakdown of Ergon Energy's proposed expenditure for new capability in the next regulatory period.

Table 5.5 ICT expenditure – new capability initiatives

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
DMS foundation	4.6	4.6	4.6	4.6	4.6	22.8
FFA	6.4	12.7	0.0	0.0	0.0	19.1
Data centre reconfiguration	1.8	3.1	0.0	0.0	0.0	4.9
New ICT infrastructure technologies	0.9	1.2	1.0	1.0	1.0	5.1
Total new capability	13.7	21.6	5.6	5.6	5.6	51.9

Note: Figures were provided in 2008–09 dollars and escalated by a factor of 1.026 by PB to derive 2009–10 values. The Figures also exclude direct costs associated with Change Program and indirect costs associated with overheads. A separate treatment on this issue is discussed in PB's 'observations and findings' section below.

Source: PB analysis of PL706c_EE_Joint ICT AER Initiative List.xls

Based on these new areas of capability, a summary of Ergon Energy's steady state and new capability expenditure is shown in Table 5.6.

Table 5.6 Total ICT expenditure — steady state and new capability

	2010–11	2011–12	2012–13	2013–14	2014–15	Total	% of total
Total steady state	43.5	32.6	36.5	28.9	24.3	165.8	76.2
Total new capability	13.6	21.5	5.6	5.6	5.6	51.9	23.8
Total ICT capex	57.1	54.1	42.1	34.5	29.9	217.7	100.0

Note: Figures were provided in 2008–09 dollars and escalated by a factor of 1.026 by PB to derive 2009–10 values. The Figures also exclude direct costs associated with Change Program and indirect costs associated with overheads. A separate treatment on this issue is discussed in PB's 'observations and findings' section below.

Source: PB analysis of PL706c_EE_Joint ICT AER Initiative List.xls

In assessing the appropriateness of the proposed ICT expenditure, PB has focused its examination on the four new capabilities being proposed by Ergon Energy. In this context, PB reviewed the appropriateness of these new capabilities, having regard to:

132 Ergon Energy, July 2009 Regulatory proposal to the Australian Energy Regulator, distribution services for period 1 July 2010 to 30 June 2015, page 346

133 Bottom up figures were provided in 2008/09 dollars and escalated by a factor of 1.026 to reflect 2009-10 dollars. The revised figures were confirmed and provided in Ergon Energy August 2009, PB.ERG.JTK.09 and Ergon PL 706c_EE_Joint ICT AER Initiative List.

- strategic alignment of individual ICT projects or programs with the broader strategies, policies or other objectives and drivers of Ergon Energy in the next regulatory control period
- project need, materiality and timing
- options analysis that considers a range of feasible options and unit cost estimates for addressing the identified needs and objectives, with clear and logical explanations as to why the preferred option is the most efficient
- financial and/or economic appraisal that demonstrates value for money, cost savings and/or net benefits of the project or program
- procurement and delivery strategy that outlines an appropriate approach to delivering the proposed outcomes in the next regulatory control period.

The areas of assessment have been compiled on the basis of Treasury guidelines for capital business cases across several jurisdictions across Australia, and PB's previous experience in assessing business cases.

SPARQ ICT expenditure

In order to clearly demonstrate that the proposed ICT capex is prudent and efficient, PB anticipates that, at a minimum, business cases would be available for major projects, particularly those proposed within the early years of the next regulatory control period. Where full business cases have not yet been developed, PB would anticipate the existence of preliminary documentation setting out and demonstrating the materiality of the business need, options analysis, and presentation of cost–benefit considerations to support Ergon Energy's capex proposals. PB requested such information for the high-value initiatives, and while Ergon Energy was able to produce some supporting material for the new capability initiatives outlined above that generally demonstrated need, it was found that proposed expenditures were not supported by investment analysis that demonstrated prudence and efficiency (with the notable exception of the data centre initiative). A discussion of PB's findings for each of the new capabilities is outlined below.

DMS Foundations

In response to a request for the business case for DMS Foundations, Ergon Energy provided PB with its DMS Strategy and Roadmap paper, which outlined the purpose, scope, proposed direction and implementation roadmap for its DMS capability. In particular, supplementary information provided noted that Ergon Energy has adopted a 'leader–follower' approach as part of the Joint ICT initiative with ENERGEX. To date, Ergon Energy is currently participating in a Request for Tender (RFT) process being led by ENERGEX for DMS capability. In this context, Ergon Energy has indicated that it has adopted the same forecast value to that estimated and used by ENERGEX (i.e. $22.5m in 2008–09 dollars).[134]

PB accepts the proposition that there are economies of scope to be gained from bundling arrangements between Ergon Energy and ENERGEX via SPARQ in the procurement, implementation and subsequent operations of the DMS initiative, as well as leveraging lessons learnt from ENERGEX's experience. However, a stand-alone analysis, or joint business case explicitly showing the financial or economic benefits to be gained by Ergon Energy is needed to demonstrate the efficiency of the proposed expenditure. Similarly, PB is

134 Ergon Energy August 2009, PB.ERG.JTK.09

of the view that it is not prudent to adopt forecasts estimated by ENERGEX to reflect Ergon Energy's component of the DMS initiative. For example, although Ergon Energy and ENERGEX have the same expenditure values for DMS foundations, the timing of expenditure between the two businesses varies. While Ergon Energy has evenly spread its proposed expenditure over five years, ENERGEX on the other hand has front-loaded its expenditure over the first two years of the next regulatory control period. Thus, PB does not recommend approval of the expenditure as there is insufficient evidence illustrating the efficiency benefits of the initiative.

FFA

Similar to the DMS foundation initiative, Ergon Energy has adopted a 'leader–follower' approach to FFA and has also participated in ENERGEX's RFT process for this initiative.[135] In this context, Ergon Energy has provided an FFA strategy paper outlining its application strategy including the current position of ENERGEX, risks and uncertainties, principles for implementation, benefit areas, scope and phasing.[136] In relation to the forecast, Ergon Energy has advised that it has extrapolated ENERGEX's implementation costs to estimate its expenditure, taking into consideration the scale/breath of the anticipated roll-out for its operations.

A review of the FFA strategy paper and Plan indicates that high-level benefit areas have been identified. While such benefit assessment has been made, no assessment of these benefits relative to the costs of the project has been made. Therefore, the net benefits of the project have not been measured relative to the proposed $19.1m to be expended over the first two years of the forecast period. Furthermore, in other areas where efficiency benefits have been identified, figures have not been populated in the pro forma (e.g. maintenance field crew % savings, and customer services field productivity % savings). On this basis, PB does not recommend approval of the expenditure, as the net benefits have not been demonstrated.

Data centre reconfiguration

Unlike the previous two new capabilities, a joint Ergon Energy and ENERGEX business case was provided to PB for the data centre reconfiguration initiative, which aims to migrate SPARQ's current four data centres to three as a stepping stone to the long-term goal of operating two data centres.[137] The business case considers the financial implications of transitioning from four data centres (base case) relative to the alternative options of three data centres and acceleration to two data centres; it takes into account a range of factors such as strategic fit, technical considerations (e.g. site selection) and associated risks.

To determine the net financial benefit of the initiative, a range of costs were taken into account, including construction, fit-out/establishment, and asset renewal and operating costs. However, as the estimated costs in the business case exceeded those outlined in the proposed expenditure (i.e. $4.9m in regulatory proposal versus total cost of $73m for three data centres and $69.3m for two data centres), Ergon Energy provided clarity on how the proposed expenditure reconciles with the initiative and the Plan — that is, the $4.9m relates directly to ICT fit-out and establishment costs.

Given the available visibility of the project as set out in the overall business case for this initiative, PB generally supports the analysis for the preferred option, which estimates an

135 Ergon Energy August 2009, PB.ERG.JTK.09
136 Ergon Energy August 2009, Enterprise Transformation 2010 0 Field Force Automation Strategy 2009
137 SPARQ Solutions April 2008, Business case – Three Data Centre Reconfiguration (revision number 0.3)

NPV of $29.3m (incremental cost savings of $14.2m) for three data centres. This compares to an NPV of $32.4m for two data centres (incremental cost savings of $11.1m). Thus, PB is satisfied with the need, reasonableness and associated net benefits of the overall initiative, and therefore recommends approval of the expenditure.

New infrastructure ICT technologies

Ergon Energy provided PB with its joint Infrastructure and telecommunications strategy plan (ITSP) 2018–2013[138] and accompanying management summary[139] to support its proposed expenditure for new infrastructure technologies (e.g. software, desktop hardware and storage management). The documentation provides a high-level description of the strategic objectives, domain strategies and key ICT challenges, such as cost pressures. The management summary documentation also outlines a number of benefits that would be achieved from this new capability, including but not limited to enhanced productivity, cost reductions and better value services.

While PB supports the desired outcomes of the initiative, little or no quantification of the net benefits referred to in the documentation was made. That is, no business case was available for review. As such, the underlying prudence and efficiency of the project was not demonstrated by Ergon Energy. Indeed, Ergon Energy's Investment Review Committee Charter clearly states that capital investments of greater than $500,000 require business cases and that all capital-related expenditure is discretionary unless mandated under legislation. Thus, PB does not recommend approval of the expenditure because it is not shown to be either prudent or efficient.

Ergon Energy ICT expenditure

In reviewing appropriateness of Ergon Energy's end use computing assets, PB found that Ergon Energy's RIN submission did not reconcile with the bottom-up build-up of its ICT forecast. In response to a request for clarification for reconciliation[140], Ergon Energy provided additional information, reconciling its bottom-up ICT forecast with that outlined in its submission. Table 5.7 outlines the reconciliation provided to PB.

Table 5.7 Ergon Energy ICT capex reconciliation – bottom-up versus proposed

Asset class	2010-11	2011-12	2012-13	2013-14	2014-15	Total
ICT expenditure in bottom-up forecast of projects capitalised in Ergon Energy	5.5	4.4	3.9	3.0	4.4	21.2
Change program	10.0	10.0	10.0	10.0	10.0	50.0
Subtotal direct costs	15.5	14.4	13.9	13.0	14.4	71.2
Overheads	3.8	3.6	3.5	3.4	3.1	17.4
Escalation	1.4	1.8	2.2	2.5	3.2	11.1
Conversion to 09–10$	(0.4)	(0.9)	(1.3)	(1.7)	(2.3)	(6.6)
ICT expenditure as submitted in the RIN	20.3	18.9	18.2	17.1	18.4	92.9

Source: PL840c_EE_ICT_Expenditure Reconciliation_1Sep09.xls

138 Ergon Energy August 2009, PL714c_SPARQ_ITSP 2008-2013 v1.0.pdf
139 Ergon Energy August 2009, PL715c_SPARQ_ITSP 2009-2015 Management Summary V1.1
140 Ergon Energy August 2009, PBERG.JTK.14 IT SPARQ

As shown in Table 5.7, the reconciliation outlines that Ergon Energy has included direct costs associated with implementing its end use computing assets in terms of a 'Change program' in the amount of $50m over the next control period, as well as other indirect overhead costs amounting to $17.4m, to derive its overall RIN expenditure submission of $92.9m.

When providing this information, Ergon Energy provided no justification for the 'Change program' in its submission. As the 'Change program' capex is more than double that of the end use computing assets (accounting for approximately 54% of total end use computing expenditure submitted), PB would expect, at a minimum, that a rationale, or key elements of capital business case (e.g. net benefits appraisal), be presented for our review to demonstrate that the expenditure is both prudent and efficient.

On this basis, PB is not satisfied that the additional expenditure above and beyond that directly relating to end use computing assets is justified. Consequently, PB recommends that expenditure directly relating to end use computing assets only be approved.

5.2.5 PB recommendations

PB has reviewed Ergon Energy's ICT capex proposal for the next regulatory control period. In undertaking our review, PB sought documentation demonstrating that the proposed expenditure is efficient in meeting the demonstrated business needs, and that the expenditure was prudent given these needs. As discussed above, Ergon Energy and SPARQ were unable to produce business case documents to demonstrate the prudence and efficiency of the proposed total ICT expenditure as it relates to (i) new capabilities (with the notable exception of data centre reconfiguration) and (ii) change program and overheads for end use computing assets capitalised within Ergon Energy.

Consequently, PB recommends a business-as-usual ICT expenditure forecast, with an additional allowance for the new capability initiative: the data centre reconfiguration. Table 5.8 sets out PB's recommendation for ICT expenditure capitalised within SPARQ. PB notes that expenditure in this table is capitalised within SPARQ and passes through to Ergon Energy as a service charge, as discussed in section 3.2.

Table 5.8 Recommended ICT expenditure for SPARQ capex

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Ergon Energy proposal	67.2	64.1	52.5	47.9	35.2	266.9
PB adjustment	(11.8)	(18.5)	(5.6)	(5.6)	(5.6)	(47.1)
PB recommendation	55.4	45.6	46.9	42.3	29.6	219.8

Source: PB analysis

In relation to Ergon Energy, PB recommends that the proposed expenditure be adjusted to reflect costs directly relating to investment in end use computing assets only — that is, excluding costs associated with the change program. PB has based the recommendation for Ergon Energy's capex for direct investment in end use computing assets on the proposed costs outlined in Table 5.7 with uplift to account for the related proportion of the overheads, escalation and conversion factors[141]. Table 5.9 sets out PB's recommendations for Ergon Energy's ICT expenditure for the next regulatory control period. PB notes that these adjustments are applied to the gross pool of overheads in accordance with the analysis in section 3.

Table 5.9 Recommended ICT expenditure for Ergon Energy capex

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposal	20.3	18.9	18.2	17.1	18.4	92.9
PB adjustment	(13.1)	(13.1)	(13.1)	(13.1)	(12.8)	(65.2)
PB recommendation	7.2	5.8	5.1	4.0	5.6	27.7

Source: PB analysis

5.3 Property capex

The Ergon Energy property expenditure category comprises the subcategories[142]:

- land improvements
- office equipment and furniture (excluding office equipment and furniture for new buildings)
- land and easements
- buildings (including office equipment and furniture for new buildings).

These expenditure categories are considered in the following sections.

5.3.1 Proposed expenditure

Ergon Energy's proposed and historical costs by expenditure subcategory are provided in Table 5.10.

Ergon Energy's proposed total expenditure in the next regulatory control period for the categories of property, office furniture and equipment is $386.8m. This represents a 74.4% increase from $221.8m capex in the current regulatory control period. PB has used the four categories provided in the RIN to make the overall property and office furniture and equipment comparison between current and next regulatory control periods.

141 The uplift was calculated by multiplying (i) the percentage proportion of ICT investment over total sub-total direct costs (i.e. 29.7%) by the (ii) sum of the indirect costs (i.e. $21.7m) to derive the dollar contribution of the ICT expenditure (see Table 5.8). This amount, equating to $6.46m, was subsequently added to the ICT investment of $21.2m to derive a recommended expenditure of $27.7m.

142 Ergon Energy Regulatory Proposal 2010-15 - CONFIDENTIAL.pdf p191, RIN Submission model.xls

Table 5.10 Ergon Energy– proposed and historical property capex by category

Current expenditure	2005-06	2006-07	2007-08	2008-09	2009-10	Total
Land improvements	0.0	1.6	5.7	0.0	0.0	7.3
Office equipment and furniture (excludes office equipment and furniture for new buildings)	0.9	2.2	6.9	0.8	0.5	11.3
Land and easements	0.2	11.6	1.2	0.5	1.5	15.0
Buildings (includes office equipment and furniture for new buildings)	26.9	27.5	34.6	25.8	73.5	188.3
Total current expenditure	28.0	42.9	48.4	27.1	75.5	221.9
Proposed property expenditure	**2010-11**	**2011-12**	**2012-13**	**2013-14**	**2014-15**	**Total**
Land improvements	0.0	0.0	0.0	0.0	0.0	0.0
Office equipment and furniture (excludes office equipment and furniture for new buildings)	0.5	0.5	0.5	0.5	0.5	2.5
Land and easements	0.0	0.4	0.0	2.1	0.0	2.5
Buildings (includes office equipment and furniture for new buildings)	121.6	141.3	76.6	22.2	19.8	381.5
Total proposed expenditure	122.1	142.2	77.1	24.8	20.3	386.5

Ergon Energy has forecast no expenditure for 'land improvements' in the next regulatory control period.

Ergon Energy's proposed expenditure for office equipment and furniture (excluding office equipment and furniture for new buildings) in the next regulatory control period is $2.6m, significantly lower than the $11.3m capex in the current regulatory control period. One reason for the significant difference is that the 'buildings' category includes forecast expenditure for office equipment and furniture for new buildings[143] in the next regulatory period. In contrast, the historical capex for 'office equipment and furniture' includes all expenditure on these items (both for new and existing buildings) and is therefore not a like for like comparison. Due to Ergon Energy's proposed extensive building program including new buildings, and therefore the inclusion of the bulk of new office equipment and furniture in the 'buildings' category, the 'office equipment and furniture category is based on the 2009-10 expenditure levels and is significantly lower than the historical average expenditure level. Ergon Energy advise that the forecast expenditure will provide sustainable levels for the next regulatory control period[144].

Ergon Energy has bundled the 'land and easements' expenditure category together with 'buildings'[145] in the Regulatory Proposal and PB has therefore considered this as one category referred to as 'buildings, land and easements' for the purposes of this review. Ergon Energy's proposed expenditure for 'buildings, land and easements' is $384.2m in the next regulatory control period. 89.1% higher than the $203.2m capex for these categories in the current regulatory control period.

143 Ergon Energy Regulatory Proposal 2010-15 - CONFIDENTIAL.pdf p235
144 Ergon Energy Regulatory Proposal 2010-15 - CONFIDENTIAL.pdf p235
145 Ergon Energy Regulatory Proposal 2010-15 - CONFIDENTIAL.pdf p228

Figure 5.6 provides the graphical illustration of the 74.4% increase in overall property expenditure forecast for the next regulatory control period.

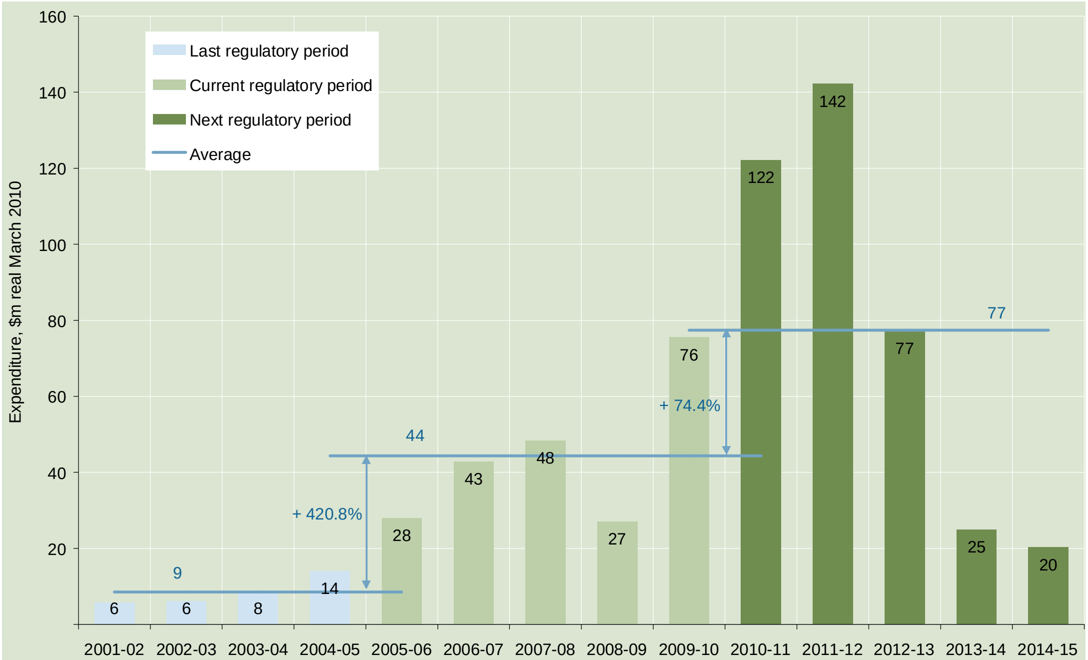

Figure 5.6 Ergon Energy– proposed property capex

Source: PB analysis

5.3.2 Drivers

Ergon Energy advised that the increase in proposed property expenditure is driven by several factors:

- the ageing property portfolio — only one new building has been built since the merger that created Ergon Energy in 1999[146]
- capital refurbishments have not been proactive — many properties require major refurbishments for which significant capital investment is required to bring current buildings up to building code standards[147]
- environmental — Ergon Energy is taking a proactive approach to constructing ecologically sustainable developments[148]
- legal compliance — the Ergon Energy risk profile for facilities management and construction is high[149]
- shareholder drivers — Ergon Energy needs to demonstrate ongoing operational excellence[150].

146 PL594c_EE_Board Paper_Corp Property Strategy_Cash Flow Impacts 28Aug06.pdf
147 ibid
148 AR319c_EE_Corporate Property Strategic Plan_V23_28Aug06.pdf
149 ibid
150 ibid

5.3.3 Policies and procedures

Ergon Energy has developed a Corporate Property Strategic Plan[151] that articulates the company's plan to expand, upgrade or replace existing facilities to better meet operational needs, better manage the ageing asset base and overcome environmental issues. Ergon Energy has adopted a hub-and-spoke model as its overarching corporate property strategy. Hubs and large spokes will contain all administrative work not directly associated with fieldwork[152]. Major hubs will contain specialist areas such as call centres and training facilities. Smaller spokes will contain area management, warehousing, local training and support[153].

5.3.4 PB assessment and findings

Ergon Energy's forecast land, buildings and easements expenditure of $384.2m over the next regulatory control period largely consists of the major expenditure items shown in Table 5.11 totalling 92% of this amount. The majority of the major buildings expenditure is proposed to occur during the first 2 years of the period.

Table 5.11 Proposed major building expenditures

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Northern region (Townsville $60m, Cairns $20m)*	36.1	42.9	16.3	14.7	14.3	124.3
Central region (Rockhampton $54m, Data Centre $20)*	38.2	32.1	47.1	2.5	0.0	119.9
Southern region (Toowoomba $12m, Maryborough $25m)*	37.5	53.9	10.3	5.7	3.4	110.8
Total	111.8	128.9	73.7	22.9	17.7	355.0

** The building program[154] detail provided by Ergon Energy does not contain an exact correlation with the major building projects listed in Ergon Energy's submission[155].*

Source: PB analysis

Expenditure forecasts are based on Ergon Energy's property strategy that was created and approved in 2006[156]. Ergon Energy formed a single entity in 1999 via an amalgamation of six separate businesses. During this period there was not a holistic property management approach, resulting in a general under-investment in this category[157]. Ergon Energy's property group was formed in 2006[158] and created the property strategy driven by the need to manage the property portfolio in a holistic sense and to align with the operational business strategy[159]. Ergon Energy's high-level business case for the strategy considers four options:

- continue the current property management approach

151 AR319c_EE_Corporate Property Strategic Plan_V23_28Aug06.pdf
152 Ergon Energy Regulatory Proposal 2010-2015.pdf p230
153 ibid
154 PB.ERG.CA.23 – 15 Year Budget 26-11-08 Vern.xls
155 Ergon Energy Regulatory Proposal 2010-2015.pdf pp232-233
156 PL640c_Board Paper 0610-32_Corporate Strategy Plan_27Oct06.pdf
157 PL594c_EE_Board Paper_Corp Property Strategy_Cash Flow Impacts 28Aug06.pdf
158 PB.ERG.CA.18 – Email from PRICE Carmel (WB) 4/8/2009
159 PL640c_Board Paper 0610-32_Corporate Strategy Plan_27Oct06.pdf

- do nothing
- adopt the building program set out in Ergon Energy's property strategy
- adopt an accelerated building program.

In 2006, the Ergon Energy Board selected and approved the adoption of the building program option set out in Ergon Energy's property strategy[160]. PB requested the analysis and detailed information supporting these options, in particular the selected option; however Ergon Energy was unable to provide this information[161]. Ergon Energy has provided a high-level options analysis but was not able to provide the information on which the options were built[162]. PB considers the high level options analysis is insufficient to demonstrate that the selected strategy is prudent and efficient.

PB would expect that, to demonstrate good governance and sound investment decision making, business cases would be available for major building projects such as those listed in Table 5.11 particularly as this expenditure is proposed within the early years of the next regulatory control period. Where full business cases have not yet been developed, PB would also expect that documentation setting out and demonstrating the business need, considering high-level options, or presenting the cost–benefit considerations would be available to support the capex proposals. Therefore, PB requested business case documentation or supporting documentation for the high-value individual projects. Ergon Energy was unable to provide these[163].

Ergon Energy advised during discussion that business cases and supporting documentation for individual projects have not yet been developed. Ergon Energy intends to develop such documentation closer to project realisation. Neither could Ergon Energy provide business case or supporting documentation for the 2010–11 proposed expenditure, as the current extent of its supporting documentation consists primarily of building concept designs with externally sourced high-level estimates.

Building capex proposed represents a 113% increase over historical levels, with the majority of this capex proposed for the first two years of the period. The proposed capex of $142.2m in 2011–12 represents a 291% increase over historical capex to date[164]. Ergon Energy provided information indicating that significant improvement has been achieved[165] in delivering the property program since the formation of the property group. Despite this, PB is concerned about the very ambitious increase in Ergon Energy's proposed building program during the early years of the next regulatory control period.

Ergon Energy advised that it recognises the magnitude of its proposed program, particularly the high levels forecast in the first two years of the regulatory control period and that the

160 *Ibid*.
161 PB.ERG.CA.5- Email from PRICE Carmel (WB) 29/7/2009, PB.ERG.CA.33 – Email from PRICE Carmel (WB) 17/8/2009
162 *Ibid*.
163 PB.ERG.CA.34 – Email from PRICE Carmel (WB) 18/8/2009
164 PB.ERG.CA.16 – Ole0.bmp: Highest expenditure historically occurred in 2007/08 at $45m. This does not include the current year delivery projected at $90m. From the RIN Submission model.xls, this equates to $48.4m (real 09–10).
165 PB.ERG.CA.16 – Ole0.bmp, PL594c_EE_Board Paper_Corp Property Strategy_Cash Flow Impacts 28Aug06.pdf

proposed program could be rearranged and deferred[166]. PB requested information on how building projects had been prioritised, but this was not provided[167].

The Ergon Energy building proposal[168] does not include any clear decisions regarding disposal of assets (land and buildings) that will no longer be required as a consequence of the proposed building program[169]. Ergon Energy has advised that revenue realised from asset disposal will be recorded on the profit and loss statement[170]. However, the treatment of the recovered value from Ergon Energy's property portfolio under the proposed building strategy is noted in Ergon Energy's property strategy[171] as well as an Ergon Energy Board paper[172] that states:

> The conservative current estimated value of surplus unimproved assets realised through the strategy is $50M. This value would be enhanced by exploring options in the second phase of the strategy.

PB requested further detail regarding the $50m estimated surplus and Ergon has revised the estimated surplus to $10.9m[173] in the next three to seven years because it is not consolidating some non-CBD locations[174]. PB expects that a change in strategy with such significant implications would warrant updating the 2006 property strategy in line with corporate planning cycles and as stated in the property strategy[175]. The update of the property strategy would also be warranted in order to demonstrate alignment between the strategy and Ergon Energy's regulatory proposal. The 2006 property strategy provided includes option values that do not reflect the proposed building program value[176].

Development of a property management strategy should consider how to achieve and maintain maximum value from the property portfolio, while maintaining the required standards of service for the asset. This would require that the assessed value of existing property holdings be taken into account in the development and management of the property strategy.

During the course of this review, PB found the following issues pertaining to the proposed building capex documentation:

- PB found that the buildings strategy was three years out of date had not been updated to take into account changes that have occurred in the interim period that affects the buildings[177].
- The management options[178] presented did not include sufficient detail to understand how the options were ranked and Ergon Energy were unable to provide the data[179] used to generate the options.

166 Discussions with Ergon 5/8/2009
167 PB.ERG.CA. 32 – Ergon Energy Issues Register.xls
168 PL594c_EE_Board Paper_Corp Property Strategy_Cash Flow Impacts 28Aug06.pdf, PL640c_Board Paper 0610-32_Corporate Strategy Plan_27Oct06.pdf, AR319c_EE_Corporate Property Strategic Plan_V23_28Aug06.pdf, RIN Submission model.xls
169 PB.ERG.CA.8 – Email from PRICE Carmel (WB) 29/7/2009
170 PB.ERG.CA.8 – Email from PRICE Carmel (WB) 29/7/2009
171 AR319c_EE_Corporate Property Strategic Plan_V23_28Aug06.pdf p10
172 PL640c_Board Paper 0610-32_Corporate Strategy Plan_27Oct06.pdf
173 PB.ERG.CA.35 –Email from PRICE Carmel (WB) 18/8/2009. Note: the value is assumed to be in 09–10 dollars as it is unspecified.
174 *Ibid*.
175 AR319c_EE_Corporate Property Strategic Plan_V23_28Aug06.pdf p11
176 AR319c_EE_Corporate Property Strategic Plan_V23_28Aug06.pdf, RIN Submission model.xls
177 PB.ERG.CA.35 –Email from PRICE Carmel (WB) 18/8/2009.

- Prioritisation of the building works[180] consisted of a list of works and a commencement date. No data was provided to support a prioritisation had taken place.

- The ability to deliver the program of building works was presented as a list of commencement dates. PB were not provided with supporting data on how Ergon Energy were going to manage the increase workload and the tight deadlines presented in the plan. The information provided was insufficient to support that the program of works could be delivered[181].

The proposed expenditure represents a considerable increase over historical levels. In addition, although Ergon Energy has recognised that the realisation of the value of surplus assets is significant, this value has not been taken into account in the development of the property strategy or proposed building program. PB finds that, as a result of the lack of supporting information and integration of the property strategy and building program, the proposed Ergon Energy property program is not prudent or efficient.

5.3.5 PB recommendations

The proposed building, land and easement expenditure has not been demonstrated to be prudent or efficient; PB therefore recommends an expenditure allowance in line with Ergon Energy's business-as-usual costs.

To establish the business-as-usual costs, PB examined the impact of removing the major building projects that were found to be not prudent and efficient and compared this to the historical expenditures. A reduction of $191.0m results after removing the major building projects listed in Table 5.11 (Townsville, Cairns, Rockhampton, Data Centre, Toowoomba and Maryborough). The average expenditure of the current regulatory control period, with the exclusion of the 2009-10 year[182], results in a reduction of $203.8m.

PB considers Ergon Energy's expenditures for the next regulatory period are likely to increase due to forced maintenance as a consequence of not undertaking or deferring the proposed building program. Hence, PB is of the view that a minimum reduction of $191.0m, in line with the removal of the major projects, would lead to expenditures that are prudent and efficient.

Table 5.12 shows PB's recommended expenditure for property for each year of the next regulatory control period.

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178 PL594c_EE_Board Paper_Corp Property Strategy_Cash Flow Impacts 28Aug06.pdf.
179 PB.ERG.CA.33 – response to question requesting the analysis undertaken to support the options
180 PL716c – 15year budget spreadsheet 26-11-08 Vern.xls
181 PL595_EE_Delivery of Corp Property Program_30Jul09.pdf
182 As expenditure in the current period is quite volatile, the 2009-10 expenditure is excluded as it is a forecast and our review process has not substantiated the current year expenditure. It also represents a considerable increase over the actual expenditure for the remainder of the current period. PB notes that the 2008-09 year expenditure also contains a portion that was forecast by Ergon Energy at the time of submitting its Regulatory Proposal; however, this forecast was based on committed programs of work and is considered to be accurate.

Table 5.12 Recommended capex for property

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy Proposal	122.2	142.2	77.1	24.9	20.4	386.8
PB adjustment	(83.0)	(103.0)	(37.9)	14.3	18.8	(190.8)
PB recommendation	39.2	39.2	39.2	39.2	39.2	196.0

Source: PB analysis

5.4 Fleet capex

The Ergon Energy fleet expenditure category comprises one subcategory — motor vehicles.

5.4.1 Proposed expenditure

Proposed expenditure for fleet has increased from $160.2m in the current regulatory control period to $160.5m in the next regulatory control period. This is an average escalation adjusted increase of 0.2% between the two regulatory periods. The trend in fleet expenditure between 2001 and 2015 is illustrated in Figure 5.7.

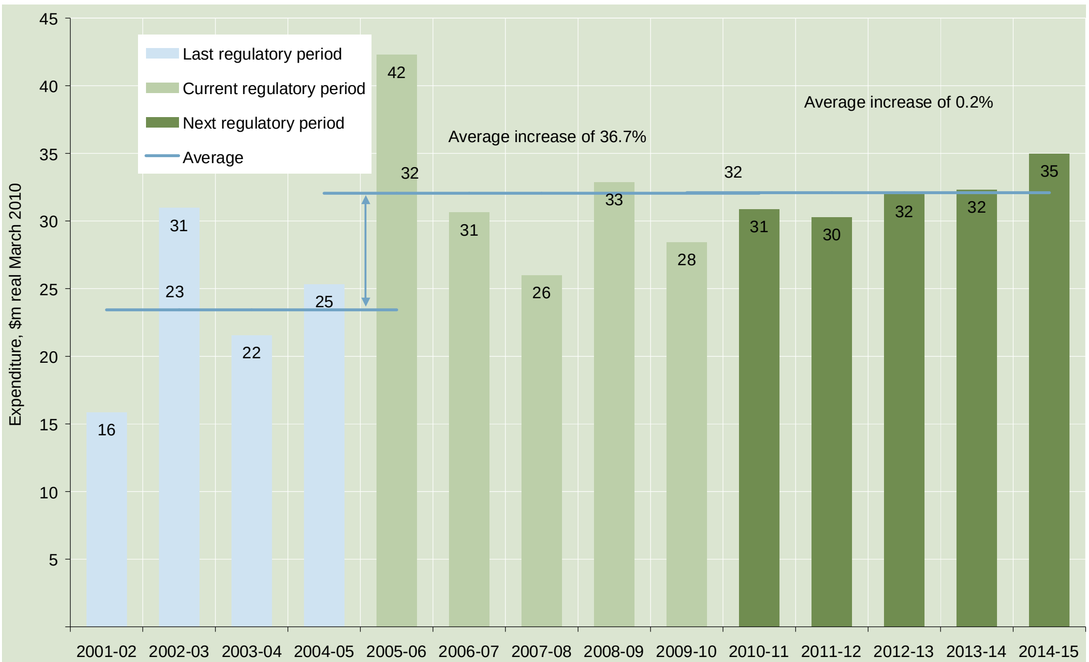

Figure 5.7 Ergon Energy's fleet capex

Source: PB analysis

5.4.2 Drivers

Ergon Energy states that the proposed fleet expenditure is based on business-as-usual practice, and that this expenditure forecast is derived from the cost of replacing existing vehicles, consistent with forecast staff requirements[183].

183 Ergon Energy Motor Vehicle Use Policy, EP78 Version 3

5.4.3 Policies and procedures

Ergon Energy's *Fleet management team strategic plan*[184]' provides an outline of the processes and practices by which Ergon Energy determines its current and projected vehicle fleet size and composition. A motor vehicle use policy document[185] also exists that references another document named 'Fleet Policy EP18' which Ergon Energy was unable to locate[186]. Ergon Energy has recently altered its policies on light vehicles, increasing from three-year to four-year replacements as a consequence of a benchmarking study[187] undertaken by UMS in 2008.

Ergon Energy's fleet plan for the next regulatory period is aligned with its *Fleet asset management strategy*. The plan employs an approach in accordance with Ergon Energy's Get Fit initiative, a policy that aims to reduce capital and opex on motor vehicles[188].

5.4.4 PB assessment and findings

PB considers that prudent and efficient fleet management would demonstrate:

- alignment of the fleet strategy to the fleet plan for the next regulatory control period
- documented strategic alignment
- that timing of expenditure is driven by need, in accordance with the company vehicle policy
- that the quantity and type of vehicles in the existing fleet is appropriate to the size and scale of the business
- that motor vehicles have been acquired and disposed of in a cost-efficient manner.

The timing of fleet expenditure is driven by Ergon Energy's motor vehicle replacement policy[189]. This is conducted using age-based replacement criteria by vehicle type. PB verified adherence to this policy through analysing Ergon Energy's *2007/08 Fleet asset management annual review*[190] and discussions with Ergon[191] regarding this document. PB was satisfied with Ergon Energy's explanations for higher-than-forecast expenditure in 2007–08 for some motor vehicle categories. For instance, the threefold increase in expenditure on EWP plant compared with forecast expenditure on this motor vehicle type was due to the delivery of units ordered in previous financial years[192].

To determine whether the quantity and type of vehicle purchases are appropriate for the size and scale of the business, PB reviewed the fleet benchmarking and modelling report prepared by UMS. PB notes that the UMS report recommended a number of actions for Ergon Energy's fleet management, including extension of the replacement policy for light

184 Ergon Energy Group Services Fleet Management Team Strategic Plan, V5, 23 March 2009
185 Ergon Energy Motor Vehicle Use Policy, EP78 Version 3
186 PB.ERG.CA.12 – Email from PRICE Carmel (WB) 3/8/2009
187 UMS Group, Ergon Energy Fleet Benchmarking and Modelling, Final Report
188 UMS Group, Ergon Energy Fleet Benchmarking and Modelling, Final Report, p. 3
189 Ergon Energy 2009, *Fleet management asset management strategy, V5: future state assessment* (20 March 2009)
190 Ergon Energy 2008, *2007/08 Fleet asset management annual review*, p. 6 (August 2008)
191 Discussions with Ergon Energy 05/08/2009
192 Ergon Energy 2008, *2007/08 Fleet asset management annual review*, p. 6 (August 2008)

vehicles from three to five years[193]. PB notes that Ergon Energy's fleet management asset management strategy reflects the new 4 year replacement cycle for passenger vehicles, and 2WD and 4WD light commercial vehicles[194]. Ergon Energy advised PB that the forecast expenditure for replacement of light vehicles is based on the updated policy[195].

The UMS report benchmarked the size of Ergon Energy's fleet against 21 Australian and international utilities[196]. The comparative analysis indicated that (adjusting for geographic area, customer density and line distance) Ergon Energy could potentially reduce its fleet by 95-99 vehicles to achieve a 3.5% decrease in capital expenditure[197]. Ergon Energy's Investment Review Committee has examined the UMS recommendation and committed to a 7.0% (200 units) decrease in mobile assets[198] over the 2008-09 to 2011-12 period.

With respect to the cost efficiency of the acquisition and disposal of fleet vehicles, PB notes the fleet benchmarking and modelling conducted by UMS where Ergon Energy is considered an industry average performer in supply chain strategy[199]. Ergon Energy's procurement follows the State Purchasing Policy for quotes and tenders including value for money consideration as evaluation criteria[200]. Discussions with Ergon Energy indicated that quotes are sought from a number of fleet suppliers for each motor vehicle type to ensure that fleet are purchased at the lowest cost[201]. PB concludes that Ergon Energy's procurement processes should result in efficient costs for fleet capex.

To form a view on the quantity of vehicles PB considered Ergon Energy's workforce plan and forecast employees numbers during the next regulatory control period. Ergon Energy has significantly increased staff numbers during the current regulatory control period from 3,360 to 4,489 staff[202]. The workforce plan indicates that staff numbers are forecast to decrease to 4,439[203] i.e. during the next regulatory control period. PB notes that expenditure in the current period has been volatile and shows a significant increase compared with the previous regulatory control period. The fleet capex does not correlate to the increase in staff numbers on a year by year basis. Given vehicle replacement frequencies differ for different categories (eg 3, 4, 6, 8 and 10 year frequencies in use) it is not possible to draw concrete conclusions with respect to expenditure volatility. PB notes that UMS recommends a phasing in of the extension of replacement frequencies to smooth expenditure peaks[204]. At a high level PB would expect that fleet requirements and related expenditure should decrease on a relatively proportional basis to the reduction in staff numbers.

On the assumption that fleet expenditure is proportional to employees PB analysed cost per employees over the current and forecast regulatory control periods. The analysis indicated that fleet expenditure per employee is forecast to decrease in the next regulatory control period. The average fleet expenditure per employee for the current regulatory control period is $7.7k compared to the forecast of $7.1k for the next regulatory control period[205]. This represents an 8% decrease in expenditure per employee. This is congruent with the

193 UMS Group, Ergon Energy Fleet Benchmarking and Modelling Final Report, p. 7
194 AR435c_EE_Fleet Management Asset Management Strategy p18, 20, 22
195 Discussion with Ergon Energy 05/06/2009
196 UMS Group, Ergon Energy Fleet Benchmarking and Modelling Final Report, p. 19
197 UMS Group, Ergon Energy Fleet Benchmarking and Modelling Final Report, p.5
198 AR435c_EE_Fleet Management Asset Management Strategy p36
199 UMS Group, 2008, Fleet benchmarking and modelling – Final Report.pdf, p10
200 AR325_EE_Fleet Management Strategic Plan V5 23Mar09.pdf
201 Discussions with Ergon Energy 05/08/09
202 PL725c_EE_Staff_Numbers_At 30_Jun_04 to 30_Jun_15.pdf
203 PL725c_EE_Staff_Numbers_At 30_Jun_04 to 30_Jun_15.pdf
204 UMS Group, 2008, AR034c UMS Fleet benchmarking and modelling final report 7Aug.pdf p33
205 AER.PB.Q.CA.36.pdf. PB Analysis based on total employees in the current regulatory control period and the sustained growth scenario in the next regulatory control period.

reduction in fleet expenditure as recommended by UMS (95-99 vehicles resulting in 3.5% decrease in expenditure) and Ergon Energy's decision to reduce vehicles by 200 (resulting in a decrease of 7% in expenditure).

On the basis that Ergon Energy has demonstrated fleet expenditure to be in line with vehicle replacement needs consistent with staff requirements and is proactive in taking opportunities to reduce fleet expenditure through independent assessment, PB concludes that Ergon Energy's fleet expenditure is prudent and efficient.

5.4.5 Recommendations

PB has concluded that Ergon Energy's proposed expenditure on motor vehicles is prudent and efficient. Therefore, PB recommends no adjustment in fleet expenditure for the next regulatory control period, as shown in Table 5.13.

Table 5.13 Recommended fleet capex

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposal	30.9	30.3	32.0	32.3	35.0	160.5
PB adjustment	0.0	0.0	0.0	0.0	0.0	0.0
PB recommendation	30.9	30.3	32.0	32.3	35.0	160.5

Source: PB analysis

5.5 Tools and equipment capex

The Ergon Energy tools and equipment expenditure category comprises one subcategory — plant and equipment.

Proposed expenditure for tools and equipment has decreased by 59% to $38.8m (compared with expenditure of $95.8m in the current regulatory control period). The trend in expenditure on tools and equipment between 2001 and 2015 is illustrated in Figure 5.8.

Figure 5.8 Ergon Energy's tools and equipment capex

Source: PB analysis

5.5.1 Drivers

Ergon Energy's key driver for expenditure on tools and equipment is to ensure that Ergon Energy employees have the tools and equipment to perform their work in a safe and efficient manner[206]. Ergon Energy's expenditure is closely aligned to expenditure on the Capital Works Program[207].

5.5.2 Policies and procedures

Ergon Energy's policy in relation to tools and equipment outlines the processes and practices by which it determines its current and projected tooling and equipment levels.

Purchases of tools and equipment are expensed (i.e. not capitalised) and are budgeted for by managers in the annual budget process[208]. Ergon Energy has already developed a number of tools and equipment standards, and the asset management plan specifically includes standardisation of tools and equipment to ensure fitness for purpose and provide best value for money. Standardisation allows Ergon Energy to provide flow-on savings in areas such as standardisation of vehicle fit-outs[209].

Under Ergon Energy's previous Enterprise Bargain Agreement (EBA), tool and equipment allowances were paid to some staff; this arrangement will change under the new EBA in which Ergon Energy will provide all tools and equipment to staff[210]. Ergon Energy's procurement procedures for tools and equipment reference the *Tools and equipment manual* to ensure adherence to standards[211]. Ergon Energy's tools and equipment framework[212]

206 AR447c_EE_Tools and Equipment Forecast Report_16Feb09.pdf
207 AR447c_EE_Tools and Equipment Forecast Report_16Feb09.pdf p. 3
208 AR447c_EE_Tools and Equipment Forecast Report_16Feb09.pdf
209 *Ibid*.
210 *Ibid*.
211 *Ibid*.

contains relevant safety standards and procedures for introduction of new tools, procurement, maintenance, testing and disposal.

5.5.3 PB assessment and findings

Ergon Energy has forecast expenditure of $38.8m on tools and equipment over the next regulatory control period. This represents a 59% decrease relative to the current regulatory control period. Discussions with Ergon Energy indicated that the higher historical expenditure level was driven by greater expenditure on very expensive tool and equipment items in the current regulatory control period together with productivity factor improvements proposed in the next regulatory control period[213].

PB conducted a high-level review of this expenditure but did not investigate any of the drivers for change in expenditure. This is due to the fact that expenditure on tools and equipment has decreased and is relatively small in the context of overall non-system capex.

5.5.4 PB recommendations

PB recommends no adjustment to the expenditure proposed by Ergon Energy for tools and equipment, as outlined in Table 5.14.

Table 5.14 Recommended expenditure for tools and equipment

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposal	7.5	7.6	7.8	7.9	8.0	38.8
PB adjustment	0.0	0.0	0.0	0.0	0.0	0.0
PB recommendation	7.5	7.6	7.8	7.9	8.0	38.8

Source: PB analysis

5.6 Summary of findings and recommendations

This section presents a summary of PB's key findings and recommendations relating to Ergon Energy's non-system capex (including SPARQ ICT) for the next regulatory control period. PB's recommended non-system capex is set out in Table 5.15.

Key findings

End use computing assets

Ergon propose to spend $92.9m on end use computing assets in the next regulatory control period, an average decrease of 47.6% compared with the current regulatory control period.

PB recommends a reduction of $65.2m to the proposed expenditure to reflect costs directly relating to investment in end use computing assets only – that is excluding costs associated with Change Program for which no information was provided to demonstrate prudence or efficiency.

212 AR073_EE_BS001700R100_Managing Tools & Equipment Framework_V.pdf
213 Ergon Energy year, Regulatory proposal to the Australian Energy Regulator: distribution services for period 1 July 2010 to 30 June 2015, section 23.7.5

SPARQ ICT

SPARQ Solutions propose to spend $266.8m on Information & Communications Technology in the next regulatory control period in order to provide contracted services to Ergon Energy.

PB recommends a reduction of $47m to the proposed capex as SPARQ and Ergon are unable to demonstrate prudency and efficiency of ICT expenditure relating to new capabilities (with the exception of Data Centre Reconfiguration). This reduction in capex impacts on the service charge which forms part of the overheads as is discussed in section 3.2.

Property

Ergon proposes to spend $386.8m on property in the next regulatory control period, an average increase of 74.4% compared with the current regulatory control period.

PB recommends a reduction of $191.0m to the proposed expenditure which reflects a business-as-usual approach as the need and timing for the proposed building program is not demonstrated and alternatives were not generally considered.

Fleet

Ergon Energy proposes to invest $160.5m in the next regulatory control period, an average increase of 0.2% compared with the current regulatory control period.

PB recommends no changes to the expenditure forecast in this category.

Tools and equipment

Ergon Energy proposes to spend $38.8m on tools and equipment in the next regulatory control period, an average decrease of 59% compared with the current regulatory control period.

PB recommends no changes to the expenditure forecast in this category.

Table 5.15 presents PB's recommended non-system capex.

Table 5.15 PB's recommended non-system capex

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
End use computing assets						
Ergon Energy proposal	20.3	18.9	18.2	17.1	18.4	92.9
PB Adjustment	(13.1)	(13.1)	(13.1)	(13.1)	(12.8)	(65.2)
PB Recommendation	7.2	5.8	5.1	4.0	5.6	27.7
Property						
Ergon Energy proposal	122.2	142.2	77.1	24.9	20.4	386.8
PB Adjustment	(83.0)	(103.0)	(37.9)	14.3	18.8	(190.8)
PB Recommendation	39.2	39.2	39.2	39.2	39.2	196.0
Fleet						
Ergon Energy proposal	30.9	30.3	32.0	32.3	35.0	160.5
PB adjustment	0.0	0.0	0.0	0.0	0.0	0.0
PB recommendation	30.9	30.3	32.0	32.3	35.0	160.5
Tools & equipment						
Ergon Energy proposal	7.5	7.6	7.8	7.9	8.0	38.8
PB Adjustment	0.0	0.0	0.0	0.0	0.0	0.0
PB Recommendation	7.5	7.6	7.8	7.9	8.0	38.8
Total non-system capex						
Ergon Energy proposal	180.9	199.0	135.1	82.2	81.8	679.0
PB Adjustment	(96.1)	(116.1)	(51.0)	1.2	6.0	(256.0)
PB Recommendation	84.8	82.9	84.1	83.4	87.8	423.0

Source: PB analysis

6. Opex review

This section presents PB's review of Ergon Energy's proposed opex for the next regulatory control period. In undertaking our review, PB has provided technical advice regarding the efficiency and prudence of opex forecasts provided by Ergon Energy, and aims to provide input to assist the Australian Energy Regulator in its assessment of the opex objectives, criteria and factors set out in clause 6.5.6 of the NER.

6.1 Opex overview

Ergon Energy has submitted an opex proposal of $1,898m for the next regulatory control period. During the current regulatory control period, Ergon Energy expects the total opex to be $1,543m[214], 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 23% increase in real terms over the current regulatory control period.

The profile of the opex spend over the 10-year period is shown in Figure 6.1.

Figure 6.1 Ergon Energy opex — 2001 to 2015

Source: PB analysis and AR539c_RIN Submission Model.xls, template 2.2.2 opex

In accordance with Ergon Energy's RIN submission model[215], the forecast opex comprises seven main cost categories:

- network operations — relates largely to operating support services and some activity associated with the reconfiguration of the distribution network

214 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 (refer to the Notes section of this report).

215 RIN Submission Model.xls, Table 1 (operating expenditure by category) in template 2.2.2, operating expenditure, 01/07/09

- preventive network maintenance — comprises scheduled inspection and maintenance activities. This work is carried out at predetermined intervals, or in accordance with prescribed criteria, in order to minimise the probability of network failure, minimise total life cycle costs, meet required operating conditions and performance standards, and keep staff and the public safe
- corrective network maintenance — involves planned repair work identified and assessed as defects from preventive maintenance or customer reports, in order to prevent an unplanned outage or dangerous electrical events
- forced network maintenance — involves unplanned repair, replacement or restoration work that is carried out as quickly as possible after the occurrence of an unexpected event or failure in order to bring the distribution network to at least its minimum acceptable and safe operating condition
- meter reading (mass market) — relates to collecting, processing, loading and publishing meter data for market participants in the context of Ergon Energy's NER obligations as a Metering Data Provider for types 5, 6 and 7 metering installations
- customer service — relates to activities for customers that are ancillary to the provision of Ergon Energy's broader network, connection and metering services, including: cold water reports, check inspections, revenue protection and customer support
- other operating costs — include self-insurance, the demand management innovation allowance, demand management opex, guaranteed service levels, and training costs.

6.1.1 Opex in the current regulatory control period

Ergon Energy's opex in the current regulatory control period is estimated to be $1,542.4m, in accordance with the key expenditure categories 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 operations	17.9	27.3	32.2	27.4	26.2	131.0
Preventive network maintenance	57.4	61.0	102.0	88.2	94.6	403.2
Corrective network maintenance	89.0	117.1	75.67	102.6	98.4	482.8
Forced network maintenance	58.7	22.3	44.5	43.34	40.4	209.2
Meter reading	9.5	11.1	11.1	12.0	11.6	55.3
Customer services	35.5	29.8	26.3	29.5	27.9	149.0
Other opex	20.1	21.3	19.9	25.6	24.9	111.8
Total	288.1	289.9	311.7	328.6	324.0	1,542.3

Source: PB analysis and AR539c_RIN Submission Model.xls, template 2.2.2 opex

For the historical three years 2005–06 to 2007–08, the opex excludes street lighting but includes some expenditure that will be classified as Alternative Control Services from 1 July 2010. For the two estimated years of 2008–09 and 2009–10, the expenditures only include

Standard Control Services. In all years, the shared costs (overheads) have been allocated in accordance with the AER's approved Cost Allocation Method.

6.1.2 Forecast opex

Ergon Energy's opex in the next regulatory control period is estimated to be $1898.8m. A breakdown of this expenditure by key expenditure category is provided in Table 6.2.

Table 6.2 Proposed opex for the next regulatory control period

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Network operations	26.4	26.3	26.7	27.2	27.5	134.1
Preventive network maintenance	108.8	119.56	120.12	123.4	121.7	593.6
Corrective network maintenance	121.99	121.5	122.8	117.9	105.67	589.9
Forced network maintenance	41.0	40.89	41.3	41.4	41.1	205.7
Meter reading	11.8	11.8	12.0	12.3	12.45	60.4
Customer services	19.8	19.9	20.2	20.6	20.8	101.3
Other opex	40.5	41.6	42.3	43.89	45.5	213.8
Total	370.3	381.6	385.4	386.7	374.7	1,898.8

Source: AR539c_RIN Submission Model.xls, template 2.2.2 opex.

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 proportions and increases

	% of total forecast opex	Average % real increase from current period
Network operations	7	2
Preventive network maintenance	31	47
Corrective network maintenance	31	22
Forced network maintenance	11	(2)
Meter reading	3	9
Customer services	5	(32)
Other opex	11	91
Total	100	23

Source: PB analysis and AR539c_RIN Submission Model.xls, template 2.2.2 opex.

The key observation from Table 6.3 is that Ergon Energy is proposing a significant increase (47%) in its preventive network maintenance program, suggesting a strategic move into a more proactive asset management approach that leverages off leading, rather than lagging, key performance indicators. This matter is discussed further in section 6.2.

The profile of expenditure over the current and next regulatory control period varies in real terms in accordance with Figure 6.2.

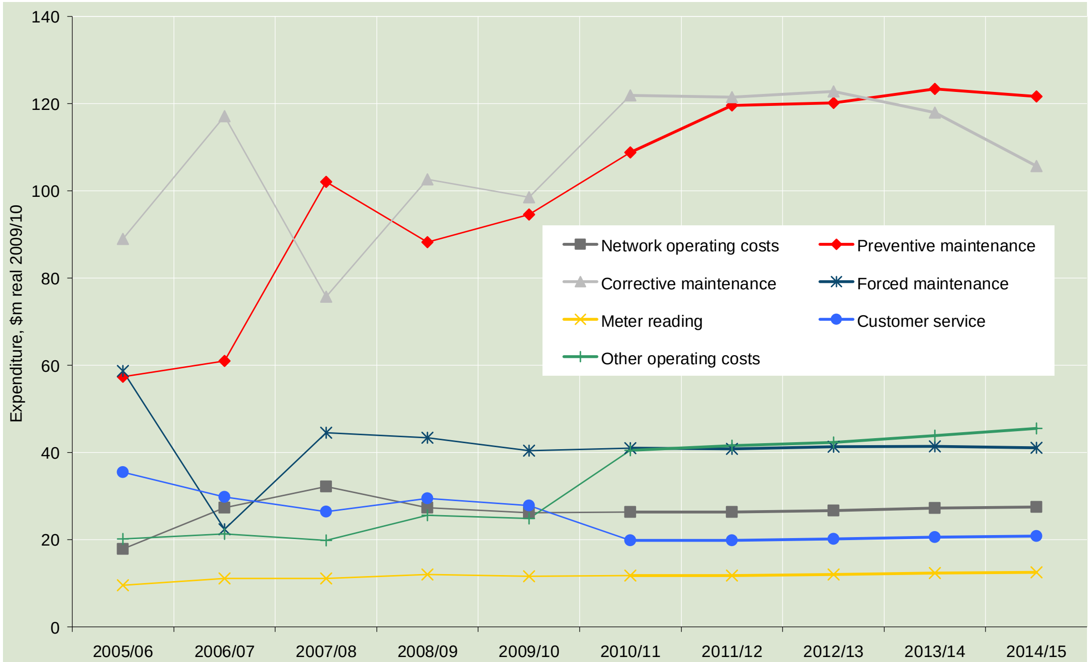

Figure 6.2 Proposed opex for the next regulatory control period — trends

Source: PB analysis and AR539c_RIN Submission Model.xls, template 2.2.2 opex

Particularly relevant and evident in regard to Ergon Energy's forecast opex increases are the elements of management of corridors and sites and easement vegetation. These elements are captured implicitly within each of the three network maintenance categories, and comprise 29% of the entire forecast opex, as shown in Table 6.4. They are separated and investigated in further detail in section 6.8 of this report.

Table 6.4 Proposed opex for the next regulatory control period — vegetation and corridors and sites

	2010–11	2011–12	2012–13	2013–14	2014-15	Total
Preventive — vegetation	17.3	17.7	18.4	18.2	16.9	88.5
Preventive — corridors & sites[1]	6.5	6.6	6.6	6.7	4.4	30.8
Corrective — vegetation	78.1	77.5	78.0	72.6	60.2	366.4
Corrective — corridors & sites[1]	12.23	12.5	12.67	12.9	13.0	63.3
Subtotal	114.1	114.3	115.7	110.4	94.5	549.0
Total opex	370.1	381.5	385.5	386.7	374.7	1,898.5
% vegetation, corridors & sites	30.8	30.0	30.0	28.5	25.2	28.9

[1] PB has estimated these figures based on scaling direct costs in 07–08 from the NARMCOS outputs by 1.35 for overheads, 1.0834 for real escalation and 1.04551 to translate to 2009–10.

Source: PB analysis and EE Response to AER-PB Q.VP.34 - Annual Trimming Cycle Costs in $Real$2009-10, 30/07/08

Based on our review of section 27.3.2.7, section 7.3 and AR404 of Ergon Energy's submission, PB has formed a view that the increasing system operating costs from 2005–06 to 2009–10 are largely a response to the findings presented as part of the 2004 EDSD review[216]. Ergon Energy was required to provide the QCA with the approach planned to achieve the required outcomes and submit revised and increased capex and opex forecasts to support the plan.

The key findings of the EDSD review that impact on system operating costs include:

- preparation of Annual Network Management Plan — Ergon Energy is required under its licence to prepare plans to identify where capital investment and target maintenance is required across their networks
- more conservative planning criteria — Ergon Energy is adopting more conservative planning assumptions so that, if assets fail across the system, there will be sufficient backup capacity to ensure customers don't lose supply
- effective maintenance program — Ergon Energy has increased its program of preventive maintenance and effective vegetation management
- improvement of asset management system — Ergon Energy was required to expedite upgrades to its asset management system to improve its capital and maintenance planning capability
- increased number of apprenticeships and joint training arrangements — Ergon Energy and ENERGEX were required to increase apprenticeship intakes and collaborate to identify and deliver joint technical training to deliver better trained apprentices and tradespersons.

Increased costs from these increased responsibilities have been compounded by overspends that Ergon Energy explains arise from:

- increased labour, material, contractors and other costs
- increased direct and shared costs as a result of increased maintenance works and higher employee numbers
- increased quantities and unit rates compared with forecasts, in particular for vegetation management, pole inspections and access track maintenance
- a move to 24-hour control rooms
- significant one-off events such as: Tropical Cyclone Larry; new union collective agreements; changes in the treatment of ICT costs to overheads, as opposed to entirely in capex; and changes to the treatment of fees from the Electrical Safety Office (ESO) and the Queensland Competition Authority (QCA).

6.2 Operations and maintenance approach and strategy

Ergon Energy's asset management framework and plan is still under development[217], but is designed around a strategic business model separating the roles of:

216 AR158, EDSD Review Electricity Distribution & Service Delivery.pdf
217 Ergon Energy Regulatory Proposal 2010–2015, section 17.2.3, p. 134.

Asset Owner — acting on behalf of the Board and shareholders, and responsible for setting enterprise-wide asset-related targets for service and financial return and defining policy, strategic direction goals, governance functions and risk appetite (refer to AR024c, Asset Management Plan Volume 1 — Framework)

Asset Manager — responsible for developing and managing the asset-related portfolio and related strategy, objectives, plans and actions (refer to AR024c, Asset Management Plan Volume 2 — Practice)

Service Provider — responsible for budgeting, resource allocation and delivering the program of work, effectively and efficiently (incomplete, Asset Management Plan Volume 3 — Operations and Service Delivery).

6.2.1 Key policies and documentation

Within this framework, there are a number of key policies and processes described in section 17 of the proposal, which directly inform and influence the forecast opex proposed by Ergon Energy:

- EP51 Asset Management Defect Policy and the Network Defect Classification Manual — detail the framework for defect prioritisation, defect remediation and compliance reporting to ensure the electrical network assets are operated and maintained in a safe condition, and in order to mitigate failures and unplanned opex
- Asset Maintenance Strategy — provides an overall outline of Ergon Energy's approach to asset maintenance, as informed by identified drivers
- Strategic Plan for Asset Renewal — at an asset class level, describes the strategy for asset renewal and maps the path from the current state of assets to an intended future state
- Vegetation Strategy 2010–2015 — outlines the long-term approach to vegetation management at both a summary and concept level
- Asset Equipment Plans 2009 — contains detailed and specific plans that document the maintenance inspection cycles and replacement strategies for 26 defined asset classes (e.g. meters, poles, pole tops, conductors and connectors, zone substation transformers)
- Network Preventive Maintenance Programs for 2010–2015 — identifies statutory obligations at an asset class level, and the five-year forecast of the quantity, budget and resource hours per annum, by region for preventive maintenance expenditure
- Meter Asset Management Plan — describes the asset management methodology applied to the electricity metering asset class in order to maximise the technical and operational performance and value of meter equipment over the asset life cycle
- Strategic Workforce Plan 2008–2018 — produced to ensure that Ergon Energy will have sufficient (internal and external) labour resources to deliver both its capex and opex projects and programs
- Disaster Management Plan, Emergency Management Plans and Contingency Plans — document Ergon Energy's processes for: rapid response to large-scale disasters;

regionally based actions in the lead-up to and during significant network events; and the management of unplanned outages resulting from failure of major plant, respectively.

These key polices and strategy documents inform the opex forecasts in accordance with Table 6.5.

Table 6.5 Policy document and expenditure mapping

	Network operations	Preventive maintenance	Corrective maintenance	Forced maintenance	Meter reading	Customer services	Other opex
Defect policy and classification manual		✓	✓	✓			
Asset maintenance strategy		✓	✓	✓			
Strategic plan for asset renewal		✓	✓	✓			
Vegetation strategy		✓	✓	✓			
Asset equipment plans	✓	✓	✓	✓	✓	✓	✓
Network preventive maintenance programs		✓					
Meter asset management plan		✓	✓	✓	✓	✓	
Strategic workforce plan	✓	✓	✓	✓	✓	✓	✓
Disaster management plan	✓	✓	✓	✓			
Emergency management plans	✓	✓	✓	✓			
Contingency plans	✓	✓	✓	✓			

Source: PB analysis

6.2.2 Asset management practices and performance

Ergon Energy's asset maintenance practices are associated with time-based inspections. There are no instances identified where the condition or performance of an asset dictates the maintenance requirements. Even with poor-performing assets, the approach is to increase inspection timings rather than to optimise maintenance based on condition indicators or operations.

Increased maintenance due to condition or performance is generally undertaken:

- as required for poles, where a level 2 serviceability assessment is undertaken for a pole identified as suspect by an inspection
- at the requested interval for high-risk distribution lines experiencing poor reliability performance attributed to conductor connector failures
- as required for high-risk cables

- at increased defined routine intervals for power transformers, regulators, reactors and critical distribution transformers or those greater than 1 MVA capacity, as informed through routine oil sampling and dissolved gas analysis (DGA).

Maintenance practices are based on asset condition information captured during the time-based inspection cycles and is an integral component of Ergon Energy's management practices. For example, as part of the wood pole inspection program, Ergon Energy undertakes visual, audible and probe-based testing; and for major zone substation equipment, a comprehensive oil analysis program (inclusive of DGA, which is outsourced to Powerlink) is integral to Ergon Energy's maintenance practices.

Ergon Energy undertakes no preventive maintenance on fuses or lightning arrestors, which are high-volume, low-cost plant. However they are inspected as part of the asset (pole) pole inspection program and failed surge arrestors are reclassified and scheduled for replacement.

Ergon Energy's life cycle costing approach is based on historical costs, anticipated inspection, overhaul and defect rates, and other maintenance activity. It does not consider the asset population in the context of where each asset is in its life cycle and does not account for the ageing nature of the assets.

With specific reference to Ergon Energy's *Asset maintenance strategy*[218] (which directly informs 73% of the total five-year opex forecasts through the preventive, corrective and forced network maintenance cost categories), the following performance and practices are noted.

Asset performance

The existing performance of the assets and network is measured by the following lagging indicators:

- a three-year moving average '% pole reliability' indicator that has improved from 99.993% in March 2006 to 99.997% in January 2009, and which can be directly compared to the Queensland *Electricity Safety Act 2002* performance target of 99.990% (which can be interpreted as 100 pole failures per annum in a population of 1,000,000). This indicator is measured by unassisted pole failures. In summary, the actual performance of the pole population has been and continues to be significantly better than the target

- a pole replacement rate of 0.46% and a pole nailing rate of 1.33% of the number of poles inspected

- a three-year moving average '% cross arm reliability' indicator that has slightly deteriorated from 99.9965% in February 2006 to 99.9947% in January 2009, as measured by unassisted cross arm failures, but which is still considerably better than the 99.990% target

- a three-year 'line asset failure rate' of 0.67 per 100 km per annum, which compares favourably to a Swedish University study that included an industry average failure rate for similar assets of 0.93 per 100 km per annum

218 AR355_EE_Asset Maintenance Strategy_V0.8_Apr09.pdf

- an annual failure rate of 0.01387 (12 units) for power transformers over the 2007–08 financial year, and with a population that is generally inclusive of units with very high moisture content due to a tropical environment which increases the overall risk profile

- annual failure rates of 0.0044, 0.0017 and 0.0028 (11, 9 and 6 units) recorded for circuit breakers, current transformers and voltage transformers, respectively.

Asset management practices

Existing practices implicit in Ergon Energy's opex activities include:

- aligned inspections — one ground-based visit by a trained inspector covers items such as poles, pole tops, conductor, vegetation, stays and pole-mounted equipment to the extent possible. These are mature inspections, which were carried out on a three-year cycle (since 2002) and are now carried out on a four-year cycle (since 2006). Also, field data is captured on hand-held computers that interface and directly upload data into the asset management data base. The handheld devices facilitate reasonableness testing on-site and contain previous inspection results for operator analysis. Minor maintenance is also carried out by the inspectors, covering matters such as pole treatment for decay, termite treatment and replacement of stay guards

- coordinated and off-set inspections — Ergon Energy ensures that its high-risk pole top inspections are offset in time to ground-based inspections to reduce the inspection cycle resolution and to maximise the opportunity to discover rapidly developing defects. Access track inspections are also planned just prior to asset inspections to ensure that the objective of the ground-based inspections will not be compromised by inability to access the assets.

- bundling of defect-related work packages — any defects arising from inspections are combined into work orders, allowing field staff to fix multiple issues on the feeder. In developing these work orders Ergon Energy also reviews proposed capital works in the area and, if possible, combines the defect rectification and capital work into a single work order. Reviewing the proposed capital works program in an area also ensures that assets scheduled for replacement are not maintained

- off-line assessment of asset and defect data to inform strategies and risk assessments, with the aim of developing some leading performance indicators and, in particular, a substation defect classification manual.

Systems based maintenance

Ergon Energy has an efficient approach to internal staffing levels, which involves maintaining staffing levels such that staff are always fully deployed, and using an outsourcing strategy to increase service delivery capacity when required. This approach applies to both the opex and capex program of works.

In addition, Ergon Energy employs a systems-based approach to maintenance works. This approach minimises field trips to and from the assets in two ways. Firstly, asset inspectors have been trained to carry out all pole and line inspections concurrently, and the results of these inspections are loaded at the site into handheld computer devices, then immediately uploaded into the asset maintenance data base. These field inspections are also programmed on a feeder basis (as opposed to individual pole or cross arm) to minimise travelling, and where possible, inspectors are dispatched directly to the field from their homes, saving travel time to depots.

The asset managers review the field-captured data results and combine defect rectification works into job lots so that the number of outages are minimised and each outage optimised to achieve the maximum amount of work during the interruption. In addition, the opex work packages are combined with any proposed capital works to ensure that assets are not repaired if they are programmed to be replaced shortly thereafter.

6.2.3 Summary

Having reviewed the considerable asset management documentation presented by Ergon Energy, PB concludes that its asset management practices appear to be comprehensive and reflective of the needs of Ergon Energy 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. The documentation also clearly recognises the unique regional characteristics and challenges associated with the large supply area over which Ergon Energy operates, and appears to be well aligned to the normal processes and practices used by business.

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 H1-H2-H3 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. Ergon Energy's strategic intentions are evidenced by the well-presented long-term goals of the business in its *Asset maintenance strategy*[219] document, which outlines in detail:

- the current state of the asset management capability in terms of functions such as asset performance, life cycle costing, information systems, standards, condition-based maintenance, governance and planning, and contract management
- the future (desired) state of the business, which intends to include the following functions within its practices: alignment to the internationally recognised PAS 55 specification to integrated asset management; significant expansion of its asset condition monitoring; increased use of reliability-centred maintenance (RCM) principles and root/incident cause analysis; and development of advanced condition-informed management, including an asset criticality ranking framework to assist in prioritising and optimising maintenance strategy decisions
- a preliminary implementation plan that outlines intentions, but does not present any specific objectives or tangible milestones.

As a result of our discussions with Ergon Energy asset managers, our review of the documentation presented including the 26 asset equipment plans, and the written and verbal responses to our often-detailed and specific questions relating to network performance and vegetation management, PB considers that the forecast opex expenditures are based on prudent and orthodox asset management principles, processes and procedures. Some

[219] AR355

unique circumstances and legacy issues are apparent due to the formation in 1999 of the current Ergon Energy entity from an amalgamation of smaller distribution businesses. However, the approach taken to system-wide time-based preventive maintenance cycles, coupled with clear asset defect manuals, should provide a reasonable framework to move to a more efficient and advanced condition-based style of asset management in the future.

PB does note that whilst Ergon Energy has a number of internal procedures related to the consideration of its broad based non-network alternative (demand management) programs, it has not presented any existing business policies or strategies that clearly and succinctly outline Ergon Energy's objectives in this area. Whilst this does not appear to have significantly influenced the prudency and efficiency of the individual demand management programs proposed, PB does consider it may influence the overheads associated with delivering the programs, as discussed further in section 6.10.

6.3 Forecasting methodology

Section 26 of the Ergon Energy proposal presents a significant level of detail in a systematic and transparent manner about the approach adopted to develop its opex forecasts.

A short description of the forecasting methodology for each major cost category adopted by Ergon Energy is shown in Table 6.6.

Table 6.6 Opex cost category forecast methodology

Activity	Forecast methodology
Network operations (7% of total opex)	2007–08 base year, adjusted for abnormalities with no growth
Preventive network maintenance (31% of total opex)	Bottom-up forecasts across each asset equipment type: o identified the different unit types and quantities of preventive maintenance (i.e. asset populations, growth rates, inspection cycle times, etc.) required o identified unit costs for each unit of work and calculated the total cost of preventive maintenance as the product
Corrective network maintenance (31% of total opex)	Bottom-up forecasts for vegetation and access track (71% of the entire corrective maintenance forecast) Balance informed from aggregate level in 2007–08 base year, adjusted scope changes (amounting to an additional 4% of total corrective maintenance), including: o repairing issues managed in the safety incident system o dismantling old replaced lines o asbestos clean-up o increasing failure rates of meters Balance subsequently allocating to the 26 asset classes based on historical and expected failure rates and subject matter expertise
Forced network maintenance (11% of total opex)	Aggregate level in 2007–08 base year, adjusted for abnormalities and with no growth
Meter reading (3% of total opex)	2007–08 base year, adjusted for abnormalities and scope change for NER obligations and FRC impacts
Customer services (5% of total opex)	2007–08 base year, adjusted for abnormalities and scope change
Other opex (11% of total opex)	2007–08 base year, adjusted for abnormalities and scope changes, including: o training o self insurance o demand management o DM innovation allowance

Source: PB analysis

For the key network maintenance cost categories (preventive, corrective and forced), Ergon Energy has identified its forecast in accordance with the 26 asset classes underlying the businesses asset management approach, as outlined in Table 6.7.

Table 6.7 Asset classes

Asset classes adopted by the Ergon Energy asset management system			
01- Meters	08 - Distribution air break switches	15 - Corridors and sites	22 - ZS AC and DC systems
02 - Poles	09 - Fuses	16 - Vegetation	23 - ZS civil
03 - Pole tops	10 - Lightning arrestors	17 - ZS transformers	24 - Communication
04 - Conductor and connections	11 - Distribution services	18 - ZS circuit breakers	25 - Protection
05 - UG cables and joints	12 - Public lighting	19 - ZS CTs and VTs	26 - Control
06 - Distribution transformers	13 - Distribution earths	20 - ZS outdoor switchyards	
07 - Distribution enclosed switches	14 - Distribution reactors and regulators	21 - ZS capacitor banks	

Source: PB analysis and Narmcos Data Model.xls

In addition to its documentation, Ergon Energy has also provided a set of three detailed and inter-related spreadsheet models which have been independently verified by PwC[220] to support its opex forecasts:

- the NARMCOS[221] data model
- the PL561c_SC Opex data model
- the SC Opex and Capex model.

Effectively, the forecasting approach use to determine the opex levels in the last year of the current regulatory control period and the five years of the next regulatory control period included three sequential stages of modelling:

220 PwC, PL551c_Ergon Energy - AER2010 Financial Models AUP Report (Final) 220609.pdf

221 The Network Assets Replacement Maintenance Capital Expenditure Operating Expenditure Summary model

Stage 1 — a detailed bottom-up determination by Ergon Energy of direct network maintenance-related costs (excluding shared overheads) across key regulatory categories in 2007–08 dollars using asset quantities, as presented in the NARMCOS data model. This model explicitly includes 26 separate asset classes[222] in each of the key network maintenance categories (preventive, corrective and forced). The asset class forecasts are informed through a combination of either volumes drawn directly from the preventive maintenance programs as outlined in the detailed Asset Equipment Plans[223], used together with estimated defect rates and unit cost rates from the master list spreadsheet; and in some cases (such as the forced maintenance category expenditures) they are extrapolated from historical levels experienced in the current period and the base year.

Stage 2 — where network operations and 'other' regulatory category expenditures are included by Ergon Energy with the network maintenance costs from the NARMCOS data model, as informed through either a bottom-up approach or extrapolated from expenditures on the current period and the base year.

These costs are then rolled up into 13 network-based cost categories and 9 non-network cost categories within the SC Opex data model; each is then itemised into its cost escalation category components of labour, materials, contractors or 'other', as informed through historical experience using the business's directly charged Chart of Accounts[224].

Stage 3 — where, within the SC Opex and Capex model, each of the cost categories is escalated by Ergon Energy in terms of the real labour and materials forecasts that have been independently sourced; where the gross pool of shared overheads are apportioned to the opex categories on the basis of the AER's approved CAM; where the overheads themselves are also escalated for real labour and materials growth; and, finally, where the expenses are escalated from the reference financial base year of 2007–08 to 2009–10 dollars for use directly in the RIN templates.

PB assessment and findings

While the models presented to PB and AER were transparent given their detail, they were not integrated and linked spreadsheets. Consequently, changes and sensitivity studies affecting the inputs to one area would not dynamically update the total opex forecasts as presented in 2009–10 dollars in the RIN templates. In particular, neither PB nor AER could test the sensitivity of workload escalators as applied to the NARMCOS model asset classes except through a detailed investigation at a line item level. The presentation of the models in this manner detracted from PB's ability to review the robustness of the models and to provide a degree of verification that they were completely accurate. To a large extent, PB has relied upon the independent review undertaken by PwC to increase our confidence in this area.

In general, the fundamental approach undertaken by Ergon Energy – involving a detailed bottom-up build of all the key preventive and corrective maintenance components based on volumes and unit rates where practical, or using base year and scope change extrapolation of historical costs in other (lower valued) areas – is considered by PB to be a pragmatic and

222 One of these asset classes is public lighting, which has been subsequently removed from the Standard Control spreadsheets for ring fencing purposes.
223 AR226
224 PL748c

generally accurate approach to forecasting opex. A number of the key principles integral to Ergon Energy's annual budgeting process (i.e. the way in which the cost escalation categories were informed from the Chart of Accounts) were included in the approach.

PB considers that, in comparison with the approach adopted by other electricity distribution network businesses in classifying asset classes and forecasting opex costs, the level of resolution is appropriate and reasonable for Ergon Energy's business.

In conclusion, PB believes the staged approach adopted by Ergon Energy is well considered and reasonable given the transparent nature of the data sets presented and its multiple asset class approach (which aligns with the businesses asset management framework).

However, certain aspects of the forecasting methodology lacks integration — for example:

- The corrective maintenance requirements have not been informed directly by the forecast capital program. Of particular concern is that none of the asset growth escalators used in the opex forecasts were in any way informed by the significant capex program.

- The forced maintenance requirements have not been informed by the forecast capital program. PB would expect that, with a material increase in replacement capex, plant failure rates and emergency response requirements would decrease.

- The vegetation management program and the forced maintenance requirements have not been coordinated. Significant numbers of forced outages can be attributed to vegetation and storm-related damage, so a significant increase in expenditure to remove rural backlogs and proactively manage vegetation using a biodiversity model should provide considerable reliability improvements over the next regulatory period.

PB has addressed each of these matters as part of its review of key opex categories in sections 6.4 to 6.10 of this report.

6.3.1 Workload escalation

Ergon Energy has adopted an asset specific approach to workload escalation resulting from the commissioning of growth assets during the next regulatory control period within its NARMCOS model (i.e. workload escalation is included at a direct cost level across each of its asset classes). It has done so by using both the projected quantities of new assets and the preventive maintenance cycles applicable to those assets that will be commissioned during the next regulatory control period.

Existing asset populations within each of the 26 asset classes have been escalated based on a fixed growth rate from the year 2006–07 over the outlook period (as informed by historical increases in populations). Importantly, there is no direct relation to the actual forecast capex program of work. The growth rates included by Ergon Energy in its opex forecast are summarised in Table 6.8.

Table 6.8 Network growth escalation included in the opex forecasts

Asset population growth rate	Asset classes	Approximate population in 2007–08
0%	Distribution regulators	550
1.0%	Distribution enclosed switches Distribution air break switches	3,500 7,600
1.1%	Distribution services	458,500
1.5%	ZS transformers ZS circuit breakers ZS CTs and VTs ZS AC and DC systems ZS civil	850 2,300 13,900 330 395
1.6%	Poles Pole tops Conductor and Connectors Fuses Distribution earths Corridors and sites Protection Control	962,200 1,474,600 962,255 806,700 90,500 98,000 12,270 278
2.3%	Public lighting	126,220
2.5%	Distribution transformers (pole and pad)	3,420
3.0%	Lightning arrestors	199,900
4.6%	ZS capacitor banks Distribution regulators	135 390
5.4%	UG cables & joints – cable UG cables & joints – pillars	4,480 96,260
Bottom-up	Meters Vegetation ZS outdoor switchyards communications	n/a n/a n/a n/a

Source: PB analysis and AR226_EE_Asset Equipment Plans 2009.zip

PB assessment and findings

PB is generally satisfied that there is a rationale for increasing preventive maintenance to allow for new assets, and therefore the inclusion of growth rates as applied to population levels across asset classes is reasonable in principle. However, the approach adopted by Ergon Energy is simplistic as it has not been referenced against the actual growth in the forecast capex program. In PB's view, when adopting a bottom-up forecasting approach at an asset class level, actual asset quantities and work volumes should be directly informed by the actual forecast capex program proposed, whilst accounting for the principle that new assets require less preventive maintenance (often not being inspected at all, as is the case with new poles) and much lower defect rates. Given the simple approach adopted by Ergon Energy, any variations in the growth-related capex program will have no impact on the opex needs as the growth levels have been informed solely by historical increases in populations. As Ergon Energy is significantly increasing its forecast capex over the next regulatory period, however, and giving due regard to PB's specific recommendations in the following section in relation to new pole and service inspections, we consider this simple approach is reasonable. This finding is supported in part by the relatively low growth rates that have been adopted, for example, the annual growth in capex[225] in key asset categories is as shown in Table 6.9.

Table 6.9 Growth escalation in the capex forecasts

Average annual capex growth from 2009-10 to 2014-15 (including escalation)	Key asset classes
20%	Overhead sub transmission lines
8%	Overhead distribution lines
4%	Distribution equipment
18%	Substation bays
10%	Distribution substation switchgear
24%	Zone transformers
2%	Distribution transformers
17%	Other equipment

Source: PB analysis and AR539c_RIN Submission Model.xls, template 2.2.1 capex

Where Ergon Energy has used a high annual growth rate, it has documented the reasons within its respective asset equipment plans, as follows:

- ZS capacitor banks — high growth is based on the average of the most recent three financial years
- distribution regulators (and reactors) — the AEP growth rate is anticipated to be 1%, and the modelling, which uses a 4.6% growth rate, appears to be an error. However, PB considers this error is likely to be immaterial as this asset class represents the second lowest preventive maintenance line item (<$275,000 p.a.) and the lowest corrective maintenance line item (<$45,000 p.a.). Furthermore, for the reactor component of this asset class, Ergon Energy has not included any growth element, whereas the asset equipment plant indicates that a growth rate of 1% should have been used
- underground cables and joints — the high rate has been adopted to reflect the high number of connections in comparison with the total number of new services.

225 The growth rates presented are based on annual expenditure including real labour and material escalation, so they are not a direct indication in the growth of volumes of assets (i.e. they overstate the growth).

Notwithstanding the immaterial errors identified for distribution regulators (and reactors) above, PB considers these reasons are reasonable since they are for asset classes that, based on engineering function, are expected to grow at relatively higher rates than others and they are applied to asset classes that have relatively low opex associated with them.

PB has identified two specific areas where it considers Ergon Energy's workload escalation has been aggressive and has proposed reductions in the opex allowances in accordance with the following assessments:

- PB recommends removing the growth escalation in ground-based inspections for new poles from the forecast. This is expected to equate to $11.46m[226], however Ergon Energy would need to verify this amount using its detailed models. This recommendation is based on the fact that for preventive maintenance of poles Ergon Energy has forecast an inspection of every pole in the population (as of 30 June 2008) on a four-yearly cycle, including a growth factor of 1.016% p.a. As a result, all new poles installed for growth and replacement in the next period will be included in the inspection cycle. Typically, electricity distribution network businesses do not inspect poles installed as part of a growth-related project (i.e. a new feeder, as opposed to individual pole replacements) during the first 2 cycles, commencing inspections only in the third cycle. PB considers this lag effect is a practice that a prudent and efficient operator would incorporate in its forecast methodology, and PB's proposal of removing the growth escalation reflects this approach

- PB also recommends removing the growth escalation for the full inspection of distribution services from the forecast, because the 12-year inspection cycle means new services would have their first inspection beyond the next regulatory control period. This is expected to equate to $2.75m, but Ergon Energy would also need to verify this amount using its detailed and integrated models.

PB's recommended reductions to forecast expenditure relating to the removal of growth escalation in the two specific asset categories are summarised in Table 6.10.

Table 6.10 Recommended reduction in opex for growth escalation due to lag in inspections

Growth escalation reduction	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposal	37.0	37.5	38.1	38.6	39.2	190.4
PB adjustment — poles	(1.4)	(1.8)	(2.3)	(2.8)	(3.3)	(11.6)
PB adjustment — services	(0.1)	(0.5)	(0.6)	(0.7)	(0.9)	(2.8)
PB recommendation	35.5	35.2	35.2	35.1	35.0	176.0

Source: PB analysis

6.3.2 Impact of input cost escalation

In order to test the impact of the input cost escalation (as discussed in section 3.1.2), PB has removed the escalation to produce a version of the opex forecasts that are more directly

226 PB has assumed an overhead escalation of 1.35, and real escalation of 1.0834 (50% of the cumulative real escalation over the five-year period for labour/contractors), and a factor of 1.04551 to convert the direct 07–08 costs to 09–10 levels.

reflective of the need for opex as a result of the growth in asset volumes resulting from the corresponding capital works programs.

Table 6.11 presents the contribution of real-cost escalation to the total forecast system opex expenditures for the next regulatory control period.

Table 6.11 Base opex and the real annual cost escalation included in the forecast opex expenditures for the next regulatory control period

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Total opex (no escalation)	345.6	350.0	347.5	342.6	326.5	1,712.2
Real cost escalation	24.5	31.5	38.0	44.1	48.2	186.3
Ergon Energy–proposed system opex	370.1	381.5	385.5	386.7	374.7	1,898.5

Source: PB analysis and SC Opex and Capex Model.xls

This exercise indicated that the impact of the real-cost escalation factored into opex forecasts for the next regulatory control period was $186.3m, or an uplift of 10.9% on the base opex. Sensitivity analysis indicates that real cost escalation contributes to the $186.3m increase in the proportions of labour: 47.3%, materials: -0.3%, contractors: 51.1% and other: 2.0%.

Figure 6.3 displays the real-cost escalation included in each of the annual opex expenditure forecasts.

Figure 6.3 Base opex and the real annual cost escalation included in the forecast opex expenditures for the next regulatory control period

Source: PB analysis

Trends in each of the key cost categories after the removal of real escalation over the outlook period are shown in Table 6.12 and graphically in Figure 6.4.

Table 6.12 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 operations	17.9	27.3	32.2	27.4	26.2	24.6	24.2	24.1	24.2	24.1
Preventive maintenance	57.4	61.0	102.0	88.3	94.6	100.8	108.7	107.2	108.0	104.5
Corrective maintenance	89.0	117.1	75.7	102.6	98.5	112.9	110.4	109.5	103.2	90.7
Forced maintenance	58.7	22.4	44.5	43.4	40.4	39.4	38.6	38.5	38.0	37.1
Meter reading	9.5	11.1	11.1	12.0	11.6	10.9	10.7	10.7	10.7	10.7
Customer services	35.5	29.8	26.4	29.5	27.9	18.8	18.6	18.5	18.6	18.5
Other opex	20.2	21.3	19.9	25.6	24.9	38.2	38.9	39.1	40.0	40.9
Total system	288.2	290.0	311.8	328.8	324.1	345.6	350.1	347.6	342.7	326.5

Source: PB analysis and SC Opex and Capex Model.xls

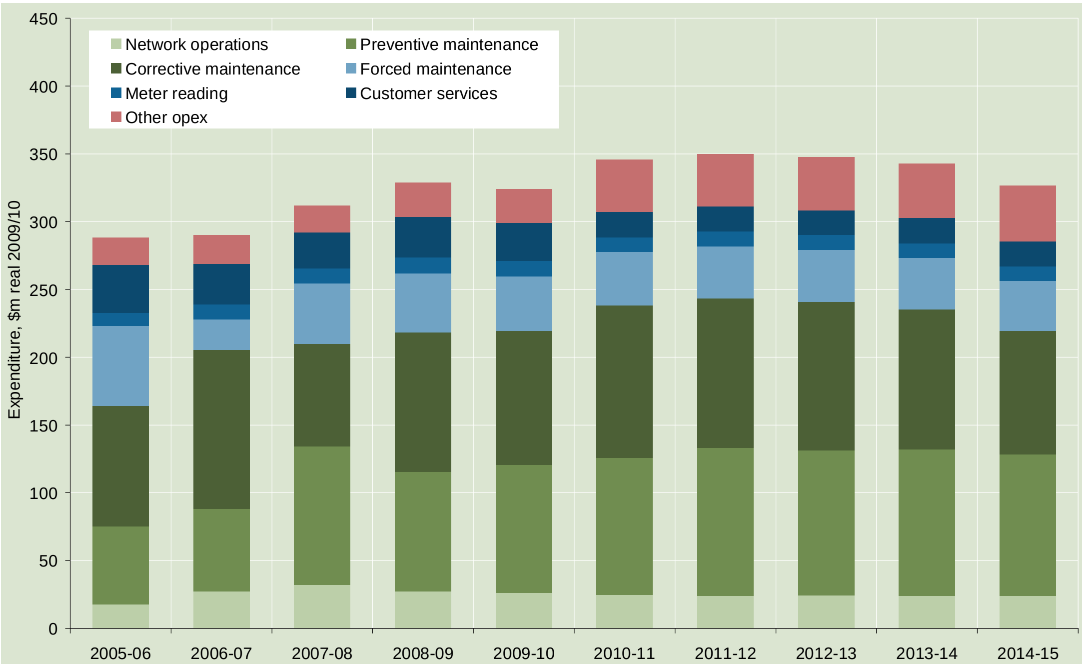

Figure 6.4 Historical and forecast system opex — real escalation removed from forecasts

Source: PB analysis

Table 6.13 presents the percentage increase in opex compared with the previous year for the period 2008–09 to 2014–15. Where the step change exceeds 5%, the value has been highlighted.

Table 6.13 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 operations	(15%)	(4%)	(6%)	(2%)	0%	0%	(1%)
Preventive maintenance	(14%)	7%	7%	8%	(1%)	1%	(3%)
Corrective maintenance	36%	(4%)	15%	(2%)	(1%)	(6%)	(12%)
Forced maintenance	(3%)	(7%)	(3%)	(2%)	0%	(1%)	(2%)
Meter reading	8%	(4%)	(6%)	(1%)	0%	0%	(1%)
Customer services	12%	(6%)	(32%)	(1%)	0%	0%	(1%)
Other opex	29%	(3%)	54%	2%	0%	2%	2%
Total system	5%	(1%)	7%	1%	(1%)	(1%)	(5%)

Source: PB analysis and SC Opex and Capex Model.xls

As is evident from Table 6.13, significant step changes are expected to occur in all but two of the regulatory categories: network operations and forced maintenance. In these two categories, it can be inferred that work volumes are expected to decrease given that unit costs remain constant (as no real labour cost escalation is included in this analysis).

For the categories where there is a notable increasing step change in proposed operational expenditures — preventive maintenance, corrective maintenance, meter reading, customer services and other opex — the reasons for such changes are examined in detail in sections 6.5, 6.6, 6.9 and 6.10 of this report.

6.3.3 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.

As discussed in section 4.3, Ergon Energy's 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 corrective and forced maintenance, and will result in improved reliability and public safety.

Ergon Energy is projecting a significant increase in replacement capex in the areas of:

- conductors and connections
- pole tops
- distribution air break switches

- underground cables and joints
- zone substations (ZS) current transformers (CTs) and voltage transformers (VTs)
- protection
- distribution services.

PB assessment and findings

PB has examined Ergon Energy's Asset Equipment Plans, its regulatory submission and supporting documents, its detailed opex forecasting approach for the next regulatory control period, and has held discussions with Ergon Energy staff. As part of this review, PB has found no specific evidence to suggest that the capex/opex trade-off is explicitly taken into account in the development of replacement programs. While growth in the asset base is accounted for as part of the volume escalation applied to asset classes, no recognition is made that poor condition plant undergoing increased maintenance at present will be the plant to be replaced. PB has identified that, in the case of Ergon Energy's SCADA acceleration strategy[227], the key benefits explicitly include quantified metrics associated with improved reliability and reduced operational costs linked with reduced forced maintenance and control centre and field crew requirements. However, these benefits are not realised until the strategy has been fully implemented, which is beyond 2015 and the end of the next regulatory control period.

On the basis that Ergon Energy has not incorporated any capex/opex trade-off as part of its bottom-up development of the preventive or corrective maintenance forecasts, and given the 72% increase and magnitude ($1,214.1m) of the asset replacement capex proposed, 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%[228] of this ratio to calculate the recommended adjustment in the preventive and corrective 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 Ergon Energy asset base has been calculated by PB from the Post Tax Revenue Model (PTRM)[229] as $9.3b from multiplying the depreciated replacement cost by the ratio of the expected life divided by the remaining life for each network asset class.

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 maintenance and repair expenditures as shown in Table 6.14. The growth and replacement capex forecasts are based on PB's recommended allowances as per section 4 of this report.

227 AR342

228 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.

229 SCPTRM Submission Model.xls

Table 6.14 PB opex/capex trade-off calculations

	2010–11	2011–12	2012–13	2013–14	2014–15
Network growth capex ($m)	448.8	514.8	575.7	624.1	678.2
Undepreciated RAB ($m)	9,300.0	9,571.0	10,421.0	11,917.0	14,121.0
Annual forecast asset replacement expenditure ($m)	167.6	193.4	219.0	244.8	270.5
Compounding asset replacement expenditure ($m)[1]	83.8	264.3	470.5	702.4	960.1
Percentage of compounding asset replacement to undepreciated RAB	0.90%	2.76%	4.51%	5.89%	6.80%
Preventive and corrective maintenance ($m)	230.7	241.04	243.0	241.3	227.3
Recommended reduction in maintenance and repair ($m)	(0.42)	(1.33)	(2.19)	(2.84)	(3.09)

Note 1 – assuming the asset replacement capex recommended by PB is evenly spent throughout the year.

Source: PB analysis

The resulting reduction in preventive and corrective maintenance recommended by PB as a result of a top-down estimate of the capex/opex trade-off is $8.66m, as shown in Table 6.15.

Table 6.15 Recommended reduction in preventive and corrective maintenance to account for the asset replacement capex trade-off

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Proposal	215.2	223.1	223.5	220.6	207.6	1,090.0
Difference — capex/opex trade-off	(0.42)	(1.13)	(2.19)	(2.84)	(3.09)	(9.7)
PB recommendation	214.8	222.0	221.3	217.8	204.5	1,080.4

Source: PB analysis

6.3.4 Cost estimation

In regard to the efficiency of Ergon Energy's unit rates, as used to inform the opex forecasts, PB notes the following matters outlined in section 32.2.2 of the submission:

- Unit rates are informed through different approaches, including consideration of: the time taken to perform jobs in the field, as well as travel costs; average current contract schedule costs; average current costs of materials; and historical costs of undertaking activities.
- A feedback loop between work volumes and historical and market costs is used to inform unit rates within the business's centralised cost-estimating process (Phoenix).
- Over the next regulatory control period, up to 59% of Ergon Energy's total system opex will be market tested through procurement of contracting services or materials.
- Ergon Energy's procurement processes are robust and well tested, including through independent reviews in which the business achieved 'the highest ranked score of any

government or private organisation benchmarked by the DecisionMAX Health Check Program since its inception in 1999 in the UK and Australia'[230].

- Ergon Energy uses well-established technical standards for its maintenance activities.

Because of the significant area across which Ergon Energy operates, it uses the following methods when considering the locational impacts on its opex-related unit costs:

- A single unit rate is calculated for each activity and this becomes the standard rate for application in forecasting and budgeting across Ergon Energy.
- An assumption is made that the historical costs capture the weighted average of locational factors.
- Where a unit rate is developed using the estimating system, the unit rate is stripped back to a base unit, with no allowances for overtime, travel, contingency amounts, living away from home etc. The amount for the travel and other labour-related additional costs is based on the total costs for these components over a range of jobs. This amount becomes the allowance made above the base costs, providing both a single rate for all of Ergon Energy irrespective of location and an internal single benchmark or target rate.

PB assessment and findings

In PB's view all of the matters outlined in section 32.2.2 of the proposal are key aspects to ensuring an overall prudent and efficient basis for establishing opex allowances. The processes adopted by Ergon Energy are evidence of the business-as-usual process and practice framework that should inform an efficient forecast.

The only area of concern that PB has identified from our review is the lack of any clear and explicit evidence that Ergon Energy has captured some economies of scale in its forecasting methodology, in particular in the context of the significant increase in maintenance and inspection requirements over the next regulatory control period.

PB considers that the approach adopted by Ergon Energy in accounting for and forecasting the locational impacts associated with its vast operating area are accurate, but perhaps overly simple given their significant influence on overall opex[231]. A more targeted approach to this aspect of forecasting opex unit costs could provide insights into efficiency opportunities.

In regard to service delivery, PB is only aware of a few other Australian distributors that have trained their asset inspectors to carry out all on-site inspections while on location, and then use a systems-based approach to programming the rectification of the defects found. We consider this to be a very efficient way of managing distribution assets and contend that this approach should contribute to overall cost efficiency.

PB asked Ergon Energy to provide some internal benchmarking of its opex costs against those procured from contracted service providers to inform some degree of efficiency of overall opex costs. However, Ergon Energy only provided us with information about customer-initiated capital works; we received no opex comparisons. PB was therefore not

230 Ergon Energy Corporation Limited 2009, Regulatory proposal to the Australian Energy Regulator: distribution services for period 1 July 2010 to 30 June 2015, p.332

231 In the case of full service inspections, the geographic/locational cist comprises 43% of the total direct cost.

able to provide any advice on the effectiveness or efficiency of service delivery arrangements at a functional level.

6.4 Network operations opex

Network operating costs include the activities of monitoring and controlling the transmission, sub-transmission and distribution networks from two 24-hour operation control centres. Principal activities are: switching and outage coordination; managing energy flows; coordinating with Powerlink and NEMMCO; fault management; and contingency planning. Some expenses associated with network protection and communication changes and field-based switching are also booked to network operations cost centres.

6.4.1 Proposed expenditure

The proposed expenditure for network operating costs as presented in the Ergon Energy proposal is shown in Table 6.16. 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 network operations cost category.

Table 6.16 Proposed network operations opex for the next regulatory control period

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposal	26.36	26.33	26.67	27.21	27.51	134.08
Ergon Energy proposal — no escalation	24.64	24.20	24.10	24.19	24.05	121.18

Source: PB analysis and AR539c_RIN Submission Model.xls, template 2.2.2 opex

Ergon Energy has forecast its network operations opex using 2007–08 as a base year, adjusted for abnormalities and with no growth

6.4.2 PB assessment and findings

In accordance with its Network Operations forecast report[232], Ergon Energy has stated that this group will continue to function in the existing business manner with the same functional design, and any increases in workload (i.e. as associated with the increased capex program) will be absorbed through productivity and efficiency gains. This is consistent with the observed reduction in opex forecasts over the next regulatory period (after real labour escalation has been removed).

As a result of our review of the operation forecast report, including the presentation of a detailed bottom-up (FTE-based) budgeting process informed through historical actual costs, plus the inclusion of a number of specific key performance indicators (KPIs) and performance targets related to operational excellence and safety and environment aspects, PB is satisfied that the forecast represents a prudent and efficient allowance. This conclusion is not altered by the fact that Ergon Energy's Network Operation group has recently moved to two 24-hour control centres, and staff numbers have thus been increased.

232 AR236c_EE_Network Operations Forecast Report (Works Planning).pdf

PB considers the base-year opex identified is efficient and Ergon Energy has made appropriate adjustments to remove abnormalities.

6.4.3 PB recommendations

PB considers the forecast allowance is prudent and efficient, and we have not recommended any adjustment to the proposed opex. Table 6.17 summarises our recommendations.

Table 6.17 Recommended network operations opex for the next regulatory control period

	2010–11	2011–12	2012–13	2013–14	2014–15	TOTAL
Ergon Energy proposal	26.4	26.3	26.7	27.2	27.5	134.1
PB adjustment	0.0	0.0	0.0	0.0	0.0	0.0
PB recommendation	26.4	26.3	26.7	27.2	27.5	134.1

Source: PB analysis

6.5 Preventive maintenance opex

Preventive maintenance costs include the activities of scheduled inspection and maintenance across the network asset base in accordance with 26 separately classified asset equipment categories.

6.5.1 Proposed expenditure

The proposed expenditure for preventive maintenance as presented in the Ergon Energy proposal is shown in Table 6.18. 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 preventive maintenance category. Vegetation management and corridors and sites preventive maintenance costs have been separated; these are reviewed in section 6.8.

Table 6.18 Proposed preventive maintenance opex for the next regulatory control period

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposal	108.8	119.6	120.2	123.34	121.7	593.6
Ergon Energy proposal — no escalation	100.8	108.7	107.2	108.0	104.5	529.2
Ergon Energy proposal — vegetation and corridors and sites removed	23.8	24.3	25.1	24.9	21.3	119.4

Source: PB analysis and AR539c_RIN Submission Model.xls, template 2.2.2 opex

Ergon Energy has forecast its preventive maintenance opex using a detailed bottom up approach across each asset equipment type.

6.5.2 PB assessment and findings

Table 6.18 indicates that, after removing real escalation and vegetation and corridors and sites, there is a considerable increase in preventive maintenance requirements over the next regulatory control period.

The Asset Equipment Plans[233] for each asset class and the NARMCOS model describe in detail the approach to preventive maintenance for each asset type.

To give an indication of the materiality of preventive maintenance across the key asset classes (after excluding vegetation and corridors and sites), the proportion of total preventive maintenance in 2010–11 in direct expenditure from NARMCOS is shown in Table 6.19.

Table 6.19 Proportion of preventive maintenance by key asset class in 2010–11

Asset class	% total preventive in 2010–11	Asset class	% total preventive in 2010–11
02 – Poles	41.7%	07 - Dist. Enclosed Switches	1.9%
01 – Meters	10.3%	19 - ZS CTs & VTs	1.8%
13 - Dist. Earths	5.4%	26 - Control	1.1%
08 - Dist. Air Break Switches	5.3%	04 - Conductor & Connectors	1.1%
11 - Dist. Services	5.2%	22 - ZS AC & DC Systems	1.1%
03 - Pole Tops	4.9%	18 - ZS Circuit Breakers	1.0%
24 - Comms	4.4%	06 - Dist. Transformers	0.6%
05 - UG Cables & Joints	4.1%	14 - Dist. Reactors & Regul.	0.4%
17 - ZS Transformers	3.1%	21 - ZS Capacitor Banks	0.1%
25 - Protection	2.3%	09 - Fuses	-
23 - ZS Civils	2.1%	10 - Lightning Arrestors	-
20 - ZS Outdoor Switchyards	2.1%		

Source: PB analysis and AR539c_RIN Submission Model.xls, template 2.2.2 opex

Table 6.20 summarises Ergon Energy's proposed changes to its approach to preventive maintenance, as described in each of the Asset Equipment Plans and the NARMCOS model.

233 AR226_EE_Asset Equipment Plans 2009.zip

Table 6.20 Increased inspection and maintenance by asset class

Asset classes	Preventive program	Inspection cycle	Five-year direct cost impact ($m 07–08)
Meters	LV CT metering accuracy	Every 5 years	6.48
	Receiving inspection	All units	0.16
	Ripple and time control	3000 p.a.	0.30
	Smart Meter pilot	-	4.51
Poles	Pole top inspections (high rainfall)	Every 4 years	-
Pole tops	High risk lines – visual inspections mast	Every 4 years	1.22
	High risk lines – visual inspections aerial	Every 4 years	3.02
UG cables & joints	Underground pillar internal inspections	Every 8 years	3.82
	High risk cable assessment	Condition/risk	1.08
Distribution services	Full inspection of overhead services	Every 12 years	25.85
Distribution reactors regulators	Routine inspection program	Every 6 months	1.29
ZS circuit breakers	Internal inspection and testing of switchboards	Every 10 years	0.43
ZS CTs and VTs	Epoxy CT and VT partial discharge tests	Every 4 years	0.75
Communications	UbiNet requirements	n.a.	8.80
Protection	Recloser and sectionaliser battery repl.	Every 2 years	0.71
Control	Ripple control system inspections	Annually	0.52
	Control and equipment room maintenance	Every 6 months	0.07
	RDAS equipment room maintenance	Every 6 months	0.13

Source: PB analysis and AR226_EE_Asset Equipment Plans 2009.zip

Based on the qualified risk assessments presented in each of the AEP reports, PB considers the vast majority of the new programs are prudent and reasonable, and that Ergon Energy has adopted reasonable and pragmatic inspection cycles for its new programs to balance costs with safety and compliance needs.

In particular, PB notes the historical records of safety-related incidents presented by Ergon Energy relating to shocks and tingles for overhead services (for which there is a population of over 450,000) and underground pillars (for which there is a population of over 106,000).

The exception to the above general conclusion is the ground-based inspections (primarily covering poles, but also including the visual inspection of other asset classes) which are undertaken on a four-year cycle. This approach is adopted in order to meet the regulatory requirement of five-year inspection cycles as detailed in the ESO's Code of Practice for Works. Ergon Energy advised that, while the regulation allows for a longer inspection cycle based on a detailed risk-driven engineering assessment, such an assessment is unlikely to be conducted until a full collection of cycle data is complete and further engineering analysis has been performed by Ergon Energy.

Ergon Energy previously conducted three-year inspection cycles for wood poles from 2002 and increased this to four-year cycles in 2006. By 2010, it will therefore have completed at least two full cyclic inspections of its pole asset population, leading to a detailed and comprehensive understanding of the condition of these assets. In PB's view the three year cycle approach adopted in the past has directly led to the Ergon Energy wood pole fleet demonstrating excellent reliability performance (as discussed in sections 6.2.2 and shown in Figure 6.5), with low replacement requirements and nailing rates, and with an unassisted failure rate at an industry-leading level — currently only half the rate of the required standard. On this basis, PB considers it would be reasonable for Ergon Energy to extend its pole inspection cycle to at least 4.5 years, as this is not likely to detrimentally affect the businesses risk profile or pole failure rate, whilst still allowing for a suitable operational margin to ensure that all poles are inspected within the regulatory required time frame of five years. PB also considers this approach would bring Ergon Energy closer in line with similar distribution businesses, such as ENERGEX which already adopts a five year inspection cycle. The increase in inspection cycle from 4 to 4.5 years would reduce preventive inspection opex by $15.35m[234], as outlined in Table 6.21.

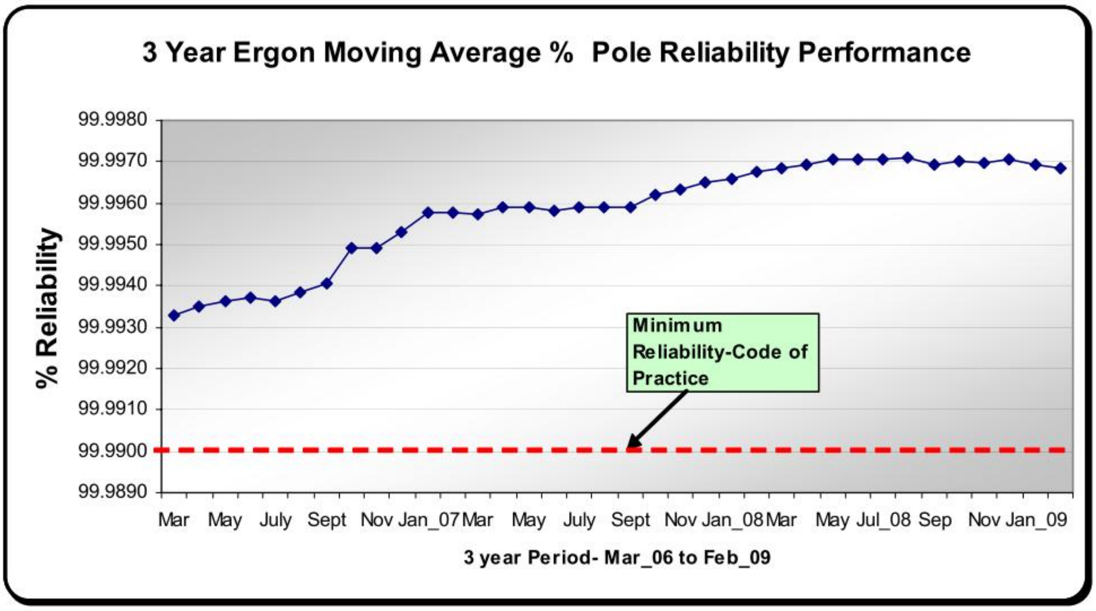

Figure 6.5 Ergon Energy pole asset reliability performance

Source: AR355_EE_Asset Maintenance Strategy_V0.8_Apr09.pdf , p. 10

PB also reviewed the need for a materially new opex requirement associated with the full inspections of overheads services. This has arisen due to the large number of distribution services identified that are not installed in accordance with current standards and which have possibly incorrect polarity and faulty neutral connections, potentially leading to personal injury or death. An ESO audit conducted in April 2007[235] identified that the current visual inspection program is not effective in identifying these risks, so in response, a significant increase in full inspections for customer overhead services was implemented by Ergon Energy. While PB recognises and accepts the need to undertake these full inspections, PB's view is that it would be prudent and efficient to reduce the coincident visual inspections at the same rate that the full inspections are increasing, given that they achieve similar outcomes, after the completion of the pilot program in 2009–10. This has the impact of reducing the preventive maintenance opex by $2.90m, as outlined in Table 6.21.

234 Assuming the growth escalation has previously been removed as per Table 6.10 of this report. The approach adopted to quantifying the adjustment is conservative as it has not accounted for extensions in the cycle for the numerous other inspection programs that are coordinated with the key ground-based inspection program.

235 AR226_EE_AEP 2009_11_Customer Low Voltage Services.pdf, p.7

6.5.3 PB recommendations

PB recommends a reduction in preventive maintenance opex of $18.25m during the next regulatory control period. The reductions would result from an increase in the pole inspection cycle frequency to 4.5 years and a reduction in the visual inspections in response to the increase in full inspections.

Table 6.21 Recommended preventive maintenance opex for the next regulatory control period

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposal	108.8	119.6	120.2	123.4	121.7	593.7
PB adjustment – reduced service inspections	0.0	(0.7)	(0.7)	(0.7)	(0.7)	(2.8)
PB adjustment – pole inspections to 4.5 years	(3.1)	(3.1)	(3.1)	(3.1)	(3.1)	(11.0)
PB recommendation	105.7	115.8	116.4	119.6	117.9	575.4

Source: PB analysis

6.6 Corrective maintenance opex

Corrective maintenance costs include the activities associated with planned repair work in response to defects that have been identified as part of preventive maintenance. Approximately two-thirds of the corrective maintenance program relates to vegetation management and access track remediation. For the purposes of PB's assessment, these items have been separated and are reviewed in section 6.8.

6.6.1 Proposed expenditure

The proposed expenditure for corrective maintenance as presented in the Ergon Energy proposal is shown in Table 6.22. 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 corrective maintenance category. Vegetation management and corridors & sites preventive maintenance costs have been separated from the forecast and these are reviewed separately in section 6.8.

Table 6.22 Proposed corrective maintenance opex for the next regulatory control period

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Proposal	121.9	121.5	122.8	117.9	105.7	589.8
Corrective maintenance – no escalation	112.9	110.4	109.5	103.2	90.7	526.7
Ergon Energy proposal – no vegetation and corridors and sites	31.5	31.5	32.1	32.4	32.3	159.8

Source: PB analysis and AR539c_RIN Submission Model.xls, template 2.2.2 opex

Ergon Energy has forecast its corrective maintenance opex using a detailed bottom up approach for the key cost category of vegetation management, which is discussed in section 6.8.

For the other asset equipment types Ergon Energy has used 2007–08 as a base year from which to forecast expenditures.

6.6.2 PB assessment and findings

Ergon Energy has advised that the forecast has been based on 2007–08 costs (its Ellipse works management system was in place at this time), and on the basis that there were no abnormal items identified in the underlying defect-related data.

Ergon Energy adjusted its base year historical costs for scope changes (amounting to an additional 4% of total corrective maintenance), including:

- repairing issues managed in the safety incident system
- dismantling old replaced lines
- asbestos clean-up
- increasing failure rates of meters.

The forecast corrective maintenance opex was subsequently allocated the to the 26 asset classes based on historical and expected failure rates and subject matter expertise. Table 6.21 indicates that, after deducting real escalation and the costs associated with vegetation management and corridors and sites, there is some minor growth anticipated in the corrective maintenance category.

Regarding the forecast methodology, the introduction of a scope change within the corrective maintenance opex allowance for the dismantling of old lines that have been replaced is not considered by PB to be a prudent or reasonable approach, as this work is project-related and should be capitalised[236]. Ergon Energy has identified that 4% of the corrective maintenance allowance is attributed to various scope changes, and that 40% of the 4% scope change is attributed to the project-related line replacements. Therefore, PB is recommending that a 1.6% (4% x 0.4) reduction be made to the corrective maintenance forecast, as shown in Table 6.23, to remove the scope increase proposed by Ergon Energy as this is likely to have been included in previous capex forecasts. Specifically, PB has not added this reduction back into the capex forecasts as there is evidence this is already included as part of capex project cost estimating processes, and it has been treated as being double counted.

PB considers the balance of the base-year opex proposed is prudent efficient, and that Ergon Energy has made appropriate adjustments to remove abnormalities and include justified and three additional and reasonable scope changes.

236 PB notes that in PL601c, Ergon Energy explicitly includes the removal of an existing line in its capital cost estimate.

6.6.3 PB recommendations

PB recommends a reduction in corrective maintenance opex of $9.44m during the next regulatory control period. The reductions would result from the removal of the estimate for dismantling old lines, which PB believes should be capitalised as part of project costs.

Table 6.23 Recommended reduction in corrective maintenance to remove line replacement works

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Ergon Energy proposal	121.9	121.5	122.8	117.9	105.7	589.8
PB adjustment	(2.0)	(1.9)	(2.0)	(1.9)	(1.7)	(9.5)
PB recommendation	119.9	119.6	120.8	116.0	104.0	580.3

Source: PB analysis

6.7 Forced maintenance opex

Forced maintenance costs include the activities associated with unplanned repair or restoration work that is carried out as quickly as possible after an event or an outage in order to return the network to an acceptable and safe operating condition. This typically includes outages due to storms and plant failures.

6.7.1 Proposed expenditure

The proposed expenditure for forced maintenance as presented in the Ergon Energy proposal is shown in Table 6.24. 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 forced maintenance category.

Table 6.24 Proposed forced maintenance opex for the next regulatory control period

	2010–11	2011–12	2012–13	2013–14	2014–15	TOTAL
Ergon Energy proposal	41.0	40.9	41.3	41.4	41.1	205.7
Ergon Energy proposal – no escalation	39.4	38.6	38.5	38.0	37.1	191.6

Source: PB analysis and AR539c_RIN Submission Model.xls, template 2.2.2 opex

Ergon Energy has forecast its corrective maintenance opex using a detailed bottom up approach for the key cost category of vegetation management, which is discussed in section 6.8.

For the other asset equipment types Ergon Energy has used 2007–08 as a base year from which to forecast expenditures.

6.7.2 PB assessment and findings

The forecasting methodology adopted by Ergon Energy took the 2007-08 as a base year and adjusted this value down by 7%[237] to account for the floods that occurred in that year. This timeframe reasonably accounts for significant beneficial efficiencies associated with the introduction of the Ellipse system in 2006–07, while also including the detrimental effects of flooding in 2007–08.

Table 6.24 indicates that, after removing real escalation, there is no forecast increase in the forced maintenance expenditure requirements.

PB considers the forecasting approach (i.e. establishing a base-year from the average over the three year period 2006-07 to 2008-09) is suitable for the purposes of projecting the baseline forced maintenance opex allowance because it captures the benefits of the Ellipse investment and smoothes out storm-related impacts. PB is concerned, however, that the forecast opex does not sufficiently account for Ergon Energy's proposed and significant asset replacement and preventive and corrective maintenance forecasts. In particular:

- the significant increase in strategic vegetation management
- the increased inspection programs that are targeted at reducing unplanned asset failures (specifically, the high-risk pole top inspections, the high-risk cable testing, the service inspections, and the reactor and regulator inspections)
- the significant increase in asset replacement capex culminating in a forecast $1.0b over the next regulatory period (specifically in the asset classes of conductor and connectors, pole tops, ZS transformers, underground cables and joints, ZS instrument transformers and protection equipment).

Ergon Energy contends that the proposed asset replacement capex and other maintenance activity will not significantly reduce the forced maintenance requirements as is it largely driven by adverse weather conditions that cannot be readily managed.

To consider this matter further, PB has investigated the causes of outages as reported in the 2007–08 Annual Network Reliability Performance Report[238]. Table 6.25 contains the analysed data.

Table 6.25 2007–08 faults by cause code

Fault trigger	Number of events	% by number
Storm	1,717	11%
Failed – unknown	5,973	39%
Lightning	2,067	14%
Conductor	1,113	7%
Forced	1,724	11%
Unassisted failure	517	3%
Vehicle machinery	482	3%
Trip and manual re-close	643	4%

237 Ergon Energy Corporation Limited 2009, Regulatory proposal to the Australian Energy Regulator: distribution services for period 1 July 2010 to 30 June 2015, p.276

238 PL704c

Fault trigger	Number of events	% by number
Leakage / plot top fire	181	1%
Birds	776	5%
Total	15,193	100%

Source: PB analysis and PL704c_EE_Annual Network Reliability Performance Report_2007-08.pdf

Assuming that 50% of all faults with an unknown trigger are associated with some form of plant failure (on the basis that the unknown cause code represents such an unusually large proportion of the total number of faults, and given that the categories of storm, lightning and third party involvement are already explicit and assumed to be reasonably accurate), the data in Table 6.25 suggests that around 40% of all incidents are related to plant condition and performance[239]. While this is not a direct indicator of costs associated with the events, PB recommends using it as an indicator of the proportion of forced maintenance that can be improved by the proposed asset replacement capex and the various increased maintenance activities proposed by Ergon Energy.

PB recognises that a growing asset base means there are more assets that may be affected by storms and external influences. However, we still consider that a well-targeted, prioritised and significant asset replacement program should have an immediate and noticeable benefit in terms of a reduction in forced outages due to plant failures, and therefore should provide direct reliability improvements. On this basis, PB recommends a downwards adjustment of $6.7m (or 3.3%) of the forced maintenance opex. This would likely be realised in reductions in the unplanned maintenance associated with the asset equipment classes of corridors and sites, services protection, and communication and conductors/connections since this is where the asset replacement program is primarily targeted. The size of the reduction has been informed by:

- removing all growth in direct costs forced maintenance opex over the next regulatory period compared with the 2010-11 levels for every asset class
- reducing the corridors and sites direct costs in the NARMCOS model line entries in the same proportion as that proposed by Ergon Energy for the vegetation management after the first four year cycle has been completed (i.e. by 7.5% in 2012/13, by a further 8.11% in 2013/14 and by a further 8.82% in 2014/15i), as per Figure 6.6, to reflect the principle that the costs of the program will reduce after one full cycle of the four year program proposed, and
- applying an overhead escalation of 1.35, and real escalation of 1.0834 (50% of the cumulative real escalation over the five-year period for labour/contractors), and a factor of 1.04551 to convert the direct 07–08 costs to 09–10 levels.

239 It is noted that this proportion of incidents reflects the asset-related performance of other DNSP businesses such as ETSA Utilities also.

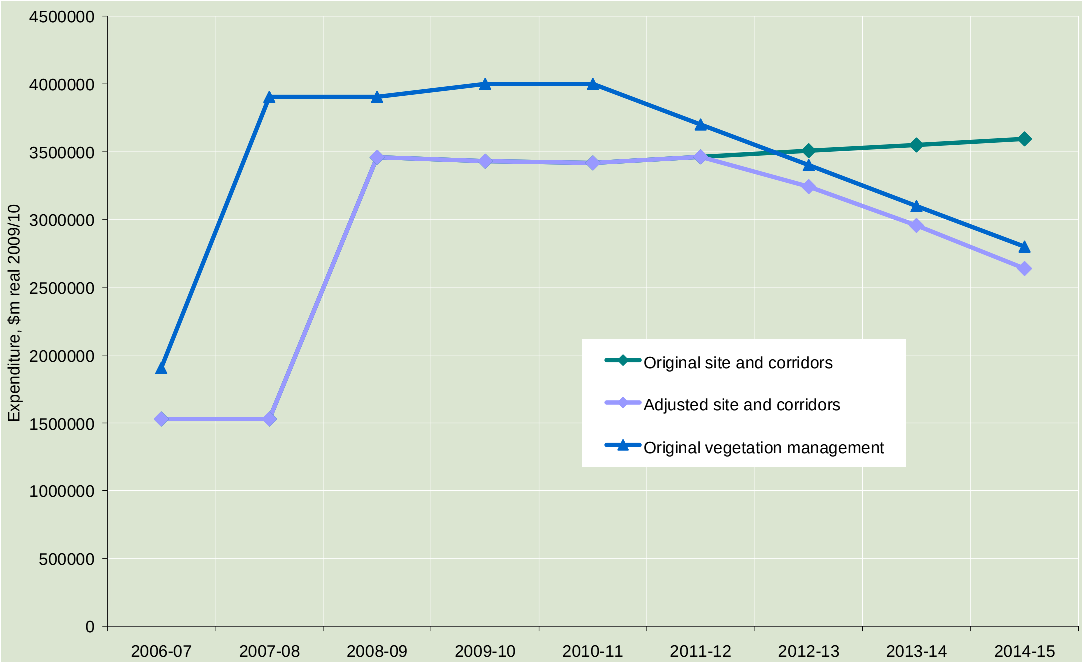

Figure 6.6 Ergon Energy direct costs associated with forced maintenance for sites and corridors

Source: PB analysis and NARMCOS model

6.7.3 PB recommendations

PB recommends a reduction in forced maintenance opex of $6.70m during the next regulatory control period (see Table 6.26). The reductions would result from removal of any growth in such maintenance to account for Ergon Energy's strategic move to condition based maintenance coupled with its targeted asset replacement program aimed at reducing the number of unplanned asset failures.

Table 6.26 Recommended forced maintenance opex for the next regulatory control period

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposal	41.0	40.9	41.3	41.4	41.1	205.7
PB adjustment	0.0	(0.4)	(1.2)	(2.1)	(3.0)	(6.7)
PB recommendation	41.0	40.5	40.1	39.3	38.1	199.0

Source: PB analysis

6.8 Vegetation management, access corridors and sites opex

Preventive vegetation management relates to scoping the vegetation work, including identification of how much cutting is required and by how many crews, while corrective vegetation maintenance relates to the actual cutting and therefore the vast majority of costs. Activities associated with bushfire mitigation, cultural heritage management, weed management and endangered species are included in this category.

Preventive maintenance for access track (corridors) and equipment sites relates to the routine inspection program associated with powerlines, enclosed substations and pad-mount substations; corrective maintenance is the response to defects identified as part of the inspections.

6.8.1 Proposed expenditure

The proposed expenditure for vegetation management, access corridors and sites maintenance as presented in the Ergon Energy proposal is shown in Table 6.27.

Table 6.27 Proposed vegetation and corridors and sites opex for the next regulatory control period

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Preventive – vegetation	17.3	17.7	18.4	18.2	16.9	88.5
Preventive – corridors and sites[1]	6.5	6.6	6.6	6.7	4.4	30.8
Corrective – vegetation	78.1	77.5	78.0	72.6	60.2	366.4
Corrective – corridors and sites[1]	12.2	12.5	12.7	12.9	13.1	63.4
Subtotal	114.1	114.3	115.7	110.4	94.6	549.1
Total opex	370.1	381.5	385.5	386.7	374.7	1,898.5
% vegetation, corridors and sites	30.8%	30.0%	30.0%	28.5%	25.2%	28.9%

[1] PB has estimated these figures based on scaling direct costs in 2007–08 from the NARMCOS outputs by 1.35 for overheads, 1.0834 for real escalation and 1.04551 to translate to 2009–10.

Source: PB analysis and EE Response to AER-PB Q.VP.34 - Annual Trimming Cycle Costs in $Real$2009-10, 30/07/08

As detailed in Table 6.27, the two elements of Ergon Energy's forecast opex for management of corridors and sites and easement vegetation comprise 29% of the entire forecast opex when combined.

Ergon Energy has forecast its vegetation management and corridor and sites maintenance opex using a detailed bottom up approach.

6.8.2 PB assessment and findings

The forecast methodology adopted for each expenditure item is based on a detailed bottom-up build of work volumes. For vegetation management, this has been informed through sampling condition assessments undertaken by VEMCO[240] (an independent vegetation management company), which adopted Ergon Energy's self-imposed vegetation clearing standard as documented in its Code of Practice Powerline Clearance (Vegetation) 2006[241] and its biodiversity model strategy as a guideline of the required work.

The biodiversity strategy sets different time-based clearing intervals across 14 different regions covering 2,115 pre-defined vegetation zones. Examples of the intervals are 12, 18 or

240 The sampling covered 21% of the total network spans.
241 AR076, P55C06R01

24 months for urban easements, and 24, 36, 48 or 60 months for rural easements. The biodiversity strategy was an outcome of a detailed review extending from 2006 to 2008, which identified that approximately 50% of the rural network had not been cleared for over 4 years. The review proposed a change in approach from fixed annual and three-yearly cycles for urban and rural areas, respectively, to varied cycles that allow for variations in climate and vegetation. Work is prioritised based on: a Normalised Difference Vegetation Index (NDVI) produced by the Bureau of Meteorology; whether it is an initial or regular cycle; customer numbers; voltage levels; locations; and other special circumstances (such as wet tropics or World Heritage status).

Volumes of vegetation clearance work, including the rural backlog, were informed through the VEMCO sampling data, while unit costs were based on scenarios that compared an average of historical competitively tendered rates internal to Ergon Energy with those provided by independently by VEMCO[242].

Under Ergon Energy's proposed strategy, legislative compliance is expected to be achieved by mid-to-late 2012. However, a fully sustainable vegetation management program in accordance with the biodiversity model and standard clearance dimensions will only be achieved by the end of the full cycle after the rural backlog is cleared. As the longest biodiversity interval is 60 months, this means that a sustainable vegetation position will not be reached until mid-to-late 2017.

Over the current regulatory period, Ergon Energy has been issued with a number of non-compliance Improvement Notices from the ESO relating to trees in contact with electric lines, as well as customer and internal staff initiated requests — a situation that is reactive and not cost-effective.

In regard to access tracks and equipment sites, Ergon Energy is proposing to continue with its routine inspections (either every 6 months, annually or every 2 years, based on the type and size of substation installation) and to introduce a new 4-yearly routine inspection cycle for its access tracks. Also proposed are a significant program to introduce standard keys and locks on gates for access tracks, and an increase in corrective access track remediation (effectively doubling the existing allowance from $4m to $8m (direct 07–08 costs). Ergon Energy has experienced changes to occupational health and safety work practices that demand a better standard of access tracks that would allow larger and heavier vehicles access to lines; it is also experiencing an increasing need to remediate tracks due to wash-outs and general erosion and deterioration.

Ergon Energy has provided clear evidence of the need for a significant change in approach to vegetation management. PB is generally satisfied that the developing vegetation strategy[243] and a consequential increase in costs is prudent. This is particularly the case with respect to the non-compliance in the rural network vegetation zones and the need to mitigate bushfire risks. PB is also satisfied that the proactive biodiversity-based strategy is likely to provide a long-term efficient framework for vegetation management.

PB notes the following positive aspects captured within Ergon Energy's proposed approach, which we consider to be critical in regards to a prudent and efficient approach:

242 Ergon Energy advised that it adopted the average as the unit rates provided by VEMCO were considered too low — i.e. they do not include all known costs, they were possibly not relevant to the size and remoteness of the Ergon Energy network with its high travel and LAFH costs, and were yet to be validated in the Queensland market place. Furthermore, Ergon Energy considered that the unit rates based on the Ergon Energy historical costs were too high — i.e. there is an opportunity to implement a different contracting model and more efficient work practices to those adopted in the past.

243 PL 586c, AR448c, AR022c, AR076 and AR226

- a costing model which explicitly accounts for the difference between the first cycle and subsequent cycles, progressively decreasing the work volume and costs
- the application of risk assessment processes to effectively prioritise the vegetation inspection and cutting programs
- the use of appropriate systems to manage field data, and monitor and report on progress of the program
- effective scheduling of work to match tree growth, using appropriate cutting profiles and inspection cycles to effectively address the risks of vegetation coming into contact with conductors
- a scheme of monitoring and auditing that ensures that all work is conducted in a manner that maximises productivity, quality and safety.

With respect to the forecasting and efficiency of costs, PB identified a 5% unit cost increase in the predictive costing models for the two scenarios based on Ergon Energy's historical costs. Ergon Energy has not justified this increase to its historical competitively sourced unit costs, and PB recommends that this increase be removed from the forecast. The impact of removing the 5% uplift factor is $11.93m[244] over the next regulatory control period, as shown in Table 6.28. PB also notes that Ergon Energy has not incorporated any economies of scale within its modelling to offset the significant increase in volumes of vegetation work proposed to eliminate the backlog under the biodiversity model approach. Furthermore, no evidence has been presented to verify the methodology, relevance, robustness or the transparency of the costs provided by VEMCO and used by Ergon Energy to inform its opex forecasts.

Ergon Energy has made specific allowances for the management of endangered species, declared plants (weeds) and cultural heritage management as part of its preventive vegetation allowance. While the need for each of these activities is specified and justified, Ergon Energy has incorporated a cumulative growth factor in the allowances for each of these activities of 80%, 40% and 100%, respectively, for the five-year period from 2010–11 to 2014–15, increasing the direct 2007–08 costs from $1.9m to $3.1m. In the absence of any detailed justification for the increases in these three areas by Ergon Energy, PB considers the proposed level of expenditure in 2010–11 is more reflective of a prudent and efficient level, and that productivity improvements over the next regulatory period associated with increasing experience, relationship development and repeat activities should be sufficient to cover any increase in expenditure required. PB recommends a further reduction of $4.61m[245] to remove the activity growth included in these three areas, as shown in Table 6.28. PB also notes that there is an additional allowance as part of the corridor and sites opex allowance for cultural heritage and environment checks and remediation, so PB considers this matter should be sufficiently captured as part of Ergon Energy's overall forecasts.

With regard to Ergon Energy's proposal for increased preventive and corrective maintenance associated with its corridors and sites, PB considers a move from a reactive to an increasingly proactive strategy has merit in that it will ensure remediation work can be undertaken in a more controlled manner instead of under emergency situations. On this basis, the increases in preventive maintenance appear prudent and, coupled with other asset inspection programs, should provide sufficient information for Ergon Energy to undertake targeted and effective corrective maintenance.

244 Estimated based on the assumption that the direct costs (in $m 2007–08) were multiplied by a factor of 1.35 to allow for overheads, 1.0883 for real escalation, and 1.04551 to covert to 2009–10. Ergon Energy should use its detailed model to verify this adjustment.

245 Estimated as noted in footnote 211.

In addition to the preventive inspections, Ergon Energy is also anticipating a significant step change (effectively a doubling of direct costs from $4m to $8m (real 07–08) per annum) in corrective maintenance to remediate defects identified as part of the inspections. This step change has not been substantiated, and whilst Ergon Energy expects the subsequent inspection cycles to take less time and generate fewer defects[246], there is no reduction in forecast preventive or corrective costs to account for this. PB recommends that a notional 30% increase in work volume from that required in 2009/10 (instead of the 100% increase proposed by Ergon Energy) be included in the forecast allowance to account for a moderate and reasonable increase in corrective maintenance in order to capture opportunities from the proactive risk management approach. Data captured during the new inspection program should provide sufficient information for Ergon Energy to prioritise its remediation works. PB recommends a reduction of $23.65m[247].

Another significant step change included in the preventive access track opex allowance is the systematic installation of new keys and locks on access track gates to improve security. Ergon Energy is proposing to install 300,000 units, or approximately 3 per kilometre of access track (including those for the remote SWER lines), at a total estimated cost of around $9.21m (based on direct costs of $6m (real 07–08) over the next regulatory control period. While conceptually there is some merit and convenience in using a common key system for access tracks, Ergon Energy has not justified this material increase in opex through either a risk assessment or an economic assessment. On this basis, PB recommends that a nominal allowance of $0.92m is included to allow for the prioritised and selective replacement of 24,000 units (in addition to the 60,000 installed within the current regulatory period) ensuring that there is a new lock and common key across, on average, each kilometre of track. The associated reduction in opex is shown in Table 6.28.

PB anticipates that the approach proposed by Ergon Energy in its strategic vegetation management and corridor and sites maintenance will provide significant performance improvements in the context of reduced forced maintenance and improved reliability performance, especially in the rural network.

6.8.3 PB recommendations

PB recommends a reduction in vegetation management, corridors and sites opex of $48.48m during the next regulatory control period. The reductions result from removal of the 5% uplift in unit costs, removal of activity growth, reduction of growth in corrective opex for access tracks to 30%, and a reduced number of keys/locks in the forecast program.

246 AEP-15, Access Tracks and Equipment Sites, p. 8

247 Estimated as noted in footnote 211. This approach also removes the 1.6% growth escalator included by Ergon Energy, and is conservative in that it does not reduce the corrective maintenance required after the completion of the first four-year cycle.

Table 6.28 Recommended vegetation management and corridors and sites opex for the next regulatory control period

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Proposal	114.2	114.3	115.7	110.3	94.7	549.2
Difference – remove 5% uplift in unit costs	(2.6)	(2.6)	(2.5)	(2.3)	(2.0)	(12.0)
Difference – remove activity growth	(0.0)	(0.5)	(0.9)	(1.4)	(1.8)	(4.6)
Difference – only 30% growth in corrective for access & sites	(4.3)	(4.5)	(4.7)	(4.9)	(5.1)	(23.2)
Difference – reduced volume of keys/locks	(2.1)	(2.1)	(2.1)	(2.1)	(0.0)	(8.4)
PB recommendation	105.2	104.6	105.5	99.6	85.8	500.7

Source: PB analysis

6.9 Meter reading and customer services opex

Meter reading costs include the activities relating to collecting, processing, loading and publishing meter data for market participants in the context of Ergon Energy's NER obligations as a Metering Data Provider for types 5, 6 and 7 metering installations. This opex category specifically excludes metering maintenance work, as this is captured in network maintenance activities.

Customer services costs include customer-related activities that are ancillary to the provision of Ergon Energy's broader network, connection and metering services, including: cold water reports; check inspections; revenue protection; customer support; managing safety compliance; and customer advisory services. This opex category specifically excludes retail and call centre activities, which are treated as overheads.

6.9.1 Proposed expenditure

The proposed expenditure for meter reading and customer services as presented in the Ergon Energy proposal is shown (separately) in Table 6.29.

Table 6.29 Proposed meter reading and customer services opex for the next regulatory control period

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposal – metering	11.8	11.8	12.0	12.3	12.5	60.4
Ergon Energy proposal – metering – no escalation	10.9	10.7	10.7	10.7	10.7	53.7
Ergon Energy proposal – customer services	19.8	19.9	20.2	20.6	20.8	101.3
Ergon Energy proposal – customer services – no escalation	18.8	18.6	18.5	18.6	18.5	93.0
Total — proposal	31.6	31.7	32.2	32.9	33.3	161.7
Total — proposal, no escalation	29.7	29.3	29.2	29.3	29.2	146.7

Source: PB analysis and AR539c_RIN Submission Model.xls, template 2.2.2 opex

Ergon Energy has forecast its meter reading and customer services opex using 2007–08 as a base year, adjusted for abnormalities and scope change for NER obligations and FRC impacts.

6.9.2 PB assessment and findings

Table 6.29 (above) indicates that, after removing real escalation, there is no growth or step change in work proposed in the meter reading or customer services cost categories. PB understands the customer service opex in 2009-10 includes a portion of alternative control services, which are excluded from the next regulatory control period forecasts.

Ergon Energy has outlined its opex forecast of customer care, including meter reading, in a work-planning section report[248]. This document outlines how the majority of customer care work is classified as either Standard Control Services or Alternative Control Services and forecasts direct costs in accordance with the key activities of:

- customer installation services
- network metering
- meter reading — mass market
- prescribed services for retailers
- prescribed services for others
- public/consumer safety
- Guaranteed Service Level processing and payments.

The direct forecasts are reproduced in Table 6.30 for transparency.

248 AR272c_EE_Customer Care Forecast Report including Meter Read.pdf

Table 6.30 Direct opex forecasts from Works & Contract Management (WCM) group for the next regulatory control period

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Standard Control Services	10.6	10.6	10.6	10.6	10.6	53.0
Alternative Control Services	13.7	14.3	15.1	16.0	16.7	75.8
Unregulated	0.2	0.2	0.2	0.2	0.2	1.0
Total	24.5	25.1	25.9	26.8	27.5	129.8

Source: AR272c_EE_Customer Care Forecast Report including Meter Read.pdf, table 6

These figures can be compared directly to Ergon Energy's opex modelling, as presented in Table 6.31.

Table 6.31 Direct opex forecasts modelled by Ergon Energy for the next regulatory control period

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Meter reading	7.5	7.5	7.6	7.7	7.8	38.1
Customer services	13.0	13.1	13.1	13.3	13.5	66.0
Total	20.5	20.6	20.7	21.0	21.3	104.1

In PB's view, the significant difference between the direct costs input into Ergon Energy's forecast modelling (Table 6.31) of $104.1m and the standard control service costs in Table 6.30 of $52.86m strongly suggest that Ergon Energy has included a proportion of its alternative control services or unregulated activities in its forecast allowance[249].

On this basis, PB recommends that such expenditure be removed as it should be captured through other regulatory provisions. In order to estimate the impact on the forecast opex included by Ergon Energy for this purpose, PB has used the ratio of meter reading to customer services activities as indicated by the direct costs forecast by the Works and Contract Management business unit in Table 6.31 (i.e. 36.6%:63.4%) and on the Standard Control Services direct costs in Table 6.30 to arrive at a split between the two categories, and then scaled each of these by the ratio of the direct costs in Table 6.31 to the allowances sought by Ergon Energy in its RIN template, as shown in Table 6.32.

249 PB raised this matter with Ergon Energy, and received advice to the effect that it "urges caution in assuming that all of the detail in AR272c is completely accurate", and that "the forecast produced by the business-as-usual budget forecast process was adopted for preparing the Regulatory Proposal forecasts" and that it "can warrant that the analysis in AR272c is reasonable in reaching the AER forecast" (refer EE Response to AER-PB Q.VP94 - Opex Reconciliation with Doc AR272c, email 09/09/09).

Table 6.32 Opex forecasts for the next regulatory control period

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Meter reading – allowance	11.8	11.8	12.0	12.3	12.4	60.3
Meter reading – direct	7.5	7.5	7.6	7.7	7.8	38.1
Meter reading ratio	1.6	1.6	1.6	1.6	1.6	8.0
Customer services – allowance	19.82	19.86	20.19	20.60	20.81	101.3
Customer services – direct	12.99	13.05	13.11	13.32	13.53	66.0
Customer services – ratio	1.5	1.5	1.5	1.5	1.5	7.5

Source: PB analysis and AR539c_RIN Submission Model.xls, template 2.2.2 opex

6.9.3 PB recommendations

PB recommends a reduction in meter reading and customer service opex of $79.56m during the next regulatory control period. The reductions result from removal of Alternative Control Services activities inadvertently included in the Standard Control Service forecasts. PB's recommended allowance for meter reading and customer services after removing these items is presented in Table 6.33.

Table 6.33 Recommended meter reading and customer service opex for the next regulatory control period

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Ergon Energy proposal -Meter reading	11.8	11.8	12.0	12.3	12.5	60.4
Ergon Energy proposal -Customer services	19.8	19.9	20.2	20.6	20.8	101.3
Ergon Energy proposal -Subtotal	31.6	31.7	32.2	32.9	33.3	161.7
PB adjustment – Meter reading	(5.7)	(5.8)	(5.9)	(6.1)	(6.3)	(29.8)
PB adjustment – Customer services	(9.6)	(9.7)	(9.9)	(10.2)	(10.5)	(49.9)
PB adjustment - Subtotal	(15.3)	(15.5)	(15.8)	(16.3)	(16.8)	(79.7)
PB recommendation - Meter reading	6.1	6.1	6.2	6.2	6.2	30.8
PB recommendation - Customer services	10.2	10.2	10.3	10.4	10.3	51.4
Subtotal	16.3	16.3	16.5	16.6	16.5	82.2

Source: PB analysis

6.10 Other opex

Other operating costs include the activities associated with training, the demand management innovation allowance (DMIA), self-insurance, demand management (DM) opex and the cost of operating under the Guaranteed Service Level (GSL) regime[250].

[250] It is noted that GSL components have been included in both Customer Services and Other opex categories.

6.10.1 Proposed expenditure

The proposed expenditure for other operating costs, as presented in the Ergon Energy proposal, is shown in Table 6.34. 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 other operating costs category.

Table 6.34 Proposed other operating costs opex for the next regulatory control period

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposal	40.5	41.6	42.3	43.9	45.5	213.8
Ergon Energy proposal – no escalation	38.2	38.9	39.1	40.0	40.9	197.1

Source: PB analysis and AR539c_RIN Submission Model.xls, template 2.2.2 opex

Ergon Energy has forecast its ‘other’ opex using 2007–08 as a base year, adjusted for abnormalities and scope changes including training, self insurance, demand management and the DM innovation allowance.

6.10.2 PB assessment and findings

When compared to ‘other’ opex in the 2009-10 year of $24.9m, Table 6.34 indicates that, after removing real escalation, there is a significant step change in work proposed in the ‘other’ cost category. This has been attributed by Ergon Energy to:

- inclusion of an allowance of $20.1m over the five-year period for self insurance (this allowance is excluded from PB’s review)
- inclusion of an allowance of $1m per year (nominal) over the five-year period for the DMIA
- inclusion of training costs of $20m per annum, which were previously included as overheads
- inclusion of $61m over the five-year period to cover anticipated non-network (DM) opex.

During the current regulatory control period training costs were included as part of the shared costs pool. Due to a change in accounting treatment (in 2005-06, the international Financial Reporting standards changed the accounting standard such that training costs could no longer be capitalised), training costs of approximately $20m per annum will be treated as operating expenditure. Ergon Energy is legally obliged to conduct a large amount of training, particularly to ensure that safe work practices are used in the field. Training will also target skills for SCADA and communications systems. PB understands that there has not been an increase in training cost proposed by Ergon Energy[251] and has not investigated the details of this opex element further.

PB has not indentified any evidence to suggest that Ergon Energy has included opex costs associated with self insurance outside of the self-insurance opex allowance.

[251] Ergon Energy Corporation Limited 2009, Regulatory proposal to the Australian Energy Regulator: distribution services for period 1 July 2010 to 30 June 2015, p.155

PB has reviewed the proposed DM opex in further detail.

Ergon Energy states that the DM opex allowance consists of broad-based programs (as opposed to project-specific deferral considerations, which will be considered as part of capex expenditure), as outlined in Table 6.35.

Table 6.35 DM program opex forecasts

	2010–11	2011–12	2012–13	2013–14	2014–15	TOTAL
Program management	3.1	3.1	3.1	3.1	3.1	15.5
Large customers	0.6	1.2	1.2	1.2	1.2	5.4
Residential customers – other[1]	2.2	2.2	2.2	2.2	2.2	11.0
Airconditioning DLC[1]	3.3	3.4	3.4	3.5	3.6	17.2
Pool pumps[1]	0.7	0.7	0.7	0.7	0.7	3.5
Rural customers	1.1	1.1	1.1	1.1	1.1	5.5
Energy conservation one-stop shop	0.7	0.7	0.7	0.7	0.7	3.5
Total	11.7	12.4	12.4	12.5	12.6	61.6

Source: Regulatory Proposal, table 82, p.313

Note: [1] the disaggregation was undertaken by PB and has been confirmed By Ergon Energy as correct

The scope of work associated with each item in Table 6.35 is explained below:

- program management — internal costs to manage the various DM initiatives
- large customers — an extension of the Townsville commercial and industrial customer pilot project where the opex is an allowance to directly pay customers that have demonstrated demand reduction aggregating to 20 MW
- residential customers – other — an allowance for the promotion of existing load control tariffs, maintenance of load control relays, hot water demand load control (DLC), and customer appliance end use information
- air-conditioning DLC — extension of the pilot trial to 500 residential and 15 commercial customers, a finessing of the business model to allow for a second geographic site to be included
- pool pumps — trial for over 400 pool pumps to have a demand enabled reduction device to be installed
- rural customers — energy audits, off-peak pumping, and storage and hot water promotion
- energy conservation one-stop shop — for the creation of a centre of excellence in regional Queensland focused on customer education programs and energy efficiency.

As part of our review, PB notes that Ergon has no existing investment approval documents for the broad-based programs planned for the next regulatory control period. However, it did provide preliminary business case documentation for the residential pool pump and residential air-conditioning trials, and a detailed business case (inclusive of net benefit analysis) for the Townsville program targeting large customers. This latter business case was predicated on the basis that the DM would avoid or defer network capex based on a figure of $700,000/MW.

Notwithstanding the lack of preliminary cost–benefit analysis undertaken by Ergon Energy to support its significant increase in DM-related opex, PB is of the view that the various new trials and trial extensions proposed by Ergon Energy are well targeted and provide a pragmatic approach to increasing awareness and opportunities for demand-side activity. Furthermore, the initiatives will leverage off the existing load control relay infrastructure in an efficient manner.

However, Ergon Energy is proposing that $15.45m (25% of the DM allowance) was for internal project management, and that $2.63m of this can be directly attributed to an increase required to manage the proposed program compared with the current program[252]. As part of the business case for the Townsville large-customer pilot program, management costs were also included in the scope of work. PB also notes that Ergon Energy lacks a single, centralised demand management strategy or policy to present the wider objectives of its initiatives. The development of such a document is likely to improve wider co-ordination of the initiatives and capture some economies of scale and therefore further reduce internal project management costs.

PB considers the proportion of project management costs associated with the DM activities is not prudent and efficient, and recommends the $2.63m allowance to manage the proposed programs is excluded from the total allowance in accordance with Table 6.36. Economies of scale and productivity improvements arising from work practices associated with the remaining $12.8m for project management should reasonably allow for the new programs to be implemented.

6.10.3 PB recommendations

PB recommends a reduction in other operating costs opex of $2.63m during the next regulatory control period. The reduction results from removal of the program management forecast.

Table 6.36 Recommended other operating costs opex for the next regulatory control period

	2010–11	2011–12	2012–13	2013–14	2014–15	Total
Ergon Energy proposal	40.5	41.6	42.3	43.9	45.5	213.8
PB adjustment	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(2.5)
PB recommendation	40.0	41.1	41.8	43.4	45.0	211.3

Source: PB analysis

6.11 Specific Reviews - Inter-business benchmarking

The AER undertook inter-business benchmarking studies to assist in forming a view on the overall level of opex proposed by the Queensland and South Australia distribution network businesses.

252 This figure was also based on Ergon Energy's undertaking a significant large-customer program over the next regulatory period. However, the program was eventually scrapped.

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* (see Figure 6.8) and the normalised study of *opex/km versus customer/line length* (see Figure 6.7).

These studies are contained in the internal AER analysis provided to assist PB [253], which compares the Queensland and South Australia distributors forecast opex for the next regulatory control period against an efficiency frontier calculated using ACT, NSW, QLD and SA distributors 2007–08 financial year historical opex expenditures and network statistics. The use of actual (rather than regulatory-approved 2007–08 financial year expenditures) is preferred by PB, as these are representative of the opex costs realised 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[254] is 0.7599 and for the normalised study of *opex/km versus customer/line length* the R squared is 0.9269.

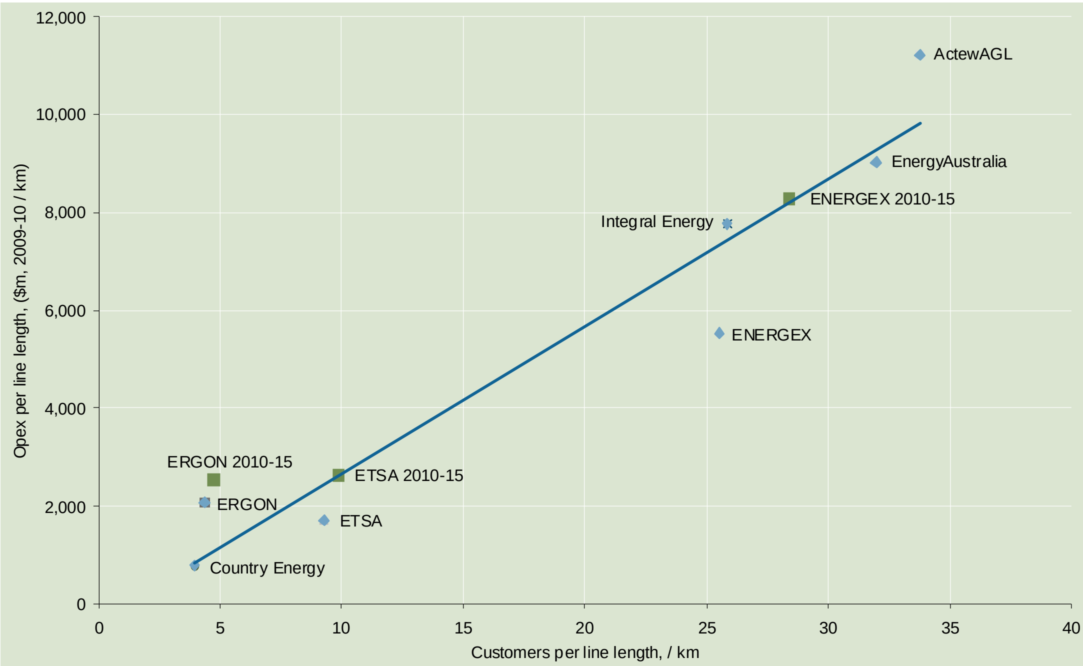

Figure 6.7 Normalised analysis of opex per km versus customers per line length
Source: AER Benchmarking Study

253 AER Opex Benchmarking 2001–02 to 2008–09

254 The R squared correlation factor indicates the degree of correlation where the closer R squared is to 1 the more closely correlated the items being modelled are.

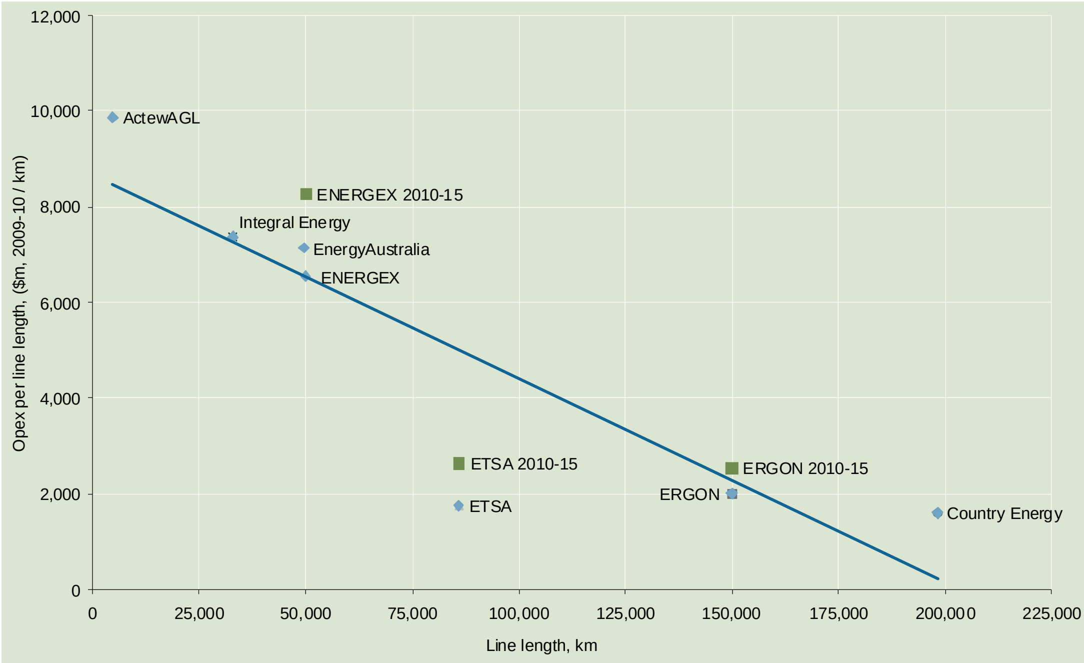

Figure 6.8 Simple ratio analysis of opex per km versus line length in km
Source: AER Benchmarking Study

Both these studies place the Ergon Energy forecast opex for the next regulatory control period between those achieved by Country Energy and ETSA Utilities. On the relative efficiency frontier dictated by opex/km vs. customer/line length (Figure 6.7), Ergon Energy's opex is seen to be relatively high. In the simple ratio of opex/km vs. line length study (Figure 6.8), Ergon Energy is on the relative efficiency frontier.

PB summary

PB believes that the AER benchmarking study indicates that Ergon Energy's opex forecasts are relatively high from a top-down inter-business comparative perspective. To a limited extent, this provides some support to the downwards adjustments PB has recommended to the AER as part of its detailed review of the forecast opex allowance.

PB notes the following reasons identified during our review that provide insight into why Ergon Energy's opex benchmarking may differ from the peer group:

- the treatment of Ergon Energy's ICT costs, which are treated as corporate overheads
- the inspection cycle–based approach to preventive maintenance, where efficiencies associated with contemporary condition or performance-based maintenance are not captured
- the considerable issues associated with the large supply area, in the context of: the vegetation management and corridor and sites requirements, including the significant rural backlog; the exposure to inclement and volatile weather; general travel costs; etc
- the general challenges associated with managing an asset that includes a Single Wire Earth Return (SWER) network extending to over 65,000 km in length and servicing only 26,000 customers.

6.12 Summary of findings and recommendations

This section presents a summary of PB's key findings and recommendations relating to Ergon Energy's forecast opex for the next regulatory control period.

Key findings

Ergon Energy proposes to spend $1,898.5m on opex in the next regulatory control period, an average increase of 23% compared with the current regulatory control period.

Network maintenance, including preventive, corrective and forced maintenance accounts for $1,389m, or 73% of the entire forecast.

Within the network maintenance forecast is an amount required for vegetation management and access track and site clearing summating to $549m, or 29% of the entire forecast.

Policies, documentation and modelling to support the asset management approach and the forecasting methodology is 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 in the current state, to a future state capturing more condition based knowledge and informed through leading indicators – reflective of an increase in strategic preventive maintenance requirements.

Pole and line asset performance is very good, while there are a significant number of annual failures occurring for substation plant such as transformers, switchgear and instrument transformers.

Except for the impact of network growth escalation, the opex forecasting approach adopted by Ergon Energy is reasonable and transparent, based on a detailed bottom-up view of asset quantities or work volumes across key asset categories in all the material areas, or a pragmatic top-down view informed by historical experience in areas where this is not practical.

For network growth escalation, the opex forecasting approach used by Ergon Energy includes only a simplistic view of the impact on opex associated with the growth of the network, and does not suitably capture the actual capex program proposed, nor integrate the various strategies, including capex/opex trade-off, effectively. PB recommends removal of some forecast opex related to incorporation of growth rates.

At a high-level, service delivery practices are reasonable and efficient, as is the estimating approach used to inform unit costs.

In comparison with a small sample of Australian DNSPs, Ergon Energy's opex forecasts appear relatively high from a top-down perspective using a composite size variable to normalise the businesses, and some reasons to explain this observation are indentified.

Network operating costs

Ergon Energy proposes to spend $134m on network operating costs, an increase of 2% compared with the current regulatory control period.

PB assessed Ergon Energy's proposed expenditure as prudent and efficient given the existing business approach and design of the workgroup, and the transparent bottom-up forecast.

Preventive maintenance

Ergon Energy proposes to spend $594m on preventive maintenance in the next regulatory control period, an average increase of 47% compared with the current regulatory control period.

Detailed asset equipment plans outline existing and new inspection programs across 26 asset categories, with a coordinated ground-based inspection program forming the foundation of the overall inspection program.

A number of new inspections are proposed in response to safety, regulatory and compliance issues.

Based on the excellent performance of the pole assets, there is an opportunity to move from a 4-year to a 4.5-year inspection cycle to improve opex efficiency, PB recommends a reduction in opex of $15.35m estimated to result from this change.

The number of visual inspections of customer services could be reduced based on the roll-out of a full inspection program in parallel, PB recommends a reduction in opex of $2.9m estimated to result from this change.

Corrective maintenance

Ergon Energy proposes to spend $590m on corrective maintenance in the next regulatory control period, including a significant component of vegetation clearing, an average increase of 22% compared with the current regulatory control period.

The top-down forecasting approach for asset based corrective maintenance is pragmatic, prudent and efficient, however it is recommended a scope increase to allow for dismantling old replaced lines is removed, resulting in a $9.44m reduction in this expenditure as this work is covered by the capex program.

Forced maintenance

Ergon energy proposes to spend $206m on forced maintenance in the next regulatory control period, an average decrease of 2% compared with the current regulatory control period.

PB found the methodology for determining the base-line maintenance requirements is reasonable, however Ergon Energy has not appropriately captured the benefits of its targeted asset replacement program to reduce forced maintenance need in the final years of the next regulatory period. PB recommends a reduction in forced maintenance opex of $6.70m during the next regulatory control period.

Vegetation management and corridors & sites

Ergon Energy proposes to spend $549m on vegetation management and corridors & sites in the next regulatory control period.

Ergon Energy has provided clear evidence of the need for a significant change in approach to its vegetation management, including a significant rural backlog and non-compliance with clearance standards.

The developing strategy, based on a biodiversity model with varying time-based clearing intervals across various regions and numerous pre-define vegetation zones is prudent and should deliver efficient long term cost outcomes.

However, PB recommends a reduction in vegetation management, corridors and sites opex of $48.48m during the next regulatory control period resulting from removal of a 5% uplift in unit costs, removal of unsubstantiated scope increases and a significantly reduced volume of keys and locks for access gates.

Customer service and meter reading

Ergon energy proposes to spend $101m on customer service in the next regulatory control period, an average decrease of 32%.

Meter reading costs are proposed to increase by 39% to $60m in the next regulatory control period.

PB recommends a reduction in meter reading and customer service opex of $79.56m during the next regulatory control period resulting from the inadvertent inclusion of Alternative Control Services activities in the Standard Control Service forecasts.

Other Opex

Ergon Energy proposes to spend $214m on ‘other’ opex in the next regulatory control period, an average increase of 91%.

PB recommends a reduction in ‘other’ opex of $2.63m during the next regulatory control period resulting from removal of a component of the program management forecast required for demand management initiatives.

PB recommendations

PB recommends that the forecast opex allowance for the next regulatory control period should be reduced by $188.0m, or 9.9% to $1,710.5. PB’s proposed adjustments are shown in Table 6.37.

Table 6.37 Recommended opex for the 2010-2015 regulatory control period.

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Network operations						
Ergon Energy proposal	26.4	26.3	26.7	27.2	27.5	134.1
PB adjustment	-	-	-	-	-	0.0
PB recommendation	26.4	26.3	26.7	27.2	27.5	134.1
Preventive maintenance						
Ergon Energy proposal	108.8	119.6	120.2	123.4	121.7	593.7
PB adjustment – reduced growth for poles	(1.4)	(1.8)	(2.3)	(2.8)	(3.3)	(11.6)

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
PB adjustment – reduced growth for services	(0.1)	(0.5)	(0.6)	(0.7)	(0.9)	(2.8)
PB adjustment– capex opex trade-off	(0.4)	(1.3)	(2.2)	(2.8)	(3.1)	(9.8)
PB adjustment – reduced service inspections	-	(0.7)	(0.7)	(0.7)	(0.7)	(2.8)
PB adjustment – reduced pole inspections	(3.1)	(3.1)	(3.1)	(3.1)	(3.1)	(15.5)
PB recommendation	103.8	112.2	111.3	113.3	110.6	551.2
Corrective network maintenance						
Ergon Energy proposal	121.9	121.5	122.8	117.9	105.7	589.8
PB adjustment – remove line replacement works	(2.0)	(1.9)	(2.0)	(1.9)	(1.7)	(9.5)
PB recommendation	119.9	119.6	120.8	116.0	104.0	580.3
Forced network maintenance						
Ergon Energy proposal	41.0	40.9	41.3	41.4	41.1	205.7
PB adjustment – removal of growth	-	(0.4)	(1.2)	(2.1)	(3.0)	(6.7)
PB recommendation	41.0	40.5	40.1	39.3	38.1	199.0
Vegetation management, access corridors & sites						
Allowance included implicitly within preventive and corrective maintenance						
PB adjustment – remove 5% uplift in unit costs	(2.6)	(2.6)	(2.5)	(2.3)	(2.0)	(12.0)
PB adjustment – remove scope increases	0.0	(0.5)	(0.9)	(1.4)	(1.8)	(4.6)
PB adjustment – reduce growth escalators for access and sites	(4.3)	(4.5)	(4.7)	(4.9)	(5.1)	(23.5)
PB adjustment – reduced quantity of keys/locks	(2.1)	(2.1)	(2.1)	(2.07)	(0.0)	(8.4)
PB recommendation	(6.4)	30.8	29.9	28.6	29.2	118.5
Meter reading						
Ergon Energy proposal	11.8	11.8	12.0	12.3	12.5	60.4
PB adjustment – removal of ACS	(5.7)	(5.8)	(5.9)	(6.1)	(6.3)	(29.8)
PB recommendation	6.1	6.0	6.1	6.2	6.2	30.6
Customer services						
Ergon Energy proposal	19.8	19.9	20.2	20.6	20.8	101.3
PB adjustment – removal of ACS	(9.6)	(9.7)	(9.9)	(10.2)	(10.6)	(50.0)
PB recommendation	10.2	10.2	10.3	10.4	10.2	51.3
Other opex						
Ergon Energy proposal	40.5	41.6	42.3	43.9	45.5	213.8

	2010-11	2011-12	2012-13	2013-14	2014-15	Total
PB adjustment – removal of DM project management	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(2.5)
PB recommendation	40.0	41.1	41.8	43.4	45.0	211.3
Total opex						
Ergon Energy proposal	370.1	381.4	385.4	386.6	374.7	1,898.2
PB adjustment	(31.6)	(35.1)	(38.3)	(41.3)	(41.5)	(187.8)
PB recommendation	338.5	346.3	347.1	345.3	333.2	1,710.4

Source: PB analysis

7. Deliverability

This section of the report presents PB's review of Ergon Energy's plans to deliver its proposed works program for the next regulatory control period, including the strategies the business has put in place.

Ergon Energy is proposing an extensive opex and system capex[255] program of work (PoW) over the next regulatory control period, which in total are increasing from $868m in 2009-10 to $1,327m in 2014/15 (excluding vegetation management, 'other' opex costs and non-system capex). This represents an increase of 53% over the outlook period, as shown in Figure 7.1.

Figure 60: *Annual change in Ergon Energy full time equivalent staff and contractors associated with system work for 2005-06 to 2014-15 (regulated and unregulated[61])*

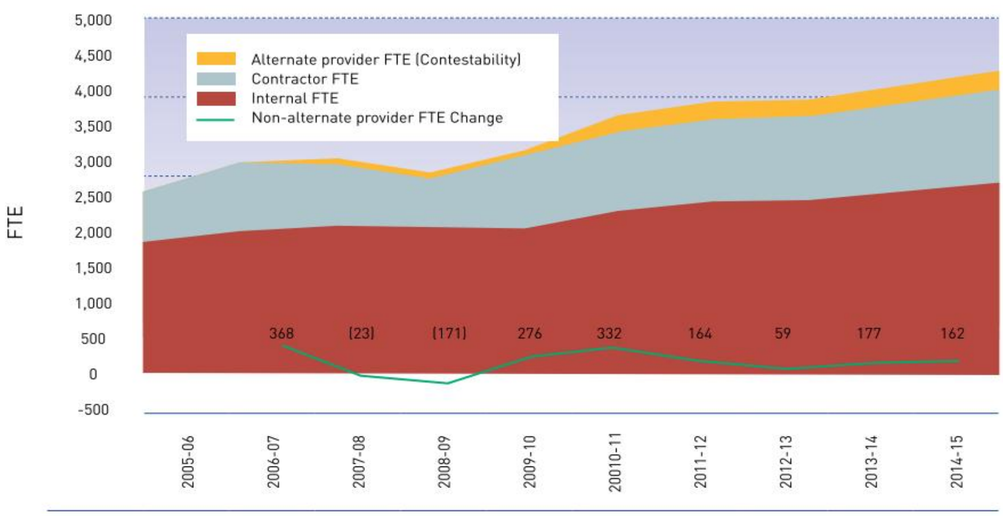

Figure 7.1 Ergon Energy opex over the 2005-2015 period

Source: Ergon Energy submission, p.350

Ergon Energy's internal field or "system" staffing levels (measured in FTE's required to deliver the PoW) are forecast to increase by 31% over the next regulatory period. A significant increase in outsourcing (Contractor FTEs) will also be required as well as increases in the work eligible to be undertaken by alternative providers[256]. Ergon Energy will also have to ensure delivery of materials necessary to construct the proposed capital works and deliver the asset replacement works, including long lead time assets such as transformers and circuit breakers.

As outlined in Figure 7.1, across its entire PoW (both capex and opex) Ergon Energy realised a growth in internal FTE's (non-alternate provider FTE) of 368 to deliver the 2006/07 works. The increase in 2006/07 exceeds the peak forecast growth in FTE's in the year 2010-11 of 332 FTE's and demonstrates that Ergon Energy has been able to ramp up at this rate in the current regulatory period.

255 The increase in non-system capex has not been considered in this section as a large proportion of the non system capex relates to purchases of plant, equipment and services from external parties e.g. ICT, fleet, property, tools and equipment, which will not translate into proportional increases in the need for FTEs within the business.

256 Alternate providers are utilised by Ergon Energy to provide contestable services for the construction of Urban Residential Developments (URD).

7.1 Expenditure across major asset categories

After removing real labour and material escalation over the outlook period, and while still accounting for general workload escalation as a result of the increasing asset base, the material (step) increases in opex are proposed in the areas of:

- preventive and corrective maintenance - vegetation management (scoping and cutting) and corridors & sites (inspections and remediation)
- preventive maintenance – pole top inspections (aerial and mast mounted cameras)
- preventive maintenance – full overhead service inspections
- preventive maintenance – meters, including a smart meter pilot program
- ‘other’ opex - demand management

The growth characteristics across the aggregated regulatory categories are shown in Figure 7.2, showing opex requirements tapering off towards the end of the next regulatory period.

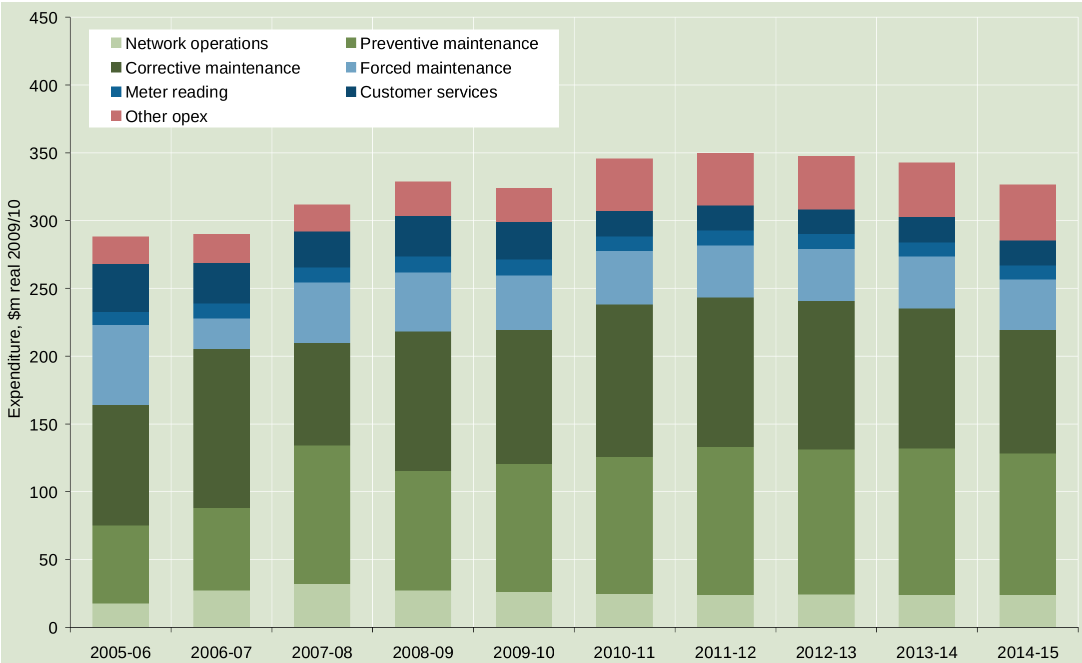

Figure 7.2 Historical and forecast system opex - real escalation removed from forecasts

Source:PB analysis

Figure 7.3 shows Ergon Energy’s proposed increases within it capex program (prior to the removal of real labour and material escalation). Increases are occurring across all asset classes, but in particular in the areas of (in order of materiality):

- overhead distribution lines
- distribution transformers
- underground distribution cables
- overhead sub-transmission lines
- substation bays

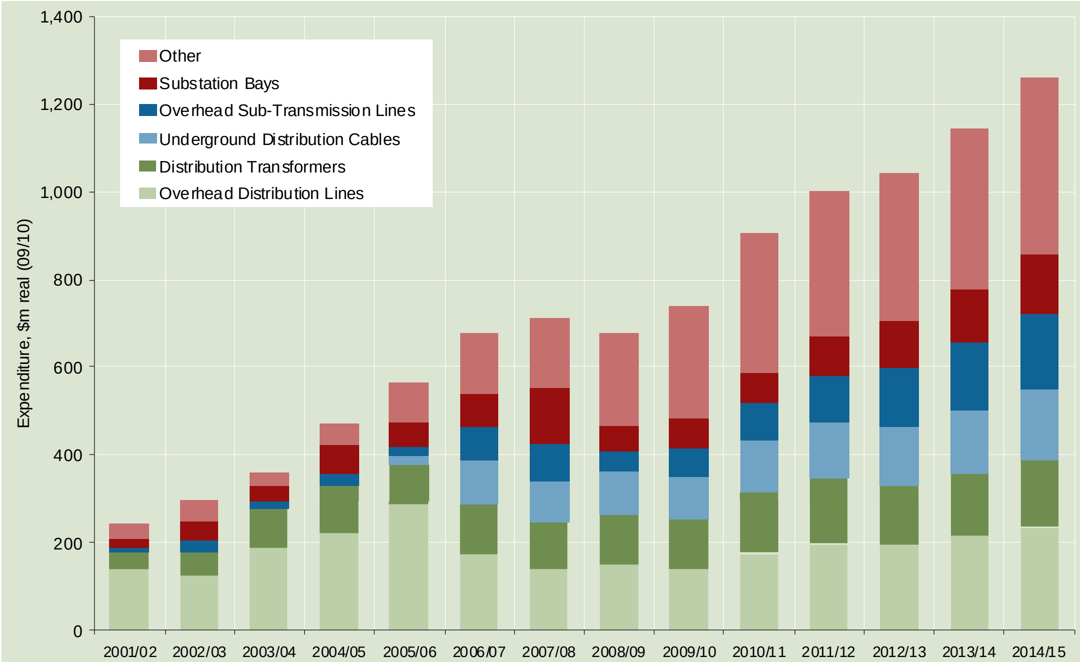

Figure 7.3 Ergon Energy capex over the 2005-2015 period – real escalation is included.

Source: PB analysis

7.2 Resourcing strategies

The approach to Ergon Energy's resourcing strategy over the next regulatory control period has been a determination of forecast FTE requirements informed through the number of historical FTE's and actual costs in the base year 2007/08. Subsequently application of annual pro-rata changes based on the forecast expenditures have produced FTE forecasts for the next regulatory period.

Some allowance has been made to account for the increased use of third-party providers to deliver Customer Initiated Capital Works (CICW), and implicit in the modelling is an assumption that the existing internal business resources will provide an average productivity improvement of 3%. (i.e. the pro rata number of FTE's required in any one year as been decreased by 3% in the forecast). The internal capability in July 2007 was approximately 1,962 FTE's. The external capability in July 2007 was approximately 839 FTE's.

Ergon Energy also undertakes a routine (business–as-usual) strategic workforce planning process, which takes account of the profile of the existing workforce, recruitment and attrition rates, turnover rates and causes, long term supply and demand forecasts, critical job groups and a gap analysis leading to specific workforce related recommendations and actions[257]. This report covers the period 2008–2018 and highlights that there is a considerably diminishing supply of staff (through separations and possible retirees) creating a significant gap in resource requirements at an organisational level. A number of short term and longer-term strategies and actions have been put in place to manage this gap of internal resources.

Underpinning the internal resource strategy is a substantial program to develop new staff and reduce dependence on the external labour market through growth of the workforce –

257 AR268c_EE_Strategic Workforce Plan 2008-18_May08.pdf

including around 430 positions for apprenticeships, technical traineeships and graduate engineers.

Ergon Energy's ability to recruit the necessary additional resources is strengthened in light of the recent global financial crisis and the subsequent increased availability of resources in comparison with the current regulatory control period.

In regards to the external contract labour market, Ergon Energy does not depend on general market information it relies upon a strategy of building long term relationships in the context of contractor panels.

Ergon Energy is proposing to extend its alternative provider model for Urban Residential Developments (URD) to include commercial, industrial and large customers in order to introduce contestability into this significant component of the large customer initiated capital works program.

Ergon Energy also has well established period contracts with key suppliers to ensure reliable and cost-effective access to contract labour including:

- vegetation management
- meter reading, and
- overhead construction and maintenance.

7.3 Materials procurement

Ergon Energy has well established procurement processes to ensure it will be able to obtain the materials (including those with long lead times) required to underpin deliverability of the PoW. An add-on module to Ellipse called Optimiser, is being used to analyse historical order quantities (last 3 years), current inventory levels, safety stock levels, and average delivery times so that reordering of over 85 percent of all stock items can be done automatically.

Ergon Energy has well established period contracts with key suppliers to help ensure reliable and cost-effective access to materials including:

- insulators
- cables and conductor
- surge arrestors
- outdoor circuit breakers and air break switches
- distribution transformers
- protection relays
- pole nails
- capacitor banks

7.4 Summary of assessment and findings

In the context that all of Ergon Energy's preventive and corrective vegetation management will be outsourced, as well as the vast majority of its preventive and corrective line based maintenance (capturing inspections), PB considers that deliverability of the opex step changes from a cost category perspective is reasonably achievable subject to the availability of the competitively sourced external resources. This principle is supported in that the work volumes are significant, ongoing, readily amenable and historically suited to outsourcing. PB considers there is likely to be sufficient interest from existing and new third-party service providers to realise the specific opex requirements.

As illustrated in Figure 7.3, the nature of the increases in capex across asset classes in the next regulatory period is relatively gradual and there are no significant step changes across any one year or in any one category. If the impacts of real labour and materials escalation are removed, the gradual increase in work volumes would be even less pronounced. Historical increases in capex in key asset classes from 2005/06 to 2006/07 demonstrates that Ergon Energy has successfully ramped up capex delivery capability at a rate similar to that required in the next regulatory control period. However more recently Ergon Energy has advised in the June 2009 capex report that it delivered only 79% of its annual budget[258], although PB notes that the capex delivered was $818m compared with its regulatory estimate for 2008/09 of $732m.

Volume 3 of Ergon Energy's Asset Management Plan – which specifically targets the role of the Service Provider and how the business will deliver its approved program of works is incomplete[259], and scheduled to be completed in 2010. Effectively, Ergon Energy has undertaken only a high-level and cursory review of its capability to deliver the forecast program of works based on a simplistic FTE assessment informed through expenditure/FTE ratios. Two of the three internal business documents provided by Ergon Energy were in draft[260] form and had not been finalised to support Ergon Energy's delivery capability for the proposed PoW.

Ergon Energy is relying on its demonstrated ability to deliver the 2006/07 PoW to support deliverability in future years. In PB's view, the general approach adopted by Ergon Energy to support its capability to deliver the next regulatory period PoW represents some degree of risk in that the business' capability to source its future labour needs has been quantified in a simple manner and not rigorously tested. Specifically, it has been identified that even after allowing for a 3% productivity improvement from the existing workforce, the demand will materially increase whilst supply will also materially decrease. Of particular note is the business' significant increase in asset replacement capex, which tends to include a high degree of brown field type work that tends to lead to more complicated and demanding projects less suited to outsourcing.

PB considers the material procurement practices historically employed by Ergon Energy provide some confidence that it will be able to deliver the necessary plant, equipment and materials to deliver its PoW, however long lead time zone substation transformers and poles for feeder developments are key components that are missing from the existing contracts outlined.

258 Email, EE Response to AER-PB Q.VP.63 - Actual 2008-09 Capex, 03 August 2009
259 Ergon Energy Revenue Submission, p.134
260 Ergon Energy, Draft, PL730c_EE_Energy Services Workforce Capability Plan_2007-09.pdf; Ergon Energy, March 09, PL733c_EE-People Strategy Framework_Mar09.pdf – marked as draft in the footer; Ergon Energy, AR268c_EE_Strategic Workforce Plan 208-18.pdf – final version provided

Whilst PB considers there are some risks associated with the approach Ergon Energy has undertaken to verify its PoW deliverability (in particular the growing gap between its internal labour resources and the demand that will be placed on it), PB also considers that on the balance of evidence these risks are not likely to prevent the business from delivering its PoW in the timeframes suggested on the basis that:

- the business has a number of strategies in place to engage and retain its internal ageing workforce, and attract new employees
- the business has demonstrated it can ramp up its PoW as shown in 2006/07
- the business delivered a capex program of $818m in 2008/09
- the proposed capex includes a significant component associated with 37 new urban zone substations that are well suited to outsourcing
- Ergon Energy has well established technical standards for undertaking the design and construction of works, as well as to maintain its assets;
- PB's forecast capex recommendation to the AER constitutes a 18.7% reduction from that proposed
- PB's forecast opex recommendation to the AER constitutes a 10% reduction from that proposed
- the business has long standing relationships with third party contractors to supply both labour and materials
- there is likely to be a reasonable level of competition from external contractors for a significant portion of the increases in the PoW (i.e. vegetation management, inspections)
- the business undertakes a reasonable amount of non-regulated work and these resources can be used to balance regulated work needs.

PB considers that Ergon Energy should escalate the application of its short term and longer-term strategies and actions arising from its strategic workforce planning, in order to ensure it can increase its internal labour workforce and deliver the necessary 3% productivity improvements required over the next regulatory period.

7.5 PB Recommendations

Ergon Energy should have the resource capability and material procurement processes in place to be able to deliver its proposed operating and capital programs of work during the next regulatory control period.

8. Service standards

Ergon Energy proposes to maintain and improve its level of reliability of supply service performance to meet the MSS limits set out in the Queensland *Electricity Industry Code*. In section 4.4, PB has assessed that the proposed expenditure to achieve these levels of performance is not prudent and efficient and has recommended reductions. 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 the time when Ergon Energy was required to submit its Regulatory Proposal. In this section, we review Ergon Energy's proposed values for the established parameters, including the recommendation of appropriate targets.

8.1 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 Ergon Energy's Regulatory Proposal, are as follows:

- the parameters to be included in the scheme are unplanned SAIDI and unplanned SAIFI (for urban, short-rural, and long-rural feeder categories), and telephone answering
- parameter definitions are in accordance with the STPIS[261]
- the overall cap on revenue at risk is 2% and the cap on the customer service parameter (telephone answering) is 0.5%
- incentive rates are in accordance with the STPIS
- the events excluded from the reliability data are in accordance with the STPIS requirements[262] [263].

Ergon Energy also proposes targets for reliability parameters to be consistent with the Framework and Approach Paper. This is discussed in section 8.2.2.

261 In calculating the reliability parameters SAIDI and SAIFI, Ergon Energy has used the monthly average of connected customers rather than the simple average for the year as specified in the STPIS. This approach is also adopted in reporting to QCA. PB has examined the two methods and finds no material difference in the SAIDI or SAIFI calculated by each method.

262 Ergon Energy 2009, Regulatory proposal to the Australian Energy Regulator: distribution services for period 1 July 2010 to 30 June 2015.

263 AER 2009, Final framework and approach paper application of schemes Energex and Ergon Energy 2010–15, section 2.6.2

8.2 PB assessment and findings on reliability of supply parameter

PB makes the following observations and findings regarding the reliability of supply parameter.

8.2.1 Suitability of data

The reliability data has been audited. PB sighted the annual audit reports for 2004–05 to 2007–08. The current report states that network performance data is of a very high quality and consistency, and that the systems and processes used by Ergon Energy in maintaining and reporting the data are robust and sufficient to achieve the ± 5% accuracy required[264].

The historical data includes planned interruptions, which are not included in the STPIS definition. Ergon Energy has identified these interruptions from the code associated with the outage. PB confirms that they have been correctly excluded from the historical data. ENERGEX also use this outage code to 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 reliability data when calculating reliability performance under the scheme.

Ergon Energy states in section 44.4.12 of its regulatory proposal that it has excluded from the historical data all network outages related to generation faults. PB notes that this is not in accordance with clause 3.3 of the STPIS, which only allows exclusion of load-shedding events due to a generation shortfall. Ergon Energy advised that such events occur infrequently and are unlikely to have a material impact on the network average performance as measured by SAIFI and SAIDI. PB concurs and is of the view that the omission of such data will not have a material effect on the suitability of historical data.

PB concludes that no issues are evident that might affect the use of the reliability data in the STPIS scheme.

8.2.2 Targets

In the Framework and Approach paper, the AER indicated that targets for reliability should be set at the lower of the minimum service standards (MSS) targets set by QCA[265] and the average of historical performance in the current regulatory period. Ergon Energy has proposed targets for the reliability parameters at the same values as the MSS.

The MSS are set for SAIDI and SAIFI using definitions that are consistent with the STPIS and are net of the impact of excluded events that are determined on the same basis as the STPIS[266]. The MSS targets include both planned and unplanned interruptions. As the STPIS is for unplanned interruptions only, Ergon Energy has modified the MSS targets to remove the impact of planned interruptions and to include the impact of service fuse and beyond outages.

PB notes that the MSS are minimum levels of service performance, whereas the targets under the STPIS are set at an average of performance (adjusted as necessary for any likely

264 Parsons Brinckerhoff 2009, Review of network reliability performance accuracy against the Department of Minerals and Energy's minimum service standards – audit report for 2007–08, p. 4

265 QCA 2009, Final decision: review of electricity distribution network minimum service standards and guaranteed service levels to apply in Queensland from 1 July 2010.

266 Electricity Industry Code 2008 (Qld), pp. 121 & 126.

reliability improvement from capex or opex forecast). By setting its internal business targets at 10% better than the MSS targets, Ergon Energy is ensuring service performance of at least the minimum standard.

Ergon Energy provided figures showing the network reliability performance against the MSS targets from 2003–04 to 2007–08 (*Network performance strategy 2010 to 2015*, Figure1). These figures indicate that network performance is significantly better than the MSS targets in 2006-07 and 2007-08.

Ergon Energy verbally stated[267] that no specific expenditure has been proposed in the next regulatory control period to improve reliability to meet the MSS targets required by the Electricity Industry Code, and that any reliability improvements would arise from changes to planning standards and improved maintenance practices that were implemented following the issue of the EDSD review recommendations[268]. PB notes that approximately $120m of capex is proposed in the reliability category for improvements that could be expected to improve some aspects of reliability performance, as measured by the indicators SAIDI and SAIFI, in the next regulatory control period, although PB has recommended a reduction in this expenditure to reflect business-as-usual levels of expenditure (see section 4.4), PB also notes that the forecast expenditures proposed in the Regulatory Proposal reflect the new planning standards and maintenance practices. PB concludes that the reliability performance improvements proposed for the next regulatory control period will result from the expenditures forecast for the next regulatory control period.

PB concludes that setting the on-average targets for the reliability parameters SAIDI and SAIFI at the minimum MSS levels is inappropriate. This is because the MSS targets do not reflect Ergon Energy's likely average service performance resulting from the proposed forecast expenditures. For the reasons set out below, PB recommends that the reliability targets be set at Ergon Energy's internal business targets rather than at the MSS targets as proposed by Ergon Energy in its Regulatory Proposal:

- The internal targets are set at an average performance rather than as a minimum performance.
- The internal targets reflect the likely service performance consistent with the proposed forecast expenditures and will ensure that Ergon Energy 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.

8.3 PB assessment and findings on customer service parameter

PB makes the following observations and findings regarding the customer service parameter.

8.3.1 Suitability of data

Data is available for the past five-year period. This includes the time when the network and retail activities within Ergon Energy were separated. This change did not impact on the call centre facility relating to the network function.

267 Meeting held on Tuesday 14 July 2009.

268 Office of Energy, Department of Natural Resources, Mines and Energy July 2004, *Electricity distribution and service delivery for the 21st century*.

Data has not been subject to audit; however, Ergon Energy states that the data is taken directly from the telephone answering system for the fault call number. PB did not audit the telephone system data, but sighted data reports from the telephone answering system that were consistent with the data contained in the Regulatory Proposal.

PB concludes that no issues are evident that might affect the use of the telephone answering data in the STPIS scheme.

8.3.2 Targets

Ergon Energy proposes to set targets based on the average of the previous five years of data. PB confirms the calculation of the average performance is 76.8% of calls answered in 30 seconds.

The historical data presented in the Regulatory Proposal, however, does not contain exclusions as allowed under clause 5.4(a) of the STPIS, which refers to events described in clauses 3.3(a) and 3.3(b) of the STPIS[269]. Ergon Energy states that its phone management system and records are currently unable to exclude telephone calls associated with events arising from load shedding, the failure of transmission assets, or imposed obligations as described in clause 3.3(a) of the scheme, but believes that the inclusion/exclusion of these events would be immaterial. This is because these events historically only impact parts of Ergon Energy's network and generally not for a complete day and therefore are not likely to have a material impact on the telephone answering performance when measured over a year. PB agrees with this assessment.

Ergon Energy is able to exclude telephone calls associated with a major event day as described in clause 3.3(b) of the scheme. Ergon Energy provided information that indicates the average impact of excluding events under STPIS clause 3.3(b) is a 0.5% improvement giving an average performance of 77.3% of calls answered in 30 seconds[270].

Based on this information, PB recommends that the target for the telephone answering parameter should be set at 77.3% for each year of the next regulatory period.

8.3.3 Revenue at risk

In its Regulatory Proposal, Ergon Energy accepted that the maximum revenue increment or decrement allowed by the STPIS for the telephone answering parameter of 0.5% would apply. PB notes, however, that the overall revenue at risk has been reduced as a transitional arrangement to 2% rather than the normal 5%.

PB considers the requirements of the NER would be met by maintaining the value of the telephone answering parameter in the scheme at about 10% of the total incentive (i.e. 0.5% divided by 5%). For an overall cap of 2%, this equates to a cap on the telephone answering parameter of 0.2%. Hence PB recommends that the maximum revenue increment or decrement for the telephone answering parameter be set at 0.2%.

269 Clause 3.3(a) refers to events arising from load shedding, the failure of transmission assets, or imposed obligations. Clause 3.3(b) refers to the exclusion of a major event day.

270 Ergon Energy 2009, Regulatory proposal to the Australian Energy Regulator: distribution services for period 1 July 2010 to 30 June 2015, Table 118

8.4 Summary of findings and recommendations

This section summarises PB's findings and recommendations in relation to service standards.

PB's findings in relation to Ergon Energy's reliability of supply parameter are as follows:

- The quality of Ergon Energy's historical data is suitable for target setting.
- The targets for SAIDI and SAIFI should be set at Ergon Energy's internal business targets, rather than at the MSS targets as proposed by Ergon Energy, to reflect the likely future average service performance after taking account of the proposed capex and opex likely to impact on future service levels.

PB's findings in relation to Ergon Energy's customer service parameter are as follows:

- The quality of Ergon Energy's historical data is suitable for target setting.
- The target for the telephone answering parameter should be set at 77.3% for each year of the next regulatory period, to reflect historical performance less an allowance for the exclusion of telephone calls associated with major event days as described in clause 3.3(b) of the scheme.
- The maximum revenue increment or decrement for the telephone answering parameter be set at 0.2% rather than at 0.05% as proposed by Ergon Energy.

In summary, we recommend that the values for the performance parameters shown in Table 8.1 be included in Ergon Energy's STPIS.

Table 8.1 Recommended performance incentive scheme

Parameter	Unit	Rate %	Targets				
			2010-11	2011-12	2012-13	2013-14	2014-15
SAIDI							
Urban	minute	0.023	129	128	127	127	126
Short rural	minute	0.020	296	291	287	283	279
Long rural	minute	0.004	699	687	675	664	652
SAIFI							
Urban	per interruption	1.764#	1.69	1.68	1.66	1.64	1.63
Short rural	per interruption	2.060#	3.06	3.02	2.98	2.94	2.91
Long rural	per interruption	0.601#	5.59	5.52	5.44	5.37	5.29
Customer service							
Telephone answering	percentage	-0.040	77.3	77.3	77.3	77.3	77.3

Source: PB Analysis

Note: # per 0.01 interruptions

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

9. Generic limitations of this report

9.1 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.

9.2 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.

9.3 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's 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.0 Exclusions

For the avoidance of doubt, under the revised PB proposal – and as agreed with the AER – PB will not be undertaking the following items which were originally anticipated in the original PB proposal (March 2009):

- pre-lodgement meetings with the businesses
- unit cost benchmarking
- comparative business benchmarking (including historical versus forecast)
- review of external factors and obligations
- cost pass-through items
- the review of submissions from interested parties

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 distribution 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 reviews for ETSA Utilities, Ergon Energy and Energex were undertaken 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' forecast capital expenditure (capex), operating and maintenance 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[1]. 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.

1 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.

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;
- substitution possibilities between opex and capex; and
- the provision for efficient non-network alternatives such as demand management.

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 opex and 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 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 meet with the AER prior to receipt of the proposals to discuss in more detail the approach to the review and the AER's expectations.

A.2.2 High-level review of historic opex and capex

The AER will review actual and forecast capital and operating expenditures that have occurred or are forecast to occur over the current regulatory period compared with the expenditure levels forecast at the time of the last determination. It will also examine material variances between forecasts and actuals and the drivers for the differences. This information will assist 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. Historic capex and opex will be assessed separately for each DNSP.

The consultant is required to use the findings from the review of forecast and actual expenditures in the current regulatory period in its assessment of forecast capex and opex.

The AER will share with its consultant its high level historic opex and capex review and any other relevant comparative analysis it undertakes. The AER will aim to provide this information to its consultant in a timely manner so that it can be used in the development of the consultant's advice.

A.2.3 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 primary engineering consultant to verify the effect of any revised maximum demand forecasts that are developed as a consequence of the recommendations of the demand consultant.

The AER anticipates that the DNSPs will propose real cost escalators for 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. In addition, 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 review the application of the escalators and advise whether they are appropriate. The consultant will also need to review the process by which the DNSP's escalators have been applied and whether the process, including the weightings used, is appropriate.

A.2.4 Review of policies and procedures

The DNSPs have been asked to provide the key 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 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; substantiate why they are reasonable and appropriate with reference to clauses 6.5.6 and 6.5.7 of the NER; and provide an estimate of the impact on the proposed allowances.

A.2.5 Review of forecast capex and opex

The consultant is to test the magnitude of the capex and opex forecasts submitted by the DNSPs by examining the application of the submitted policies and procedures (see section 2.4 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 their regulatory proposals. This information is to include a listing of all major projects and programs above a specified threshold.[2]

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 to be conducted by the AER 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 and procedures have been applied appropriately.

Should the consultant identify relevant policies and procedures 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 and procedures 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 its 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.

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.

[2] The 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.

A.2.6 Service standards

The 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 recommending 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 may have on its performance.

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 the 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.

A.4 Pre-determination conferences

The consultant shall attend the pre-determination conferences to be held by the AER during the review process. The conferences are to be held in Brisbane on 8 December 2009 (Energex and Ergon Energy) and in Adelaide on 9 December (ETSA Utilities). The purpose of these conferences is to provide the AER with the opportunity to explain its draft distribution determinations. The consultant is not required to attend the public forums to be held in August 2009 in Brisbane and Adelaide.

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 (that is, 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 1 July 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 in June 2009 and other pre-lodgement work where possible;
- meetings with the DNSPs following the submission of their regulatory proposals;
- provision of preliminary reports and presentations to AER staff on key issues identified from the consultant's high level review by late July 2009;
- provision of draft written reports on its findings by close of business 15 September 2009 (one report for the Queensland DNSPs and one for ETSA Utilities);
- presentation to the AER Board of the findings of draft reports (proposed to be 25 September 2009);
- provision of final written reports on its findings by close of business 9 October 2009 (one report for the Queensland DNSPs and one for ETSA Utilities); and
- attendance at the AER's predetermination conferences on 8 and 9 December 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 also be available for follow-up questions from the AER.

A.6 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.

A.7 Timeline – South Australian and Queensland determinations

Event	Rule	Date
Regulatory proposals submitted	**6.8.2(b)**	**1 July 2009**
Preliminary examination of proposals completed		10 July 2009
PB 1st meeting with Energex and Ergon		13-15 July 2009
Publish proposals and call for submissions		17 July 2009
PB preliminary report (Energex and Ergon)		17 July 2009
PB 1st meeting with ETSA		20-22 July 2009
PB preliminary report (ETSA)		24 July 2009
PB 2nd meeting with Energex and Ergon	Wk begin	3 August 2009
Public forum on regulatory proposals (Brisbane)		**3 August 2009**
Public forum on regulatory proposals (Adelaide)		**6 August 2009**
PB 2nd meeting with ETSA	Wk begin	10 August 2009
Submissions on regulatory proposals close*	**6.9.3(c)**	**28 August 2009**
PB's draft report due		15 September 2009
PB's draft report to DNSPs for review		22 September 2009
PB presentation to board		25 September 2009
PB's final report due		9 October 2009
Publish draft determination	**6.10.2**	**27 November 2009**
Pre-determination conference – Bris/Adelaide	**6.10.2(b)**	**8/9 December 2009**
DNSPs to lodge revised proposals	6.10.3(a)	14 January 2010
Submissions on draft determinations close*	**6.10.2(c)**	**16 February 2010**
Publish final determination	**6.11.2**	**30 April 2010**

* Proposed cut off dates for information provision by the DNSPs.

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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.